Enhanced Oil Recovery

National Petroleum Council

Enhanced Oil Recovery

EOR

An Analysis of the Potential for Enhanced Oil Recovery from Known Fields in the United States--1976 to 2000

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National Petroleum Council
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NATIONAL PETROLEUM COUNCIL

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Introduction

The October 1973 Arab oil embargo was not the first warning of impending energy shortages—nor was it the first embargo. Even without the embargo, farsighted individuals had previously called attention to the inevitability of an "energy crunch." The October 1973 embargo did, however, bring the problem "front and center."

Since then, the Administration, Congress, labor, industry, and consumers have increasingly realized that new sources of energy, new attitudes and discipline must be developed and adopted. Clearly, a comprehensive energy program is complex—a unified and complete national program must encompass the consideration of all options. The potential of each needs to be explored.

One such option is to produce more oil—*to enhance the recovery*—from domestic oil fields. When considered by itself, enhanced oil recovery (EOR) is but one of the "building blocks" in an overall national energy structure. Increased production from existing fields may well be a good source of future domestic energy supply.

In recognition of the potential of enhanced recovery, on March 18, 1975, Assistant Secretary of the Interior, Jack W. Carlson stated in a letter to National Petroleum Council Chairman, John E. Swearingen (see Appendix A for the complete text of the request letter):

> While we pursue unknown and unevaluated conventional and unconventional energy sources, we must continue to improve our ability to recover larger proportions of known oil and gas deposits on land and on the Outer Continental Shelf.

He, therefore, requested the National Petroleum Council to:

> . . . assess the state of the art of enhanced recovery for oil and gas from known oil and gas reserves . . . (appraise) the probable ranges of volumetric outcomes based on alternative economic conditions . . . (and recommend) how public policy can improve the outlook.

The Council agreed to undertake the study and, with approval of the Department of the Interior, established a Committee on Enhanced Recovery Techniques for Oil and Gas in the United States. A Coordinating Subcommittee and two Task Groups assisted the Committee in preparing the report (see Appendix B for rosters). In selecting the membership of the Committee and the working groups, an attempt was made to appoint individuals who represented the various divergent views on enhanced recovery. Some individuals and organizations are optimistic about the future of enhanced recovery in the United States, while others are pessimistic. Although individual members of the National Petroleum Council may disagree with specific parts, this study represents a consensus of the Council's views.

The Council agreed to examine known enhanced recovery methods and the recovery potential from known oil fields in the United States from the present to the year 2000. This report does not consider the impact on future supply of oil fields discovered after December 31, 1975, nor does it consider the possible application of EOR processes to those fields.

The Council did not estimate potential enhanced recovery from producing gas fields, since the opportunity for improving total gas recovery through nonconventional or enhanced recovery processes in these fields is limited. The major potential for non-conventional gas recovery is from low-permeability, presently uneconomic reservoirs. The magnitude of this potential is unknown, but may represent a substantial contribution to the Nation's future energy supply. However, very little information is available speci-

fying reservoir volume, location, reservoir geologic characteristics, or other data required to analyze potential recovery and producing rates. Therefore, estimates of possible enhanced gas recovery were not made.

This report presents estimates of what could happen under certain technical and economic circumstances and is not intended to represent a forecast of what will occur. Other recent studies on enhanced recovery were used as references when appropriate and their results are compared with the results of this study in Chapter Three.

The possible environmental impacts of enhanced oil recovery operations have been considered by the Council. Chapter Four includes a general discussion on environmental protection, and specific details on the possible effects of each process are contained in the appendices.

This report does not address the broader issues of energy policy such as energy conservation, import dependency, alternate energy forms, etc. It focuses on only one of the several possibilities to increase the supply of domestically produced petroleum. The Council feels that, despite its technical uncertainties and expected high costs, the pursuit of enhanced recovery is in the Nation's best interest. However, the degree to which enhanced recovery should be pursued as an instrument of U.S. energy policy must be addressed in the broader context of an overall policy.*

*The Council is currently conducting a study on Future Energy Prospects, which will address these broader issues. This report is expected to be completed in the Spring of 1977.

Summary

Background

The term "enhanced oil recovery" refers, in the broadest sense, to any method used to recover more oil from a petroleum reservoir than would be obtained by primary recovery. In primary recovery, naturally occurring forces, such as those associated with gas and liquid expansion or influx of water from aquifers, are utilized to produce the oil. Conventional secondary recovery methods, such as waterfloods, are considered to be "enhanced recovery" methods under this broader definition. Waterflooding of reservoirs, in which water is injected to supplement original reservoir forces and drive more oil to producing wells, currently accounts for about half of U.S. oil production. For this study, however, "enhanced oil recovery," or "EOR," is considered in a more narrow sense, and it is defined as: the additional recovery of oil from a petroleum reservoir over that which can be economically recovered by conventional primary and secondary methods.

The petroleum industry has conducted extensive research on enhanced oil recovery since the 1930's. As a result, several potential processes have been developed and field tested. Some of these processes are designed to recover the oil left in a reservoir after waterflooding or following other conventional secondary recovery processes. These EOR processes—usually the third type of recovery method employed in the reservoir—have been called "tertiary" recovery methods. Because some of the enhanced recovery processes may be used as an alternative to waterflooding or other conventional secondary recovery processes, the term "enhanced oil recovery" as used in this report is considered to have a broader meaning than "tertiary" oil recovery.

The potential of enhanced oil recovery is of significant interest because of the number of U.S. fields to which it might be applied. While recovery in individual reservoirs is highly variable, the average recovery from conventional primary and secondary recovery methods in all U.S. reservoirs is expected to be only about one-third of the original oil in place, leaving nearly 300 billion barrels in currently known reservoirs. A portion of this remaining oil will constitute a target for enhanced oil recovery. The rest exists in unfavorable geologic or geographic regions or is so diffusely spread out in the reservoir rock that it very likely will not be recoverable by any process.

Three general classifications of EOR have shown significant promise and are considered in this study. These classifications are: (1) chemical flooding; (2) carbon dioxide miscible flooding; and (3) thermal methods. Of these, only one of the thermal methods (steamflooding) has been proven by several large-scale commercial applications. The other processes are receiving limited field testing at this time, but most of them have not been put into large-scale, commercial use because of their high cost. For projecting the potential for enhanced recovery, this study assumes that EOR technology will continue to improve. It does not, however, consider the effects of future major technological breakthroughs.

Analysis Procedures

This study is based primarily on a review of the applicability of EOR processes to a data base of 245 known reservoirs in California, Texas, and Louisiana. From this data base, extrapolations were made for all reservoirs in the three states and for the United States as a whole. Potential producing rates during the 1976-2000 time frame and incremental ultimate recovery achievable from EOR processes started during the period 1976-2000 were calculated for 30 sets of economic assumptions. The potential producing rate and incremental ultimate recovery results

shown in this study are only for application of EOR processes to reservoirs discovered as of December 31, 1975. Discoveries after that date are not considered in this report.

Before this economic review was begun, the technical feasibility of process application to the data base reservoirs was established. A screening procedure, based on process characteristics, reservoir geologic conditions, and fluid properties, was used to make this determination. When a reservoir passed the screening procedures for more than one process, dominance criteria were applied to select the process which would be expected to be most suitable, considering chances of success, potential recovery and economics.

Calculations were made of incremental ultimate recovery and potential producing rate. The calculations used simplified equations and were based upon the limited information contained in the original data base for the 245 reservoirs.

The next step was to determine the detailed costs associated with implementing each enhanced oil recovery process. These included process-independent cost data, such as costs of drilling and completing wells, and process-dependent costs, or those costs peculiar to each EOR process evaluated. Costs associated with environmental protection have been included in the detailed cost analyses of each process.

Finally, the economics of each project (the application of the assigned process to its respective reservoir) were evaluated for five possible oil prices, three minimum rate of return cases, and two tax cases. The economic criteria were chosen arbitrarily to represent a range of conditions for calculation purposes only. Constant 1976 dollars were used in all analyses. The term "constant 1976 dollars" refers to the purchasing power of the U.S. dollar in 1976 without consideration of possible future fluctuations in currency value. This was used to provide a measure of comparability to projections of costs, revenues, rates of return and capital requirements, which might otherwise have been distorted by varying estimates of the unpredictable factors of inflation or deflation.

For the five oil price cases ($5, $10, $15, $20, and $25 per barrel) prices were assumed to be effective immediately and to remain constant throughout the 1976-2000 period. For example, results shown for a $20 per barrel oil price in 1990 do not mean that oil will reach a price of $20 per barrel in that year; they illustrate the potential producing rates and incremental ultimate recovery that could be achieved by EOR if oil were to be valued at $20 per barrel from 1976 on.

Three minimum discounted cash flow rates of return (DCFROR) were assumed as criteria for evaluating each reservoir. These rates (10, 15, and 20 percent) were used in the analysis only as minimum requirements and not as expectations for average results. These rates of return, as were the oil prices, were on an inflation-free basis. They correspond approximately to nominal rates of return minus the rate of inflation.

Calculations were also made for two tax cases, which represent two possible interpretations of current (July 1976) tax law. These analyses were deemed necessary because most of the EOR processes are virtually untried in commercial application, and it is not known how current tax law would be interpreted as it would apply to these projects. In essence, the "moderate" case assumed expensing of certain costs while the "restrictive" case assumed the items would be amortized over a number of years.

The incremental ultimate recovery for the United States for each economic condition was calculated by adding the projected ultimate recoveries from data base reservoirs and then extrapolating to the United States as a whole. Potential producing rates in the period 1976 through 2000 were obtained in a similar manner, with some added assumptions on rates of development.

The estimates of incremental ultimate recovery from EOR are subject to major uncertainty because of unknown reservoir characteristics and the experimental status of several of the EOR methods considered. The estimates of potential producing rate include these uncertainties, together with those implicit in the additional assumptions on rates of development. To gain perspective on the uncertainty in the results for each process, sensitivity studies were made on several critical process variables. The possible ranges of incremental ultimate recovery and potential producing rate—as a function of some of the major uncertainties—are important segments of this report. To re-emphasize, results in this study are estimates of what *could* happen and are not forecasts of what *will* occur.

Results

There are two types of results from this study. The first is a series of estimates of incremental ultimate recovery and potential producing rates that could be expected from EOR under the various economic conditions considered. These results were calculated from "base cases" for each process. *The term "base case" refers solely to best estimates of process performance and associated process costs, and implies no judgments regarding future oil prices, tax cases, or*

rate of return requirements. Estimates of process performance in the base case represent roughly the mean of expected results. The base case represents neither a minimum assured result nor, conversely, an upper bound on the potential of enhanced oil recovery processes.

The second type of results from the study is the analysis of the uncertainty in the base case estimates, and is of equal importance in describing the potential of EOR processes. At any specified economic condition, uncertainties in process performance, process cost, and reservoir characterization may affect both the total number of reservoirs to which EOR processes may be applied economically and the estimates of incremental ultimate recovery from EOR. Potential producing rate estimates involve all these elements, plus additional uncertainty in the rates of development and application of EOR processes.

The aggregate results for all U.S. fields for incremental ultimate recovery and potential producing rates are shown in Figures 1 and 2, respectively. A minimum 10 percent DCFROR requirement and the moderate tax case have been used in these figures. Since the major thrust of this study is to examine the technical outlook for enhanced oil recovery in the United States, these figures are plotted using those of the economic criteria studied which would display the greatest EOR potential. This decision is not to imply that the NPC recommends any of the price levels shown; further, the Council does not intend to imply which one, if any, of the DCFROR requirements would be acceptable or sufficient for any individual operator or for the industry as a whole.* Results under different economic conditions are shown in Chapter Three, together with more detail on the contribution of individual processes to the cumulative results for all EOR processes.

Incremental ultimate recovery from EOR processes increases with oil price, from less than 3 billion barrels at $5 per barrel to about 24 billion barrels at $25 per barrel, in constant 1976 dollars. At $5 per barrel, all EOR production is from thermal methods. At $10 per barrel, the contribution of carbon dioxide miscible flooding is about equal to that of the thermal methods. Chemical flooding has a low potential at $10 per barrel, but increases substan-

*The relationship between risk and rate of return is discussed in greater detail in Chapter Three. See especially Figure 48 for the sensitivity of incremental ultimate recovery to minimum rate of return requirements.

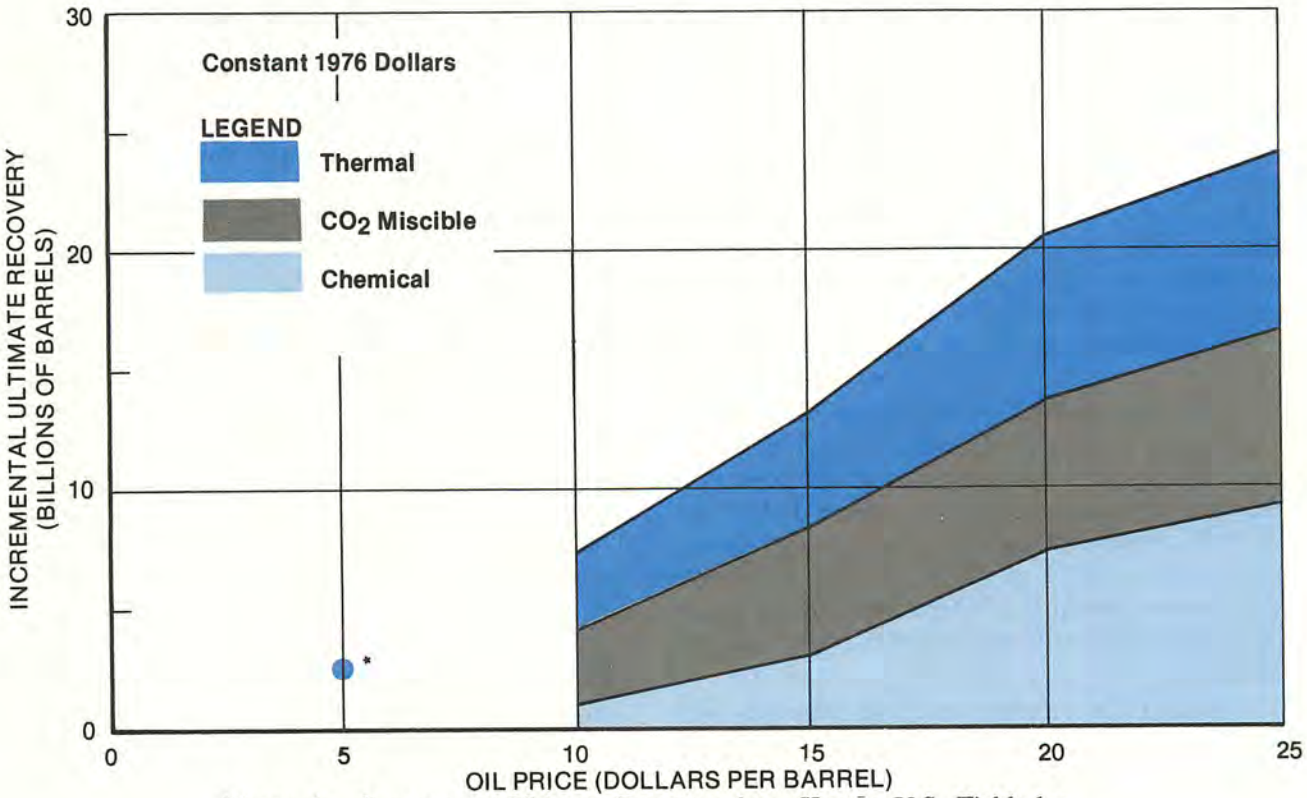


Figure 1. Incremental Ultimate Recovery from Known U.S. Fields by Enhanced Recovery Process.

*Recovery for Thermal at $5. Recovery for Chemical and CO_2 miscible flooding are zero at $5 per barrel and as shown at $10 per barrel. Recovery for intermediate prices between $5 and $10 per barrel has not been determined.

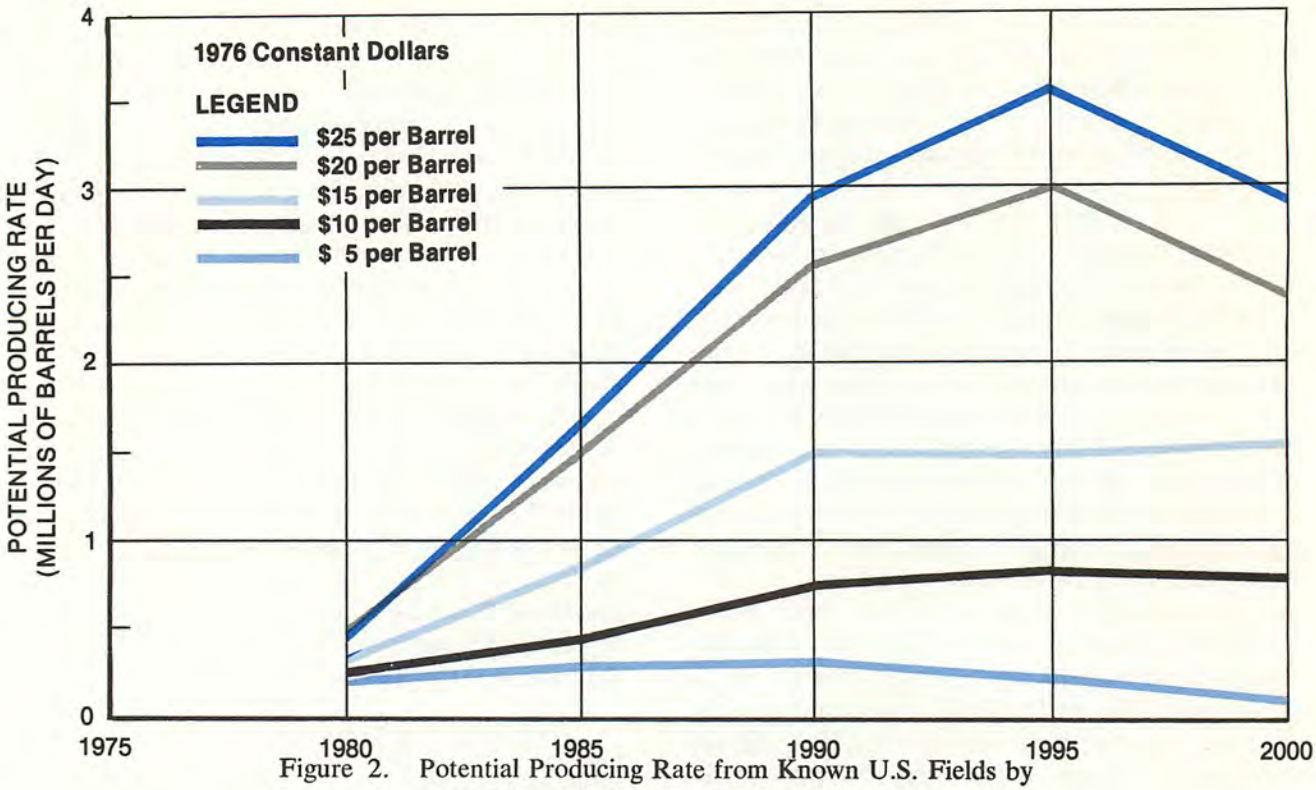


Figure 2. Potential Producing Rate from Known U.S. Fields by Enhanced Recovery Processes.

tially with price, accounting for 9 billion of the 24 billion barrel total EOR at $25 per barrel.

The potential producing rate is also sensitive to oil price. The potential rate in 1985 varies from 0.3 million barrels per day at $5 per barrel to about 1.7 million barrels per day at $25 per barrel. Peak production (for most oil prices) from application of EOR processes to currently known reservoirs is projected in 1995 (with the assumptions on rates of development and application in this study), and ranges from about 0.25 million barrels per day at $5 per barrel to 3.5 million barrels per day at $25 per barrel.

The large amount of uncertainty in the above estimates is depicted in Figures 3 and 4. Figure 3 shows the range of incremental ultimate recovery for the same economic conditions as Figure 1. Figure 4 shows the corresponding range of potential producing rates, at an oil price of $15 per barrel. The ranges shown were derived from examination of the uncertainty associated with the estimates of process performance.

If all EOR processes perform extremely well (substantially better than expected in the base case) incremental ultimate recovery might range from about 4 billion barrels at $5 per barrel to about 33 billion barrels at $25 per barrel. If all processes perform substantially poorer than assumed in the base case, ultimate recovery could range from 2 billion barrels at $5 per barrel to about 12 billion barrels at $25 per barrel. The range of incremental ultimate recovery at $15 per barrel is from 7 billion to 27 billion barrels, compared to a base case estimate of 13 billion barrels.

The uncertainty in potential producing rate at any point in time is larger than the uncertainty in ultimate recovery. With the assumptions made in this study regarding rates of development and process application, the potential producing rate in 1985 at $15 per barrel ranges from less than 0.5 million barrels per day (poorer than expected performance) to more than 1.5 million barrels per day (better than expected performance), with a base case estimate of about 0.9 million barrels per day. At peak production, expected in about 1995 with the assumptions used, the uncertainty is largest. At $15 per barrel, the potential producing rate ranges from about 0.75 million barrels per day to about 3.3 million barrels per day, with a base case of 1.5 million barrels per day.

There is an equal probability for either the high or low estimates of process performance to occur. As this broad range reflects only an estimate of the uncertainty, actual results could be even better or worse than calculated. It appears unlikely, however, that the uncertainty would be resolved in a uniformly positive or negative direction for all processes. It is more probable that some processes will perform better than expected, and some more poorly, so that the aggre-

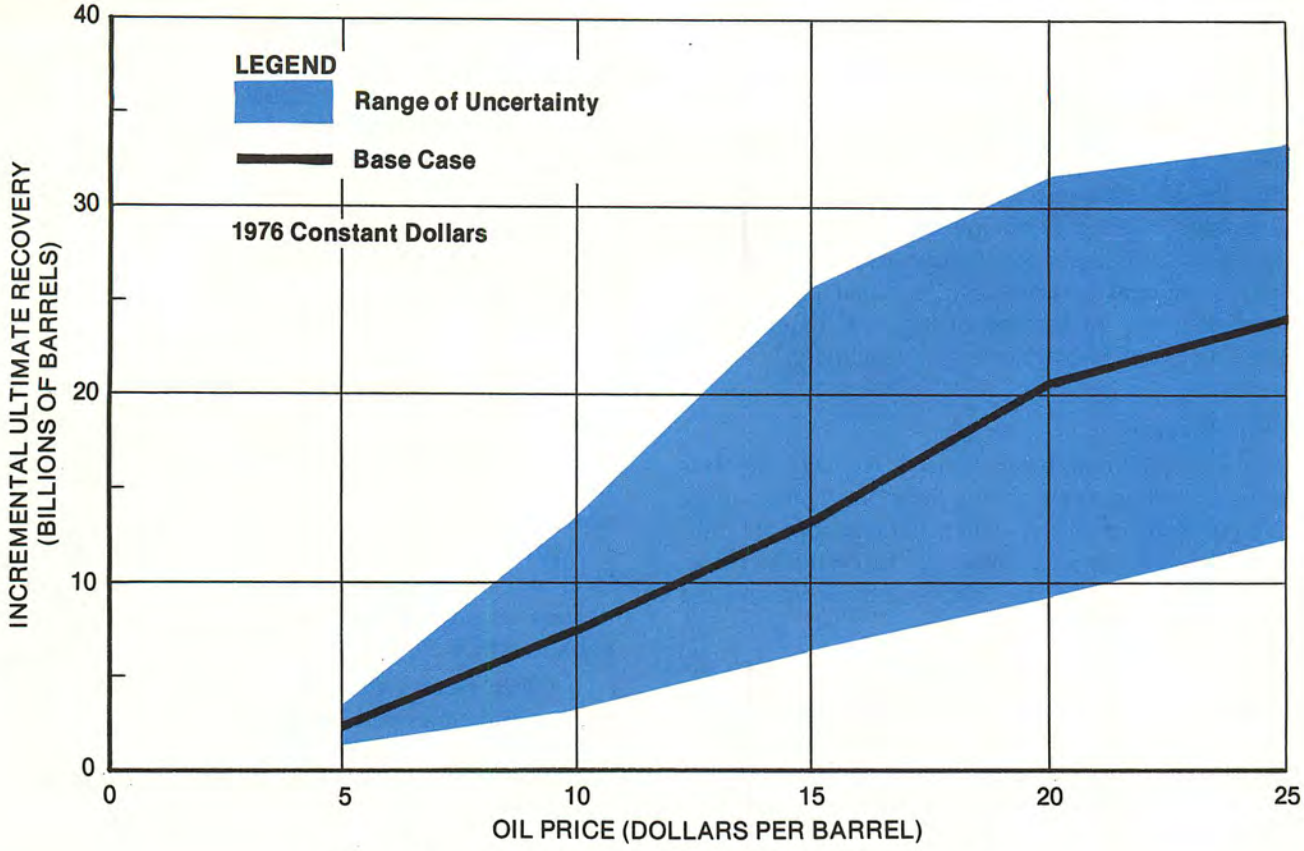


Figure 3. Uncertainty in Incremental Ultimate Recovery.

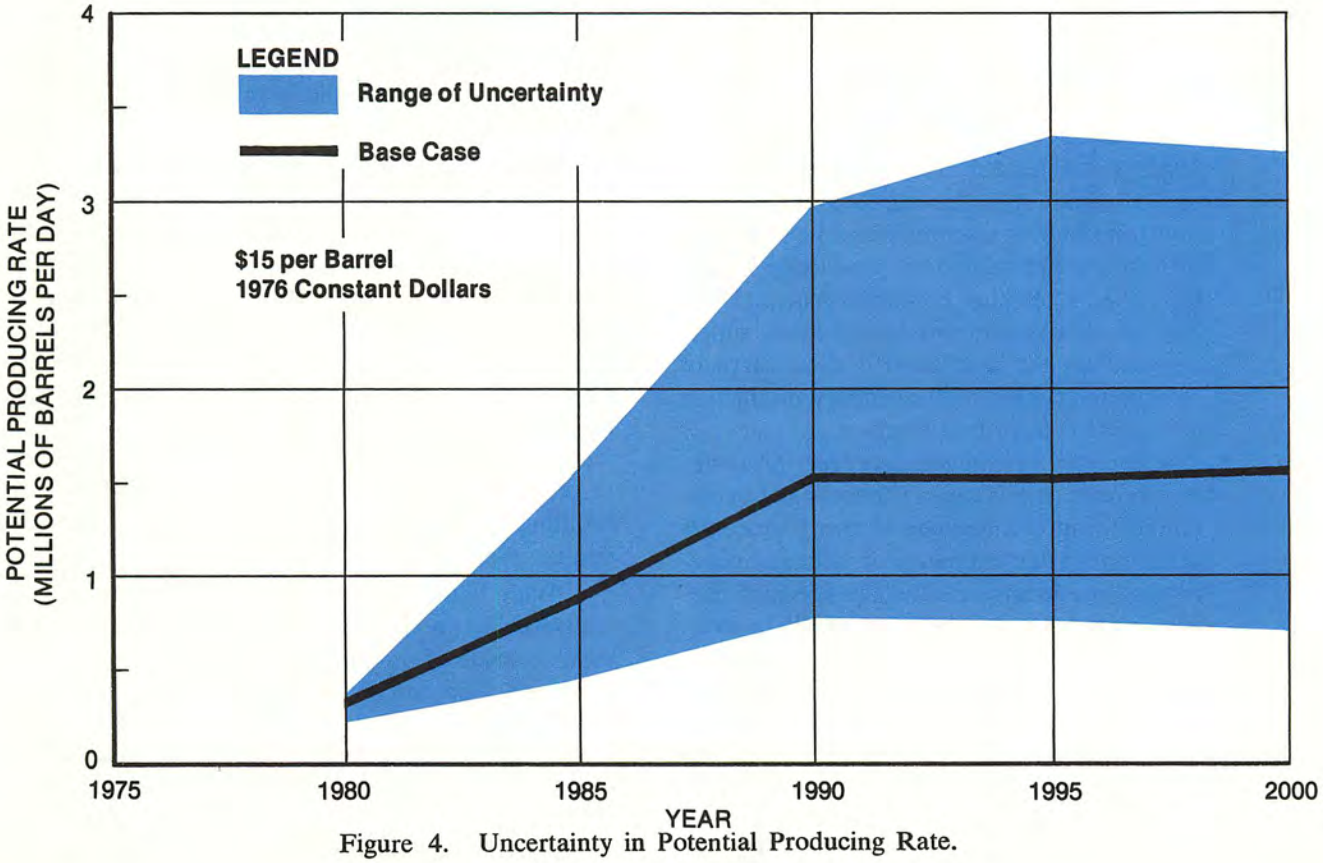


Figure 4. Uncertainty in Potential Producing Rate.

gate results are expected to be within the range shown.

Other data obtained in the course of this study and more complete treatment of the type of results shown in Figures 1 through 4 are presented in the chapters and appendices of the report. These include: discussion of possible enviromental impacts of EOR operations; examination of the sensitivity of the results to several parameters other than process performance; and an analysis of logistical requirements associated with the projected EOR activity.

Conclusions

The potential for enhanced recovery involves complex relationships among technology, economics, and government policy; valid generalizations are difficult. From this study, however, the National Petroleum Council draws the following three interrelated conclusions:

- *Enhanced recovery processes, if technically successful and broadly applied, could have a significant impact on oil production from known U.S. reservoirs during the years 1985-2000.* Assuming historical depletion trends, production of current API proved reserves (excluding North Slope) will decline to about 3 million barrels per day by 1985 and to less than 1 million barrels per day in 1995-2000. Successful application of enhanced recovery technology could slow this decline during the period 1985-2000, if the rate of technology development and field testing from 1976 to 1985 is accelerated from current levels. In fact, the rate of enhanced recovery production from known reservoirs could exceed that of primary and secondary production by the late 1980's. Figure 5 shows potential enhanced oil recovery producing rates, superimposed on the calculated decline curve of remaining primary and secondary production of current U.S. proved reserves.
- *The potential of enhanced recovery processes is uncertain at this time.* The technical uncertainties in most enhanced recovery processes are so great that estimates of ultimate recovery and producing rate for any specified economic condition may be substantially in error. Further process research, reservoir characterization studies, and field testings will be required to improve prediction capabilities.
- *Incremental ultimate recovery and the potential producing rate for enhanced recovery are highly dependent on oil price and other economic factors.* Enhanced recovery processes are inherently high-cost methods designed to recover oil which is left in the reservoir by lower-cost, conventional recovery methods. These high-cost processes are not widely used at present because current domestic oil prices and other economic factors do not permit profitable application, even when they are technically successful.

Government Policy Comments

Government policy may affect both the ultimate recovery from EOR processes, and the timing of the application of EOR technology. The principal effect will result from policies which influence the economics of EOR processes. Oil price relative to process cost will be the primary factor influencing the level of EOR application. Policies which artificially depress oil price will diminish the number of reservoirs to which EOR can be economically applied.

Other factors that have substantial effects on project economics will be sensitive to related policy. For example, tax treatment may be significant, particularly regarding the degree to which cash outlays must be capitalized rather than expensed. Policy which requires amortization of large front-end investments, such as injected chemicals, would have a severe, detrimental effect on surfactant flooding, a significant negative impact on carbon dioxide miscible flooding, and a lesser effect on thermal EOR processes. Other tax policies might have important effects.

Several policy areas, which indirectly affect project economics, may have large aggregate impacts. Since environmental protection costs are included in project costs, more stringent requirements would increase costs. Of the EOR processes studied, thermal recovery operations appear to be the most sensitive to the cost of environmental protection. Regulations which offer differential benefits to some leases or producers, such as multiple-tier price controls or regulations giving special treatment to certain classes of producers, may make unitization impossible, with resulting higher application costs, or even elimination of reservoirs from consideration.

With limited total world oil resources, all oil recoverable at real price levels as high or higher than those considered in this report, eventually may be produced. The cost of enhanced recovery might be substantially increased by delay, because of plugging of wells and abandonment of surface facilities. Moreover, the present value of the oil to the Nation is directly affected by delay. The major effect of the future direction of government policy will be to estab-

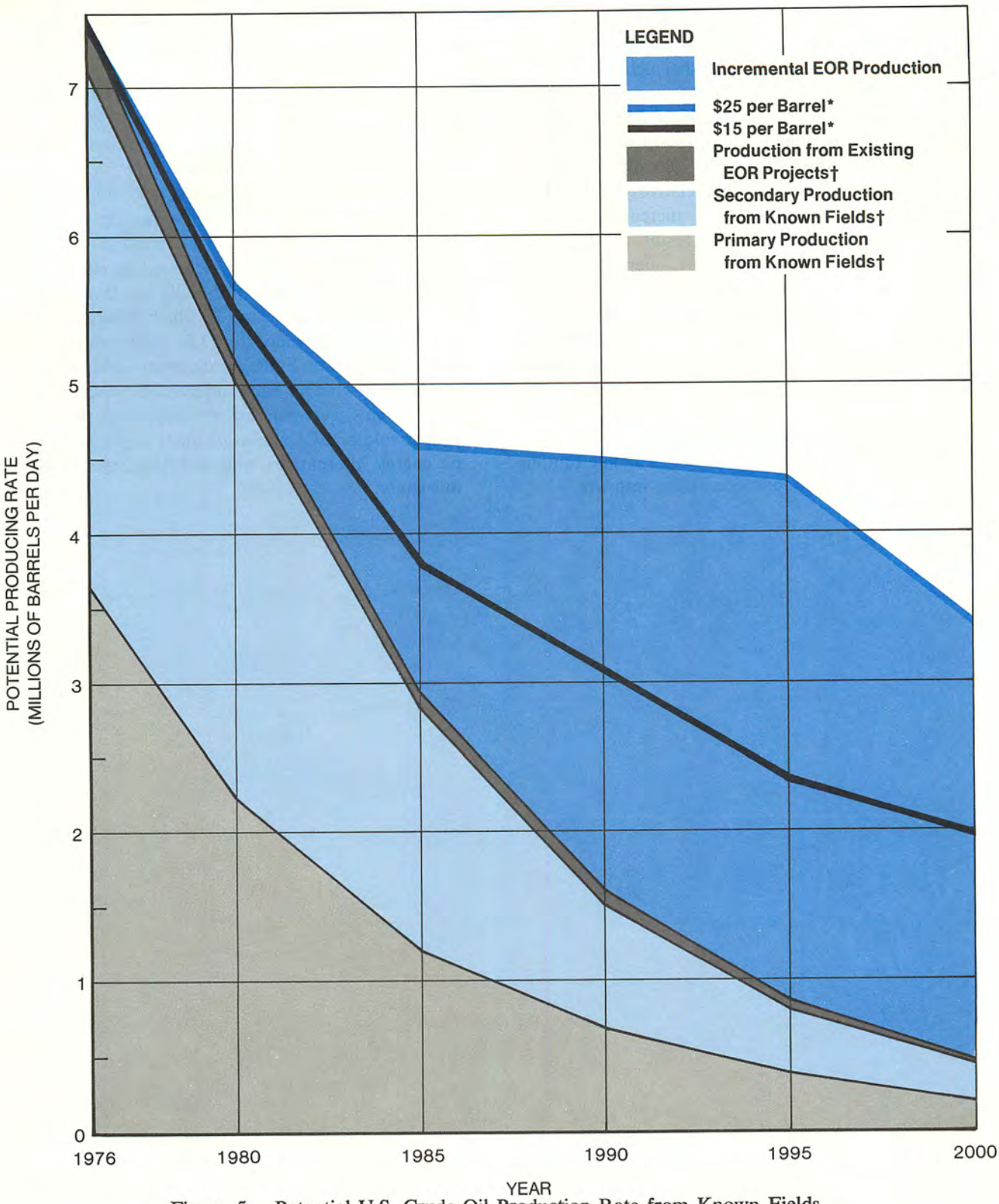


Figure 5. Potential U.S. Crude Oil Production Rate from Known Fields.

*Constant 1976 Dollars and Minimum DCFROR Requirement — 10%

†Estimated Producing Rates Based on December 31, 1975 API Reserves (See Appendix H).

Note: Production from the following sources is not considered and will be additive to the rates shown:

- Revisions except as included in API "Indicated Additional Reserves" as of December 31, 1975
- Extensions from realized enlargement of known fields
- New reservoir discoveries in known fields
- New field discoveries after December 31, 1975
- EOR from extensions, new reservoir discoveries, and new field discoveries
- North Slope, Alaska

lish *when* oil is recovered by EOR processes.

Investment in EOR processes will have to compete for available funds with other activities, such as oil exploration, which also have the potential to increase domestic petroleum resources. Higher real oil prices would provide increased incentives for all such activities, including EOR. As already stated, this study has not considered the relative value of EOR compared to other means of increasing domestic energy supply; however, one result of this study, which bears on such questions, merits emphasis: With the exception of a few thermal applications in unusually favorable reservoirs, the upside potential of EOR project economics is limited, even when the project is technically successful. There are no bonanzas in EOR. To the degree that exploration, or other alternatives, offer higher upside potential (with comparable risk and profitability expectations), they may continue to receive the majority of available funding, even if general economic conditions improve.

Enhanced oil recovery projects require long lead times and are high-risk investments. The degree of risk will decrease as the results from more large-scale projects are obtained, providing a basis for improved process engineering. The U.S. Energy Research and Development Administration (ERDA) program in support of field pilot experiments is designed to provide added field test data, and it should have some positive effects on risk considerations. Demonstration of the technical feasibility of EOR, however, will not result in increased production unless economic conditions for EOR are favorable.

There are many ways in which differential benefits could be extended to EOR applications in order to accelerate EOR development and use. The question of whether such differential treatment is in the Nation's best interest requires analysis of the proper role of EOR *vis-a-vis* other available domestic energy alternatives, and is beyond the scope of this study.

Chapter One
Background of Oil Recovery Operations

Overview of Elements of Oil Recovery

General

In the United States, 418 billion barrels of crude oil had been discovered as of December 31, 1975. Total ultimate recovery with existing economic conditions is estimated to be 137 billion barrels, of which 109 billion barrels have already been produced. Thus, the remaining proved reserves recoverable by conventional production methods are 28 billion barrels, leaving nearly 300 billion barrels of oil in currently known reservoirs.* Most of this oil is not recoverable with foreseeable technology, because of unfavorable reservoir geology, adverse fluid properties, or because it is so diffusely spread out in the reservoir rock. However, a portion of this oil volume should be producible by enhanced oil recovery methods. This report addresses the amount and rate of recovery that may be economically recoverable by EOR methods.

Domestic producing rates in 1975 totalled about 8 million barrels per day of crude oil and 2 million barrels per day of lease condensate and gas plant liquids. An approximate equivalent amount of natural gas (on a BTU basis) was also produced in 1975. Domestic oil and gas production accounted for about 55 percent of the Nation's energy needs, with another 20 percent of the Nation's needs being filled by imported oil. The remaining 25 percent was from other energy sources such as coal, nuclear and hydroelectric power.

*API, *Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada as of December 31, 1975,* Vol. 30, May 1976. All data exclude the North Slope of Alaska.

The Reservoir

Crude oil is found in underground rock formations called reservoirs. The oil resides together with water, and sometimes gas, in very small holes (pore spaces) and fractures. The size, shape, and degree of interconnection of the pores vary considerably from place to place in an individual reservoir. Thus, the anatomy of a reservoir is complex, both micro- and macroscopically. A complete, detailed, quantitative description of a reservoir is never possible. The detailed data which can be obtained from wells represents only an infinitesimal fraction of the reservoir volume, even under the best of circumstances.

Properties of crude oil and formation water in different parts of an individual reservoir generally vary only slightly, although there are notable exceptions. For different reservoirs, crude properties cover a wide spectrum of differences. Some are thinner than water, while others are thicker than cold molasses. Generally, crude oils are lighter than water. The water in different reservoirs also varies, in salinity and other mineral content.

Because of the existence of a wide range of properties of both rock and fluids, reservoirs act differently and must be treated individually.

Primary Oil Recovery

Primary oil recovery uses natural reservoir energy to drive the oil through the complex pore network to producing wells. The driving energy may be derived from one or more of the following: gas that evolves from solution out of the oil; expansion of free gas; influx of natural water; or gravity force. The primary recovery efficiency is generally low when gas

is the drive agent; much higher recoveries are associated with water drives. Reservoirs with effective gravity drainage can also have higher recoveries. Eventually, the natural drive energy is dissipated. When this occurs, energy must be added to the reservoir to produce any additional oil.

Secondary Oil Recovery

Secondary oil recovery involves the introduction of energy into a reservoir by injecting gas or water under pressure. Separate wells are usually used for injection and production. The added energy stimulates the movement of oil, providing additional recovery at increased rates.

Today, limited use is being made of gas injection because of its low oil displacement effectiveness and the need for gas supplies in the market. When gravity drainage is effective, pressure maintenance by gas injection is effective. Waterflooding is the principal secondary recovery method and accounts for about half the current U.S. daily oil production.

Efficiency of Conventional Recovery Methods

Ultimately, conventional primary and secondary recovery are expected to produce about one-third of the original oil discovered. The recovery from individual reservoirs can range from as low as 5 percent to as high as 80 percent of original oil in place (OOIP). This broad range of recovery efficiency is a result of the variations in the properties of the specific rock and fluids involved from reservoir to reservoir, as well as the kind and level of energy that drives the oil to producing wells, where it is captured.

The Remaining Oil

Oil left after conventional recovery applications is retained in the pore space of reservoir rock at a lower concentration than originally existed; the produced oil is replaced by gas and/or water in the pores. The remaining oil exists in portions of the reservoir as droplets trapped by water either in individual pores or clusters of pores; as a film lining the pore walls; or in the pores of these segments of reservoir rock which by geological conditions or well positioning were not contacted by driving fluids.

The forces that contribute to the retention of the oil are capillarity (blotter effect), gravity (buoyancy effect), and viscous forces (drag effect). These forces act simultaneously in the reservoir and the resultant effect depends on conditions at individual locations. Releasing the remaining oil so that it can be produced is the intent of enhanced oil recovery operations. Through chemical or thermal means, the objective is to increase the effectiveness of oil removal from pores of the rock (displacement efficiency) by eliminating or minimizing the oil-imprisoning capillary forces; by overcoming or utilizing the effects of gravity which cause vertical segregation of the fluids in the reservoir; by thinning the oil so that it will flow more readily; and by improving sweep efficiency, causing the injected or driving fluids to contact more of the oil-containing reservoir rock.

The degree of technical success achieved by enhanced oil recovery will depend on the development of process technology, on the behavior of the new drive fluids, and the accuracy of reservoir engineering in characterizing the physical nature of individual reservoirs.

Overview of Enhanced Recovery Methods

Enhanced Oil Recovery

For the economic parameters studied in this report, the incremental ultimate recovery is defined as the additional recovery of oil from a petroleum reservoir over that which can be economically recovered by conventional primary and secondary methods. Enhanced recovery methods capable of recovering additional oil are broadly categorized as (1) thermal, (2) carbon dioxide (CO_2) miscible, and (3) chemical flooding.

After nearly half a century of industrial research, a number of enhanced recovery methods have evolved. Some of these appear to be more promising than others. The three major categories—thermal, carbon dioxide miscible, and chemical flooding—differ in degree of complexity and in the amount of experience that has been derived from field application:

- *Thermal* is the most advanced on the learning curve in terms of field experience, and so has the least uncertainty in estimating performance if good reservoir description is available. Commercial application of some of the thermal processes has been underway for the last decade and currently contributes about 200 thousand barrels per day of enhanced oil recovery to the Nation's oil supply.
- *Carbon dioxide miscible* is lower on the learning curve than thermal, but in the middle range of complexity of the three categories used in this study. At least two CO_2 miscible programs are underway at the commercial level and several pilot tests are either under-

way or planned to evaluate this recovery method in different types of reservoirs.

- *Chemical flooding* is the most complex, is lowest on the learning curve, and has the highest degree of uncertainty. Yet, where its application can be properly designed and controlled, it may have the greatest chance to achieve maximum recovery. Over the past decade, several field pilot tests have been conducted. While some tests have been successful, most of these resulted in operators returning to the research laboratories to improve upon their chemical formulations. Currently, chemical flooding is being carefully and thoroughly field piloted, with the objectives of developing better applications technology, understanding the limitations of this method, and informing the industry at large as to field test results.

Thermal Processes

Thermal processes add heat to the reservoir to reduce oil viscosity or to vaporize the oil. In both instances, the oil is made more mobile so that it can be more effectively driven to producing wells. In addition to adding heat, these processes provide a driving force (pressure) to move oil to producing wells. There are two principal thermal enhanced recovery methods: steam injection and in-situ combustion.

Steam Injection

Steam injection has been commercially applied in California for the last decade. It occurs in two steps:

- Steam stimulation of the producing well (Figure 6), and
- Steam drive from steam injected into wells to increase production from nearby producing wells (Figure 7).

In practice, a mixture of steam and hot water is normally injected into the formation. The ratio of steam to water injected may vary from mostly steam (high quality) to mostly water (low quality).

At different times and in various sequences, different phases of steam injection may be applied to any one project. Normally, steam stimulation precedes steam drive. It is the steam stimulation phase of steam injection that began in California ten years ago. In steam stimulation, heat is applied to the reservoir by the injection of high quality steam into the producing well. The cyclic, so-called "huff and puff" or "steam soak," process uses the same well for injection and production.

This period of steam injection is followed by production of reduced-viscosity oil and condensed steam (water). The driving energy for production is the flashing of hot water (originally condensed from steam injected under high pressure) back to steam as pressure is lowered when a well is put on production. After several steam stimulation cycles, some wells are converted to continuous steam injection and others to continuous production. At this point the operation becomes a steam drive.

In-Situ Combustion

In-situ combustion has also been extensively field-tested. Heat is generated in the reservoir by injecting air and burning part of the crude oil. This reduces the viscosity, partially vaporizes the oil in place, and drives it forward by a combination of steam, hot water, and gas drive. Production is obtained at wells offsetting injection locations. In some applications, the efficiency of the total in-situ combustion operation can be improved by alternating water and air injection (see Figure 8). The injected water tends to improve the utilization of heat by transferring it from the hot rock behind the combustion zone to the rock immediately ahead of the combustion zone. Due to density contrasts, injected air tends to override in-place oil. Where gravity effects cause extensive overriding problems, steamflooding may prove to be a more efficient process. In-situ combustion is normally applied to reservoirs containing low gravity oil, but it can be applied to higher gravity oil reservoirs also. In some high-gravity oil reservoirs, in-situ combustion would compete with other EOR methods. For the reservoirs considered in this study, other EOR methods normally took precedence due to economic dominance considerations used in this study. Other alternative dominance criteria might result in greater potential use of in-situ combustion.

Carbon Dioxide Miscible Flooding

Carbon dioxide (Figure 9) is capable of miscibly displacing some oils, thus permitting recovery of most of the oil from the reservoir rock that is contacted. Miscible displacement overcomes the capillary forces which otherwise retain oil in pores of the rock. The CO_2 is not miscible with the oil initially. However, as CO_2 contacts in-situ crude oil, some of the hydrocarbon constituents of the crude oil are vaporized. At the displacement front, the

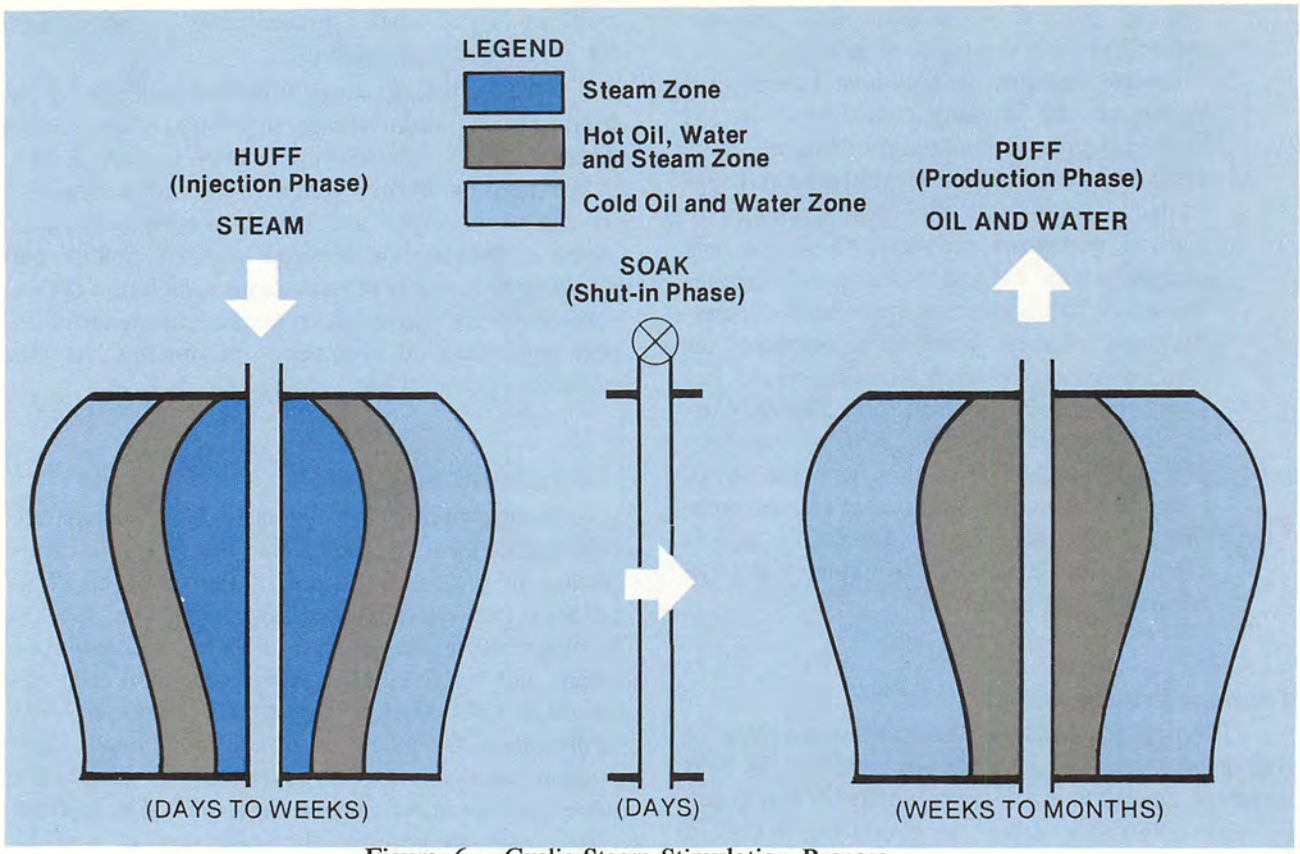


Figure 6. Cyclic Steam Stimulation Process.

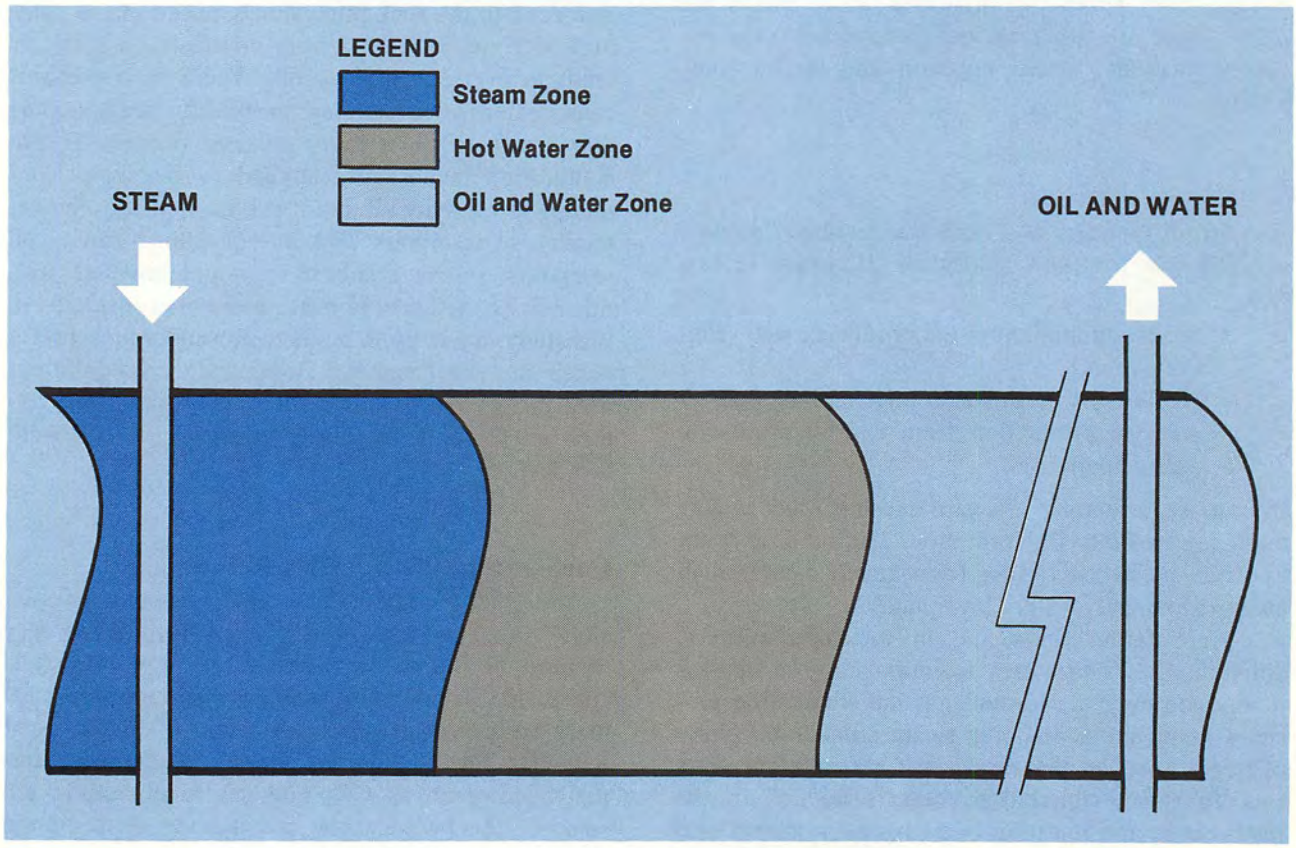


Figure 7. Steam Drive Process (Steam Flood).

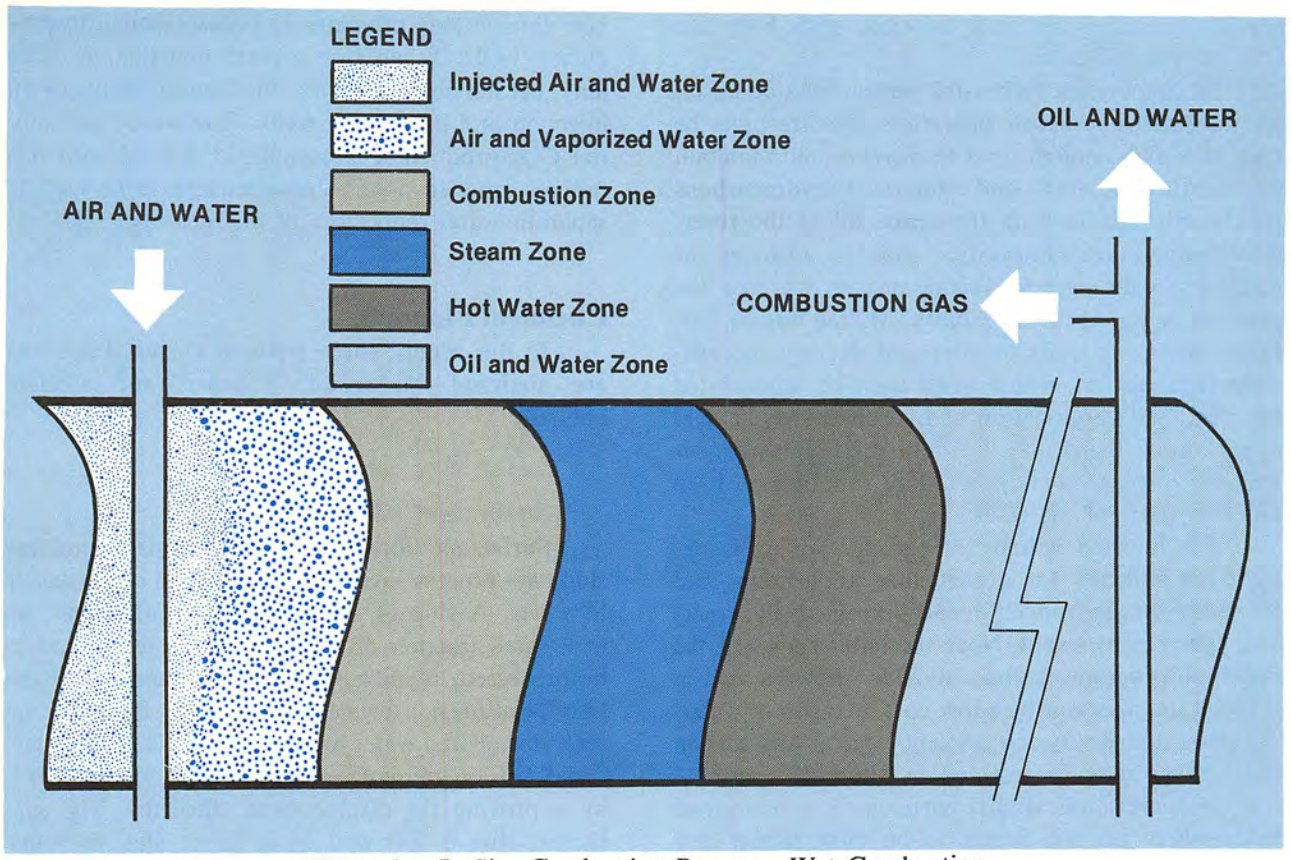


Figure 8. In-Situ Combustion Process—Wet Combustion.

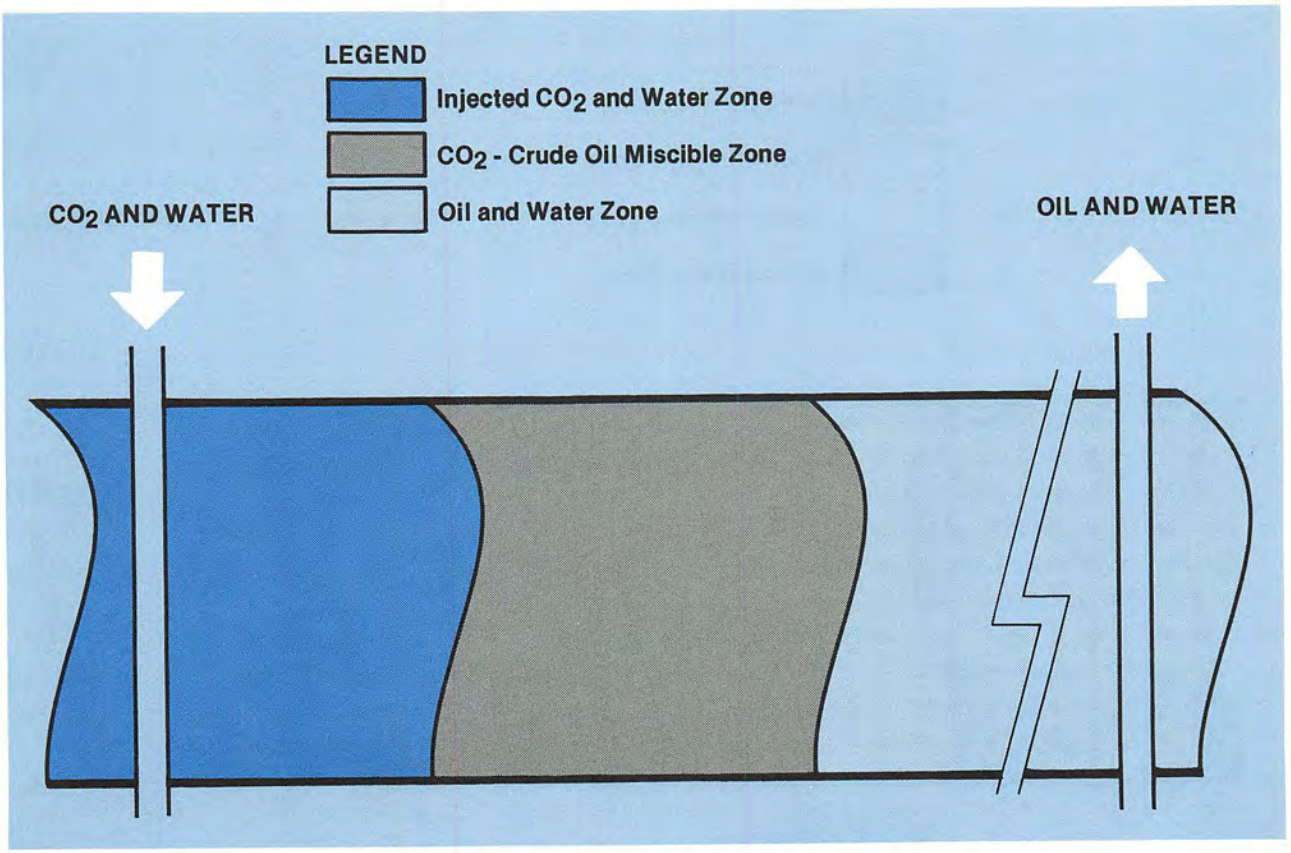


Figure 9. Carbon Dioxide Miscible Flooding Process.

resulting mixture becomes miscible with both the CO_2 and the in-situ oil.

To accomplish successful carbon dioxide miscible floods, the reservoir operating pressure must be kept at a high enough level to develop and maintain the mixture of CO_2 and vaporized hydrocarbons which are miscible with the crude oil at the reservoir temperature. Impurities such as nitrogen or methane in the carbon dioxide stream increase the pressure required for miscibility. Mixing due to flow in the reservoir tends to alter and destroy the miscible composition, which must then be regenerated by additional vaporization of hydrocarbons. In field applications, there may be both miscible and near miscible displacements proceeding simultaneously in different parts of the reservoir.

The injected volume of carbon dioxide is designed specifically for a particular application, and it usually ranges from 25 to 50 percent of the reservoir space to be swept. Near the latter stages of the injection program, carbon dioxide may be driven through the reservoir by a low-cost inert gas or water. To achieve higher sweep efficiency, water and carbon dioxide gas may be injected in alternate cycles.

In some applications, particularly in limestone fields where the use seems to be most likely, carbon dioxide may prematurely break through to producing wells. When this occurs, remedial methods may be possible by using mechanical controls in injection and production wells. However, a substantial CO_2 production is considered normal with this process, and economic considerations must include separation and reinjection of this produced CO_2.

Chemical Flooding

In this report, three types of chemical flooding are analyzed: surfactant, polymer, and alkaline flooding.

Surfactant Flooding

Surfactant flooding (Figure 10) is a multiple slug type process involving the addition of chemicals to water. A slug of surfactant material, amounting to a small fraction of the reservoir pore volume to be processed, is injected. The surfactant lowers the interfacial tension between the injected fluid and the reservoir oil and water to almost zero. This low interfacial tension minimizes the capillary forces, thereby improving the displacement efficiency. The surfactant slug is followed by a larger slug of water

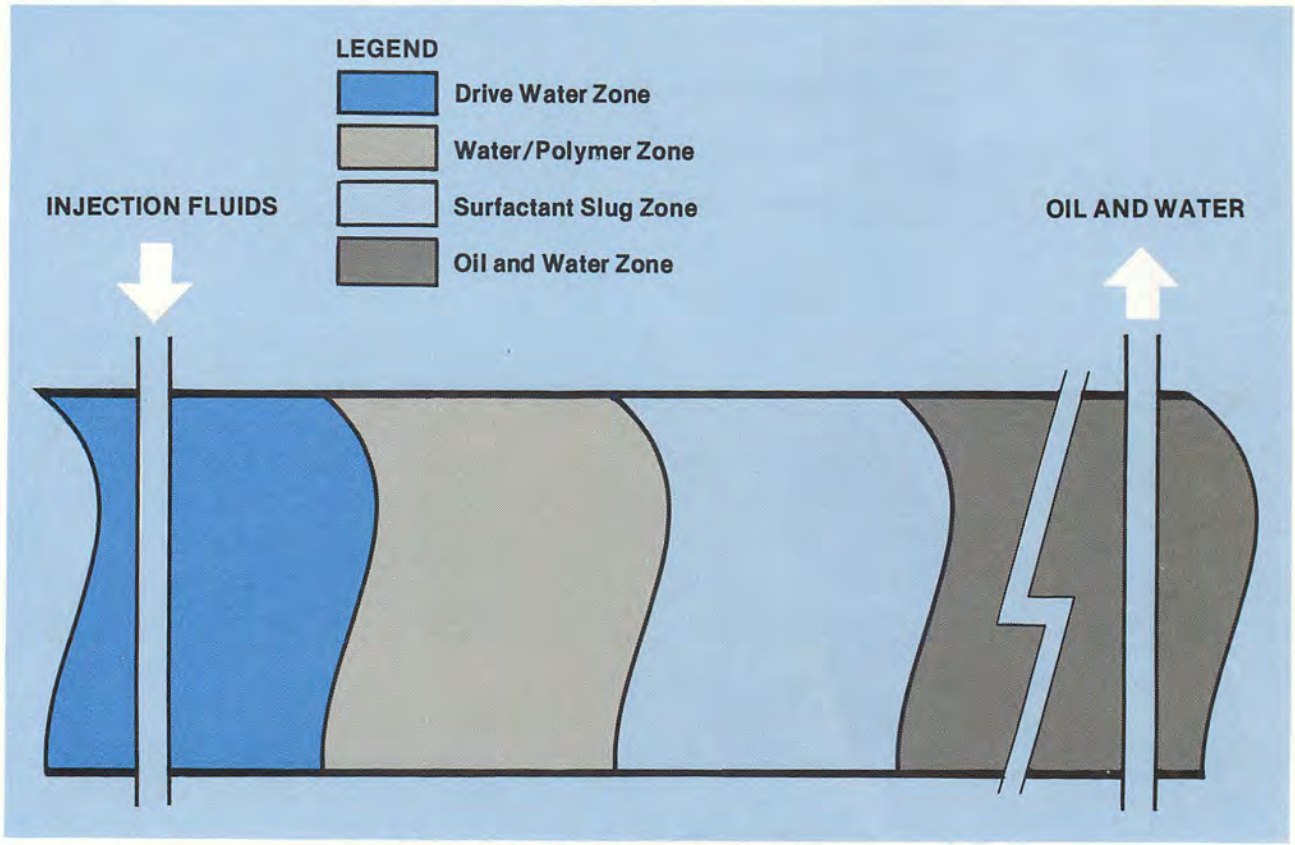


Figure 10. Surfactant Flooding Process.

containing a high molecular weight polymer. This slug usually ranges in size from 25 to 100 percent of the total pore volume of the reservoir to be processed. The water/polymer slug is used to develop a favorable mobility ratio displacement, to improve the sweep efficiency, and to preserve the integrity of the costly slug of surfactant chemicals.

Each reservoir has unique properties, and specific chemical systems must be designed for each individual application. The concentration and volume of chemicals used will depend upon specific properties of the fluids and the rocks involved.

Surfactant flooding is receiving widespread attention, both in laboratory and field tests. Pilot tests are necessary to evaluate the effectiveness of a specially designed process in each specific reservoir. Successful pilot tests are prerequisite to oil producers and chemical manufacturers making financial commitments for commercial attempts on entire reservoirs.

Polymer Flooding

Polymer flooding is an augmented waterflood. Polymers in use currently are synthetic (polyacrylamide) and biologically produced (polysaccharide). These high molecular weight polymers are added to the injection water to improve (decrease) the mobility contrast between the in-place and injected fluids. This can increase the sweep efficiency and thereby improve oil recovery. Unlike the use of polymer as a drive fluid in surfactant flooding, where it is necessary to achieve a favorable mobility ratio (less than unity) to protect the integrity of the surfactant slug, the polymer augmented waterflood is not always designed to achieve a favorable ratio. By requiring only an improved mobility ratio, the process may be used with higher viscosity oil than those for which a surfactant flood might be considered.

In operation, the polymer reduces the ability of the injected water to flow in the reservoir, which results in improved sweep efficiency. The polymer-water enters otherwise bypassed pore spaces, thus contacting more of the oil and moving it to wells. It has its greatest utility with waterfloods in reservoirs that contain viscous oils (up to about 200 cp), that are moderately heterogeneous, and that possess a permeability variation up to a ten-fold range. Increased recovery over waterflood will be modest, and the increased cost of production moderate. Currently, polymer flooding is being used commercially on a limited scale, both in the United States and elsewhere.

Alkaline Flooding

Alkaline flooding uses chemicals such as sodium hydroxide, sodium silicate, and sodium carbonate added to flood water to enhance oil recovery by one or more of the following mechanisms: interfacial tension reduction, spontaneous emulsification, or wettability alteration. These mechanisms are related to the in-situ formation of surfactants from the neutralization of petroleum acids by alkaline chemicals in the displacing fluids. Since the content of such natural petroleum acids is normally higher in the lower API gravity crude oils, this process seems to be applicable primarily, or exclusively, to the recovery of moderately viscous, low API gravity, naphthenic type crudes.

Although emulsification in alkaline flooding processes provides mobility control to a certain degree, emulsification alone may not be sufficient in sweeping highly viscous crudes; other chemicals may be required to improve mobility contrast.

Only a few field tests have been reported, a few of which were technologically encouraging (see Appendix D).

Enhanced Gas Recovery

Enhanced gas recovery represents an entirely different problem from enhanced oil recovery. Gas flows to producing wells entirely by natural expansion due to pressure reduction, and normally recovery cannot be improved economically by displacement with another fluid.

The possibility of recovering significant volumes of gas from very low permeability (tight) gas bearing formations has received much attention during the last decade. Although these deposits may contain large volumes of gas, the gas cannot normally be produced at rates sufficient to merit the costs of drilling and development. Most current research and field testing is concentrated on hydraulic fracturing of the reservoir to improve producing rates, including massive fracturing treatments which may propagate fractures in the reservoir several thousand feet. Success in field testing has been variable, apparently depending on the geologic nature of the reservoir tested.

To project the potential recovery in the time frame 1976-2000 would require both an ability to project the results of a variety of hydraulic fracture treatments in a variety of reservoirs, and definition of the target to which the process might be applied. The gas volume, reservoir location, geologic characteristic of reservoirs and other data on this potential resource are essentially undefined at this time because these factors have not been explored. Thus, it was not possible to make meaningful projections of enhanced gas recovery in this study.

Chapter Two
Analysis Considerations and Procedures

This chapter reviews general economic considerations for enhanced recovery processes, and the specific economic and technical analysis procedures used in this study. The technical and economic considerations are closely interrelated. Calculation of the potential of EOR is dependent both on technical viability of specific EOR processes in specific reservoirs, and on the number of such reservoirs where application would meet or exceed a minimum discounted cash flow rate of return (DCFROR) requirement for the economic conditions considered. The calculation procedure in this study is based on reservoir-by-reservoir examination of 245 sample reservoirs in the states of California, Texas, and Louisiana and supplemented by information from other sources. The data base was provided to the Council for this study by the Department of the Interior and was developed by Lewin & Associates in conjunction with a study for the Federal Energy Administration. Results for the United States as a whole were extrapolated from this data base.

Project Economic Considerations

General Economic Considerations

As opposed to exploration for new fields, EOR approaches are applied to known reservoirs and, thus, are not susceptible to finding risks. However, the physical and financial outcomes of most present EOR attempts may well be at least as uncertain as conventional exploration. Although reservoir locations are certain, the expenditure requirements, oil recovery effectiveness, and net unit revenues from EOR operations will vary widely from project to project. Moreover, these projects generally will require very large front-end capital commitments and long lead times before any future benefits begin to accrue.

The uncertainty associated with relatively risky ventures, such as EOR projects, requires commensurately higher than average target returns to offset attempts that fail. This would be especially true for first generation EOR efforts during the early years of development.

Estimates of project economics, as measured by discounted cash flow rate of return, differ from historic, overall book returns; project evaluations recognize expenditures in the time period in which they occur, while accounting books time-spread some expenditures through use of depreciation, depletion, and other non-cash accounts. Also, accounting books measure the aggregate performance of all foregoing investments that are still active, and these would encompass a wide spectrum of quality, ranging from highly successful to very poor.

The aggregation of successes and failures, the time-spreading of capital expenditures via depreciation and depletion charges, and the inclusion of other costs not specifically associated with individual projects will almost always result in actual booked return on investment being significantly lower than acceptable target DCFROR's for individual projects. Therefore, in order to achieve aggregate results adequate to maintain historic book return levels, target DCFROR's for individual projects must be set well above historic book rates, even for low-risk project investments.

At this time, most key determinants of prospective EOR project returns are highly uncertain. Some of these factors are:

- **Investment Cost**—Since most EOR processes are as yet untried on a large commercial scale,

the initial investment requirements are subject to substantial and unknown variance.

- **Operating Cost**—Additional uncertainties arise since large-scale operating experience is lacking at this time. Also, future escalation rates for the various operating cost items will differ from one another, and are now indeterminate.
- **Process Effectiveness**—Again, lack of experience, coupled with the physical and technological unknowns regarding reservoir configurations and process behavior, cause expected production performance to be extremely uncertain.
- **Crude Oil Prices**—The unit revenues to be derived is a key determinant of expected financial results. At this time, the future market value (world price) of oil is unknown; moreover, the regulatory policies of the U.S. Government introduce another order of oil price risk. At this time, there is no assurance that all EOR oil would be allowed to be sold at market prices. Also, it is not known at what levels future domestic oil prices may be established.
- **Taxation**—The application of existing tax laws to EOR projects (e.g., expensing versus capitalizing of injected fluids) has not yet been firmly resolved. Furthermore, ongoing determinations of tax law changes may significantly affect EOR economics.
- **Environmental Factors**—The future costs and restraints associated with environmental protection in EOR operations is uncertain at this time.

The combined impact of uncertainties associated with each of these key factors is to effect a wide variance of possible DCFROR outcomes for EOR projects, at least initially. As experience is gained, this variance should narrow to some extent, but may remain significant for some years. In the meantime, relatively high target DCFROR's will be required to compensate for the high risk of loss.

Other EOR Investment Considerations

EOR projects must compete with alternative opportunities for investment dollars, manpower, and other resources. Companies must carefully allocate their limited capital and other resources to the most productive projects; thus, EOR projects must compete with a full slate of more conventional exploration and production (E&P) and other petroleum-related activities within each company.

If the petroleum industry as a whole is to increase capital outlays beyond existing cash flow restraints, external capital must be attracted by opportunities equal or superior to non-petroleum investment alternatives of equivalent risk.

It is emphasized that high DCFROR's for prospective EOR projects are necessary, but not always sufficient to promptly effect the investments required. Industry and company cash flows must be adequate to support the additional investments. Thus, current cash generation from all petroleum industry activities is a critical determinant of total EOR progress, as is the prospective DCFROR for a specific EOR project.

Project Evaluation Case Parameters

General

In the interest of simplifying comparative case analysis, project evaluations were computed in terms of constant 1976 dollars.

Oil Price Cases

In order to assure consideration of a wide range of possible prices, crude oil prices of $5, $10, $15, $20, and $25 per barrel (constant 1976 dollars) were selected for case analysis. Simplifying assumptions made for purposes of this analysis are: (a) the prices specified represent wellhead prices for all domestic production regardless of quality, location and recovery mechanism; and (b) that these prices are immediately attained and would prevail throughout the period analyzed.

The second assumption is not unique to petroleum supply economics. Conventional supply/price analysis generally assumes that all prices considered are received in the same time of reference. The assumption that price specifications apply to all domestic oil is important in this study because petroleum prices affect some of the project costs (see process appendices) as well as the revenues.

Income Tax Cases

Tax treatment of prospective EOR projects could be a key determinant in accept/reject decisions. Although the application of existing tax law to EOR projects is not yet certain, the moderate and restrictive cases described in Table 1 are believed to be consistent with probable interpretations of existing tax law, and were selected to assess tax treatment sensitivity.

It is assumed for both cases that federal and state income tax rates would total 50 percent, and

TABLE 1

ASSESSMENT OF TAX TREATMENT SENSITIVITY

Item	Tax Treatment Cases	
	Moderate	Restrictive
Intangible Drilling and Development Costs		
— Producing Wells	Expense	Expense
— Injection Wells	Expense	Expense
— Water Source Wells	Expense	Capitalize
Hardware		
— Depreciation Method	5-year (SL)*	11-year (SYD)†
— Investment Tax Credit	10% of 2/3 of Total	7% of Total
Cost of Injected Material		
— Capitalize or Expense	Expense	Capitalize
— Depreciation Term	Not Applicable	Reservoir Life
— Depreciation Method	Not Applicable	SL*
— Tax Credit	Not Applicable	None

* Straight-line method of depreciation.

† Sum-of-the-year's digits method of depreciation.

that no depletion allowances would be applicable. A more complete discussion of EOR sensitivity to tax treatment is included in Appendix C.

Rate of Return Cases

To include a range of capital cost possibilities, minimum constant dollar DCFROR requirement cases of 10, 15, and 20 percent were selected. Most projects in the aggregation for each of these DCFROR requirement cases would exceed the specified rate, i.e., these rates are used in the analysis only as minimum requirements and not as expectations for average results.

DCFROR's derived from estimated constant dollar cash flows will be lower than those derived from estimated current (or inflated) dollar cash flows by an amount approximately equal to the inflation rate. Thus, in a 5 percent annual inflation environment, the 10, 15, and 20 percent constant dollar DCFROR's would be about equivalent to 15, 20, and 25 percent *current* dollar DCFROR's, respectively. This distinction is noted since both bases are commonly used.

While the higher portion of the DCFROR range selected probably will be most applicable during the early stages of technology development, as experience is gained and results become more predictable, required DCFROR's should decline somewhat. In any event, the results for the higher DCFROR cases also are shown in the report.

Overhead and Non-Income Taxes

Surveys of available industry data and the consensus of expert opinion indicate the following generalized estimates for project screening purposes:

Item	Estimated Cost
• Capital Investment Overhead	10 Percent of Investment
• Operating Overhead	20 Percent of Direct Operating Cost
• Production and Property Taxes	8 Percent of Producer Revenue

Overhead estimates refer to general corporate costs not directly identifiable with specific projects, but which contribute to the firm's continuing capital investment and operating activities. Examples of such costs include general management, administration, research and development (R&D), etc. While the costs of these functions are not directly tied to specific projects, they tend to fluctuate with investment and operations activity levels. Thus, estimated incremental overhead costs are appropriate items to be included in project economics.

Pilot Testing Economic Considerations

While pilot testing costs may be significant for an individual company and/or an individual reservoir, in an industry context, pilot testing will not be a large component of average EOR unit costs. For example, surfactant flooding research and development (R&D) costs, including pilot testing, may total less than $.10 per barrel of additional oil, if surfactant flooding is widely adopted. R&D costs for other processes probably will be even less.

Owing to the small unit costs for R&D, they are assumed to be covered by the overhead estimate and/or well within the precision afforded by other estimates and assumptions.

Cost Data Summary

Cost estimates were developed in two broad categories: (1) process-independent, and (2) process-dependent. Process-independent costs include widely applied items, such as well drilling and completion costs, workover costs, well equipment costs, lease equipment costs, lease operating costs, etc. Process-dependent costs are those more specifically associated with the individual processes studied. For example, for thermal methods the cost of steam generators, air compressors, and steam feedwater treatment equipment would be applicable only to that specific process. Likewise, CO_2 transmission and compression costs would be unique to CO_2 miscible operation, and surfactant costs would apply only to chemical flooding.

Process-independent cost estimates are detailed in Appendix C, and process-dependent costs are discussed within the respective process text and appendix sections of this report.

With the inflation-free economics used in this report, most costs—both process-dependent and -independent—were assumed constant, varying neither with time nor economic conditions specified. In a few cases, however, oil price and process cost were so closely related that ignoring this effect in the analysis would have caused serious distortion. For this reason, a few important cost factors, such as chemicals for chemical flooding, electric power costs for electrically driven air compressors in thermal recovery, and carbon dioxide compression costs, were assumed to vary with oil price using approximations shown in the appendices.

Economic Calculation Procedure

The approach to economic analysis employed in this study is based on the estimated economic viability of specific enhanced recovery methods as applied to sample reservoirs under each set of economic conditions specified. Details are discussed in the following section and the appendices. The steps involved in this procedure may be summarized as follows:

- The 245 sample reservoirs in California, Texas, and Louisiana were each categorized as being best suited to one or more of the enhanced oil recovery processes considered, or to none. (The screening process for determination of technical viability is discussed in the "Technical Analysis Procedures" section of this chapter.)
- The physical outcomes, i.e., the ultimate and time-rated additional oil recovery, of applying the selected EOR process(es) to these reservoirs were established.
- Using the price, cost, and tax cases specified, DCFROR's for each sample project were calculated for each set of economic parameters.
- Comparison of these results with each minimum rate of return criterion indicated whether or not requisite economic conditions were satisfied. Aggregation of results for each economic condition established total estimates for the sample reservoirs. Thus, both incremental ultimate recovery and producing rate projections for each economic condition vary primarily as a function of the number and size of the reservoirs to which application of the specified EOR process is economic at that condition.
- Results from the sample reservoirs were extrapolated twice: first, to totals for all reservoirs in the three sample states, and then to the United States as a whole. Extrapolation procedures are discussed briefly under "Technical Analysis Procedures," and are reviewed in more detail in the individual process appendices.

Technical Analysis Procedures

Estimates of the potential of enhanced recovery ultimately depend on engineering judgment. In this study, the analysis is based on consideration of the applicability of each process to each of 245 sample reservoirs in the data base. Judgment is applied first in the screening process to match reservoirs with specific EOR processes. The development of equations to calculate recovery is based on a large body of technical literature and tempered by practical operating experience. Geologic review of reservoirs was used as an additional screening criterion, both to determine applicability and to rate the quality of the reservoir for EOR applications. This second screen

was based almost entirely on qualitative judgment.

The Technology Task Group served as a forum for collective review and discussion of judgments made during the course of the study. Experts in the companies represented on the Task Groups and Coordinating Subcommittee, other companies, and universities were consulted extensively.

Detailed descriptions of the analysis procedure used for each enhanced recovery process in this study are provided in the appendices. Although minor differences exist in the detailed procedures, the basic approach used in evaluating the potential of each method was similar to the seven-step procedure outlined below.

1. State-of-the-Art Assessments
2. Data Base Review
3. Selection Procedure—Screening and ranking of data base reservoirs as potential EOR candidates
4. Dominance Determination—Designation of preferred process for each EOR candidate
5. Process Performance Predictions—Estimation of ultimate oil recovery and typical production rates for various reservoir parameters, field development, etc.
6. Process Economics—Calculations made for various economic conditions including studies of the effect of uncertainties such as process costs, recoverable oil, and timing
7. Extrapolation—EOR potential recovery and production rates obtained for reservoirs in primary data base, extrapolated to three-state totals for California, Texas, and Louisiana and to the entire United States.

State-of-the-Art Assessments

The state-of-the-art assessment for each EOR process includes a brief description of the process, including background information and a discussion of factors (reservoir parameters and crude properties) affecting its use. In addition, a brief review of field results and current applications is included. As a part of these assessments, screening criteria were developed for use in identifying potential enhanced oil recovery candidates from a list of 245 crude oil reservoirs (175 fields) contained in the primary data base described below.

Data Base Review

For this study, the data base developed by Lewin & Associates in conjunction with their study for the Federal Energy Administration* was supplemented with information from other sources. The basic data base consists of information developed from a variety of public sources for 245 crude oil reservoirs in 175 oil fields in the states of Louisiana, Texas, and California. These 175 fields contain approximately 60 percent of the oil remaining after primary recovery and conventional secondary recovery from known fields in these three states; they contain between 35 and 40 percent of the oil remaining after primary and secondary recovery in known fields in the United States, excluding the North Slope of Alaska.

In addition to the above data base, use was made of the Petroleum Data System (PDS)† data base at the University of Oklahoma, of information developed by the Gulf Universities Research Consortium for ERDA, and of American Petroleum Institute (API) statistics. Data compiled by the Interstate Oil Compact Commission were utilized in making estimates of recoverable oil saturations. Estimates of reservoir temperatures and water salinities were obtained from a number of public sources, including surveys, etc. Additions to the primary data base were transmitted to the Department of the Interior as they were made.

One of the principal sources of uncertainty in the estimates in this study of enhanced oil recovery potential arises from the lack of the detailed reservoir information that would normally be required to evaluate the applicability of enhanced recovery processes. Typically, such an evaluation will involve an extensive study of the reservoir, requiring several man-years of effort and much more detailed geologic and reservoir engineering data than is normally obtained or required in designing a conventional recovery process, such as a waterflood. This limitation was alleviated insofar as possible by combining information contained in several data bases with estimates of the variability of factors that could influence enhanced oil recovery performance. For example, the economic analyses of surfactant flooding candidates included high-, low-, and mid-range estimates of the recoverable oil saturation. In other cases, factors such as reservoir geology, the presence of extensive faulting or fractures, etc., were judged to limit the recovery potential of enhanced recovery methods.

*The Lewin data base was obtained by the Department of the Interior from the Federal Energy Administration for use in this study.

†PDS was developed by the University of Oklahoma under contract to the U.S. Geological Survey.

Selection Procedure

The screening criteria used in this study to select and rank potential EOR candidates are summarized in Table 2. A list of potential EOR candidates was obtained by applying these basic screening criteria to all reservoirs in the data base.

A typical example of the application of the screening criteria is that for CO_2 miscible flooding. The basic screening criteria for CO_2 flooding include the reservoir temperature, oil composition and viscosity at reservoir conditions, and a procedure (using the oil gravity--°API) that predicts the minimum pressure required for a miscible-CO_2 displacement. In addition, consideration is given to geologic criteria such as the absence of extensive natural fracture systems or high-permeability, stratigraphic, thief zones. When the CO_2 screens are applied to the primary data base of 245 reservoirs, the initial screening step reduces the number of possible CO_2 candidates to 165 reservoirs.

Reservoirs passing the first screening step were then subjected to a second, more detailed review. On this second review, information concerning additional factors that would influence oil recovery performance of each reservoir was included whenever such information was available. Both geological and reservoir engineering data were sought, including the gross depositional environment, general lithology, estimated degree of heterogeneity of the reservoir, success of past waterflooding, and the likely influence of gas caps or underlying aquifers. This review served as a second screening process. Some reservoirs were

TABLE 2

SCREENING CRITERIA FOR SELECTION OF EOR CANDIDATES

		Chemical Flooding Processes			Miscible Processes	Thermal Processes	
Screening Parameters	Units	Surfactant	Polymer	Alkaline	Carbon Dioxide	Steam	In-Situ Combustion
Oil Gravity	°API	⩾25	--	⩽ 35*	⩾27*	⩽25	⩽25
Oil Viscosity, (μ)	cp	⩽30*†	⩽200	⩽200	⩽10	⩾20	⩾20
Depth (D)	Feet	--†	--	--	>2,300*	>200<5000*	>5,000*
Zone Thickness (h)	Feet	--	--	--	--	>20	>10
Temperature	°F	⩽250	⩽200	⩽200	< 250*	--	--
Permeability, Average ($\bar{K}$)	md	⩾20†	⩾ 20	⩾20	--	--	--
Transmissibility (Kh/μ)	md-ft/cp	--	--	--	--	100	20
Salinity of formation brine (TDS)	ppm	⩽200,000	--*	--*	--	--	--
Minimum oil saturation at start of process							
In water-swept zones (S_{orw})	fraction	⩾.20*	--	--	--	--	--
Mobile (S_{or}-S_{orw})	fraction	--	⩾.10				
Minimum Oil Content at start of process (S_{or})	B/AF	--	--	--	--	>500	>500
Rock type	--	sandstone	--	sandstone	sandstone or carbonate	sandstone or carbonate	sandstone
Other	--	‡	‡	‡	‡	‡	‡

* See text of appropriate appendix.

† Used to estimate required well spacing for given project life.

‡ Other criteria including geological data were also considered. The specific criteria used depended upon the process. In general, reservoirs with continuous and uniform strata were ranked higher than were heterogeneous reservoirs with extensive faulting, discontinuous lens-type deposits, fractures, etc. Similarly, reservoirs with extensive underlying aquifers or overlying gas caps were ranked lower or excluded as EOR candidates in view of the decreased likelihood of a successful EOR project.

rejected because of their unfavorable properties.

Reservoirs that passed the second screen for any EOR process were ranked good, fair, or poor candidates for that process. In some reservoirs, subdivisions were made with each receiving its own rank. In general, the geological and reservoir engineering data were not adequate to provide a precise technological ranking for any given reservoir. In order to rank the reservoirs, it was frequently necessary to rely upon the experience and judgment of the geologists and reservoir engineers reviewing the available information. Although the ranking of any individual reservoir may be higher or lower than it actually deserves, the average ranking of all potential EOR candidates should offset these errors to an acceptable degree.

Again using the miscible-CO_2 process as an example, 109 CO_2 candidates remained at the end of this second screening, of which 37 were also candidates for other EOR processes. The next step in the analysis procedure was to determine which EOR process would be the dominant method.

Dominance Determination

As indicated above, some reservoirs satisfied the screening criteria for more than one recovery process. The method used for determining which EOR process would be the preferred (or dominant) process is described below.

The rankings given to the reservoir for each competing process during the second screening review were compared. In general, the process that ranked the highest was selected as the preferred method. However, if a reservoir received the same ranking for two EOR processes, economic calculations were made for both processes, and the process having the highest present value profit calculated for a rate of return of 10 percent and a crude price of $25 per barrel was selected as the dominant (or preferred) process. The effect of this procedure was to favor the selection of the process with the higher prospective oil recovery.

Of the 37 CO_2 candidates which were also candidates for other processes, CO_2 flooding was selected as the preferred process for 11; the remaining 26 reservoirs were assigned to other EOR processes, primarily to surfactant flooding.

Process Performance Predictions

Evaluations of EOR processes require that estimates be made of both the incremental ultimate oil recovery that can be achieved and typical production rates as a function of time for each candidate reservoir. As noted in Chapter Three, results were calculated both for the best estimate of parameters (the base case) and for several additional cases, to study the influence of key parameters on results. For each of the EOR processes included in this study, the critical reservoir parameters affecting process performance were identified and the impact of each of these key parameters on process economics was determined for reasonable ranges of the parameter. For all processes, the impact of various projections of recovery performance and process costs was evaluated. For surfactant flooding specifically, the profitability of surfactant flood application in each of the reservoirs assigned to that process was determined for two well spacings and for high-, low-, and mid-range estimates of (a) the recoverable oil saturations, (b) chemical costs, and (c) the size of the surfactant slug. The mid-range estimates were selected as the "most likely" values of the various reservoir parameters and, as such, were used to develop the "best estimates" of the performance of individual reservoirs. The base case results for any specified set of economic assumptions were obtained by aggregating the total potential ultimate recovery and the corresponding production rates of reservoirs satisfying the specified economic criteria.

Process Economics

General economic considerations and procedures are described in the preceding section of this chapter. A standard economic model, described in more detail in Appendix C, was used for the economic evaluations. This model utilizes the technical forecasts of oil production rates, together with cost data specifying capital requirements, operating expenses, and other costs as a function of time and provides the discounted cash flow rate of return for each economic condition. Calculations were made for each projection of reservoir performance described above for each assumed crude price ($5, $10, $15, $20 or $25 per barrel) and each of two tax treatments. The minimum crude price from those considered which would be required for the EOR process to satisfy each different rate of return criterion was then determined for each projection of process performance.

Extrapolation

The objective of this study has been to estimate the overall enhanced oil recovery potential, for the three states, California, Texas, and Louisiana, and for the entire United States, from a representative

sample of U.S. reservoirs. As indicated above, the reservoirs in the original data base contained about 60 percent of the original oil-in-place in those three states and 35 to 40 percent of the U.S. total, excluding the North Slope.

Although extrapolation of the results will introduce additional uncertainty to the projected results from the data base reservoirs, the extrapolation factors are not large and should be reasonable, since a large fraction of the total original oil-in-place in the United States was contained in the reservoirs in the data base.

The extrapolation procedures used for the different EOR processes are described in detail in the individual process appendices. However, the general approach was to develop extrapolation factors for each district (Texas), area (California), or state (Louisiana) based on estimates on the original oil in place in the data base fields and the corresponding totals for other reservoirs in each subdivision which were judged to have similar reservoir and crude properties (lithology, oil viscosity, remaining oil saturation, etc.). The rationale for using specified geographic locations for the scale-up base is that the geologic setting, and hence, the reserve and economic model, is similar over a narrow geographic base.

Since the data base reservoirs were restricted to California, Texas, and Louisiana, other sources of data were utilized for extrapolation to the remainder of the United States. The API and PDS data bases were the primary sources of information used for extrapolations although the Bureau of Mines study of *Heavy Oil Resources in the U.S.* was used in addition to the above as a guideline in extrapolating the potential of thermal methods.

Typical factors used for extrapolation from the three-state totals to those for the entire United States were 1.39 for surfactant flooding, 1.35 for polymer flooding, 1.25 for alkaline flooding, about 1.25 for CO_2 miscible, and 1.15 for thermal processes. Further discussion of these factors and their application appears in individual process appendices.

Chapter Three
Potential for Enhanced Oil Recovery

Results

The state-of-the-art assessments of EOR technology indicated considerable uncertainty in the probable performance of most EOR processes. From the outset of the study, it was apparent that a range of potential results would be more meaningful as a representation of recovery potential than any single estimate. As noted in the preceding chapter, the approach taken in this study was to obtain best estimate, base case performance and cost for each process, followed by study of the variability of results as a function of the possible range of individual critical parameters. While the base case results represent the single best estimate at this time, the range of potential results is equally important in establishing perspective on the potential of EOR processes.

Base Case Definition

The best estimate or base case performance estimates were made by developing best estimates of individual parameters, such as unit displacement efficiency, sweep efficiency, etc., which determine the calculated performance for each process. These base case performance estimates were considered to be roughly the mean of expected results. The consensus best estimate judgments were reviewed by a number of persons considered expert in enhanced recovery technology, and should represent a reasonable approximation to the overall judgment of industry at this time. *The base case represents neither a minimum assured result nor, conversely, an upper bound on the potential of enhanced recovery processes.*

The best estimate of costs for each process was developed in a manner similar to the performance estimates, with individual estimates of several key cost elements. Results shown for a "base case" thus represent best estimates of both performance and cost. *The term "base case" has no implications regarding oil price, tax case, or rate of return requirement.*

Each set of base case calculations consisted of 10 separate analyses, with computed economic results for five different oil prices ($5, $10, $15, $20, and $25 per barrel) at each of two tax cases (moderate and restrictive), with results from each analysis tested to establish reservoirs satisfying the 10, 15, or 20 percent DCFROR requirements in constant 1976 dollars.

The assumptions made in establishing the base case estimates are discussed further in the "Discussion of Results" section of this chapter.

Total of Base Case Estimates of All Processes

Since the potential of all enhanced recovery processes is so strongly dependent on economic incentive and involves uncertainties which cannot yet be fully evaluated, there is no single graph which can be used to depict the best estimate of the potential of enhanced recovery processes. The base case results can be summed to present a figure showing total for all processes, but must be determined and plotted for specified rate of return requirement and tax case (and, in the case of potential producing rate, specified values of oil price). Moreover, these estimates must be viewed in the light of the uncertainties

in process performance and process cost. All results are incremental to existing production and current API proved reserves.

The sum of the base case results for incremental ultimate recovery from all enhanced recovery processes at a 10 percent rate of return requirement is shown in Figure 11. Potential ultimate recovery from enhanced recovery processes is heavily dependent on oil price. At $5 per barrel, total potential ultimate recovery is only about 2 billion barrels and is essentially all due to thermal processes. At an oil price of $10 per barrel, potential ultimate recovery increases to about 7 billion barrels, with carbon dioxide miscible flooding contributing an amount about equal to thermal, and with a very small amount of chemical flooding oil potential. At $15 per barrel, the potential ultimate recovery of 13 billion barrels is approximately equally distributed between thermal, carbon dioxide miscible, and chemical processes.

At oil prices of $20 and $25 per barrel (and at the assumed 10 percent rate of return), chemical flooding becomes the process with highest potential. The maximum potential calculated from the sum of base case results is approximately 24 billion barrels, at an oil price of $25 per barrel.

Figure 12 shows a somewhat different picture of potential ultimate recovery for a 20 percent rate of return requirement. At this higher DCFROR requirement, incremental ultimate recovery at $25 per barrel drops from about 24 billion barrels to 15 billion barrels, with chemical flooding having a relatively small impact. The influence of rate of return requirement is discussed in the "Discussion of Results" section of this chapter.

The total base case potential producing rate for all processes, for oil at $15 per barrel and a minimum DCFROR requirement of 10 percent is shown in Figure 13. Under these economic conditions, the incremental producing rate in 1980 is projected to be approximately 300 thousand barrels per day, and is essentially all from thermal processes. Incremental production in 1985 could be approximately 900 thousand barrels per day, with chemical flooding beginning to play a significant role. By 1990, thermal processes applied to existing reservoirs would be peaking out, and carbon dioxide miscible processes would become more important with a total potential producing rate of about 1.5 million barrels per day. This further increase in CO_2 miscible flooding would tend to offset decreases in the chemical and thermal

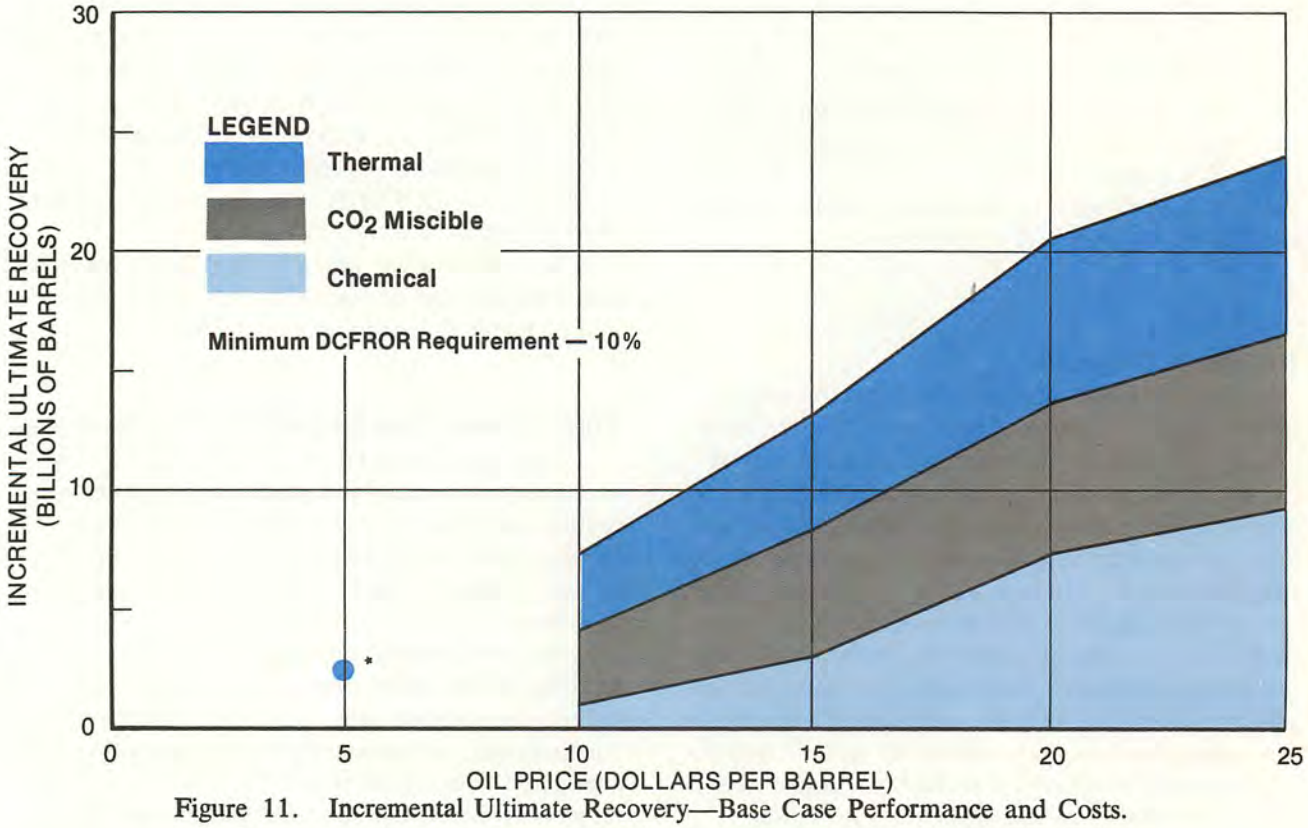


Figure 11. Incremental Ultimate Recovery—Base Case Performance and Costs.

*Recovery for Thermal at $5. Recovery for Chemical and CO_2 miscible flooding are zero at $5 per barrel and as shown at $10 per barrel. Recovery for intermediate prices between $5 and $10 per barrel has not been determined.

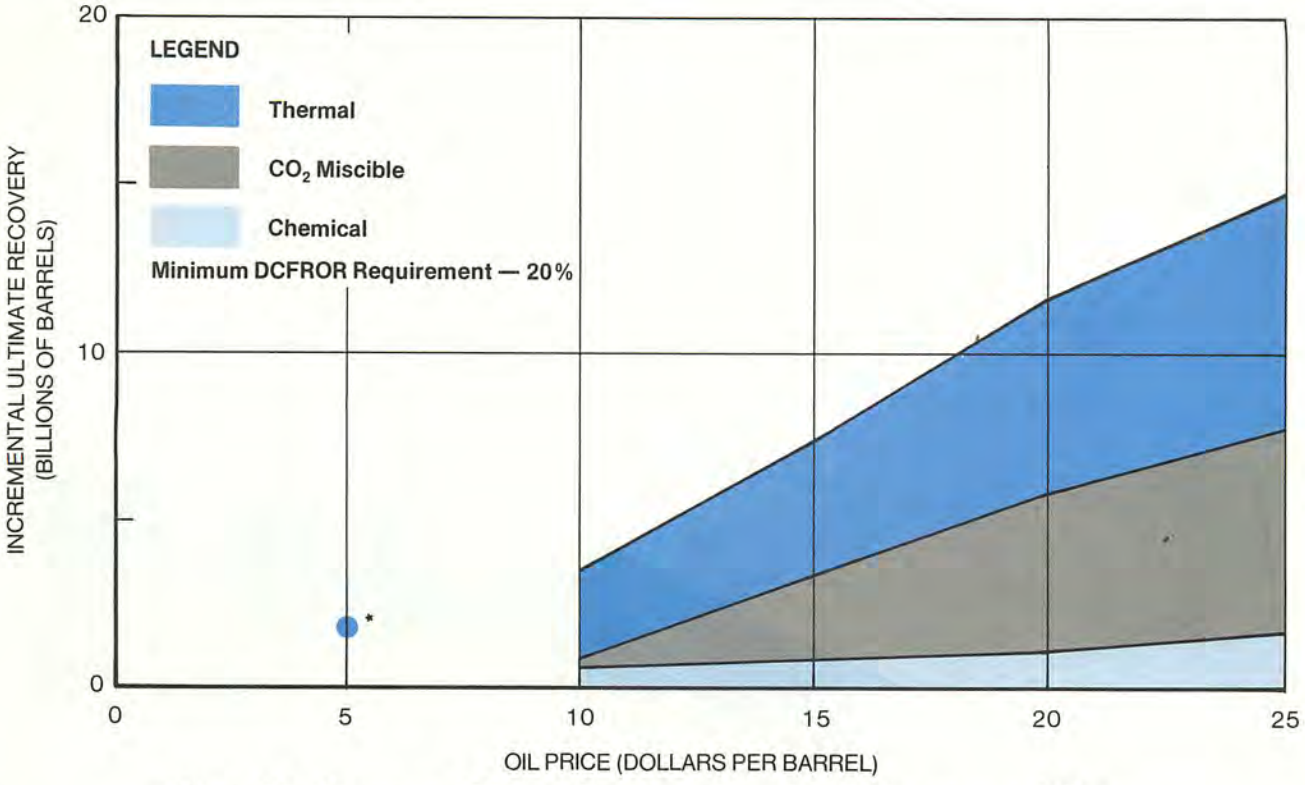


Figure 12. Incremental Ultimate Recovery—Base Case Performance and Costs.

* Recovery for Thermal at $5. Recovery for Chemical and CO_2 miscible flooding are zero at $5 per barrel and as shown at $10 per barrel. Recovery for intermediate prices between $5 and $10 per barrel has not been determined.

producing rates between 1990 and 2000, so that the total producing rate from all processes would continue to climb slightly, to approximately 1.6 million barrels per day by the year 2000.

As shown in Figure 14, potential producing rates, for an oil price of $25 per barrel, and a minimum DCFROR requirement of 10 percent are nearly double those for $15 per barrel in the time frame 1985-2000. The potential producing rate in 1980 is affected only slightly and would be approximately 500 thousand barrels per day. By 1985, however, the producing rate with a $25 per barrel oil price is expected to be potentially as high as 1.7 million barrels per day, which is more than the peak rate in the year 2000 for an oil price of $15 per barrel. The potential producing rate at $25 per barrel would continue to climb through the year 1995, and would peak at approximately 3.6 million barrels per day, dropping to approximately 3 million barrels per day by the year 2000.

Results by Recovery Process

All estimates of the total potential of enhanced recovery in the United States represent the sum of the calculated potential of individual enhanced recovery processes. The results in this study for each individual process do not indicate the absolute potential of that process if it were to be considered independently, because of the effect of dominance criteria on the results. For example, surfactant flooding, if considered by itself, would be applicable to several of the sandstone reservoirs that are considered to be candidates for carbon dioxide miscible flooding. In the event carbon dioxide miscible flooding proves to be significantly less efficient or more costly than indicated by the analysis in this study, it is entirely possible that chemical flooding would achieve a greater potential than is shown. The same type of interaction is present in several other instances.

In analyzing each process, the best estimate results were calculated first to establish a base case. The uncertainty or variability in results was then determined by calculating the sensitivity to key parameters, such as recovery performance or important process cost elements. All parameters other than the key parameter being studied were held constant at base case values during the variability analysis.

In the following presentation of results for individual process analyses, all results shown are the extrapolated values for the total United States unless

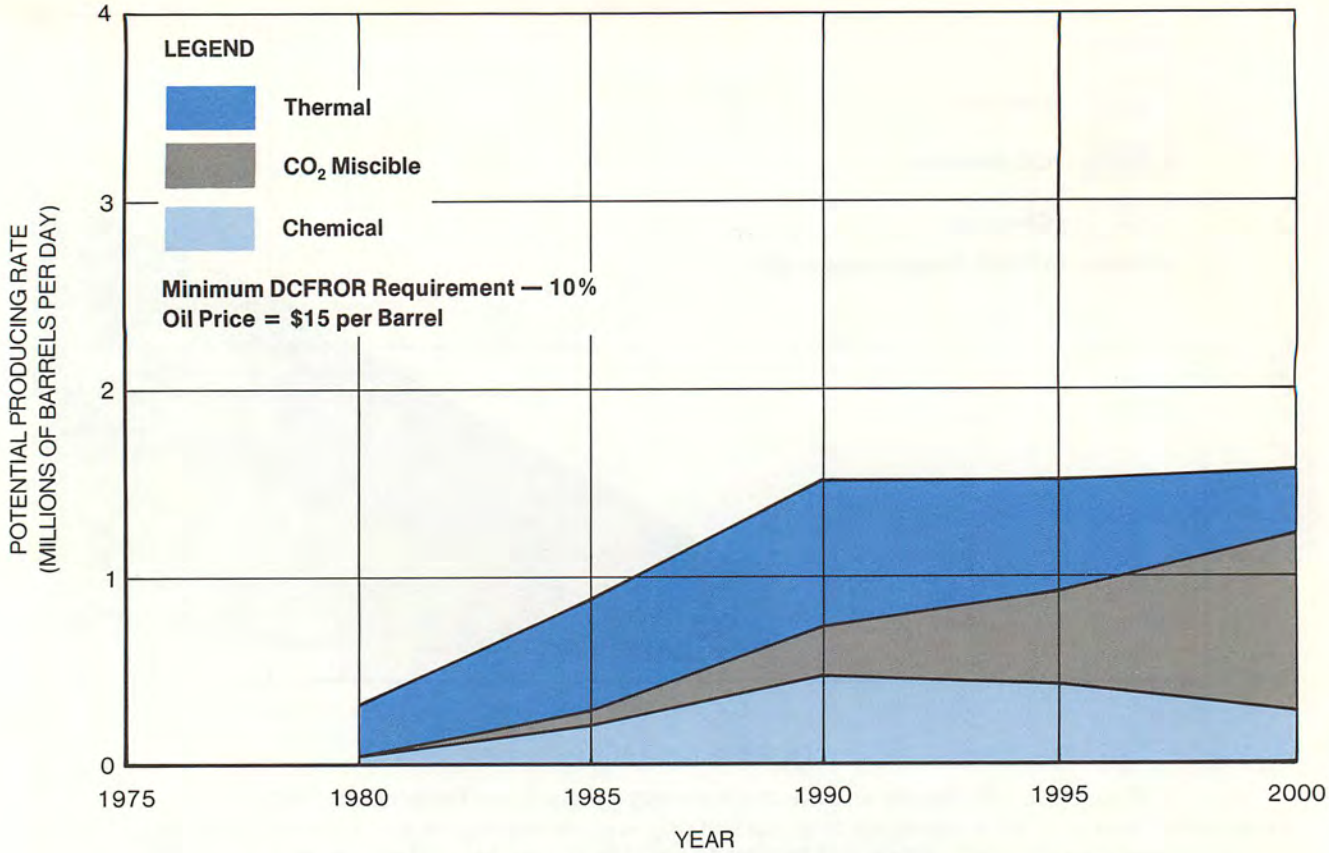


Figure 13. Potential Producing Rate—Base Case Performance and Costs.

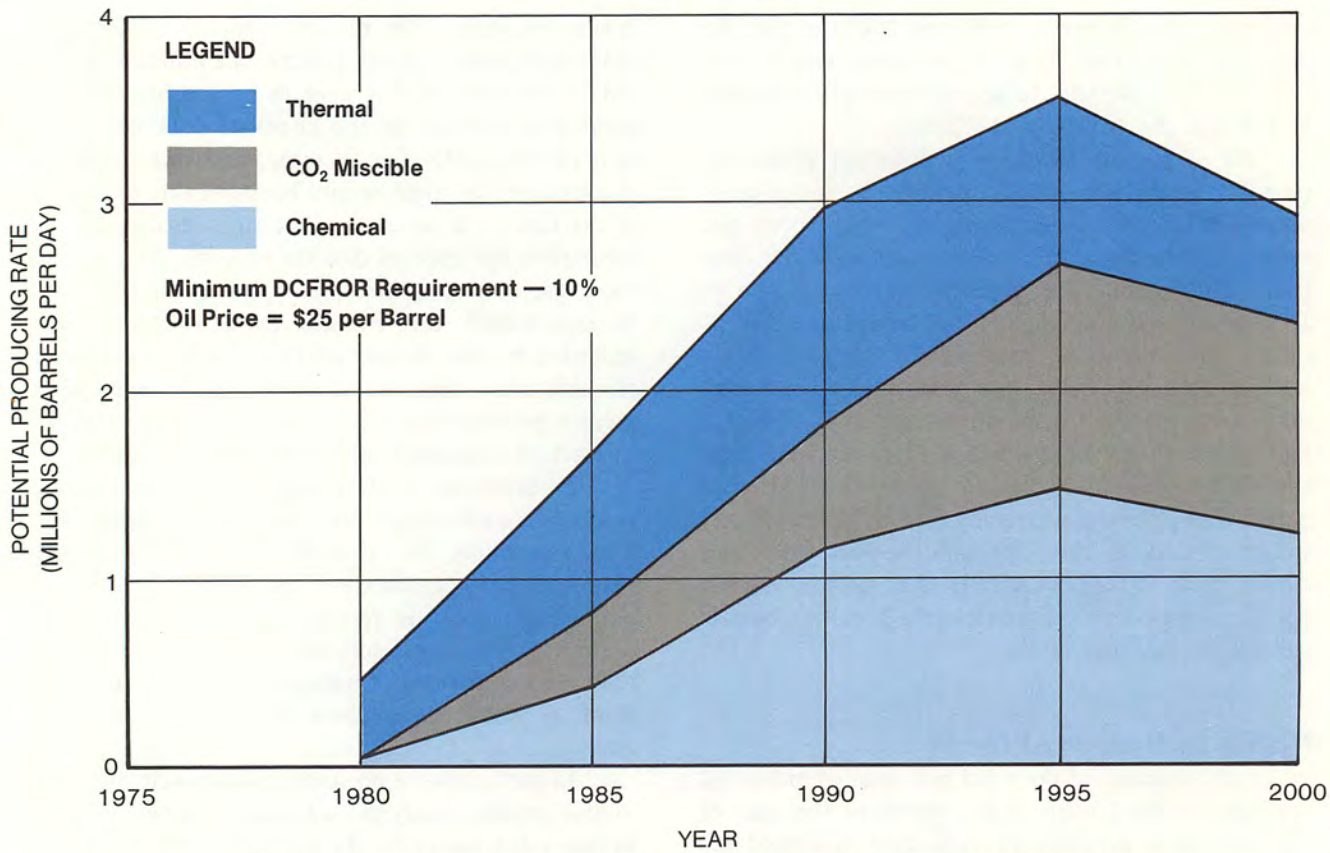


Figure 14. Potential Producing Rate—Base Case Performance and Costs.

specifically noted. All results except those specifically comparing tax cases are for the "moderate" tax case. When comparing results for different oil prices, the discounted cash flow rate of return requirement is 10 percent unless otherwise noted. Additional results for each process are presented in the process appendices.

Chemical Flooding

The base case results for ultimate recovery and potential producing rate of chemical flooding are shown in Figures 15 and 16. These results represent the sum of individually calculated results from surfactant, polymer, and alkaline flooding processes. In this analysis it was apparent that surfactant flooding, with a maximum incremental ultimate recovery of over 8 billion barrels, constituted the bulk of chemical flooding potential. The base case ultimate recovery of polymer flooding was calculated to be a maximum of approximately 470 million barrels, and of alkaline waterflooding to be a maximum of less than 400 million barrels. More detailed results for polymer and alkaline waterflooding, together with analyses of the effect of key variables, are presented in Appendix D.

The base case results for surfactant flooding are shown in Figures 17 and 18. They indicate essentially no economic production from surfactant flooding at an oil price less than $10 per barrel. This is consistent with the fact that essentially no oil has been produced economically by surfactant flooding to date. At a rate of return requirement of 10 percent, the incremental ultimate recovery from surfactant flooding is strongly affected by oil price, showing a potential of slightly over 2 billion barrels at $15 per barrel, about 6.5 billion barrels at $20 per barrel, and nearly 8.4 billion barrels at $25 per barrel. At higher required rates of return, however, the potential drops off rapidly, with few projects able to achieve as much as a 20 percent DCFROR.

Essentially no economic production from surfactant flooding is expected prior to the early 1980's under any economic condition. By 1985 potential producing rate could range from about 120 thousand barrels per day at $15 per barrel to over 300 thousand barrels per day at $25 per barrel. The peak rate from surfactant flooding on existing reservoirs, with the development schedule used in this analysis, would occur around 1995, and would range from around 350 thousand barrels per day at $15 per barrel to more than 1.4 million barrels per day at $25 per barrel.

The degree to which a single "best estimate" projection presents an incomplete picture of the potential of surfactant flooding is shown vividly in examining the variability of results as a function of oil recovery performance. Results of this analysis are shown in Figures 19 and 20. The "high" and "low" estimates of performance on these figures are defined and discussed in detail in Appendix D. Fundamentally, they represent the range of potential outcomes associated with uncertainties in reservoir oil saturation before and after a surfactant flood. Incremental ultimate recovery at $15 per barrel ranges from about 140 million barrels to over 11 billion barrels, with a base case result of slightly over 2 billion barrels. At $25 per barrel, with a base case estimate of nearly 8.4 billion barrels of ultimate recovery, results show a range of potential outcomes from about 2 billion barrels to nearly 13 billion barrels.

The corresponding range of potential producing rates for $15 per barrel in 1985 is from near zero to about 450 thousand barrels per day. At the peak producing rate in about 1995, potential producing rate ranges from near zero to about 1.8 million barrels per day.

While the high and low curves in Figures 19 and 20 are considered to be substantially less probable than the best estimates characterized by the base case, there is a significant probability that surfactant flooding results could be even higher or lower than results shown, since the range of potential results in these two figures is based on variability in only one key parameter associated with the process.

Variability in results for surfactant flooding, as a function of chemical cost, is shown in Figures 21 and 22. Since the potential recovery from surfactant flooding in any given reservoir is assumed to be independent of chemical costs in the analysis procedures, uncertainty in this parameter has an influence on the oil price required to achieve a given level of incremental ultimate recovery or production, but not on the maximum recovery attainable from that reservoir. The number of reservoirs to which surfactant flooding may be economically applied is smaller with higher chemical costs, and larger with lower chemical costs, with resulting variability in total recovery and producing rate. At an oil price of $15 per barrel, incremental ultimate recovery may vary from approximately 2 billion barrels to nearly 8 billion barrels, depending on chemical costs. Peak producing rate in 1995 would also vary from 350 thousand barrels per day to about 1.3 million barrels per day. Higher chemical costs would tend to reduce the incremental ultimate recovery at $25

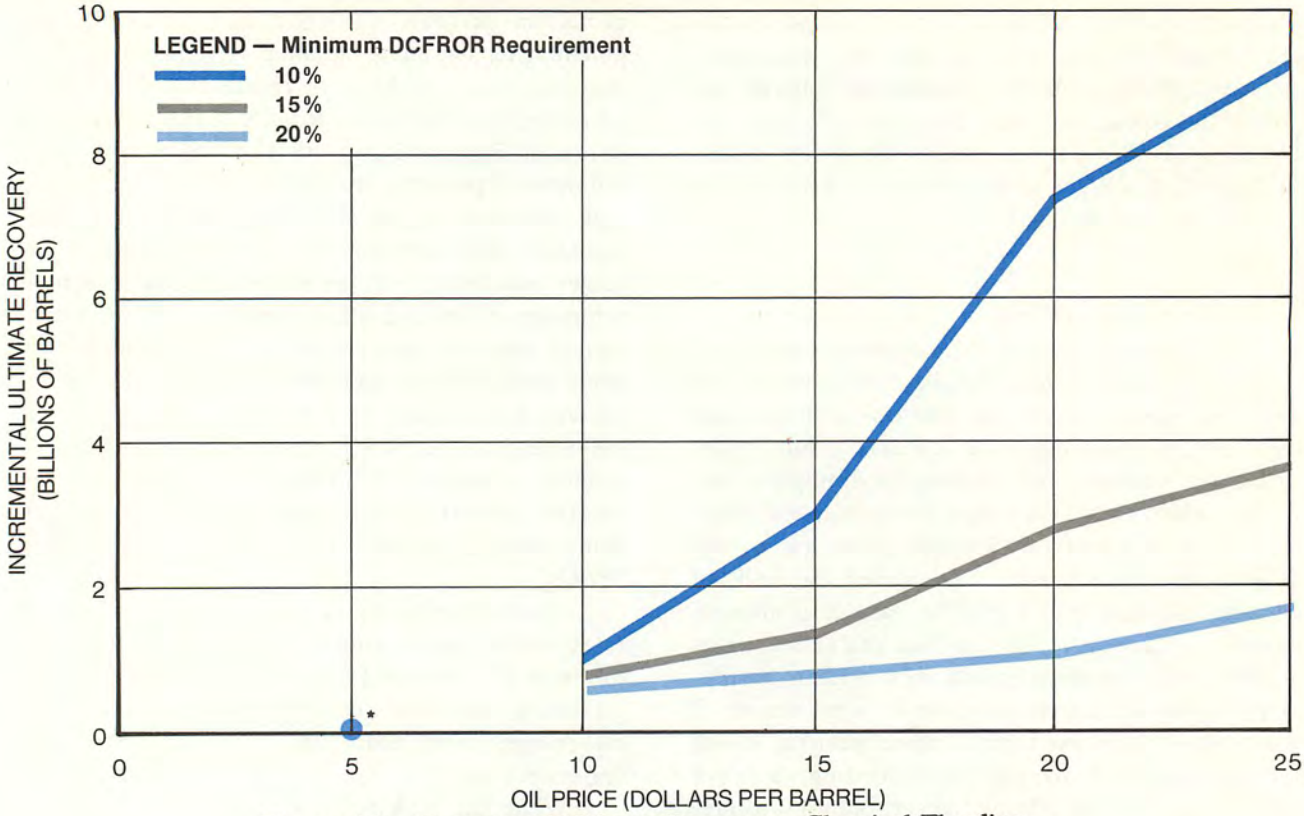


Figure 15. Incremental Ultimate Recovery—Chemical Flooding—Base Case Performance and Costs.

* Recovery for chemical flooding is zero at $5 per barrel and as shown at $10 per barrel.

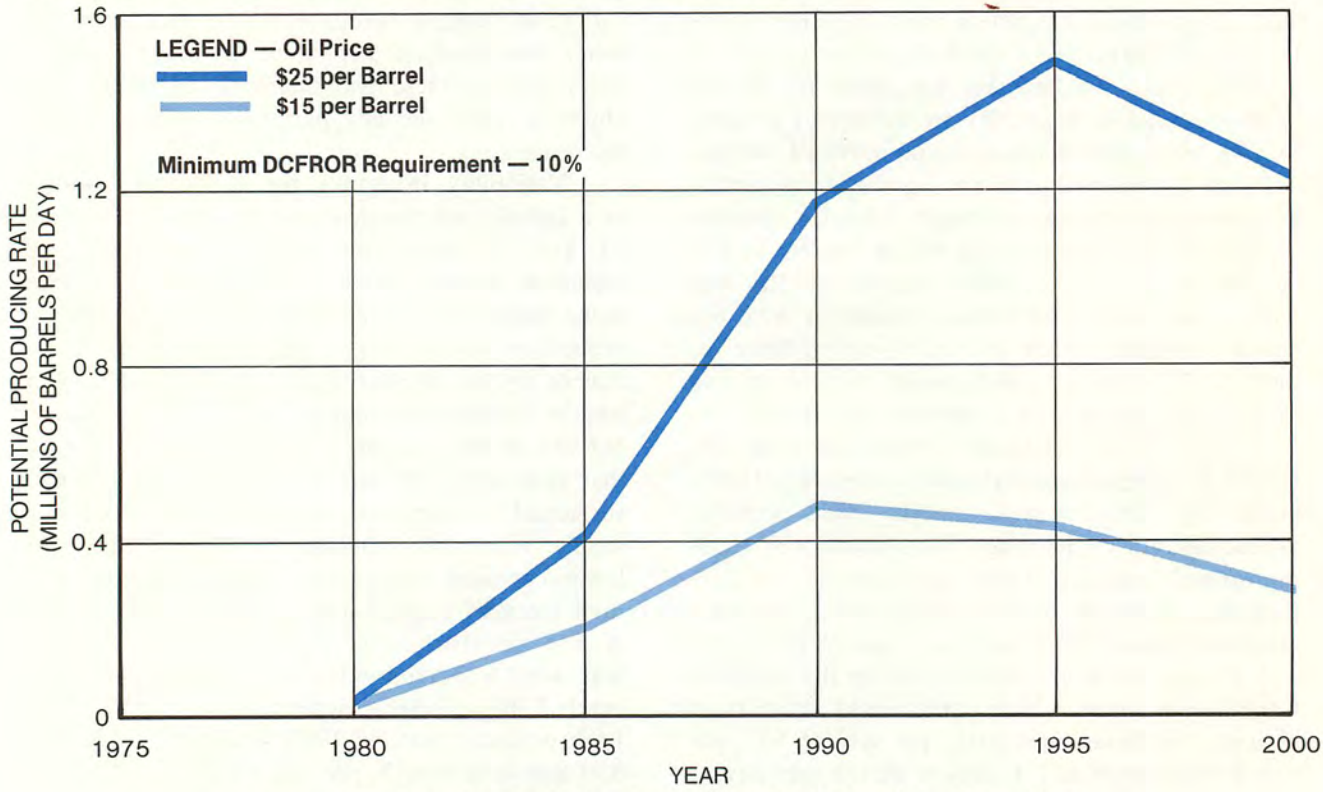


Figure 16. Potential Producing Rate—Chemical Flooding—Base Case Performance and Costs.

per barrel from a base case value of nearly 8.4 billion barrels to approximately 3 billion barrels.

The assumption that recovery in a given reservoir is independent of chemical cost was necessary to develop workable analysis procedures, but is not fully realistic. Lower chemical costs might permit larger chemical slugs, with some resulting increase in recovery. This second order effect was considered to be beyond the scope of this analysis.

Chemical costs represent a large fraction of the total cost of surfactant flooding. Since surfactant costs are directly associated with the cost of petroleum feedstocks, it was necessary to derive an escalation factor for surfactant costs based on the fraction of chemical production costs attributable to feedstock costs. This escalation factor could not be determined accurately. The range of chemical costs shown represents approximately a ± 25 percent variation in surfactant costs at any given oil price. Since both the type and quantity of chemicals required for surfactant flooding are uncertain at this time, the ± 25 percent variation used in this study is well within the bounds of the uncertainty in this key process parameter.

The variability in results for surfactant flooding as a function of other key parameters, such as the well spacing or chemical slug size used in the reservoir for this process, is shown in Appendix D.

Carbon Dioxide Miscible Flood

The base case results for incremental ultimate recovery and potential producing rate of carbon dioxide miscible flooding are shown in Figures 23 and 24.* The potential of this process is heavily dependent on oil price and reasonably sensitive to the rate of return requirement. No economic production from the process is expected at an oil price of $5 per barrel. The threshold level to begin production is between $5 and $10 per barrel with projected incremental ultimate recovery of 3 billion barrels at $10 per barrel and a 10 percent DCFROR requirement. Incremental ultimate recovery is projected at 5.3 billion barrels of oil at $15 per barrel, and as much as 7.2 billion barrels at $25 per barrel.

Even under favorable circumstances, little incremental production (over that from the few projects in existence today) would be expected before the mid-1980's. Peak production would not be expected to occur until around the year 2000, and would range from about 500 thousand barrels per day with oil at $10 per barrel to about 1.1 million barrels per day with oil at $25 per barrel. The delay in reaching peak production is due in part to time factors associated with development of CO_2 sources, transmission systems, and oilfield facilities, and in part to the relatively low injectivity and productivity of several of the reservoirs to which this process is applicable. Production by the year 1990 would be expected to be less than half of the ultimate peak producing rate for any oil price.

The several factors influencing and tending to delay production with the carbon dioxide miscible flooding process are reviewed in detail in Appendix E. The most significant factor is the time required to find and develop CO_2 reserves and to justify and build appropriate pipeline networks to bring CO_2 from where it is found to where it is needed. The analysis procedures are based on the assumption that sufficient CO_2 can be found to satisfy process requirements for each oil price assumed. The procedures include consideration of the time required for pilot testing in developing economic justification for a pipeline. The pipeline timing is assumed to be dependent on these and other economic parameters.

The potential variability in process performance makes the projections of both recovery and production rate in the base case uncertain at this time. The "best estimate" results in the base case are based on analysis procedures in which the process is assumed to perform relatively poorly in reservoirs that pass the screen but are considered "poor" candidates, and to perform well in reservoirs that are considered "good" candidates. The sensitivity of incremental ultimate recovery and potential producing rate to process performance is shown in Figures 25 and 26. In each case the upper curve is based on the assumption that all reservoirs perform at the level of a "good" reservoir and the lower curve is representative of all reservoirs performing at the level of a "poor" reservoir.

At $10 per barrel, the range of incremental ultimate recovery is from 1 to 5 billion barrels, with a base case of 3 billion barrels. At an oil price of $25 per barrel, the range of ultimate recovery is from 4.4 to 10 billion barrels, with a base case result of 7.2 billion barrels.

Potential producing rate for an oil price of $15 per barrel continues to peak around the year 2000 in all cases, but ranges from approximately 400 thousand barrels per day to 1.2 million barrels per day with a base case result of approximately 900 thousand barrels per day.

*Potential producing rates for CO_2 miscible flooding (see Figures 24, 26, and 28) are shown past the year 2000 because of the late peak in production for this process.

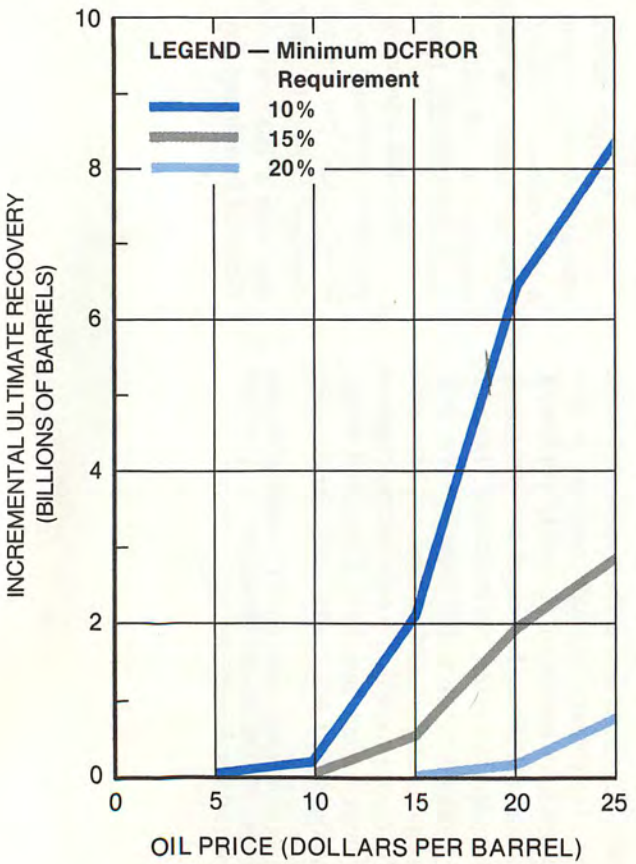


Figure 17. Incremental Ultimate Recovery—Surfactant Flooding—Base Case Performance and Costs.

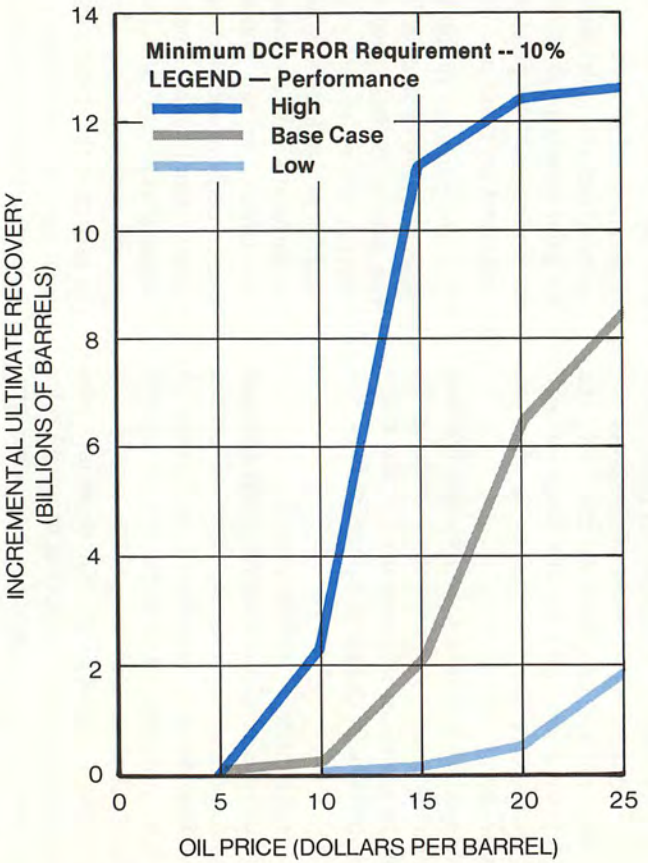


Figure 19. Surfactant Flooding—Variability of Incremental Ultimate Recovery with Recovery Performance.

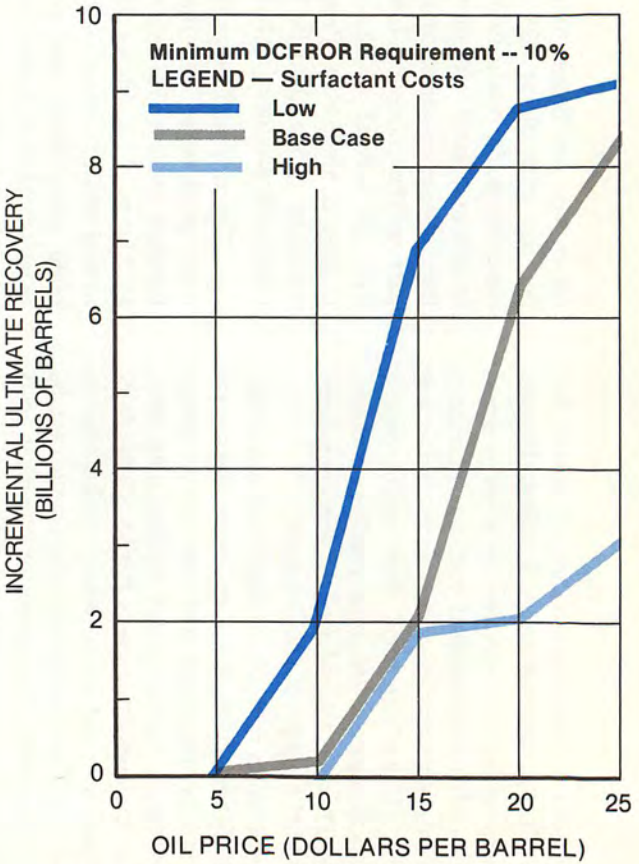


Figure 21. Surfactant Flooding—Variability of Incremental Ultimate Recovery with Surfactant Cost.

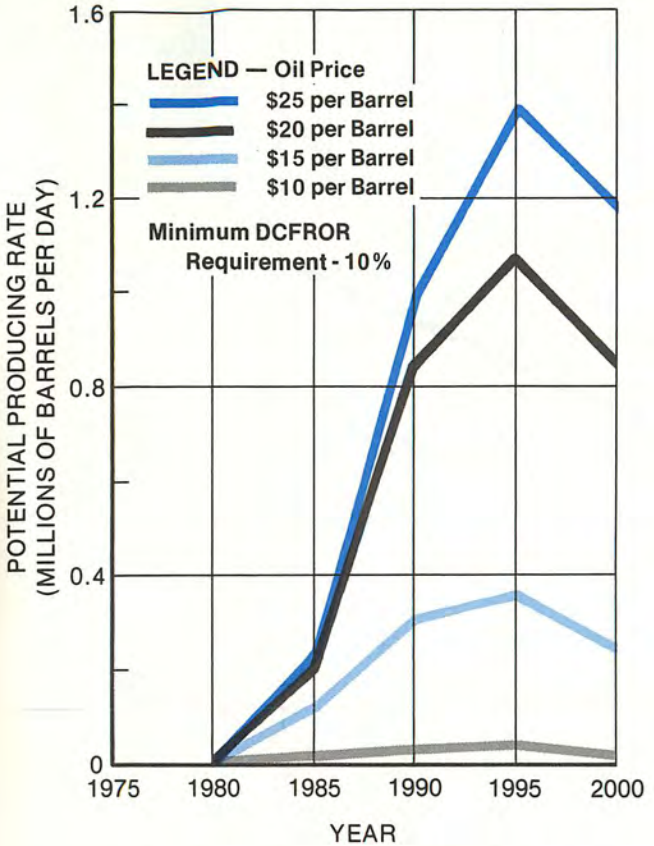


Figure 18. Potential Producing Rate—
Surfactant Flooding—
Base Case Performance and Costs.

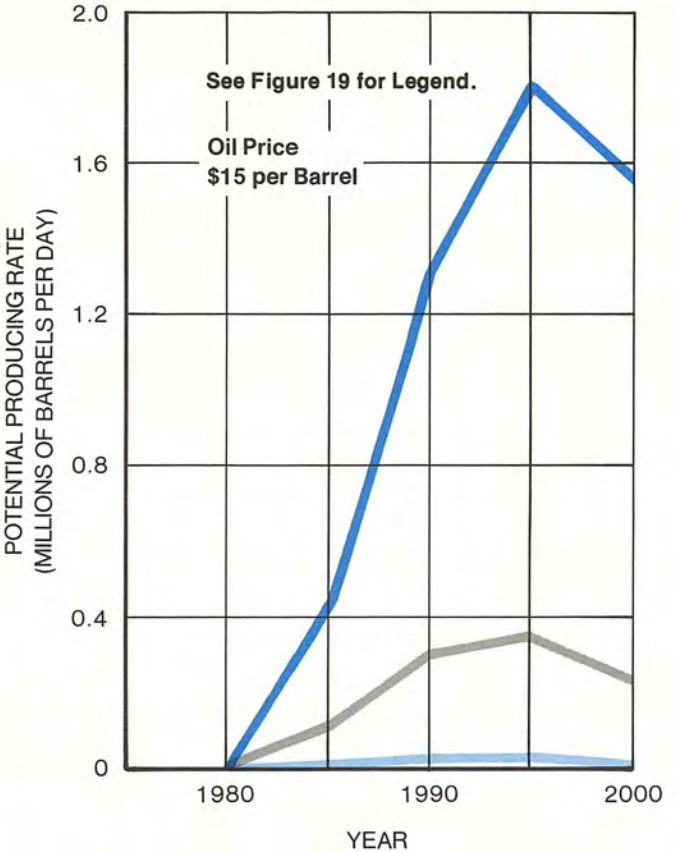


Figure 20. Surfactant Flooding—
Variability of Potential Producing Rate
with Recovery Performance.

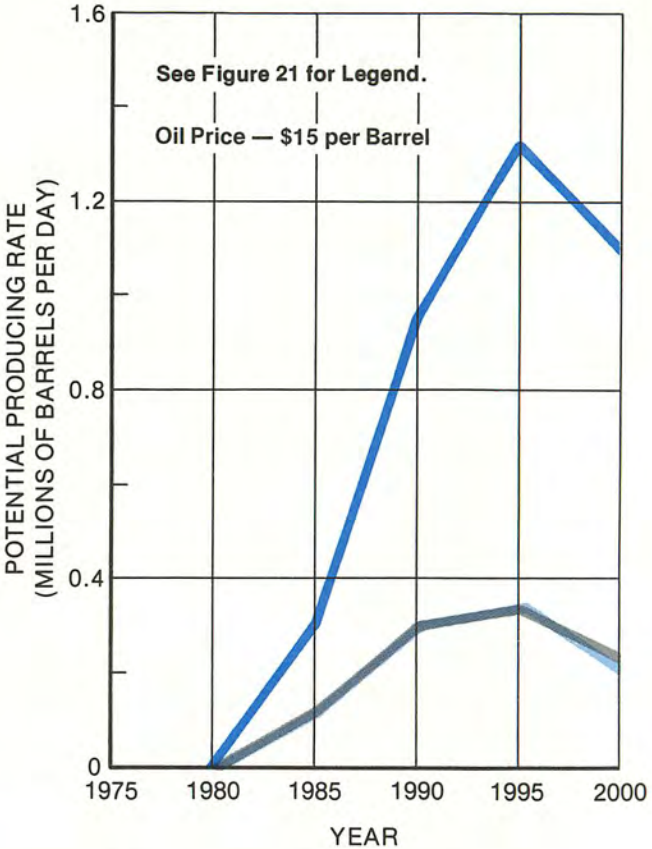


Figure 22. Surfactant Flooding—
Variability of Potential Producing Rate
with Surfactant Cost.

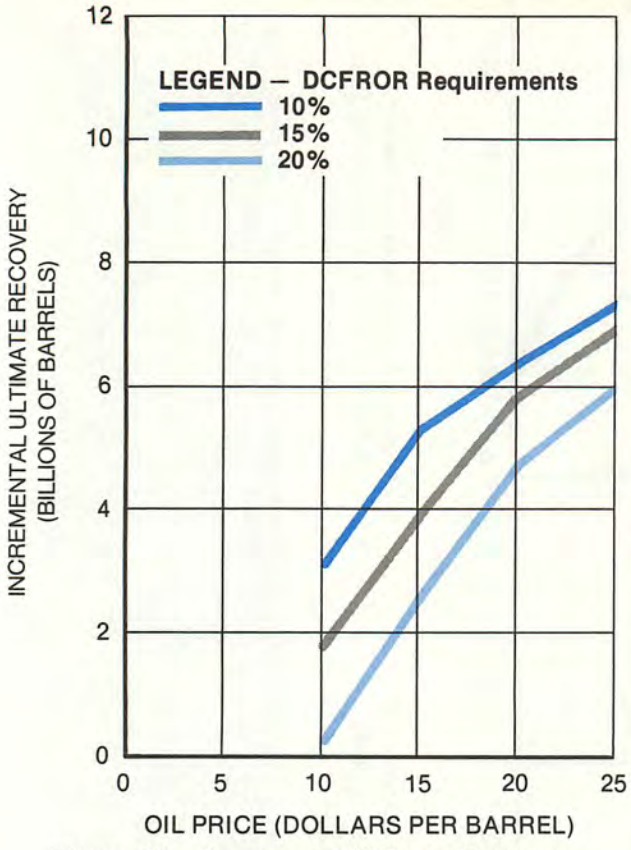


Figure 23. Incremental Ultimate Recovery—Carbon Dioxide Miscible Flooding—Base Case Performance and Costs.

Since CO_2 slug size was assumed to be a function of the economic parameters in this analysis, the recovery from any given reservoir was calculated to depend on economics. The range of estimates of incremental ultimate recovery shown in Figures 25 and 26 reflects both the impact of the performance of the carbon dioxide miscible flooding process in a single reservoir and the number of reservoirs to which the process could be applied economically.

A second major uncertainty in estimating the potential of the carbon dioxide miscible flooding process is the cost of carbon dioxide as delivered to the reservoir. This factor will be influenced strongly by the location and quality of CO_2 reserves yet to be found. Even with the assumption that sufficient volumetric reserves can be found, the development cost of such reserves and the cost to construct and operate pipelines from such reserves to the reservoirs where CO_2 is needed are speculative at this time.

Figures 27 and 28 show the sensitivity of incremental ultimate recovery and potential producing rate for the carbon dioxide miscible flooding process to the cost of carbon dioxide delivered to the reservoir.

In the base case calculations, carbon dioxide

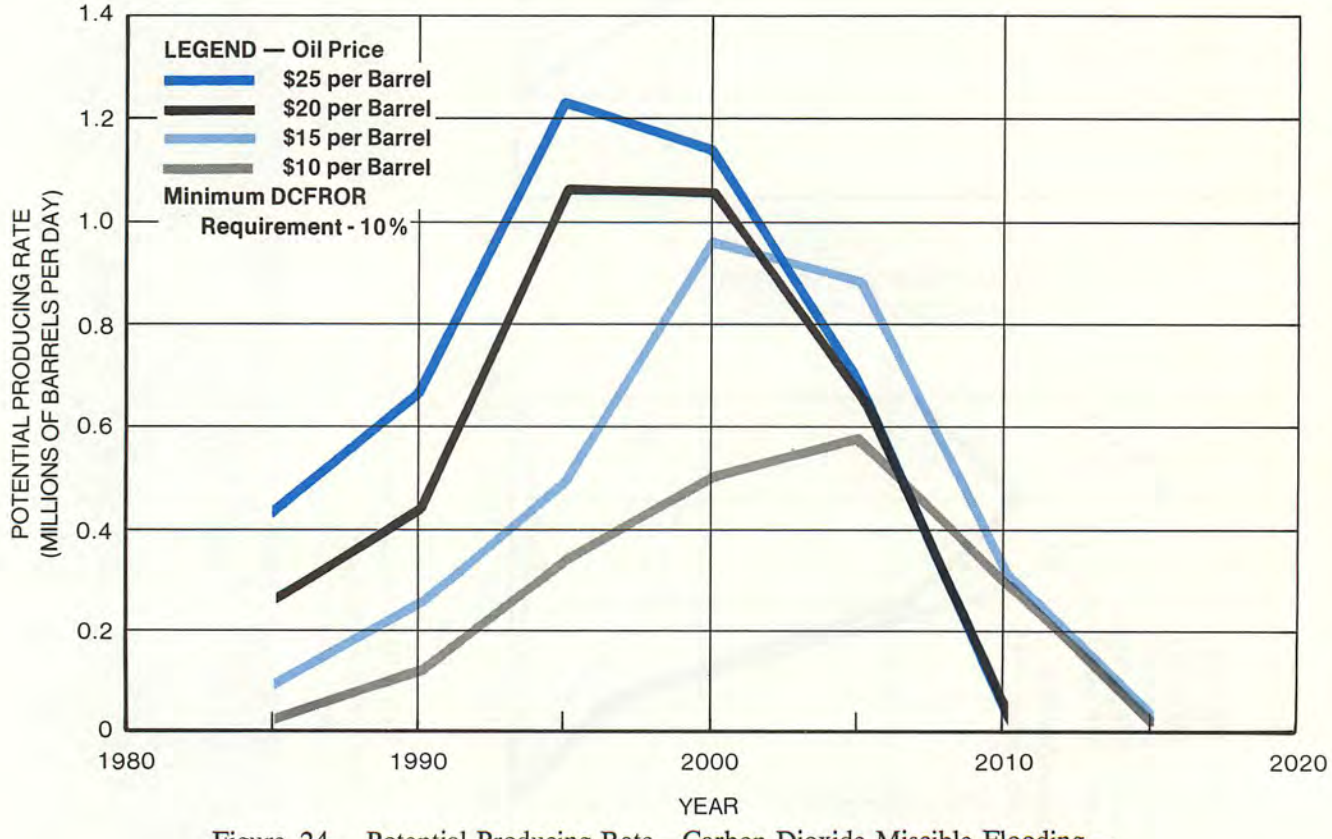


Figure 24. Potential Producing Rate—Carbon Dioxide Miscible Flooding—Base Case Performance and Costs.

cost was calculated for each reservoir based on the location of the reservoir in respect to both the assumed location of CO_2 reserves, and other reservoirs requiring CO_2 which would influence justification for a pipeline. The upper curve in Figures 27 and 28 represents potential production with lower cost CO_2 wherein the cost of CO_2 in each reservoir was assumed to be 50 percent of the cost calculated for the base case; the lower curve in both figures corresponds to production at twice the base case CO_2 cost. For higher cost CO_2, ultimate recovery at $10 per barrel drops to zero. Lower cost CO_2 shows a projected ultimate recovery of 4.6 billion barrels, with a base case of 3 billion barrels. The relative influence of carbon dioxide cost tends to decrease at higher oil prices. At $25 per barrel, the range of projected incremental ultimate recovery is from 5.8 billion barrels to approximately 8 billion barrels, with a base case of 7.2 billion barrels.

The peak potential producing rate around the year 2000, with low cost CO_2 is only marginally higher than in the base case. The primary influence of lower CO_2 costs is a higher rate of production in the time frame 1985-1995. Lower cost CO_2 would permit the start of projects with trucked CO_2 that otherwise would be uneconomic, or that would be-

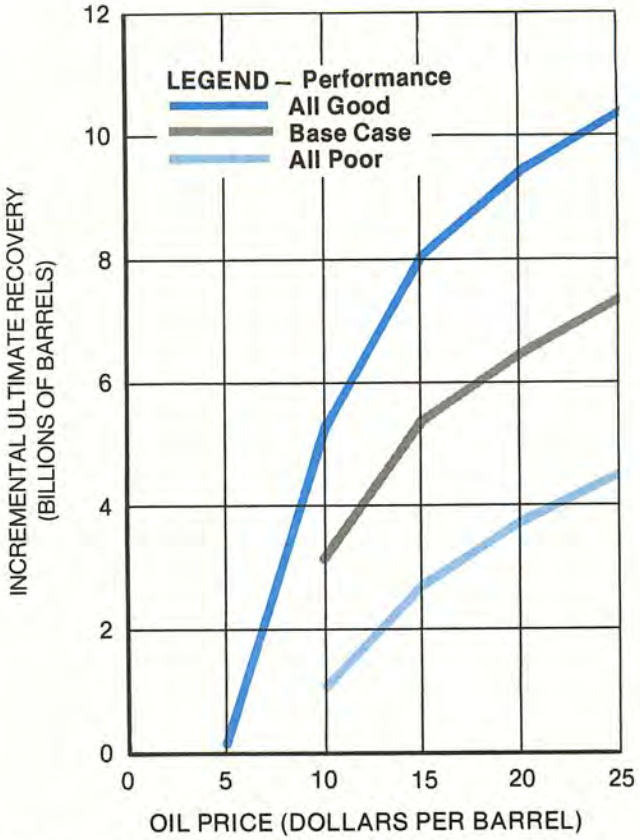


Figure 25. Carbon Dioxide Miscible Flooding—Variability of Incremental Ultimate Recovery with Reservoir Recovery Performance.

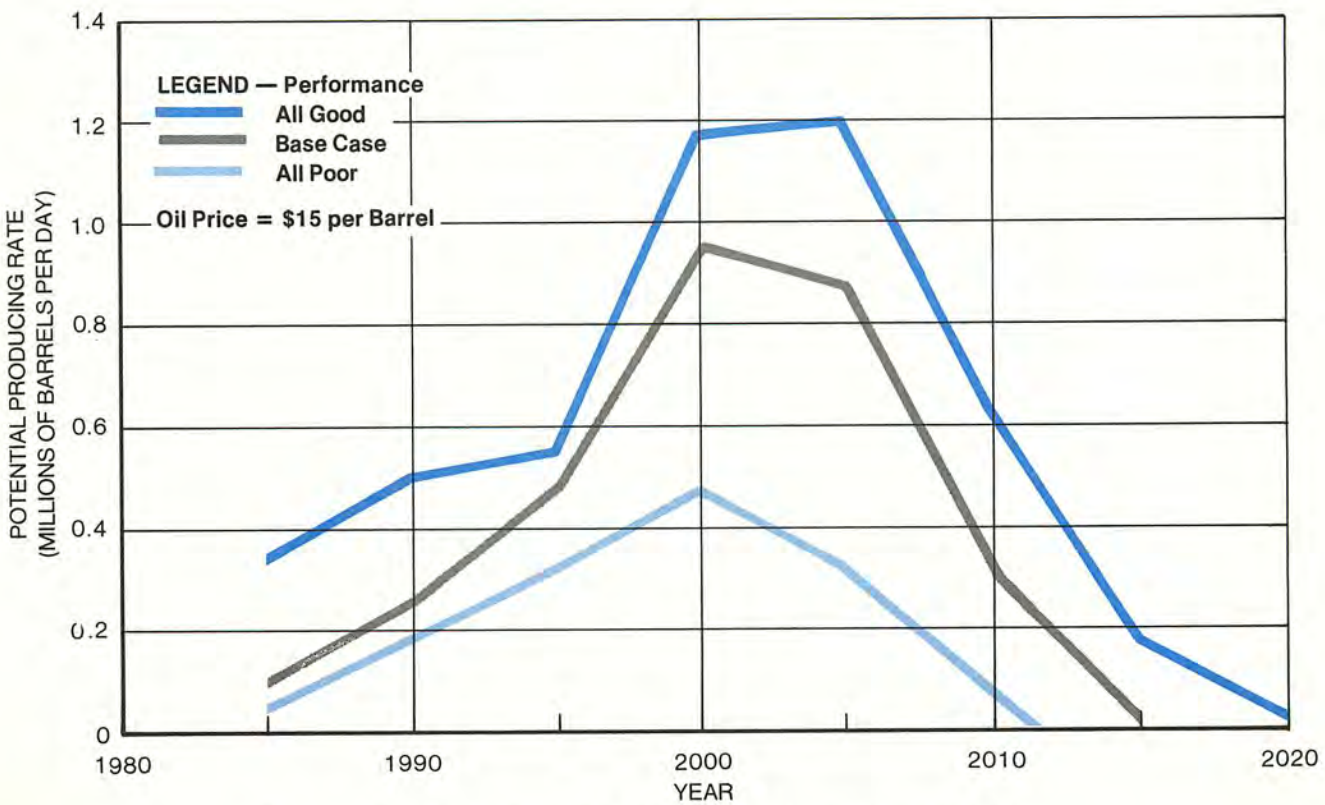


Figure 26. Carbon Dioxide Miscible Flooding—Variability of Potential Producing Rate with Reservoir Recovery Performance.

come economic only after a pipeline was justified and built. With higher CO_2 costs, however, peak producing rate of approximately 500 thousand barrels per day is only about half of that attainable with base case costs or lower CO_2 costs.

Further discussion of the variability of the potential of carbon dioxide miscible flooding with key parameters is presented in Appendix E.

Thermal Recovery

Thermal recovery encompasses the process of steam drive with associated steam stimulation, hot water flooding, and in-situ combustion. Results in this section are shown as the sum of all processes. More detailed results showing the distribution between steam processes and in-situ combustion are given in Appendix F.

The base case incremental ultimate recovery and potential producing rates for thermal recovery are shown in Figures 29 and 30. Results are sensitive to oil price but relatively insensitive to minimum rate of return requirements. The effect of rate of return is discussed in more detail in the section on "Discussion of Results." The maximum potential ultimate recovery of about 7.5 billion barrels at $25

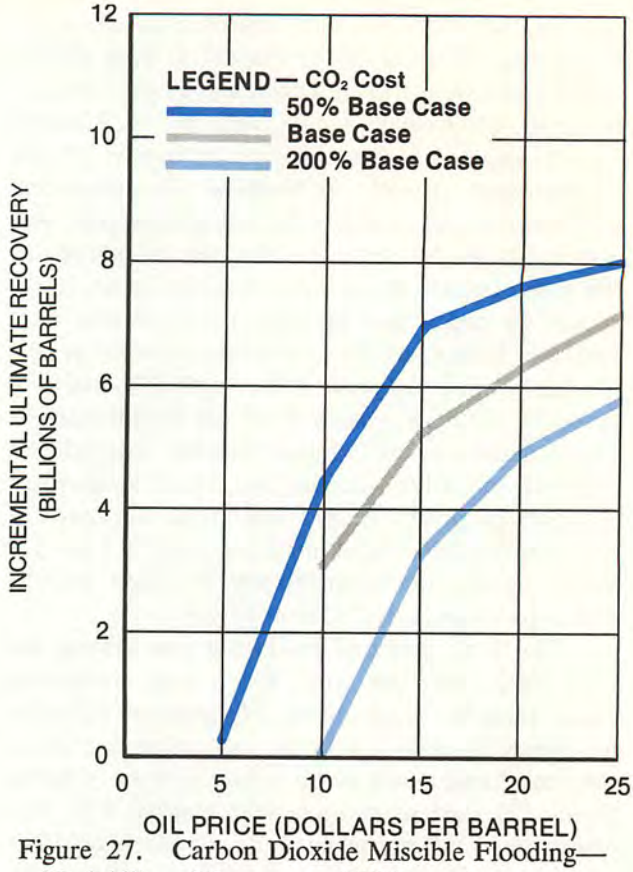


Figure 27. Carbon Dioxide Miscible Flooding—Variability of Incremental Ultimate Recovery with Carbon Dioxide Cost.

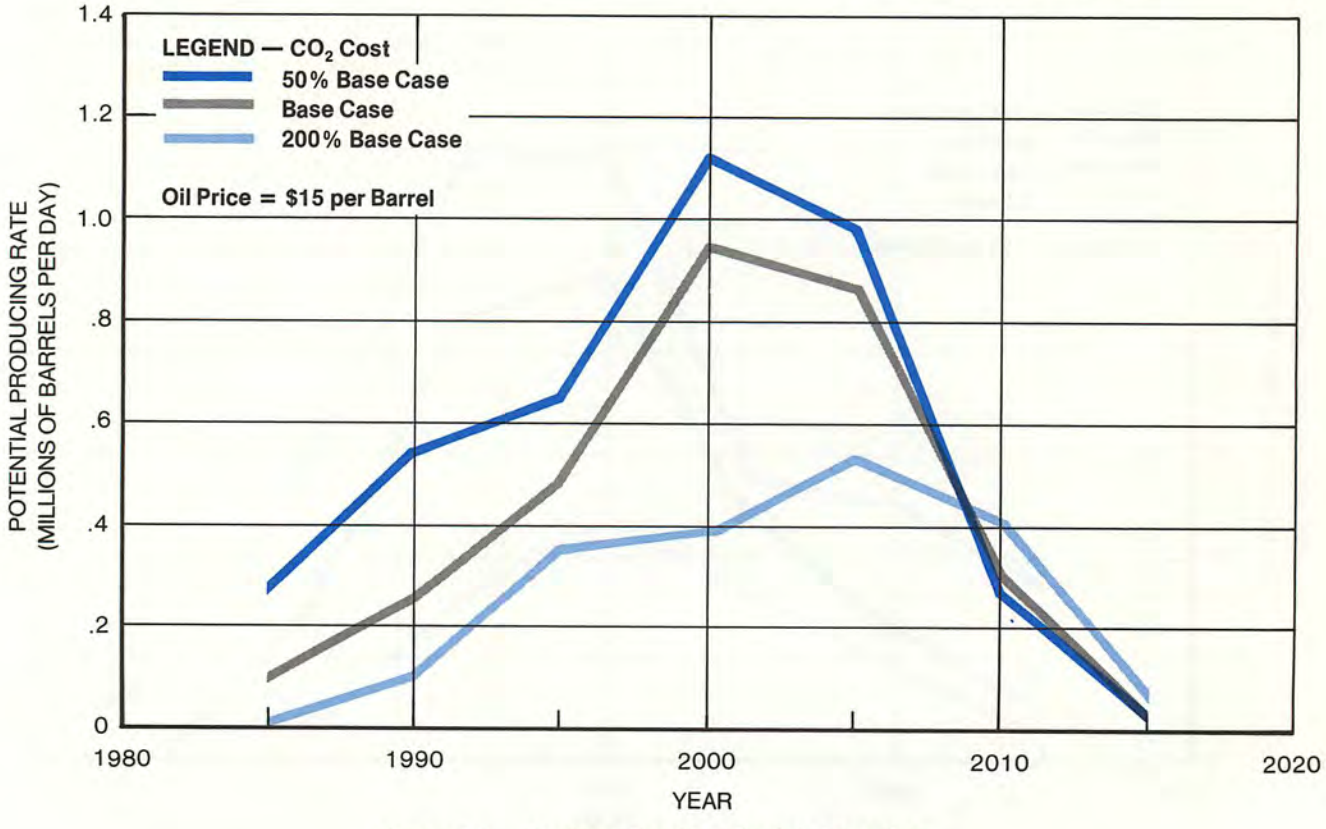


Figure 28. Carbon Dioxide Miscible Flooding—Variability of Potential Producing Rate with Carbon Dioxide Cost.

per barrel of oil is of the same order as that for surfactant or carbon dioxide miscible flooding. However, unlike the other two processes, approximately two-thirds of this potential is available at an oil price of $15 per barrel. The threshold value for accomplishing some incremental thermal recovery is about $5 per barrel, where an incremental recovery of approximately 2 billion barrels is indicated. Much of the current production from thermal methods in California is under price control which results in a price of less than $4 per barrel. Reservoirs that can be produced profitably at this price were the original "best prospects" in regard to reservoir characteristics for steam stimulation. Moreover, most are operated with relatively low cost equipment purchased before inflation had a major effect on process costs. Few, if any, new steamfloods could be started today with new equipment and operated profitably at oil prices of less than $4 per barrel.

Thermal recovery processes are the only area of enhanced recovery in which significant incremental rates of production are possible by the early 1980's. Depending on the level of economic incentive, incremental producing rates could range from about 200 thousand barrels per day to over 400 thousand barrels per day. This rate would be expected to continue to climb until about the year 1990. The producing rate at the peak in about 1990 is highly dependent on oil price, ranging from approximately 300 thousand barrels per day at $5 per barrel of oil to nearly 1.2 million barrels per day with oil at $25 per barrel. Production from the application of thermal methods to existing reservoirs would then be expected to decline fairly rapidly to a level of about 100 thousand barrels per day at $5 per barrel, or to 500 thousand barrels per day at $25 per barrel, in the year 2000.

Figure 31 shows the effect of a ±25 percent variation in recovery performance for the process applied to each reservoir. For oil at $15 per barrel, the range of potential ultimate recovery associated with uncertainty in process performance actually varies from 3 billion barrels to nearly 7 billion barrels, with a base case of about 5 billion barrels. Corresponding potential producing rates peak in about 1990 and range from 450 thousand barrels per day to about 1 million barrels per day, with a base case of 780 thousand barrels per day, as shown in Figure 32.

Figures 33 and 34 show the influence of an assumed variation in process cost from 90 percent to 125 percent of base case costs. The process cost which was varied does not include the cost of oil burned for process energy, except as this is reflected

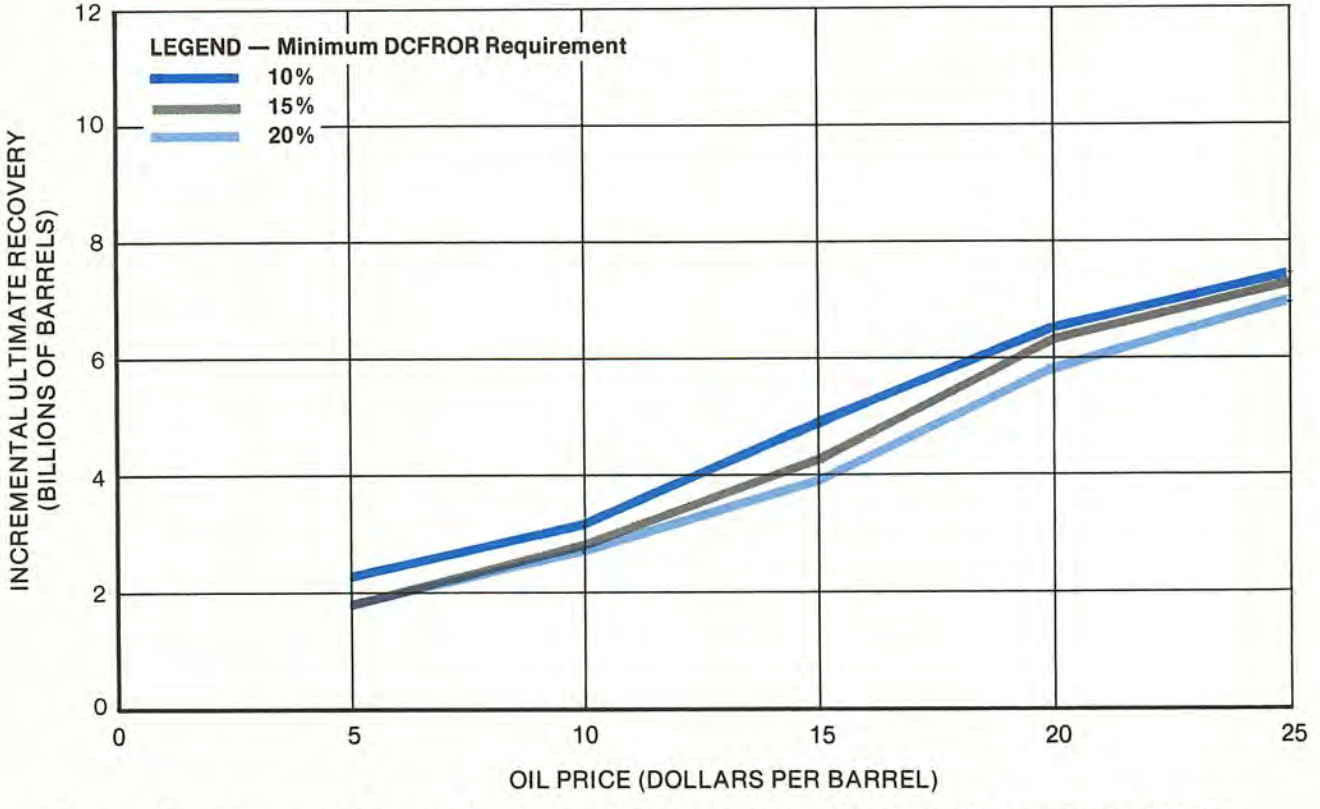


Figure 29. Incremental Ultimate Recovery—Thermal Recovery—Base Case Performance and Costs.

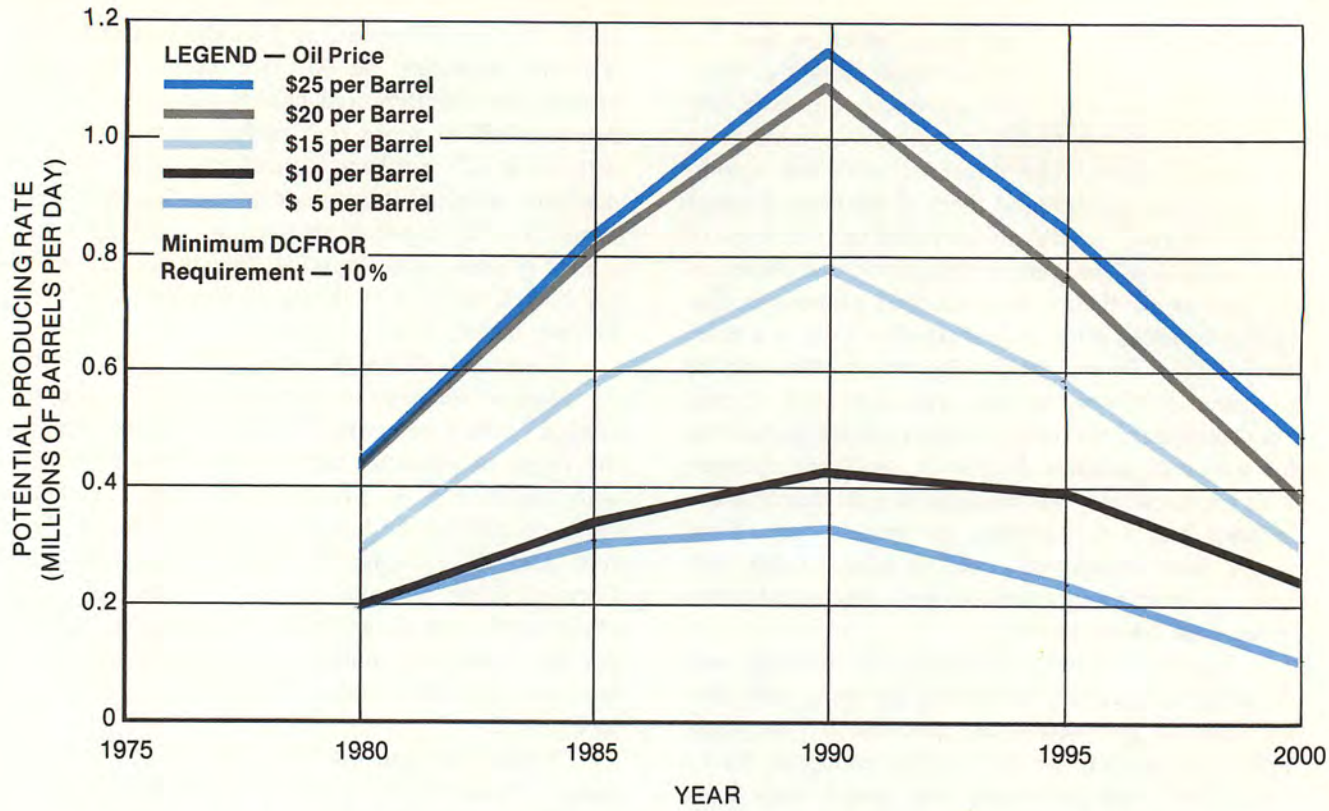


Figure 30. Potential Producing Rate—Thermal Recovery—Base Case Performance and Costs.

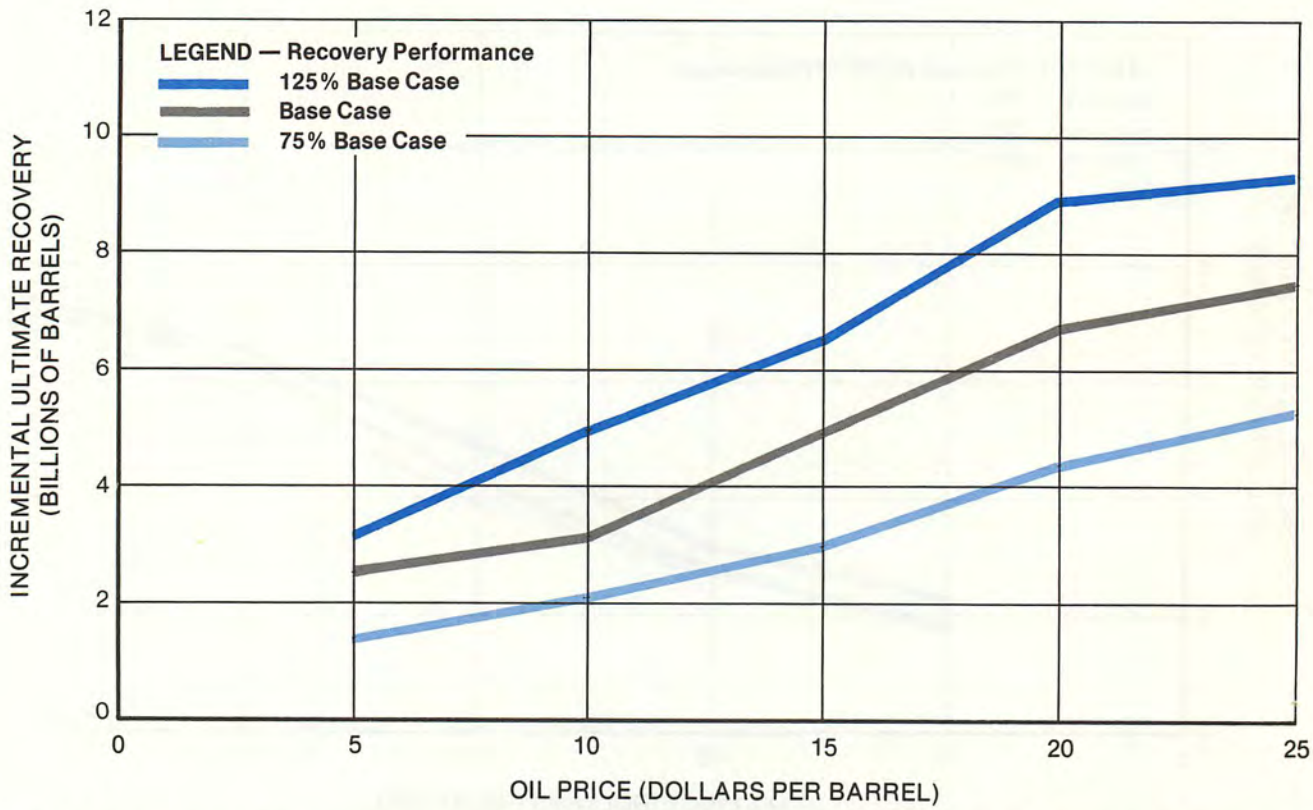


Figure 31. Thermal Recovery—Variability of Incremental Ultimate Recovery with Reservoir Performance.

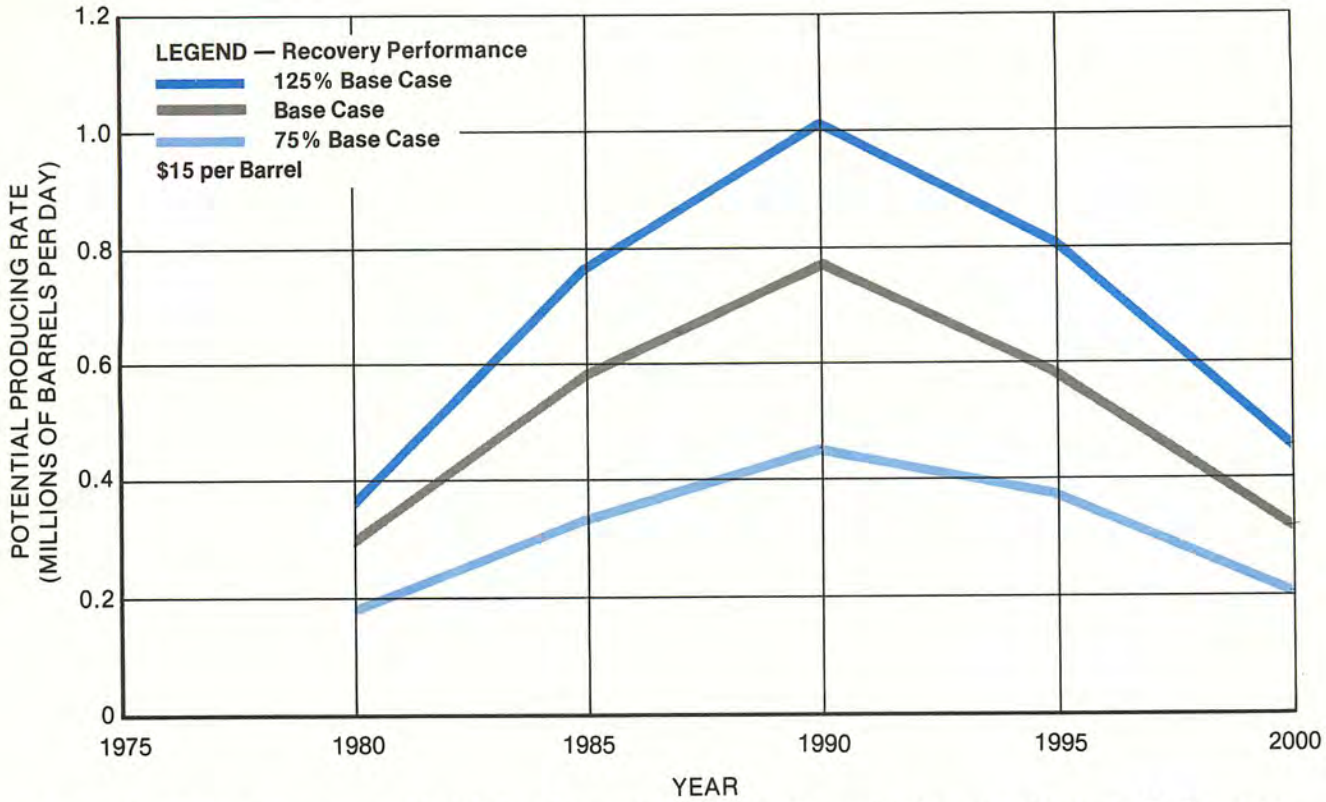


Figure 32. Thermal Recovery—Variability of Potential Producing Rate with Reservoir Recovery Performance.

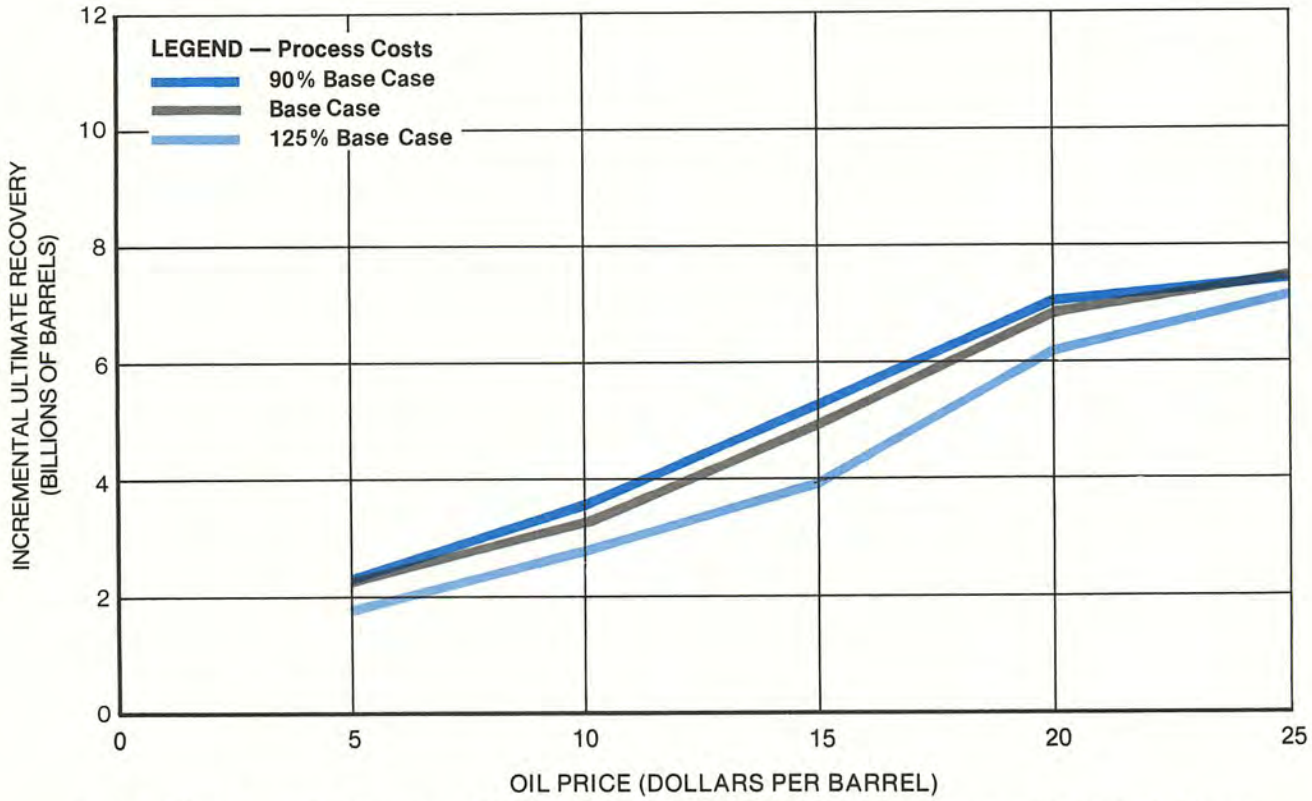


Figure 33. Thermal Recovery—Variability of Incremental Ultimate Recovery with Process Costs.

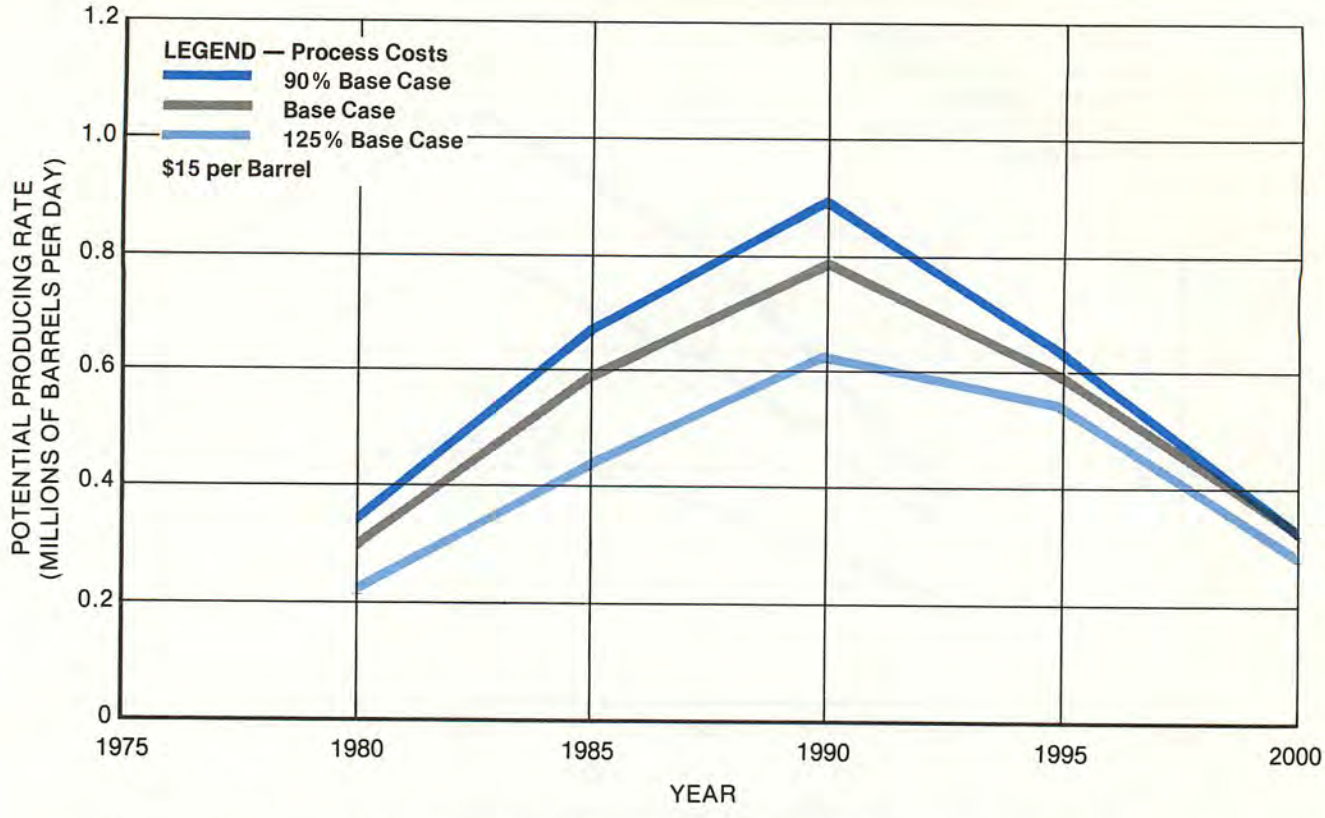


Figure 34. Thermal Recovery—Variability of Potential Producing Rate with Process Costs.

in a change in the production tax for the oil used as process fuel. As a result, only a small variation in ultimate recovery and potential producing rate is projected due to this parameter. While this probably understates the variability, it emphasizes the fact that thermal processes are far more sensitive to recovery performance than to non-fuel process costs.

Income Tax Sensitivity

Analysis of the two income tax cases specified for evaluation in this study shows that tax treatment strongly impacts on the potential magnitude and timing of enhanced oil recovery. All previous results in this chapter are based on the "moderate" tax specifications as described in Table 1, Chapter Two. To examine the effects of less favorable interpretations of existing tax laws, recovery and producing rate estimates were made for the base case estimates of performance and costs using the "restrictive" tax treatment, also described in Table 1. Longer depreciation terms and capitalization of injected fluids are key items in the "restrictive" tax treatment.

Figure 35 shows the potential incremental ultimate recovery at 10 percent DCFROR requirement for all processes for the two tax cases considered. The restrictive tax treatment would decrease the number of reservoirs satisfying specified economic criteria; it would reduce ultimate recovery by about 4 billion barrels at an oil price of $15 per barrel, and by 8 billion barrels for $25 per barrel oil. Corresponding results for a 20 percent DCFROR requirement are shown in Figure 36. The impact of the restrictive tax treatment on ultimate recovery from all processes is less at 20 percent DCFROR requirement primarily because the high rate of return requirement greatly diminishes the applicability of surfactant flooding, which is the process most sensitive to tax treatment.

Figure 37 shows the effect of the restrictive tax case on potential producing rate. Restrictive taxes would reduce potential enhanced oil recovery producing rates by about a third, or about 250 thousand barrels per day in 1985 and by 500 thousand barrels per day in the 1990-2000 period in the $15 per barrel oil price case. Figure 38 shows that the adverse effects of the restrictive case are even greater in the $25 per barrel price case, with resulting reductions in production rate of about 300 thousand barrels per day in 1985, 950 thousand barrels per day in 1990, and 1.25 billion barrels per day for 1995 through 2000.

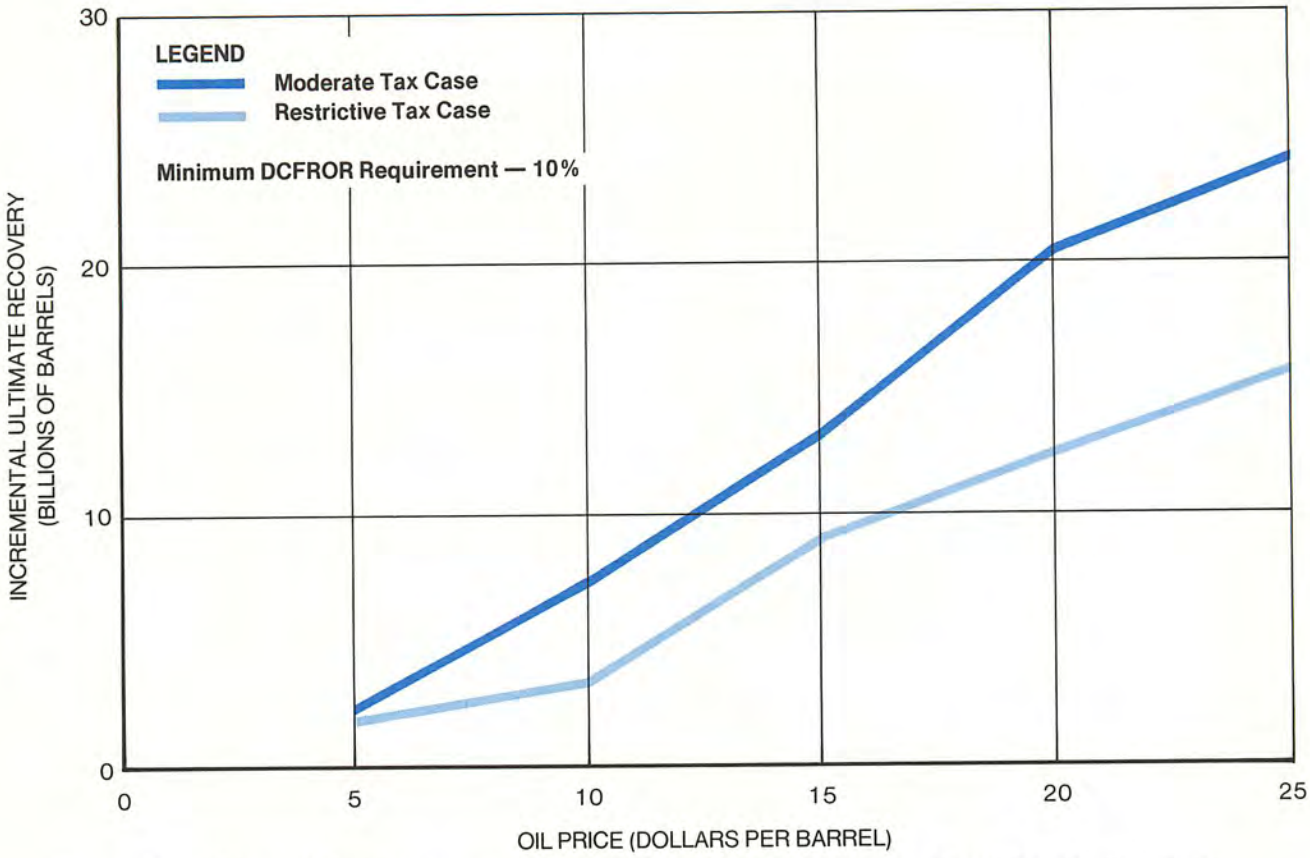


Figure 35. Effect of Tax Treatment on Incremental Ultimate Recovery—Total for All Processes.

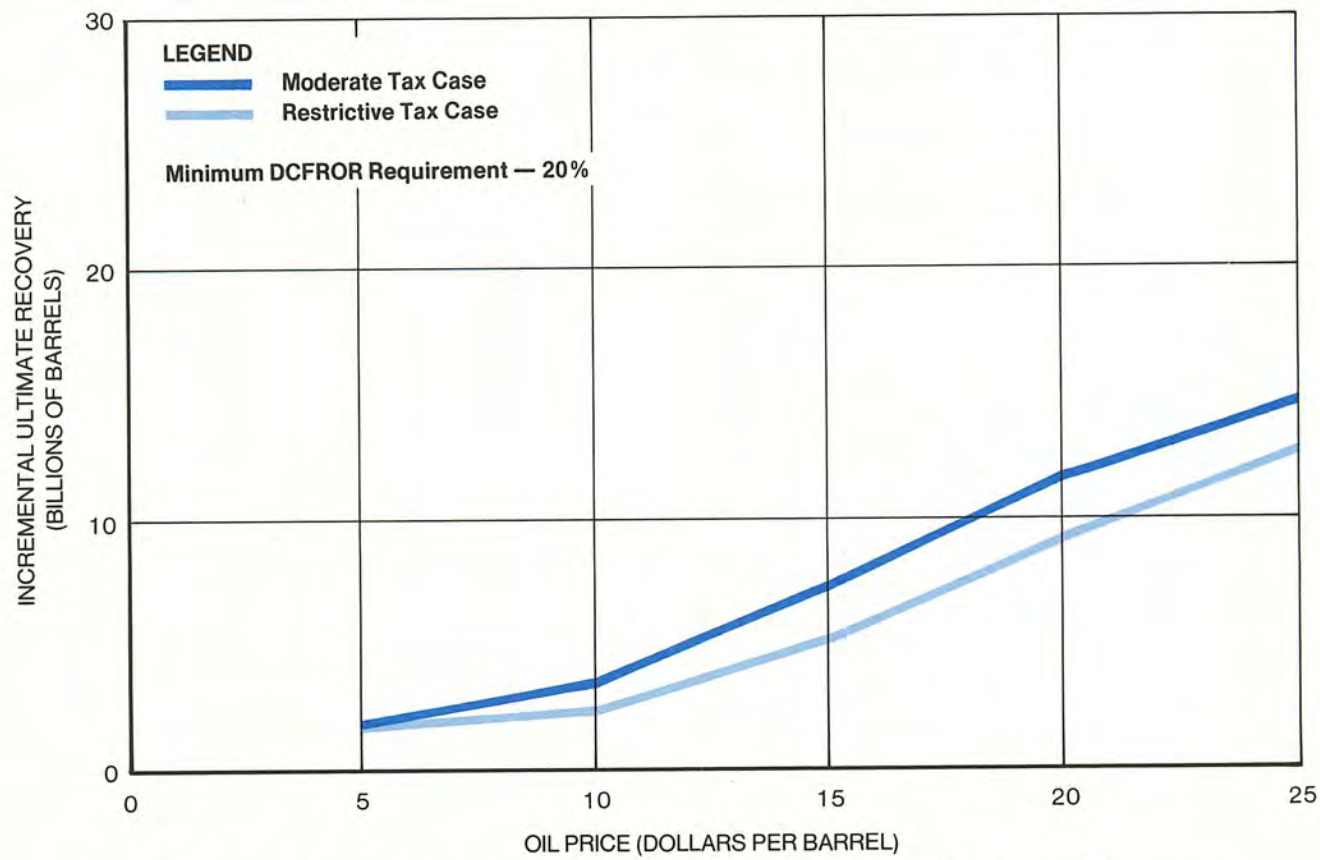


Figure 36. Effect of Tax Treatment on Incremental Ultimate Recovery—Total for All Processes.

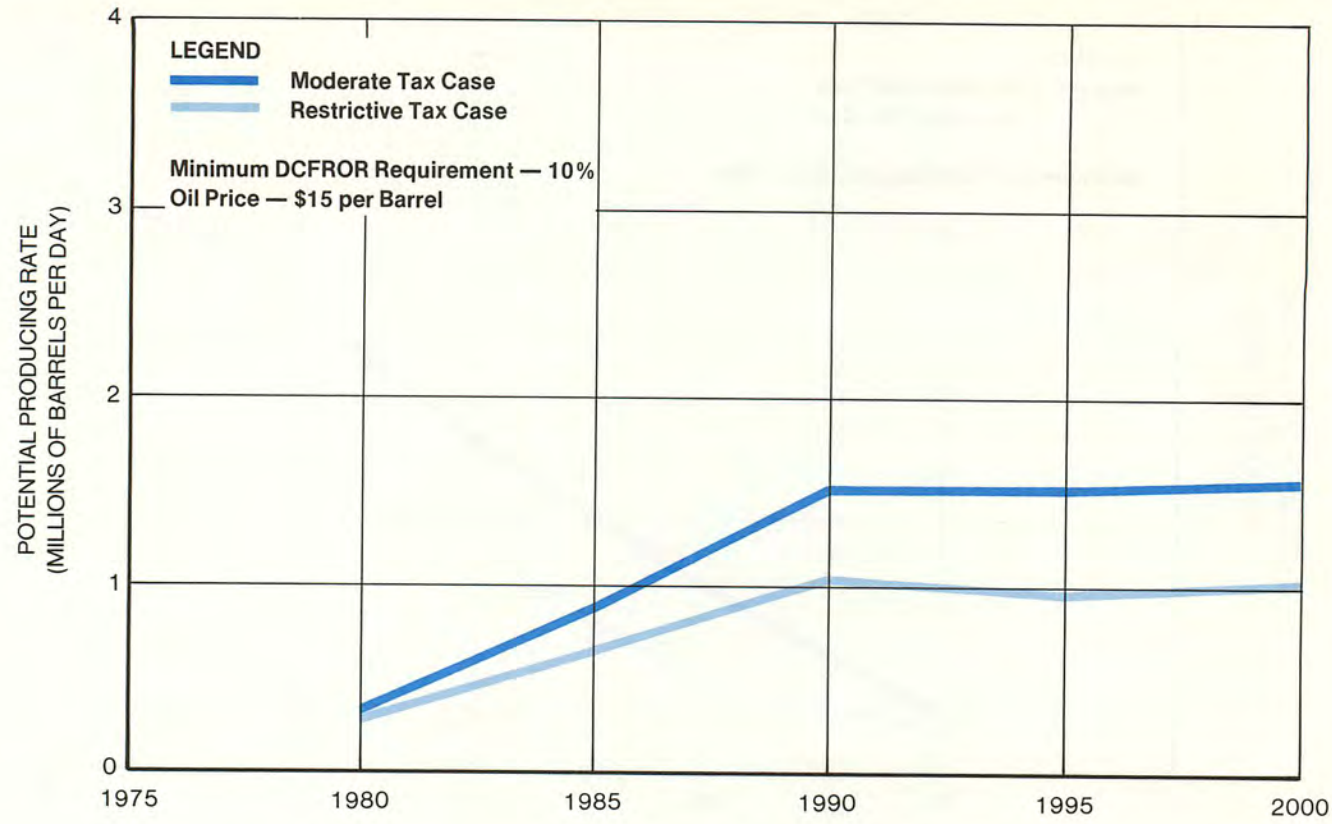


Figure 37. Effect of Tax Treatment on Potential Producing Rate—Total for All Processes.

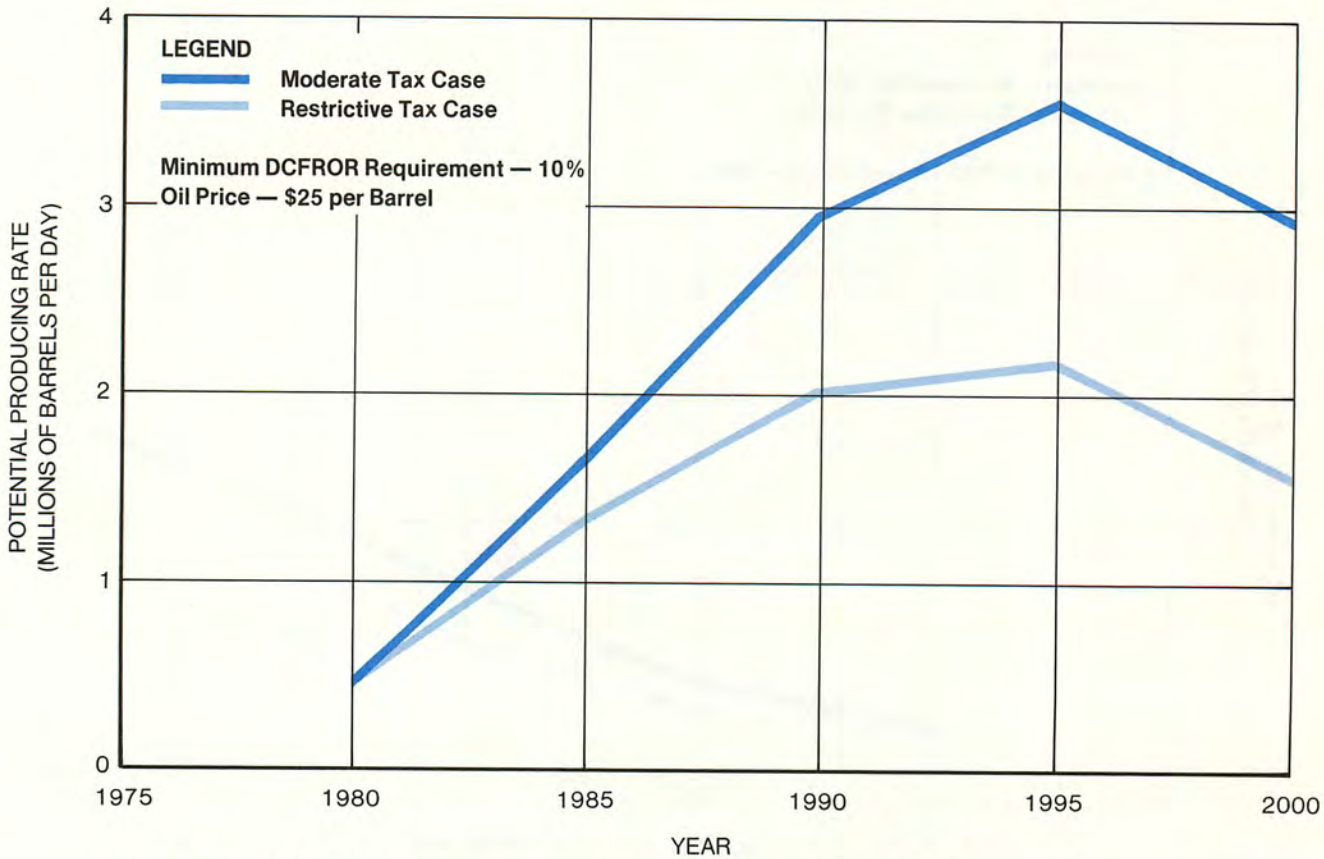


Figure 38. Effect of Tax Treatment on Potential Producing Rate—Total for All Processes.

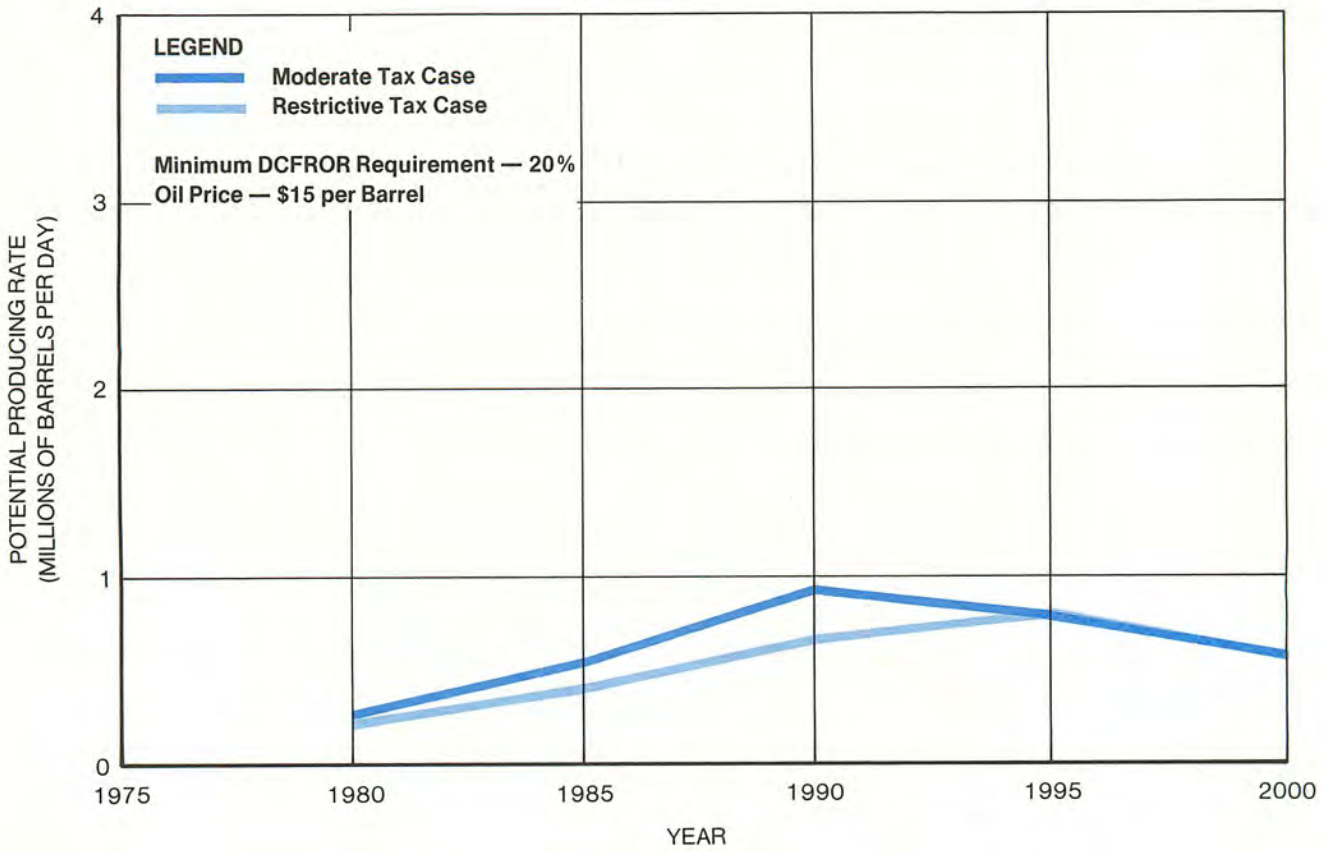


Figure 39. Effect of Tax Treatment on Potential Producing Rate—Total for All Processes.

The tax effects on potential producing rate diminish as DCFROR requirement increases, as shown in Figure 39. This is due to a corresponding decrease in the significance of surfactant flooding at high DCFROR requirement.

These comparisons demonstrate the importance of tax policy as a determinant of enhanced oil recovery potential.

Additional Cash Outlays and Field Activity Requirements

Total domestic industry cash outlays required for all enhanced oil recovery projects are estimated for key years as shown in Table 3.

These estimates show that expenditures required for EOR are extremely sensitive to oil price. The $25 per barrel case indicates annual expenditure rates of about 3 to 4 times greater than the $15 per barrel case in the 1985-1995 decade.

In the interest of providing some perspective, these annual outlay requirements for enhanced recovery compare with 1974 expenditures of $19.1 billion for all domestic exploration, development and production of oil and gas.

TABLE 3

ANNUAL CASH OUTLAY FOR ALL PROCESSES*
(Billions of Constant 1976 Dollars)

Year	$15 per Barrel Case	$25 per Barrel Case
1980	1.1	1.6
1985	3.3	8.7
1990	3.5	14.6
1995	4.0	12.8
2000	2.7	8.1
Cumulative Total Through Year 2000	69	208

* Based on a minimum 10 percent DCFROR requirement and moderate tax case.

Table 4 summarizes some key indicators of physical activity and material requirements. Additional drilling requirements of over 2,000 wells per year in the $15 per barrel case and over 4,000 wells

per year in the $25 per barrel case during the 1980-1990 decade are shown. This increment of drilling activity would represent a 5 percent to 10 percent gain over current levels of nearly 40,000 wells per year.

Although workover activities are only loosely definable at best, the additional 1,000 to 4,000 workovers per year noted in Table 4 probably would reflect a less than 10 percent gain over existing activity levels.

Of the chemicals considered, surfactants very probably will present the greatest problem in terms of new chemical plant construction requirements. With the exception of alcohols, total U.S. manufacture of surfactants of the type used in EOR processes probably totals considerably less than 0.5 billion pounds per year. This compares with the additional requirements of up to 5 billion pounds per year shown in Table 4.

Additional alkaline requirements reach about 0.3 billion pounds per year or roughly 10 percent of current total domestic production of the most commonly used materials.

Definitional problems hinder similar comparisons for polymers.

Naturally occurring CO_2 will likely be the prime source of CO_2 for EOR application on the large scale examined in this report; however, other sources such as by-product gas from ammonia plants may supply individual projects (see Appendix E for discussion of CO_2 sources).

Greater manpower requirements will be associated with increased levels of EOR activity but were not evaluated for this study. (See SPE-AIME President, Donald G. Russell's remarks at FEA Hearings, September 16-20, 1974, for quantification of manpower needs.)

Distribution of Base Case Results by State

Figures 40, 41, and 42 exhibit the distribution of total incremental ultimate recovery and potential producing rate from all processes over the 1976-2000 time frame. The results are shown for the

TABLE 4

ADDITIONAL ANNUAL ACTIVITY AND MATERIALS REQUIREMENTS FOR ENHANCED RECOVERY WORK *

	Wells Drilled Per Year	Well Workovers Per Year	Surfactant Used (Millions of Pounds per Year)
$15 per Barrel Oil Price			
1976-1980	1,100	700	0
1981-1985	2,300	1,500	700
1986-1990	2,100	1,700	1,100
$25 per Barrel Oil Price			
1976-1980	1,400	1,200	0
1981-1985	3,900	3,100	2,500
1986-1990	4,600	4,300	5,000
	Alkaline Chemicals Used (Millions of Pounds per Year)	**Polymer Used (Millions of Pounds per Year)**	**CO_2 Used (Billion Cubic Feet per Year)**
$15 per Barrel Oil Price			
1976-1980	150	20	0
1981-1985	300	100	200
1986-1990	200	150	400
$25 per Barrel Oil Price			
1976-1980	150	20	0
1981-1985	300	150	700
1986-1990	200	300	2,000

*Constant 1976 dollars; minimum DCFROR requirement of 10 percent; and moderate tax case. Data shown are in addition to the requirements of existing EOR projects.

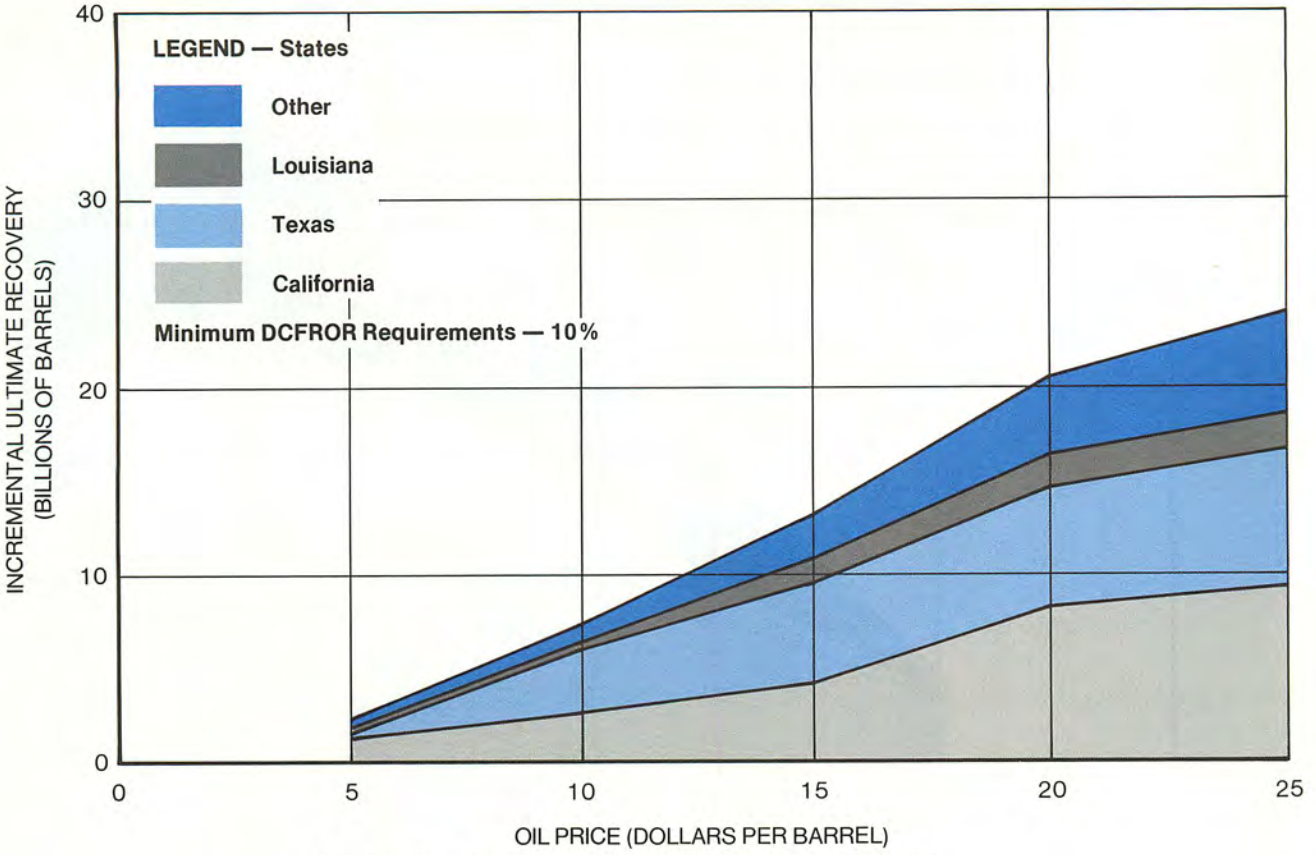


Figure 40. Incremental Ultimate Recovery by State.

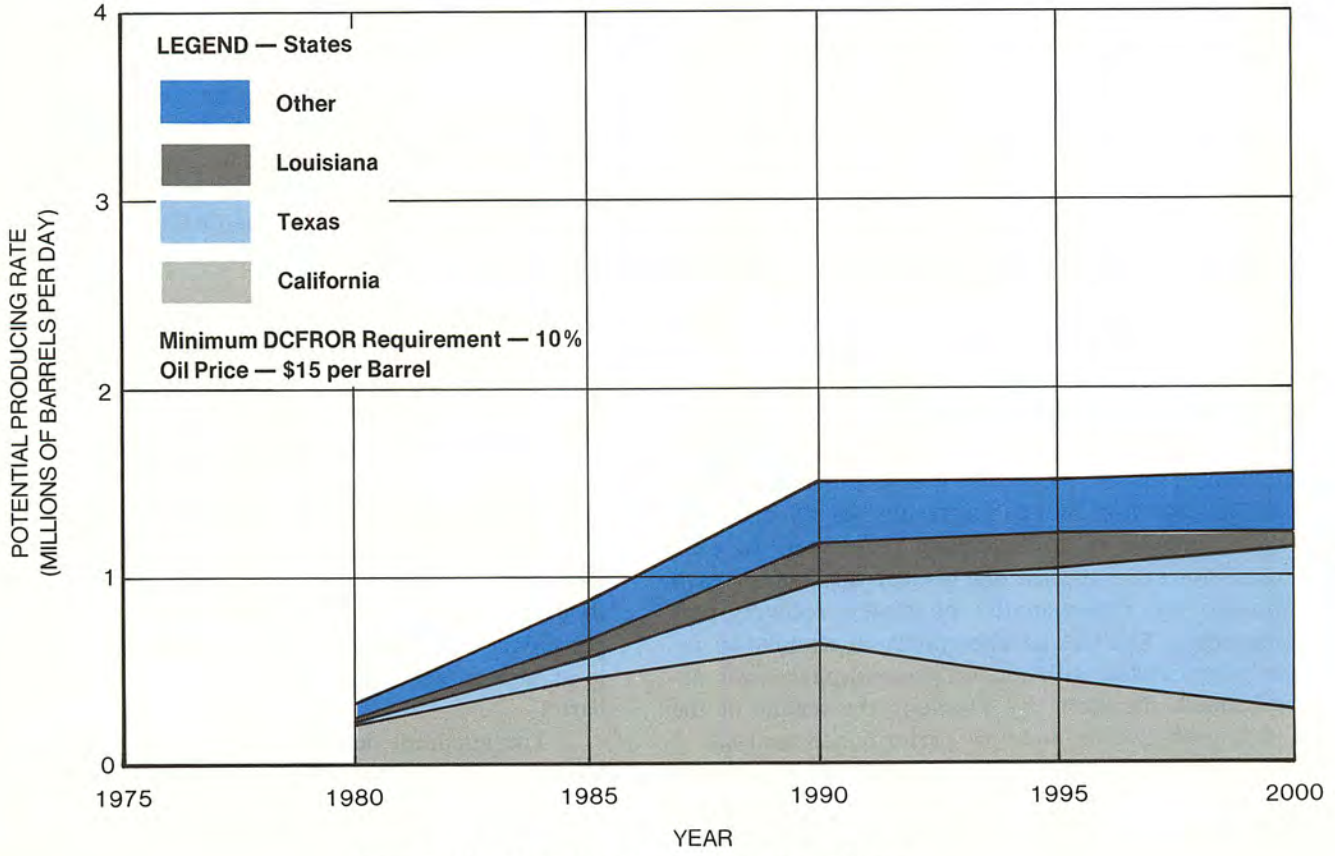


Figure 41. Potential Producing Rate by State.

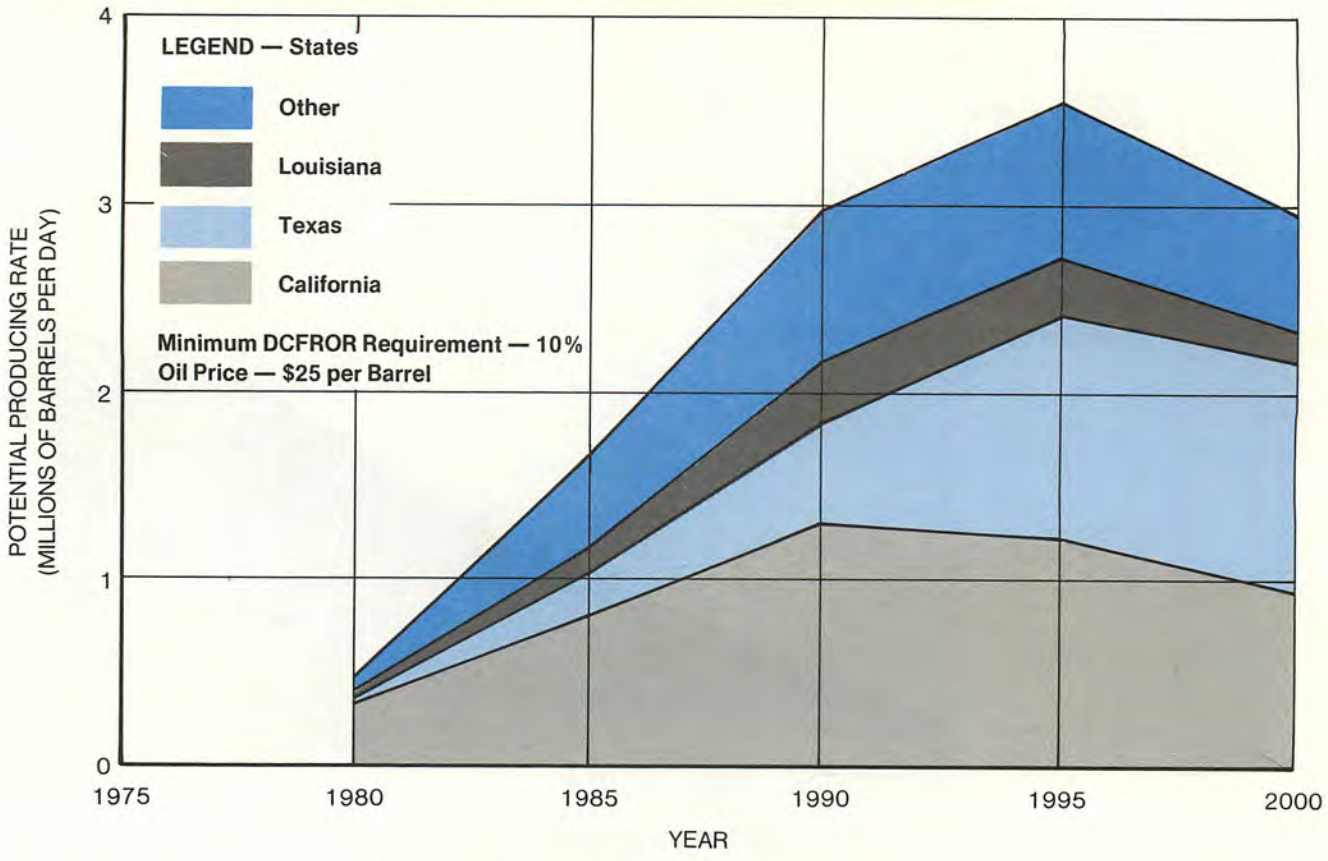


Figure 42. Potential Producing Rate by State.

three states, Texas, California, and Louisiana, as well as for other states to which results were extrapolated in this study. As indicated in the appendices, the California contribution would be predominantly from thermal methods, and carbon dioxide miscible flooding would have a major potential impact in Texas. Louisiana has a somewhat smaller potential, due in part to more efficient primary and secondary characteristics of its reservoirs.

Cumulative Variability in Results

Since different key parameters were used in analyzing the variability of possible results for each enhanced recovery process, it is impossible to show the variation in cumulative results for all processes as a function of a single key parameter. In each case, however, at least one critical variable for each process was representative of process recovery performance. The overall uncertainty in cumulative results associated with recovery performance was ascertained, therefore, by summing the results of the high performance and low performance analysis.

Figure 43 shows the uncertainty in ultimate recovery at a 10 percent DCFROR requirement based on the sum of high- and low-range performance estimates for individual processes. Results at $15 per barrel range from about 6 to about 27 billion barrels incremental ultimate recovery for all processes, with a base case of approximately 13 billion barrels. Corresponding results at a 20 percent DCFROR requirement are shown in Figure 44. The range of potential with this DCFROR requirement with oil at $15 per barrel is from 4 to 12 billion barrels.

The uncertainty in potential producing rates at 10 percent rate of return requirement is demonstrated in Figure 45, for oil at $15 per barrel, and Figure 46, for oil at $25 per barrel.

The potential producing rate in 1985 varies from about 450 thousand barrels per day to 1.6 million barrels per day at $15 per barrel, and from 1.1 to 2.4 million barrels per day at $25 per barrel. Peak rate in about 1995 varies from as little as 800 thousand barrels per day to 3.4 million barrels per day at $15 per barrel, and from about 2 million to as high as 4.7 million barrels per day at $25 per barrel.

The apparent flattening of the high-range performance curve in Figure 43 at oil prices above $15 per barrel may be in error due to the screening parameters used in this study being too severe for

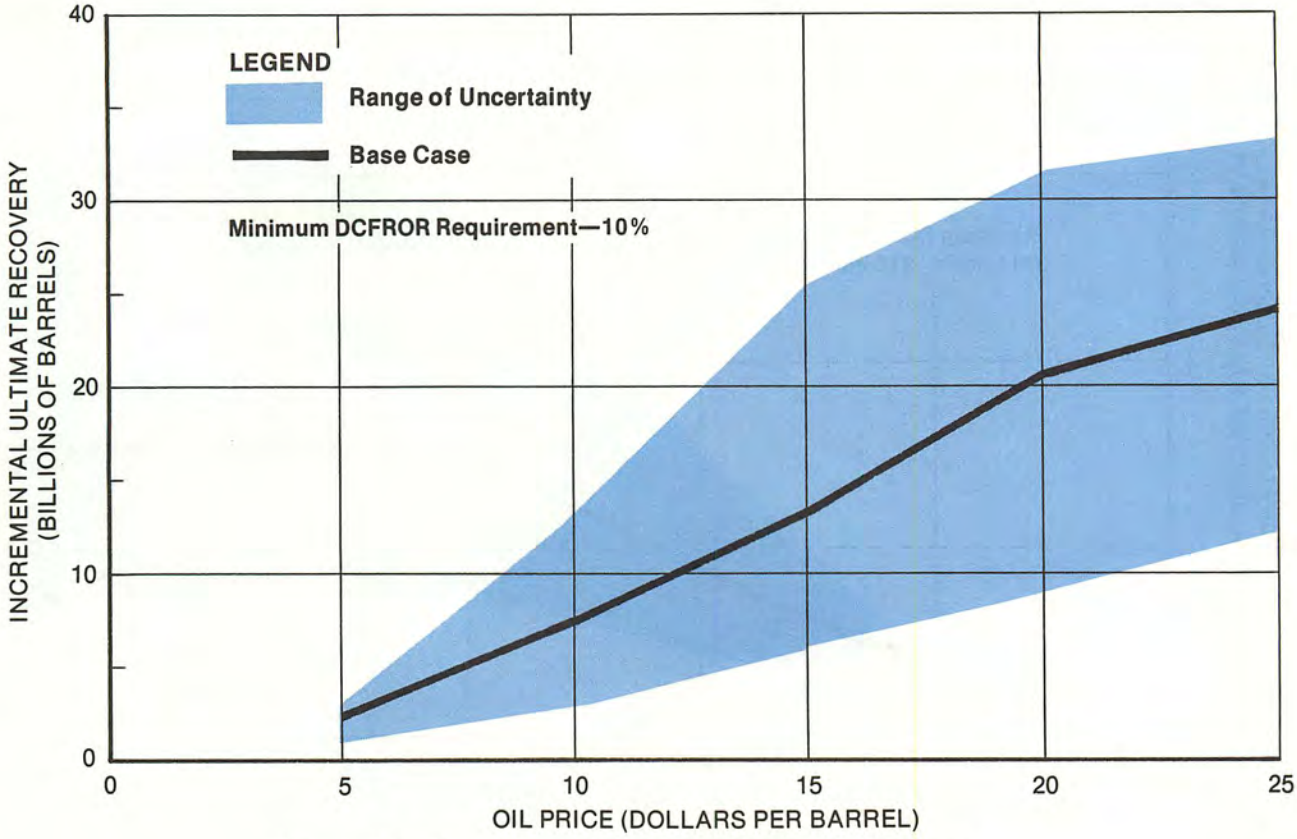


Figure 43. Uncertainty in Incremental Ultimate Recovery.

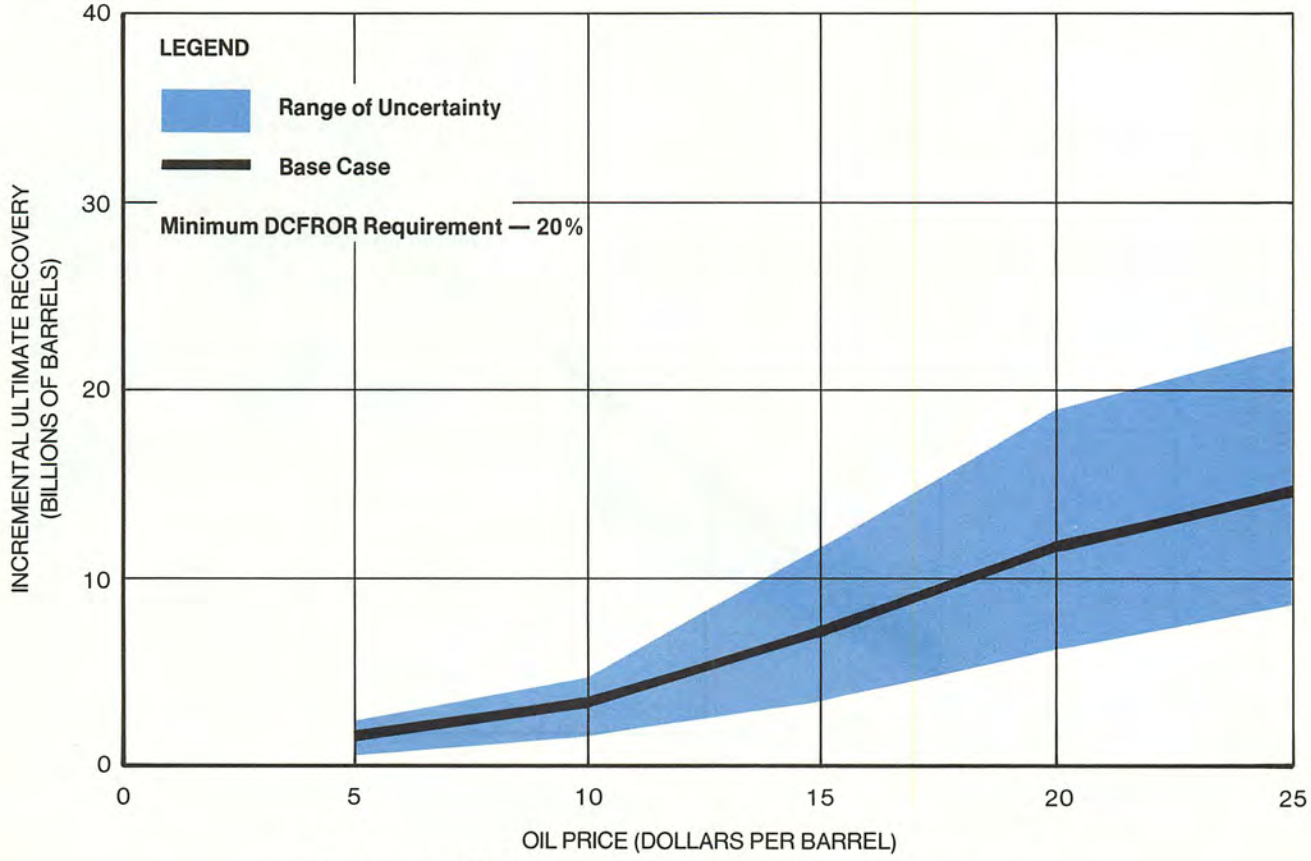


Figure 44. Uncertainty in Incremental Ultimate Recovery.

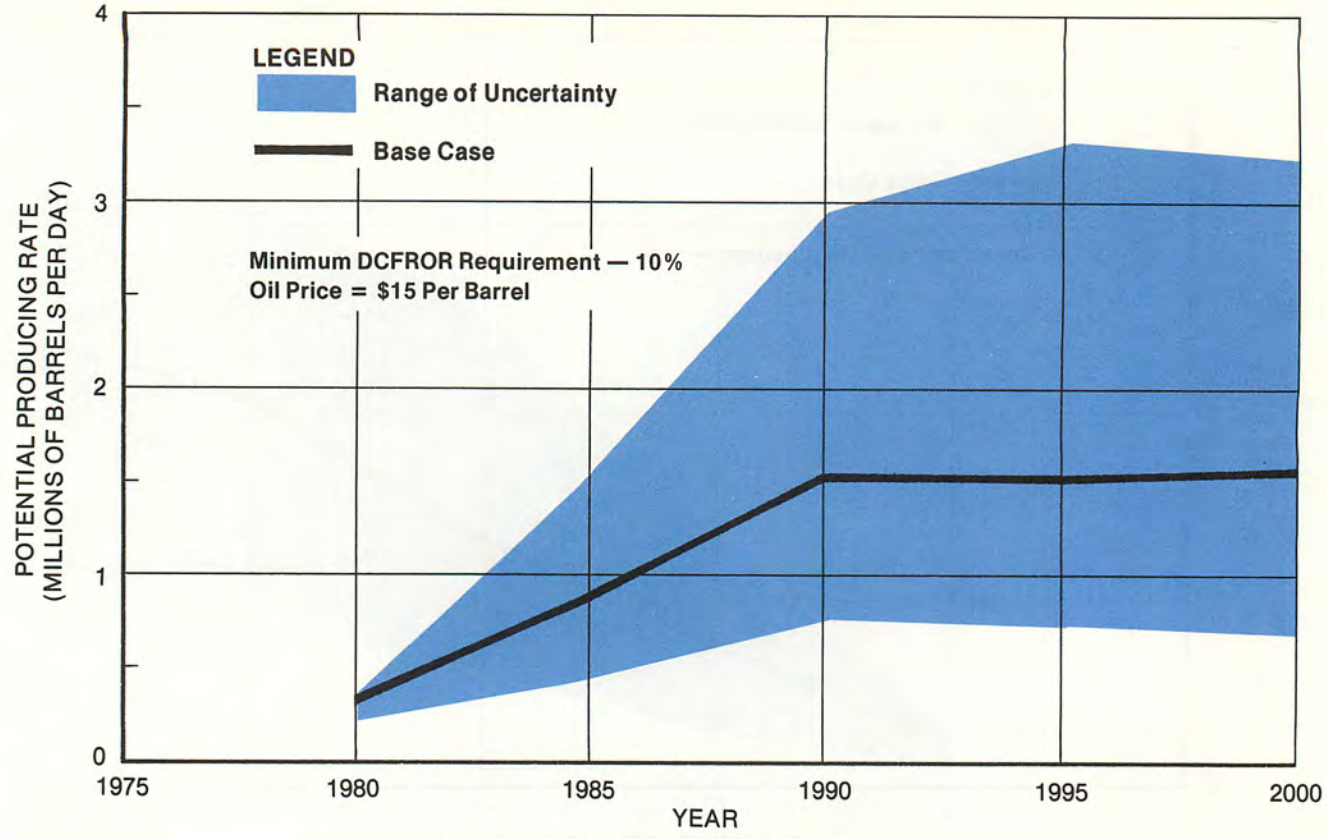


Figure 45. Uncertainty in Potential Producing Rate.

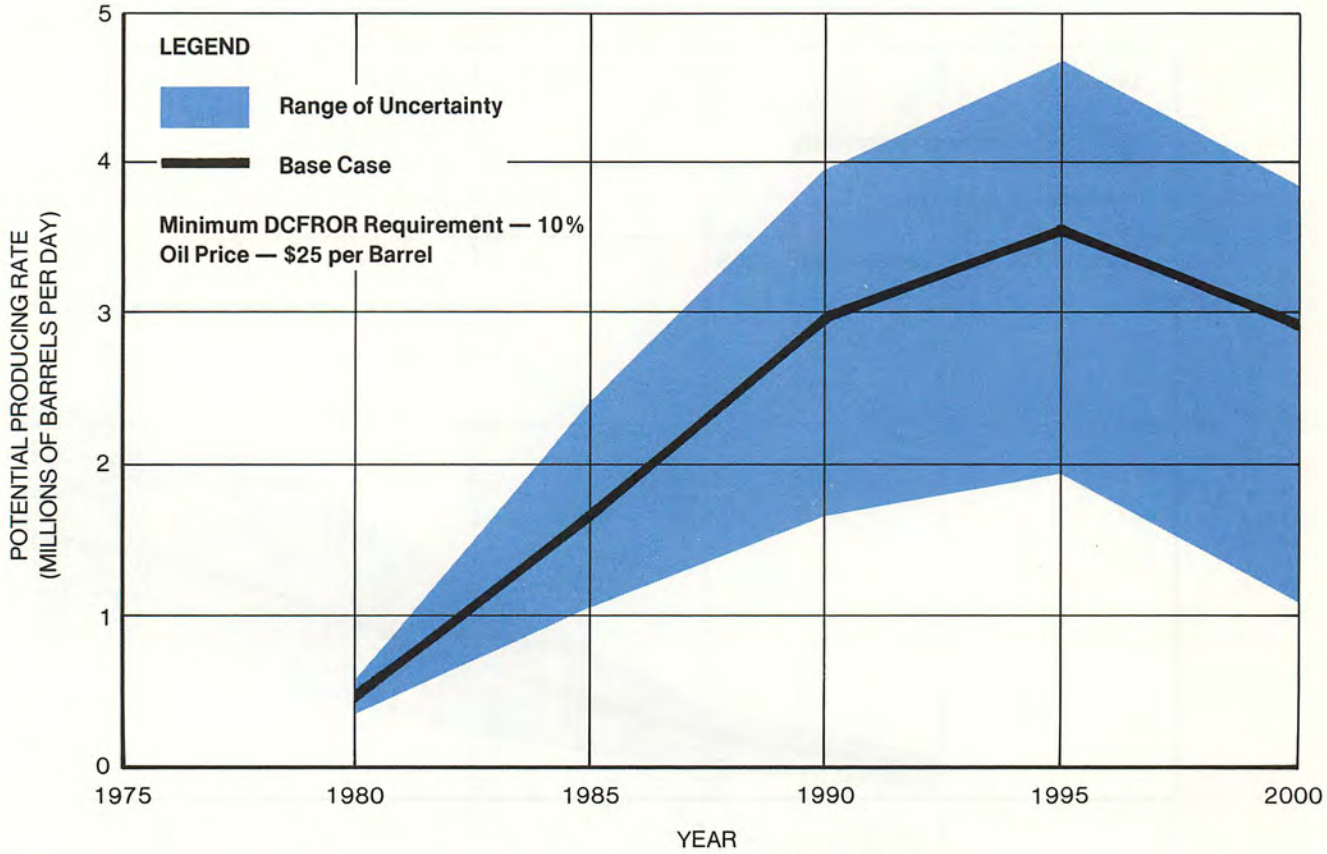


Figure 46. Uncertainty in Potential Producing Rate.

this highly favorable combination of performance and economic conditions. The screening parameters were established primarily to select candidate reservoirs assuming performance levels similar to those in the base case results. Some reservoirs excluded in the screening process might actually be economic at oil prices of $20 and $25 if performance were as favorable as that shown in the high-range curve.

Since the values shown represent the uncertainty associated only with process recovery performance, and not the several other parameters (such as process cost) that also influence the range of results, they tend to represent only the *minimum* total uncertainty in results. The variability due to other parameters is offset, in part, by the probability that all processes will not simultaneously prove to show either very good or very poor performance. Therefore, these variability analyses may be assumed to be reasonably representative of the overall uncertainty in results at a specified economic condition. Similar results may be generated for other economic conditions to obtain the full perspective on possible results.

The potential importance of enhanced recovery processes to domestic oil supply, if sucessfully applied at base case levels, is shown in Figure 47. This figure shows the potential enhanced oil recovery production rates, superimposed on the calculated decline curve of remaining primary and secondary production of current U.S. proved reserves. Production from future discoveries is not included. Derivation of this decline curve is discussed in Appendix H. At these economic conditions, EOR represents a substantial addition to potential producing rates during the time frame 1990-2000.

Discussion of Results

Enhanced recovery technology, with few exceptions, is unproven in the field. In spite of extensive industry research and hundreds of millions of dollars spent on development and field testing of enhanced recovery processes, current production from enhanced recovery processes in the U.S. today is only about 350 thousand barrels per day, with the majority of this production coming from steam stimulation and steam drive in California.

Results from this study indicate that the major reason for lack of further application of enhanced recovery processes in the U.S. today is lack of sufficient economic incentive. However, calculations showing the variability of potential results with uncertainty in the key parameters indicate that even with additional economic incentives, the potential of enhanced recovery remains highly uncertain. The history of enhanced recovery includes few pilot tests with processes, other than steam, that have been successful from both a technical and an economic standpoint. It is only through detailed engineering analysis of the many failures in attempts to apply enhanced recovery processes in the field that the industry has reached the state of the art today which permits at least some estimate of future potential. The base case results in this study represent the best estimate that could be made at this time of such future potential. It is imperative, however, that the uncertainties associated with the base case estimates be recognized.

Uncertainty

Results of this study pertaining to ultimate recovery are probably less uncertain than the results projecting potential producing rates. The question of potential producing rate involves judgments of what could happen regarding both industry and government activity which add additional potential variability to the rate at which enhanced recovery reserves available at any oil price would actually be developed.

There are four major areas of uncertainty associated with projections in this study. These are:

- Process performance
- Associated process costs
- Characterization of the reservoirs to which enhanced recovery processes may be applied
- The economic climate in which enhanced recovery is developed.

Uncertainty in results of the study is due primarily to fundamental uncertainty, with the current state of the art, regarding both EOR processes and industry ability to characterize reservoirs. It is compounded, however, by the fact that the information available to the study group was insufficient to apply detailed engineering analysis to each reservoir, even for the limited number of reservoirs in the data base used. This introduced an additional potential variability in results associated with reservoir characterization, since only the limited information in the data base, together with qualitative judgments made during the geologic review of reservoirs for the study, was applied in this analysis.

Uncertainties in process performance and cost are greatest for chemical flooding. In surfactant flooding, which makes up the bulk of chemical flooding potential, essentially *no* oil has been produced *economically* to date, although about 400,000 barrels have been produced in field tests. The results in this study, therefore, constitute an extrapolation from near zero. While the use of surfactants for enhanced

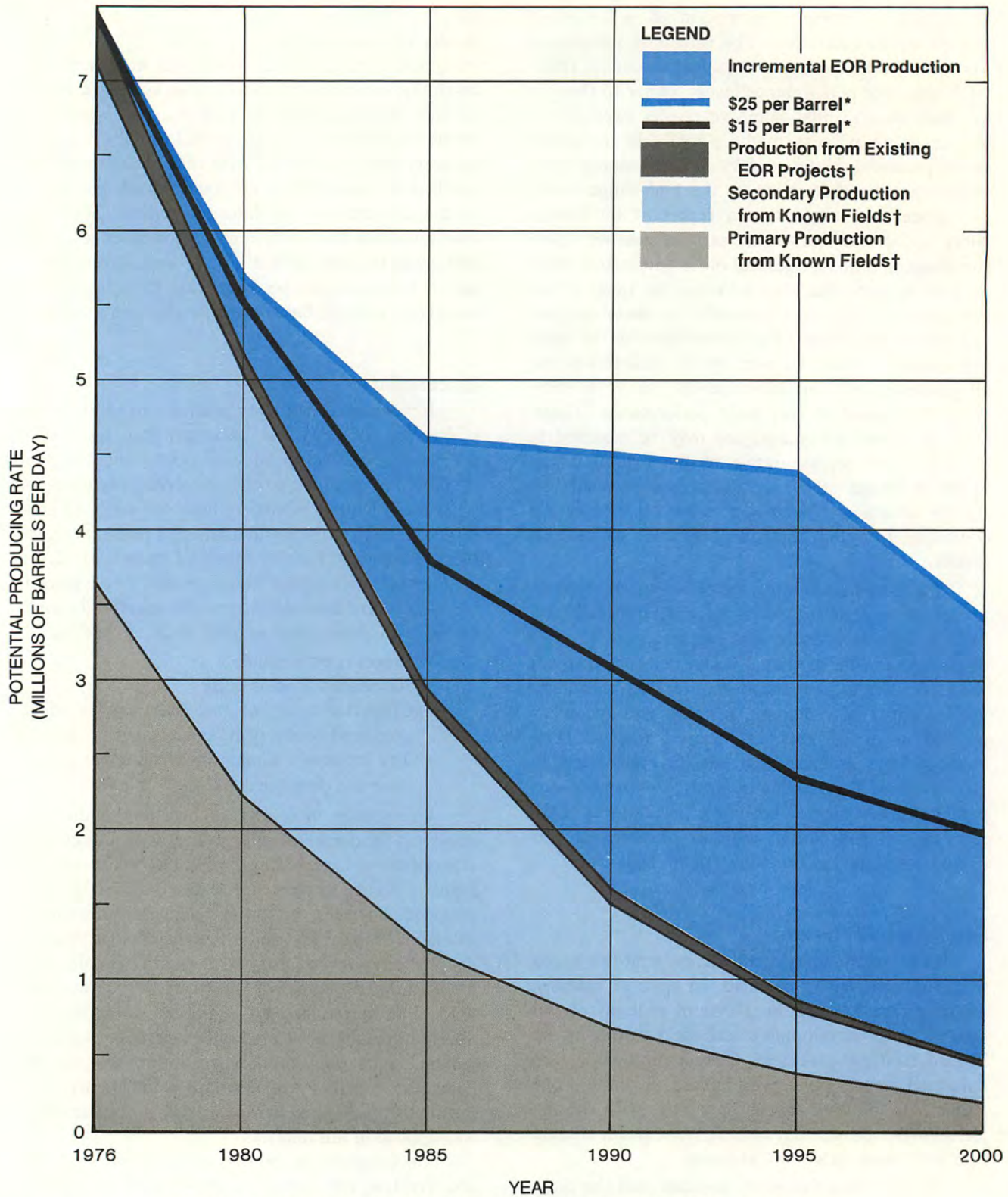


Figure 47. Potential U.S. Crude Oil Production Rate from Known Fields.

*Constant 1976 Dollars and Minimum DCFROR Requirement — 10%

†Estimated Producing Rates Based on December 31, 1975 API Reserves (See Appendix H).

Note: Production from the following sources is not considered and will be additive to the rates shown:

- Revisions except as included in API "Indicated Additional Reserves" as of December 31, 1975
- Extensions from realized enlargement of known fields
- New reservoir discoveries in known fields
- New field discoveries after December 31, 1975
- EOR from extensions, new reservoir discoveries, and new field discoveries
- North Slope, Alaska

oil recovery has been studied in the laboratory for at least 25 years, pilot testing has been somewhat limited compared to other processes, both with regard to the total number of tests and to the availability of test data in reservoirs of differing characteristics. Moreover, the process is inherently a "slug" type process; that is, a small fraction of the reservoir pore volume of chemicals is used because of their relatively high cost. This type of process has historically been the most difficult to implement economically because of the tendency of heterogeneity and other effects in the reservoir to destroy the integrity of the small slug.

On the positive side, however, the extensive industry research has brought technical knowledge of the process to a point where profitable application can be foreseen (given additional economic incentives), with substantial promise of future process improvement. There is a high current level of activity in research laboratories on chemical flooding from which continuing improvements may be expected. The time-varying screening process used in this study reflects a consensus judgment as to the probable rate of continuing improvement in process characteristics. Surfactant flooding is potentially the most flexible process of those studied in this report from the standpoint of tailoring the process to a given reservoir.

The carbon dioxide miscible flooding process is a simpler process than surfactant flooding, but has been field tested in even a smaller number of reservoirs. No oil has been produced economically in a tertiary mode to date, although the process is receiving some large-scale use in secondary recovery applications. Average residual oil saturation left by the process, sweep efficiency obtainable by the process, and resulting ratios of oil produced to carbon dioxide injected for the process are all uncertain at this time. On the positive side, the process uses a much larger slug of material, volumetrically, than chemical flooding, and has the property of regeneration of miscibility as long as pressure is maintained above miscibility pressure. This tends to make the process less sensitive to reservoir heterogeneity than surfactant flooding. It is primarily for this reason that carbon dioxide miscible flooding is the only process in this study envisioned for use in carbonate reservoirs, which tend to be highly heterogeneous.

The process appears promising and should be economic in some reservoirs today at current "upper tier" oil price. The total potential for this process in adding to U.S. reserves and production, however, is dependent not only on uncertain process characteristics, but also heavily dependent on the availability of very large quantities of sufficiently low-cost carbon dioxide where needed. Assumptions in this study regarding availability, location, and resulting cost of carbon dioxide may constitute the greatest uncertainty regarding the potential of this process.

In thermal recovery, the technology of steam stimulation is well known; this process is being applied extensively today. The recovery potential of steam drive in a given reservoir appears to be reasonably predictable, at least in those reservoirs for which there is an adequate reservoir description. The major uncertainty for steam stimulation and steam drive is in extension of this technology to new reservoirs and undeveloped parts of existing reservoirs. The degree to which process costs escalate as poorer quality reservoirs are treated is speculative, at best.

In-situ combustion involves an intermediate degree of uncertainty regarding both process performance and process cost. The in-situ combustion process has been tested extensively in the field, but has been applied economically in only a few instances. It appears to have promise, however, for some heavy oil reservoirs which cannot be treated economically with steam.

For all enhanced recovery methods the degree of reservoir characterization and engineering required for successful application may be an order of magnitude greater than for waterflooding. This has significant implications not only for the timing of development, but also for engineering and production manpower requirements to achieve the potential of this technology.

In projecting potential producing rates to achieve the ultimate potential cumulative recovery for each process, there are several additional uncertainties. The intent of this study was to project what *could* happen and not to forecast what *will* happen. The only economic variables considered explicitly in the analysis were oil price, process cost, and tax treatment. These factors do not fully describe the economic climate. The economic climate tacitly assumed in estimating potential producing rates might be characterized as "middle-of-the-road" for economic factors not explicitly studied. That is, it represents neither a minimum rate of development nor the maximum potential rate, given conditions of maximum stimulation and incentives.

It was also necessary to make tacit assumptions regarding general government policy, other than oil price, since such policy considerations may affect the rate of development of enhanced recovery processes. In projecting potential producing rates in this study, it was tacitly assumed that no major changes

from current policy would occur in areas such as ERDA funding of field pilot testing. Industry willingness to conduct pilot tests and resulting attempts at commercialization were assumed to be consistent with the oil price specified, with no major impact of factors other than oil price and tax or equivalent economic incentives on the rate of field pilot testing.

This study probably does not take into account adequately the effect of oil price on rate of development. In most cases, the calculated rate of development probably corresponds to an intermediate oil price among those studied. At lower oil prices (i.e., with a lower economic incentive), the rate of pilot testing would probably be slower than that projected, with a resulting decrease in rate of development from the rate projected in this report. At higher oil prices, the rate of development might be greater than indicated in this report.

In considering the results of this study, it is important to recognize the impact of the constant dollar, inflation-free economic conditions assumed for the analyses. For example, production shown in 1990 for an oil price of $20 is not based on the price level reaching $20 by 1990—it is based on the somewhat artificial condition of oil price immediately jumping to $20 in 1976 and remaining constant thereafter in terms of 1976 dollars.

Assumptions regarding the rate of technology evolution were developed by consensus judgments, and probably represent an intermediate rate of development corresponding to the assumed rate of field application. There is potential for more rapid evolution and for the solving of some problems which were assumed in this report to be formidable. Conversely, however, there is a possibility that the new technical developments which have been assumed in areas such as chemical flooding will not in fact be made on schedule.

Risk and Rate of Return

Two key factors in determining whether a particular enhanced recovery process will be applied to a particular reservoir, after it has been determined to be technically viable, are the anticipated DCFROR and the discounted net present value of the project. In this report, the influence of oil price on both incremental ultimate recovery and potential producing rate is primarily in affecting the number of reservoirs in which a given process can be expected to meet a specified minimum DCFROR criterion. This is equivalent to specifying a positive discounted net present value at the specified discount rate. As reviewed in more detail in Chapter Two, the rate of return used in this report is a "real" rate of return, without consideration of inflation. It is approximately equivalent to the more familiar nominal rate of return minus inflation rate. For example, the 10 percent rate of return in this report would correspond to a nominal 15 percent rate of return, if inflation were 5 percent.

One of the more significant findings in this study was that very few surfactant flooding projects are expected to show greater than a 20 percent constant dollar rate of return even with a $25 per barrel oil price. A relatively small fraction of carbon dioxide miscible flooding projects are expected to show higher rates of return. Results for surfactant flooding were shown in Figure 17, from which it is apparent that a minimum DCFROR criterion of 20 percent decreases incremental ultimate recovery to near zero. Results for carbon dioxide miscible flooding were shown in Figure 23, which indicates the detrimental effect of higher specified rate of return requirements on incremental ultimate recovery.

In any economic endeavor containing a risk element, the profitability of successful operations must be sufficient to cover losses in unsuccessful operations if the enterprise is to continue. High potential rates of return are particularly important in the early stages of implementation of new technology, when the risk of failure is highest. The history of application of major technological innovations in the petroleum business indicates that nearly all such innovations had the potential for high profits in at least a few instances, which provided the incentive to attempt application even when the technology was in its uncertain, early states. For example, in waterflooding, the high profitability of successful applications offset the early failures, leading both to further attempts under uncertain conditions and to the development of the technology required to diminish the risk. Other examples include the introduction of hydraulic fracturing, the move into offshore operations, and the exploration of high-cost frontier areas.

When the profitability of fully *successful* operations is relatively low, the risk of failure must be comparably low, or the cost of failures will more than offset the profit from succesful operations. *The state of the art in surfactant flooding and carbon dioxide miscible flooding has not yet reached this point.* Further improvements in the industry's ability to predict the results of application of this technology will be required before widespread application can be expected. This will require substantial expenditures and time for laboratory research and field pilot testing. For this reason, the projections in this report showing little production from surfactant flooding

and carbon dioxide miscible flooding until the mid-1980's appear realistic, if not optimistic. The rate of field pilot testing must increase substantially from the current rate if these results are to be achieved.

Surfactant flooding involves the highest risk of failure and shows the greatest effect of rate of return requirement on incremental ultimate recovery. Surfactant flooding is not only a high-cost process, but is also heavily "front end loaded" from an investment standpoint, because of the large fraction of overall costs associated with the injection of an expensive chemical slug. Risk and uncertainty of results, given the current state of the art, are high.

The risk associated with carbon dioxide miscible flooding ventures depends on both the nature of the application and the geographical location of the project in respect to sources of CO_2. Pilot testing of this process can be very time-consuming, since the reservoirs in which it may be applied are frequently low-permeability carbonates. In these reservoirs, the rate of movement of carbon dioxide is very low because of injectivity limits. Pilot testing can also be very costly if it is necessary to truck CO_2 to the pilot.

Alkaline waterflooding is a high-risk method because of its very limited applicability, but involves relatively low-cost injection materials. The cost of pilot testing would normally be relatively low. Polymer augmented waterflooding is also a relatively low-cost, but low-potential, process. Pilot test costs can be low. However, pilot tests are ambiguous because of the difficulty in establishing the true amount of incremental oil obtained by using the polymer. This is normally estimated by the difference between what is actually produced and what would have been obtained by waterflooding without the polymer.

The risk in applying in-situ combustion is at an intermediate level and depends on the nature of the reservoir to which it is to be applied. This process has been extensively field tested, although most of the early tests of this process utilized the "dry combustion" process, without injection of water. Pilot testing time and costs are also at an intermediate level.

Steam stimulation and steam drive are the most predictable processes considered in this report. Risks associated with process applications are relatively low, although still higher than waterflooding. When successful, relatively high rates of return may be generated. The primary risks normally are concerned with the reservoir characterization of new areas to which the process is to be applied, rather than with process characteristics themselves. Pilot testing costs

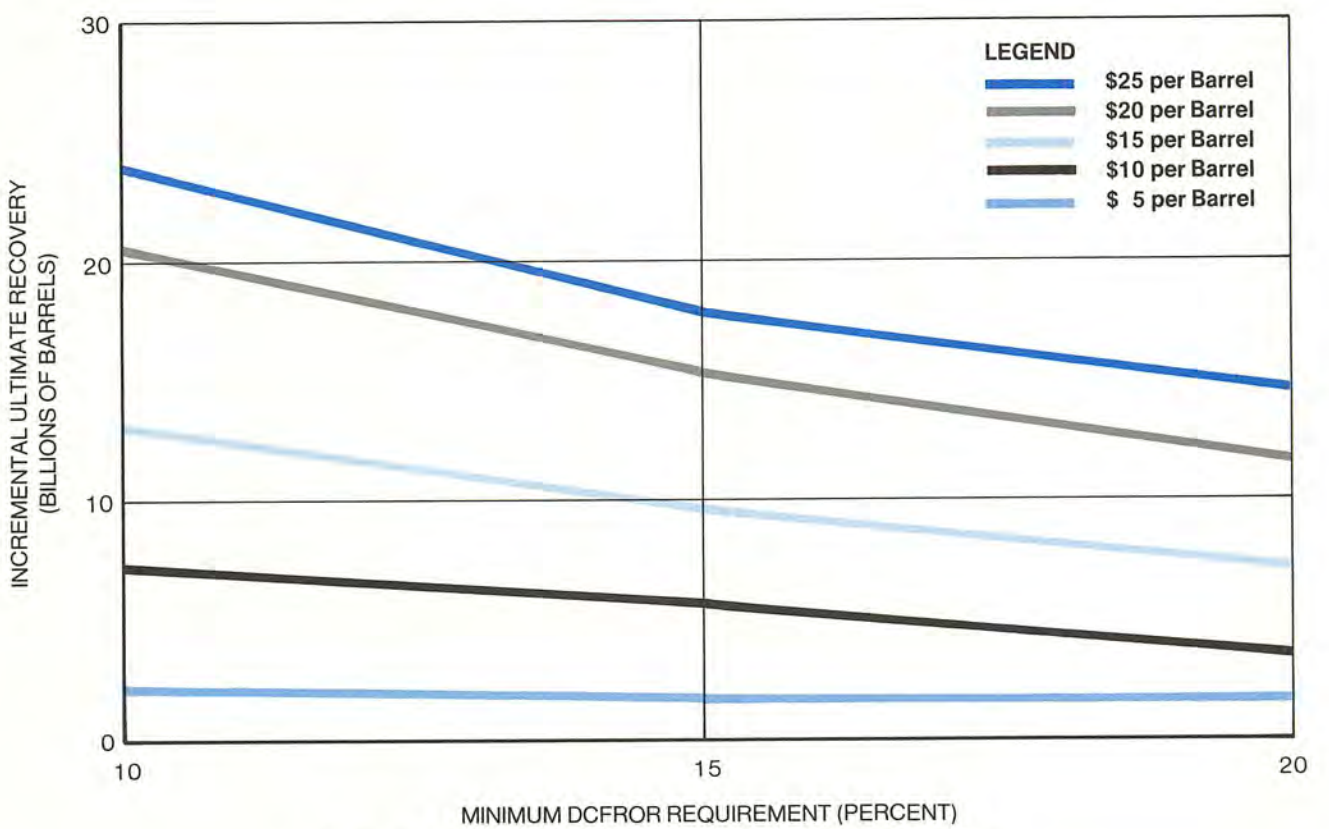


Figure 48. Incremental Ultimate Recovery—Base Case Performance and Costs.

are moderate, and pilots can normally be run on sufficiently close well spacing that results can be obtained rapidly.

The overall influence of DCFROR requirement on incremental ultimate recovery is shown in Figure 48. The need for research and pilot testing to decrease risk and minimize required rate of return is apparent.

Internal Consistency of Analysis Procedures

The treatment of sweep efficiency, residual oil saturation after waterflooding, and original oil in place as three separate, independent variables, together with the assumption that API statistics on reserves and original oil in place may be accepted for the reservoirs in question, results in mathematical over-specification of the problem. Apparent remaining waterflood reserves for the reservoirs in this study may be calculated by analyzing the oil production implied by waterflood sweep efficiency and waterflood residual as a fraction of original oil in place and then subtracting cumulative production to date. Since API does not, in general, publish reserves by reservoir, it is not possible to compare results with API statistics on each reservoir. In the aggregate, however, it appears that results based on sweep efficiency and waterflood residual from this study indicate higher apparent remaining reserves than those shown in API statistics. This raises some question as to the internal consistency of the analysis procedures, and indicates the differences which may occur in comparing independent assessments developed with different procedures, methodology, and judgment.

Some of this apparent difference is due to the method used by API in establishing reserve figures. Potential waterflood oil in parts of reservoirs which are not yet fully developed for waterflooding is not included in proved reserves by API, but is listed as "indicated additional reserves from known reservoirs." API reserves also do not include potential waterfloods which are not economic at current prices, but which would be economic at the higher oil prices considered in this study. Several California reservoirs appear to fit into one or both of these categories. API reserves also do not include additional stripper production at the higher oil prices considered in this study (see Appendix H). However, these factors, though important, do not fully explain the difference in apparent remaining reserves.

The primary question of consistency arises in examining the independent specification of waterflood sweep efficiency and residual oil to waterflooding (in the swept region). In general, the sweep efficiency for chemical flooding was assumed to be the same as waterflood sweep efficiency. The apparent difference with API reserve statistics indicates either that waterflood sweep efficiency, on the average, is not as high as assumed in this study, or that residual oil to waterflood, on the average, is not as low as used in this study. Since both parameters were selected based on engineering judgment to represent a broad range of reservoir characteristics, some degree of error would be expected in both parameters. Experience has shown that original oil in place estimates are also frequently in error.

If sweep efficiency were lower than that used in this study for both waterflooding and EOR processes, the potential for EOR would be reduced. The effect is largest for surfactant flooding. However, since the volume of surfactant injected is determined as a fraction of swept pore volume, rather than total reservoir pore volume, the economics of this process are not highly sensitive to the sweep efficiency assumed. The total potential volume of recovery is directly affected by sweep efficiency since this parameter establishes the "target oil" for the process.

If average residual oil saturation after waterflooding were higher than that used in this report, the potential for EOR processes would increase from that shown by results from this study. Calculations of the uncertainty in results as a function of waterflood residual oil shows that chemical flooding, in particular, is highly sensitive to this parameter. Since an increase in waterflood residual oil provides larger potential recovery with no substantial increase in process cost, the economics of processes such as surfactant flooding may be improved considerably by larger waterflood residual oil saturations.

The consensus judgment of the study participants is that the average waterflood residual oil used in this study is known more accurately than the average sweep efficiency. The sweep efficiencies assumed for some reservoirs in this study are probably too high. Because small errors in underestimating waterflood residual oil may counterbalance larger errors in overestimating sweep efficiency, however, there appears to be no reason to expect that this should cause either a uniformly positive or uniformly negative bias in results obtained. Further measurement of these two key parameters to establish the target oil for EOR with greater accuracy in reservoirs being considered for EOR would constitute a substantial improvement in industry ability to project the potential of EOR processes.

Incremental Cost

Examination of the recovery response to price estimates presented in this study indicates that the incremental cost of successive additional volumes of oil recovered generally increases at an accelerating rate. Indeed, this relationship is typical of any product produced under increasing cost conditions. Whether or not an increment of oil recovery justifies the indicated added cost depends primarily upon the full incremental cost of alternative energy supplies. Currently, the most readily available alternative supply is imported oil, the cost of which is its delivered price plus any implicit costs associated with supply insecurity, balance of payments burden, and other social and political disadvantages of foreign supply.

Long-range supply alternatives include several high-cost sources of domestic energy. Some U.S. energy consumers are already paying $3 and $4 per MMBTU for LNG and SNG and planned Arctic gas would cost $3 to $4 or more per MMBTU. More exotic forms of energy such as solar, geothermal, fusion, etc. may well be twice as costly depending upon locations and end-use applications. Though this study has made no attempt to compare enhanced oil recovery with these other energy sources, the development of very costly forms of energy will involve payments of a substantial premium over the present price of domestic conventional or imported energy supplies.

There is a large potential for additional EOR oil costing $20 to $25 per barrel ($3.40 to $4.25/MMBTU). This oil would cost less than the probable threshold cost of several alternative energy forms now being developed. In the event that acceptable substitutes for incremental volumes of EOR oil were not available, the value of these foregone supplies would depend upon what buyers would be willing to pay in an unconstrained market environment. If demand elasticity were low, it is entirely possible that high values would be assigned to oil supplies in a condition of restricted availability.

Another problem involved in making comparisons of the marginal value and cost comparisons of incremental oil supplies is the imprecise nature of cost estimates, particularly at price levels not yet attained.

Even if it were determined that the average cost of EOR oil were acceptable but the incremental costs were higher than desired, it would be extremely difficult to impose a segregated multi-level price system that would minimize the difference between individual producer's cost and revenues. An example would be wheat production.

Without a regimen of extremely rigid price controls, it would not be possible to pay farmers prices for their crops based upon costs of individual units of acreage rather than on overall average costs. As a practical matter, lower prices could not be paid for wheat grown on the most productive and lowest unit cost acreage with higher prices reserved for marginal lands.

It is equally illogical to tie EOR prices to specific fields and/or specific processes in relation to estimated unit cost conditions. In this sense, the economics of oil supply are not materially different than for other goods or services.

General Outlook

The indeterminate nature of the ultimate value of recoverable oil deserves emphasis. In the foregoing sections, the principal elements of uncertainty were discussed as they related to individual technologies. In addition, there is a wide range of more general unknowns relating to government resource development policies, taxes, manpower and logistics, and other considerations that may be more or less favorable than assumed in this study. The following is a list of some factors or events which could result in ultimate oil recovery greater than the range estimated in this study:

- Major breakthroughs in the efficiency of enhanced recovery techniques or methods
- The development of economic methods of applying EOR techniques other than CO_2 injection, in carbonate rocks which represent about 30 percent of the U.S. petroleum resource base
- An extension of the depth of potential economic thermal recovery of oil below the limits assumed
- Reservoir porosity and saturation levels substantially exceeding the assumed range of conditions
- The discovery of large new onshore and offshore petroleum reserves suitable for EOR application (results in this study are limited to currently existing fields)
- Lower than projected development and operating costs, resulting from favorable experience factors, or less severe than anticipated environmental related costs
- More favorable than assumed general economic conditions, including tax burdens, or access to external capital that would expand industry cash available for EOR investment.

A comparable list of negative factors could be

developed which could cause results to be even poorer than foreseen in this study.

There is no meaningful *technical* upper bound to the potential recovery of remaining oil in place except, possibly, net energy considerations. This net energy limit has not been determined, but is certainly much higher than levels considered in this report (possibly over 100 billion barrels). Constraints on recovery are ultimately established by *economic* factors. Even with the level of technology assumed to be available during the time frame 1976-2000, the slopes of the curves obtained in this study indicate a continuously increasing potential recovery level as economic incentives increase. As technology continues to advance, the economic balance will tend to shift. At any given level of technology, however, oil recovery will always be strongly affected by oil price.

Oil price and perception of future price or equivalent economic incentives are far and away the most important factors in establishing the potential of enhanced recovery processes. Industry has demonstrated a willingness to support high levels of laboratory research on enhanced recovery, together with a willingness to invest risk capital in field pilot testing in circumstances where there appears to be justification for anticipating future profitability. Moreover, in the last few years industry has shown an increasing willingness to share information on enhanced recovery technology in an attempt to accelerate the industry-wide development and application of this technology by decreasing the risk. Dissemination of technology throughout the industry can be expected to occur soon after new techniques are proven and should not represent a substantial timing factor.

The greatest potential impact of government policy is in the area of oil pricing and equivalent economic incentives. The potential effects of other government and public policy issues are discussed in Chapter Four.

Comparisons With Results of Other Studies

There have been a number of previous estimates of enhanced oil recovery potential. The results from several of these studies are summarized in Table 5.

Caution should be exercised in comparing results from the various studies since the results are not comparable directly on a one-for-one basis. Greatly differing degrees of detail went into the various projections, and different scenarios were assumed for developing reserves. Different criteria for economic parameters, such as discounted cash flow rate of return, probably were employed. The same improved recovery methods were not considered in all of the studies, and even somewhat different definitions of enhanced oil recovery appear to have been used.

With the exception of the recent Lewin & Associates study, none of the previous estimates was based on a reservoir-by-reservoir approach. In the Environmental Protection Agency (EPA) study conducted by Mathematica, Inc., a limited data base was compiled on over 350 major domestic oil fields.* However, rather than making specific reservoir estimates, oil in this data base was classified into several categories, determined by ranges of oil and reservoir properties that were believed to serve as criteria for the various enhanced recovery processes. Potential incremental recovery was estimated from the oil in the various categories. A modified Delphi survey approach was used by the Gulf Universities Research Consortium (GURC).† A series of conferences, sequential questionnaires, interim report reviews, and individual discussions was used to develop an industry consensus. In the Project Independence projection, a fraction of the previously discovered oil in place was added to proved reserves each year as a tertiary reserve component.‡ This fraction was subjectively estimated.

The Lewin & Associates projection, however, followed a methodology similar to that used in this report. The same data base on 245 reservoirs in California, Texas, and Louisiana was used as the starting point for both analyses. Individual reservoirs were screened for process suitability by applying screening criteria for reservoir and oil properties. When two or more processes appeared to be candidates in the same reservoir, dominance criteria were applied that determined the one process to be considered for each reservoir that passed the screening tests. The amount of oil recoverable by the enhanced process and the rate at which this oil would be produced were estimated for each reservoir by simple process models. Each reservoir was then subjected to an economic analysis. Finally, the results for the reservoirs in the data base were scaled up

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*Mathematica, Inc., for EPA, *The Estimated Recovery Potential of Conventional Source Domestic Crude Oils,* May 1975.

†*Planning Criteria Relative to a National RDT & D Program Directed to the Enhanced Recovery of Crude Oil and Natural Gas,* Gulf Universities Research Consortium Report No. 148, February 28, 1976.

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

to reflect totals for each process for each of the three states.

A comparison of the three-state estimate made by Lewin & Associates for ultimate recovery potential with the three-state estimate resulting from this study is given in Figure 49. The comparison was made for a minimum DCFROR requirement of 8 percent. For the range of oil prices investigated, roughly one-third as much oil was estimated to be recoverable ultimately in this study as was estimated by Lewin & Associates. Both studies projected that steamflooding, carbon dioxide flooding, and surfactant flooding would be the processes with greatest potential.

A comparison of estimated oil production rates up to the year 2000 is shown in Figure 50. An oil price of $11.28 (1975 dollars) was assumed for the Lewin & Associates projection. Their "lower bound" case assumed that enhanced oil recovery remained a high-risk technology throughout this time period. Their "upper bound" case assumed that through a massive effort in research development, and field

TABLE 5

ESTIMATES OF ENHANCED OIL RECOVERY POTENTIAL

	Potential EOR Recovery (Billions of Barrels)	Production in 1985 (Millions of Barrels/Day)
NPC Study*		
-----$ 5	2.2	0.3
-----$10	7.2	0.4
-----$15 (1976 dollars)	13.2	0.9
-----$20	20.5	1.5
-----$25	24.0	1.7
GURC†‡		
-----$10 (1974 dollars)	18-36	1.1
-----$15 (1974 dollars)	51-76	—
FEA/PIR§		
-----business as usual, $11	—	1.8
-----accelerated development, $11	—	2.3
EPA¶		
-----$ 8-12 (1975 dollars)	7	—
-----$12-16 (1975 dollars)	16	—
FEA/Energy Outlook**		
-----$12	—	0.9
FEA†† (3 states)		
-----upper bound, $11.28 (1975 dollars)	30.5‡‡	2
-----lower bound, $11.28 (1975 dollars)	15.6§§	1

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

† *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.

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

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

¶ *The Estimated Recovery Potential of Conventional Source Domestic Crude Oil,* Mathematica, Incorporated for the U.S. Environmental Protection Agency, May 1975.

** *1976 National Energy Outlook,* Federal Energy Administration.

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

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

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

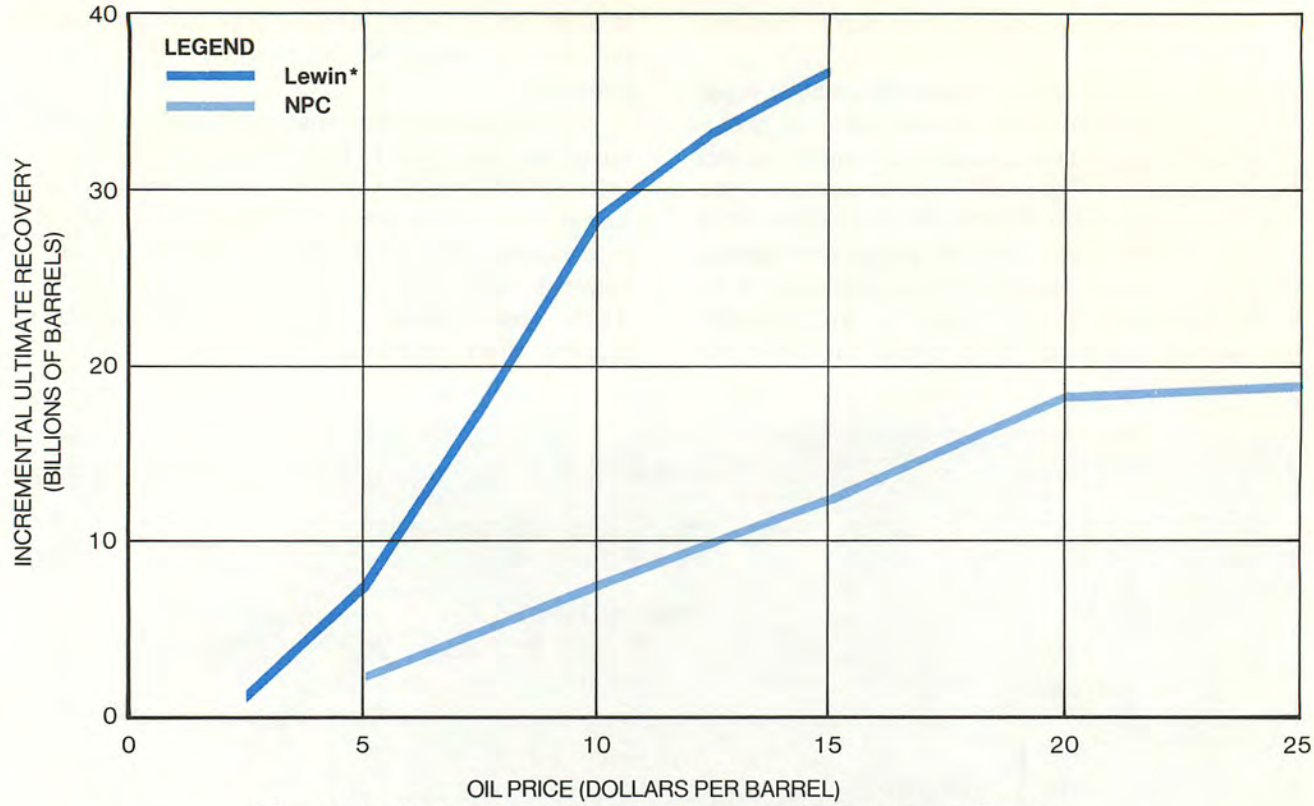


Figure 49. Incremental Ultimate Recovery—All Processes—Texas, California, Louisiana—Minimum DCFROR Requirement—8%.

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

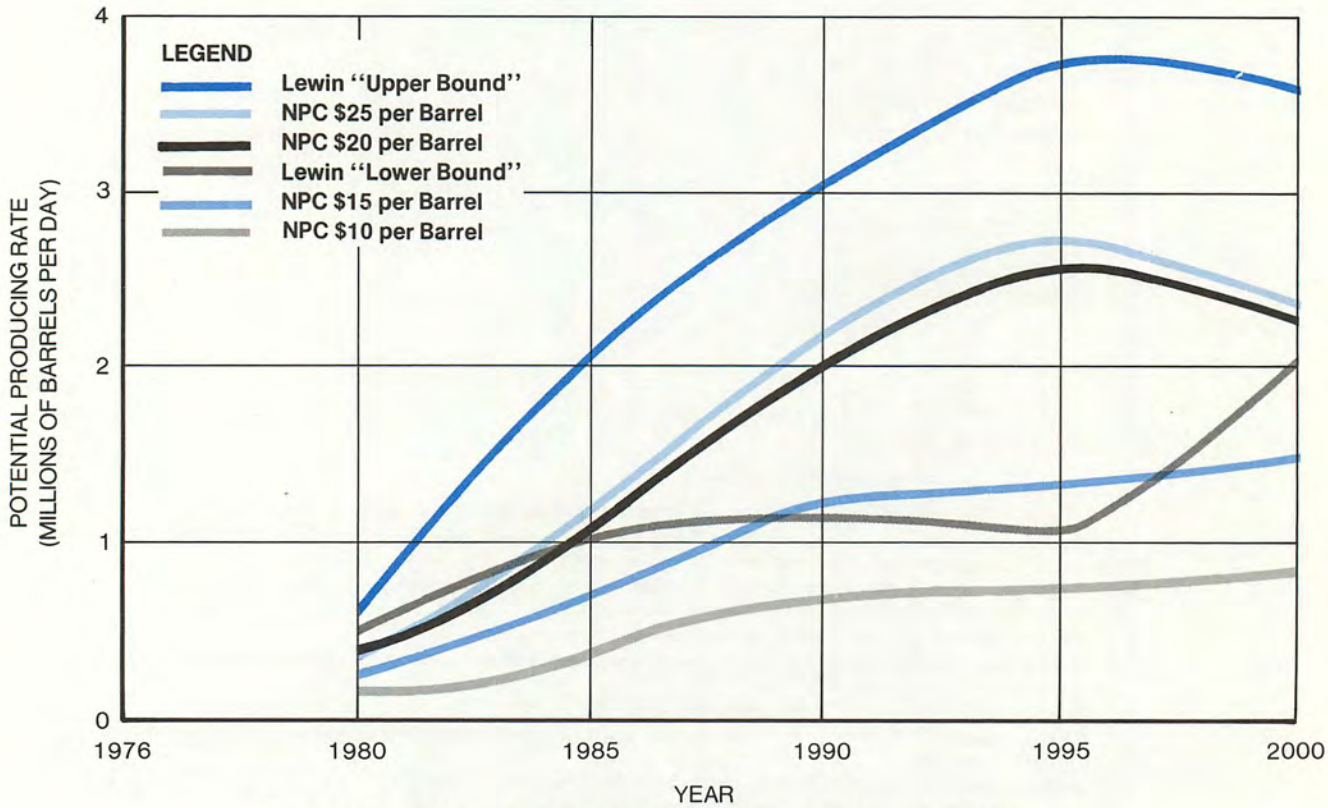


Figure 50. Projected Oil Producing Rate from Enhanced Recovery Total for Three States.

Note: All curves are based on a minimum DCFROR requirement of 8 percent except Lewin "Lower Bound" which is based on a minimum DCFROR requirement of 20 percent.

testing as a result of a concerted federal initiative, enhanced oil recovery would become a proven, conventional technology by 1990 to the degree that only an 8 percent real DCFROR is demanded for projects. The producing rates shown in Figure 50 for the NPC study were projected, assuming that at least an 8 percent DCFROR was required for project initiation. Even at the $25 oil price, the oil producing rates projected by this study do not reach the levels projected for the Lewin & Associates "upper bound" case. At this high oil price the incremental ultimate recovery projected in this study for all the reservoirs with EOR projects returning an 8 percent real DCFROR or better was still less than the incremental ultimate recovery projected by Lewin & Associates for the $11.28 oil price (19 versus 30.5 billion barrels).

Both the Lewin & Associates and NPC studies started with the same reservoir data base and used a similar reservoir-by-reservoir analysis approach, but the conclusions arrived at differ substantially. Although a direct, reservoir-by-reservoir comparison was not made and although there are numerous differences in detail between the two studies, the factors listed below appear to have contributed to a substantial part of the disagreement.

- Those reservoirs passing the process criteria in the NPC study were subjected to further review by geologists and engineers. This screening for geological factors and past performance eliminated many reservoirs from further consideration.
- The average oil saturation that the enhanced recovery fluids contact in a tertiary recovery flood was estimated differently in the two studies. For many fields this led to substantially lower oil recovery being projected by the NPC study for carbon dioxide flooding and for surfactant flooding. Lewin & Associates assumed this contactable saturation would be the material balance residual oil saturation (i.e., the saturation calculated by assuming all the oil left in a reservoir at the start of improved recovery flooding to be *uniformly* distributed throughout the reservoir). In the NPC study the view was held that carbon dioxide and surfactant solutions would flow preferentially in the previously water-invaded regions and only contact the lower waterflood residual oil saturation.
- Different methods were used to account for volumetric sweepout in the steamflood process. The method used in the NPC study should estimate less oil recovery for the thicker oil zones as a result of the gravity segregation of fluids. In addition, recovery adjustment factors were applied to the base estimates in this study (homogeneous reservoir) to account for reservoir heterogeneity and for reservoir quality.
- The unit cost to produce a barrel of enhanced recovery oil probably was different in the two studies for many of the fields examined. At any given oil price, fewer projects would be considered economically viable by the NPC study.

Additional details of comparisons with other studies are given in Appendix G.

Chapter Four
Policy Considerations

Introduction

This chapter discusses several aspects of EOR activities which go beyond the strictly technical and economic aspects discussed in the earlier chapters. Areas included are the possible social costs and benefits of EOR projects, regulations and federal policy considerations, economic incentives, and environmental considerations. These topics are more general than the earlier discussions and apply to all EOR processes and levels of activity. In fact, many of the considerations could apply to any industrial activity.

The net social effects of EOR activities appear to be beneficial and should encourage supportive regulations and government policies. EOR project feasibility and economics are sensitive to a wide range of government regulations and environmental considerations. These interactions are reviewed.

Social Costs and Benefits

The principal focus of this study is on the technological, economic and environmental factors which impact on specific EOR project results. These projects may, however, have additional significant impacts on society in general. The following sections identify and discuss various social benefits and costs associated with EOR projects and are not necessarily considered in project economic analyses.

Social Benefits

The social benefits of enhanced recovery programs are primarily political and technological. The political benefits hinge on reducing oil import requirements as a result of increased domestic production. The technological benefits relate to potential future expansion of enhanced recovery technology applications and to the resulting increased recovery of oil in place associated with both past and future discoveries. Since neither of these effects is reflected in routine project evaluations, they represent an additional social benefit of EOR activities.

Other benefits relate to economies of scale and to the flow of tax revenues. Briefly, the areas in which society might benefit from enhanced recovery programs can be outlined as follows:

- **Domestic Energy Policy**—Increases in domestic oil production could reduce foreign import requirements and permit a scaling back of emergency oil storage programs. The existence of higher domestic production levels would also reduce the Nation's ultimate vulnerability in the event that an embargo might outlast strategic storage volumes.
- **Foreign Policy and National Security**—Reduced dependence on oil imports would afford greater independence and flexibility in conducting U.S. foreign policy. Limiting oil imports from politically sensitive areas of the world would make the U.S. society and economy more secure from the disruptive effects of another embargo.
- **Expanded Use of Enhanced Recovery Technology**—Development of enhanced recovery technology for the larger, most promising U.S. fields probably will demonstrate the applicability of EOR processes, both to other domestic and foreign fields. Also some in-situ processes aimed at conventional oil may be

modified and adapted to heavy oil, shale, and/or coal recovery.

- **Expected Recovery of Reserves**—With enhanced recovery technology, producers could expect ultimately to recover an increased percentage of oil in place in newly discovered fields. Thus, fields that otherwise might be considered marginally unattractive could become economically viable. The resulting oil recovery increase would contribute to the Nation's natural resources inventory.
- **Economies of Scale**—Expansion of enhanced recovery technology and application would also cause expansion and economies of scale both in those industries supplying materials for the individual projects and in all ancillary and downstream activities. Society would benefit since these economies of scale would tend to result in lower oil costs than would otherwise occur.
- **Flow of Tax Revenues**—Severance, royalty and property taxes imposed on enhanced recovery projects would contribute to the funding of government services.

The minimum social benefit of increased domestic oil production should be measured against the price of the most prominent alternative energy supply, i.e., imported oil. Moreover, other energy alternatives, which are even more costly than imports, are being seriously and actively considered. This fact could generate other social benefits associated with increased U.S. oil production resulting from successful application of enhanced recovery techniques.

Social Costs

The potential social costs of enhanced recovery programs would primarily relate to air and water quality, health and safety, and land use. However, federal, state and local regulations will require firms involved in enhanced recovery to pay the costs of reducing environmental hazards. Moreover, enhanced recovery programs will take place within existing oil fields, and thus, will not generally require additional land use. These projects usually will employ existing lease equipment, tankage, and transportation facilities. Enhanced recovery programs will involve few, if any, major new land use requirements or industrialization commitments, which would substantially increase the social and financial burdens of the surrounding communities. In most cases, EOR projects will have little community impact since they will occur in presently producing fields.

Summary

On balance, the social benefits clearly appear to outweigh the social costs. Essentially all of the potential social costs now perceived very likely will be paid for by the operator through existing and/or future environmental protection regulations.

Regulations and Federal Policy Considerations

This section considers the impact of government regulations and controls on enhanced oil recovery potential.

The Impact of Government Controls and Regulations Upon the Cost and Availability of Capital

The major consideration affecting the petroleum industry's ability to commit additional funds to enhanced recovery projects is the attractiveness of these investments relative to alternative opportunities. Uncertainties about future price controls and taxes affect investor decisions and tend to boost minimum acceptable target rates of return. Of course, investors are not only concerned with existing rules, but with future and unpredictable shifts from the established regulatory environment.

As demonstrated in this study, the potential for the successful application of enhanced recovery methods is highly dependent upon economic factors. Public policies which reduce capital costs by increasing the potential scale of operations, lowering the required minimum rates of return for investors, and increasing the efficiency of investments, will substantially contribute to increasing ultimate oil recovery rates.

Price Effects

In an unregulated environment, market supply and demand forces determine the equilibrium prices to which both consumers and producers respond. When market price determination is unimpaired by regulatory restraints, a decentralized benefit/cost analysis is continuously being made by both consumers and producers whose responses tend toward an optimized supply/demand condition. In an activity such as enhanced oil recovery, where there are not important adverse economic or social considerations, the free market result tends toward efficient allocation of resources.

Crude oil price controls as presently administered generally discourage EOR projects because of

the difficulty of qualifying enhanced recovery from reservoirs subject to steep production decline as "new oil." Regulatory changes now being considered may help relieve this problem.

Non-Price Incentives

The U.S. Energy Research and Development Administration has authority to fund research efforts to increase U.S. energy production. Such funding has been directed in various ways to support EOR technology development and commercialization. Although most technical problems involved in enhanced recovery should be manageable within the private sector given adequate price and tax incentives, accelerated field testing of EOR technology may benefit from selective government initiatives.

Tax incentives could effectively assist in the recovery of research, development, and commercialization investments. The cases analyzed herein show that alternative tax treatment would have substantial impact on enhanced recovery.

High royalties discourage EOR investment since they are claims on gross revenues rather than net earnings and, thus, represent a burden which would preclude development of otherwise economic reserves.

Plugging and Abandonment

Many oil fields in which waterfloods were started in the 1950's have now reached advanced stages of depletion. Some are approaching their economic limit and gradually wells are being plugged and abandoned. For these fields, it would be advantageous if steps were taken to initiate enhanced recovery projects, where feasible, while the existing wells and surface equipment are still intact and usable. Otherwise, the added costs incurred in redrilling of wells and replacement of production facilities will make enhanced recovery projects more costly. In offshore operations, the potential added costs of redrilling may be compounded by the need to install new drilling platforms.

All producing states have statutes or regulations requiring oil and gas wells to be plugged upon final abandonment or within a specified time after production ceases. Such plugging requirements are designed to avert waste and pollution by preventing oil, gas and salt water from escaping at the surface or into subsurface water-bearing formations.

Ordinarily, when the field or unit operator desires to retain a well for evaluation and future reentry or injection, an exception to the plugging rule may be obtained upon application to a state regulatory agency. However, the risk exists that numerous individual operators having wells nearing the economic limits of current operations will plug and abandon such wells because they fail to see any economic incentive for future enhanced oil recovery projects in the area.

Unitization

Nearly all producing reservoirs are characterized by multiple ownership and will require unitization to implement enhanced recovery projects. Unitized enhanced recovery operations involve some cooperation among production firms. One producer usually is designated as the operator, but all parties with ownership interest share in the investment costs, operating costs and output on the basis of prearranged terms.

Under present regulatory policies, a high degree of uncertainty now exists in that unitization agreements may be precluded due to differing regulated prices and taxation provisions applicable to the different owners.

Any present or future laws or regulations establishing differential price ceilings, tax treatment or other regulatory controls for different classes of oil and gas producers substantially reduces the prospect of reaching mutual agreement on unitization required for implementation of enhanced recovery projects.

Economic Incentives

The results of this study indicate that public policies that provide increased economic incentives for the production of enhanced recovery oil will result in increased volumes. Conversely, those policies which decrease economic incentives will result in a diminished production of enhanced recovery oil. This is illustrated in Figure 1, which charts estimated EOR ultimate recovery versus oil price. An almost directly linear relationship between incremental ultimate recovery volume and crude oil prices can be observed. Likewise, Figure 2, which charts potential EOR producing rate versus time for the five assumed oil prices, clearly indicates the effect of increased economic incentives on volume.

Government actions can influence economics of enhanced recovery by price policies, tax policies, or other regulations. A serious question may be raised regarding the propriety of extending special advantages favoring EOR investment that would not be similarly provided to conventionally produced petroleum, or, indeed, any equivalent or substitutable form of domestically produced energy. It is haz-

ardous to suggest conclusions regarding the impact or desirability of policy actions specifically affecting EOR without considering their effect upon other energy supply options. Energy policy decisions must be based upon a thorough consideration of the full range of sectoral impacts and interactions, which goes well beyond the scope of this study.

The possibilities of improving economic incentives for EOR production through changes in tax policies are many. A treatment of the subject of U.S. tax policy for the petroleum industry is being prepared as part of the National Petroleum Council's study on Future Energy Prospects. This study is expected to be completed in the Spring of 1977.

Research and Development

Enhanced recovery processes are in a development stage. The rate at which development by the industry takes place depends upon the economic outlook perceived by the industry for these methods. If management were assured that oil prices indeed will rise to substantially higher levels in the future or that other developments would improve profitability, larger investments would be made in very long lead time field tests and other steps leading to commercialization of emerging EOR technology. Government policy with respect to oil price and other factors influencing EOR profitability is thus the dominant factor in establishing the level of R&D funding and the rate of evolution of technology.

From industry's point of view, economic considerations of pilot testing are not overriding; that is, industry is prepared to carry out whatever pilot tests are needed, as they have for decades. What is significant is the economics of full field-scale applications. Progress in developing enhanced recovery processes requires many field tests. As discussed elsewhere, the only way to determine if a process works is to try it out in the field. Although continuing laboratory research is desirable and necessary, laboratory-based research and development is far ahead of field trial research and development.

A major problem in pursuing field development and application of enhanced recovery processes is the lack of detailed knowledge of the properties and characteristics of reservoirs and their susceptibility to the process being applied. Funding by industry of field pilot tests is usually concentrated on testing the applicability of a specific process to a specific reservoir, with the goal of optimizing information gathered per dollar spent. Opportunities exist for obtaining additional information in such tests through supplemental funding, particularly with regard to more general considerations which may be important in relating test results to opportunities in other reservoirs. Funding of field work such as special cores and logs, single well tests, and other techniques used to establish the level and distribution of residual oil in reservoirs after waterflooding would be of broad general benefit in better defining this critical parameter.

Other less obvious incentives, which government can supply, include a patent policy which would protect the rights of those who have funded research on EOR processes. The government can also provide additional incentive for research and development by minimizing the administrative burden on joint projects between industry and the government. The negotiations, record keeping, and report requirements by the government for joint government-industry field testing projects provide a formidable disincentive.

Environmental Considerations

Scope

This section outlines possible impacts on the environment that may result from enhanced oil and gas recovery. It is a general overview rather than a comprehensive assessment of the environmental impacts associated with any specific method at a particular site. The environmental considerations for the individual processes are discussed in more detail in Appendices D, E, and F.

Environmental discussions in this report are derived from a general knowledge of the subject by the study team members. No new technological study of environmental effects was undertaken.

Background

Although some of the suggested enhanced recovery techniques are relatively new, all have been field tested, and many of the methods and chemicals suggested for enhanced recovery have been used to some degree for many years in primary or secondary production. The data collected to date and the continuing, further evolution of these techniques will aid in avoiding or mitigating detrimental environmental effects in the future. Long-range monitoring of a specific technique may be necessary to fully assess its environmental effects.

Each site being considered for enhanced recovery techniques will require evaluation from both a technical and environmental viewpoint in order to determine the best enhanced recovery method and

to define the measures necessary to protect the environment.

Throughout this study, environmental costs resulting from present or anticipated needs have been included for each EOR method in establishing total process cost; thus, the cost of protecting the environment is included in project costs by the producer.

A number of laws bear upon environmental aspects of enhanced recovery, and of these, the Clean Air Act, the Federal Water Pollution Control Act, and the Safe Drinking Water Act would have the most significance.

Areas of Concern

Water Supply

Published estimates indicate that the United States needs nearly 400 billion gallons of water a day and that these requirements may reach nearly 500 billion gallons by 1980. Since the supply of fresh, high-quality water is scarce in some areas, the amount of water used and the disposal thereof are of major concern in enhanced oil and gas recovery methods.

EOR processes that use large amounts of water are anticipated to make major use of recycling of formation water as a conservation measure. Thus, net requirements would be much less than would appear from considering only the total volume injected.

Water Quality

Problems in water quality relate to the handling and disposal of produced water. Water for enhanced recovery processes may be either fresh or saline, depending on process requirements. In the past, waterflooding commonly used saline water, in many cases with salt concentrations higher than sea water; however, some EOR methods require relatively fresh water.

The two most significant points with which danger to water quality is identified are: (1) spills of chemicals as a result of transportation, on-site manufacturing, and handling; and (2) improperly controlled disposal of chemically loaded produced water. Both of these areas can be dealt with through proper operating procedures. Further research and review of the types of chemicals planned for use and the methods for handling them appear to be the best ways for establishing adequate safeguards from potential toxic and carcinogenic effects.

The 1972 amendments to the Federal Water Pollution Control Act provide a useful framework for evaluating the potential impact for EOR techniques on water quality. A National Pollutant Discharge Elimination System Permit is required under this Act before commencing a waste-water discharge to surface waters from a point source. The intent of the Act and the discharge permits is to require use of the best available technology economically achievable by 1983 and to attain and maintain receiving water quality adequate to assure protection of public water supplies, agricultural and industrial uses, and the protection and propagation of a healthy population of shellfish, fish, and wildlife, and to allow recreational activities in and on the water. Under the Safe Drinking Water Act of 1974, the EPA is required to regulate subsurface injection and waste discharges in order to protect groundwater quality. EPA is also severely limiting discharge of produced water to surface waters.

Process water that is not recycled can be disposed of in two ways: injection into separate salt water aquifers or discharge to surface waters. Injection into separate salt water aquifers is an established operating procedure. For surface disposal, also an established procedure, process water for disposal is and will continue to be treated to meet standards of purity required by law. As new chemicals are applied to EOR, new treatment methods for disposal will have to be developed.

Groundwater aquifers, when accidentally infiltrated by chemical pollutants, are contaminated for varying lengths of time, depending on the chemicals and rock type. The concentration of the chemicals may be decreased with time and distance traveled in the reservoir. This decrease may be attributed to dilution, entrapment, absorption and degradation within the reservoir.

Groundwater aquifers when used for disposal, however, have distinct characteristics: they normally are saltwater aquifiers; they are not hydraulically connected to freshwater aquifiers; and they are commonly associated with and connected to oil reservoirs.

Leaks may occur from broken lines, improperly plugged wells, or improperly cased and cemented wells. However, existing technology, mandatory use of surface casing to protect freshwater aquifiers, and existing state monitored safety and inspection procedures used in drilling a well minimize the probability of an undetected leak. In spite of the possible accidents and potential hazards of drilling and completing wells that intersect brine and freshwater aquifers, little groundwater pollution has occurred in the past. It is felt that this record can remain intact for enhanced recovery methods by use of the same safe non-polluting work procedures.

Automatic shutdown and fail-safe devices are available. The use of such protecting devices should be given high priority.

Air Quality

Enhanced recovery can influence air quality in several ways. For example, steamflooding uses steam generators which emit combustion products; in-situ combustion uses air compressors; and in-situ combustion produces combustion products along with produced oil.

Thermal applications will have to deal with three primary constraints contained in the Federal Clean Air Act and state laws and regulations pursuant to the Act: (1) ambient air quality standards; (2) significant deterioration regulations; and in some cases, new source performance standards. Under present laws and EPA regulations, usual sized steam generators are too small to be subject to new source performance standards. The major constraints will be ambient air quality standards and significant deterioration regulations.

The EPA has set national ambient air quality standards to protect human health, allowing an adequate margin of safety (primary standards), and to protect property, vegetation, and other known or anticipated effects on public welfare (secondary standards). The primary and secondary standards are defined by permissible concentrations of carbon monoxide, photo-chemical oxidants, nitrogen dioxide, non-methane hydrocarbons, sulfur oxides and particulates. In addition, some states (for example, California) have established state ambient air quality standards which are more stringent than the federal standards. EPA regulations allow major new air pollutant sources only if they do not prevent or interfere with the attainment or maintenance of these ambient standards.

In addition, EPA regulations have been promulgated to prevent significant deterioration of air quality by sulfur oxides and particulates in regions where air quality is superior to the ambient air quality standards. These regulations allow states to classify their "clear air" regions into three zones. In the more restrictive zone (Class I), only extremely small emission sources would be permitted. In the Class II zone, new sources with moderate emissions would be permitted as long as they, in combination with all other new sources, do not exceed the allowable increment of air quality deterioration. In Class III zones, air quality would be required to meet the national or more stringent state ambient air quality standards, and emissions would be allowed to these standards.

The largest potential for thermal recovery on an extensive scale exists in California's Central Valley. Much of this region exceeds the photo-chemical oxidant and particulate air quality standards and a few locations are at or near the standard for sulfur oxides. At present, most of the oilfield areas in the Central Valley have air quality good enough to be subject to significant deterioration regulations with respect to sulfur oxides. At the present time, these areas are Class II zones which allow installations that do not exceed the allowable increment of air quality deterioration. These Class II classifications are initial ones established by the EPA, pending specific further classification by the State Air Resource Boards. If these thermal opportunity areas should be classified Zone III in the future, installations would be limited by the national or more stringent state ambient air quality standards.

Air quality maintenance plans, which each state must develop to attain and maintain national ambient air quality standards, are likely to be the mechanism for determining how the air pollution from thermal EOR applications will be controlled in California and other states in the future. Among the possible means of meeting these potential standards are (1) use of low-sulphur oil; (2) flue-gas desulfurization; and (3) the consolidation of facilities to increase the feasibility of emission control technology.

Other

Because enhanced recovery will take place in existing oil and gas fields, only minor changes should occur in present land use practices. In some cases, additional surface equipment will be needed, storage areas may be required, and additional wells may be drilled, but the overall appearances of the field will remain about the same.

Sources of noise may increase due to truck and other traffic, steam venting, well drilling, and other production activities. Noise control practices and devices will be needed to control noise levels to comply with regulations.

Manufacturers of toxic and hazardous chemicals for EOR will be required to follow laws and regulations governing the manner of transport and end-use, including evaluation in pilot tests.

CO_2 is non-toxic, but it is heavier than air so that its discharge to the atmosphere needs to be done in accordance with safe practices. H_2S, a toxic gas, will be produced from some projects. Both CO_2 and H_2S production are common in conventional oil and gas production, and regulations governing their safe handling are established under current procedures.

Other aspects for the use of chemicals which are of concern are combinations of toxicity and low degradability and synergistic effects which can convert two or more substances into one which becomes more dangerous than either one alone. A report on the Environmental Consequences of Tertiary Oil Recovery, submitted February 9, 1976, to the EPA, and prepared by Energy Resources Co., Inc., in which some of these questions are raised, indicates that the chemicals being used in combination now do not exhibit toxic or hazardous properties sufficient to raise serious environmental concern over present EOR operations. This aspect of the potential hazard from new chemical combinations in future operations should be subject to additional research.

Summary

It is natural that some concern exists as to what new environmental elements will be introduced by experimental enhanced oil and gas recovery techniques. Proper planning and research will be needed to assure that EOR operations can be carried out in the manner consistent with environmental protection needs and programs.

Most of the new enhanced recovery techniques will have considerable lead time before being put into operation. Except for thermal methods, which have had considerable use already, most of the enhanced recovery projects will not begin on a major scale until 1980 or later. Areas of potential concern should be identified and resolved in the interim.

In responding to applicable environmental laws, compliance with ambient air quality standards and significant deterioration regulations for thermal operations would appear to require considerable effort. Compliance with injection of waste water disposal regulations will also require considerable effort for all EOR applications.

Appendices

Appendix A

Request Letter

UNITED STATES
DEPARTMENT OF THE INTERIOR
Office of the Secretary
Washington, D.C. 20240

COPY

March 18, 1975

Dear Mr. Swearingen:

The President and the Congress are considering changes in energy policies to reduce the Nation's vulnerability to interruptible and high-cost energy from abroad. However, any pathway to energy independence will depend upon our ability to apply existing and new technology.

The National Petroleum Council has provided the Department of the Interior with useful advice on the extent and recovery of the Nation's oil and gas resources through such studies as Impact of New Technology, Future Petroleum Provinces, U.S. Energy Outlook, and Ocean Petroleum Resources.

While we pursue unknown and unevaluated conventional and unconventional energy sources, we must continue to improve our ability to recover larger proportions of known oil and gas deposits on land and on the Outer Continental Shelf. New and anticipated technology and major changes in domestic and world market conditions require new estimates of ultimate resource recovery. While the U.S. could expect to recover an average of about one-third of the oil and four-fifths of the gas from known reserves in the past, new conditions will undoubtedly improve the recovery rates in the future. We need to obtain the best estimates of likely new recovery rates because of the changes experienced during the past few years.

We therefore request the National Petroleum Council to assess the state of the art of enhanced recovery for oil and gas from known oil and gas reserves. Your assessment should draw from and revise such relevant data from previous advisory committee reports and reports of others as you deem appropriate and should include, to the extent possible, an appraisal of the probable ranges of volumetric outcomes based on alternative economic conditions. Additionally, your report should contain recommendations as to how public policy can improve the outlook.

We would appreciate discussing a study outline this spring for a study to be completed within a year.

Sincerely,

/s/ JACK W. CARLSON

Jack W. Carlson
Assistant Secretary of the Interior

Mr. John Swearingen
Chairman, National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Appendix B
Committee Rosters

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For Oil and Gas in the United States

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Appendix C
Additional Economic Considerations

Additional Discussion—Project Economics

This appendix contains additional discussion on various key areas bearing on the project evaluation bases employed in this study. Topics included are:

- Process-independent costs
- Discussion of income tax cases
- Crude quality price differentials, and
- Project economics calculation.

Process–Independent Costs

Introduction

For the purposes of this study, the development cost and annual operating expenses for enhanced oil recovery operations are categorized according to: (1) non-process-oriented costs and (2) process-oriented costs. Because all of the EOR processes considered in this study utilize the injection of water into the reservoir, the generic non-process cost associated with EOR was determined by estimating the costs of installing and operating waterflood projects.

In the oil producing industry, the cost of developing and operating an oil field is dependent upon numerous factors that vary from field to field, and no well, lease, or field represents the average of all the factors involved. However, guidelines were developed, under certain criteria and assumptions considered to be consistent with current (1976) practices, by which reasonable cost estimates could be made. Presented in this report are the estimated costs at mid-year 1976 for the following classifications:

- Direct annual operating expenses for waterflooding
- Cost of drilling and completing production and injection wells
- Cost of equipment for:
  - Producing well equipment
  - Lease equipment
  - Water injection equipment
- Cost of utilizing existing wells as:
  - Producing wells
  - Injection wells.

Direct Annual Operating Expenses

The major factor that influences the non-process-oriented costs associated with enhanced oil recovery is depth. Depth not only affects the cost of drilling, completing and equipping the wells, but it has a profound effect upon the annual operating expenditures. For the purpose of this study, non-process costs were estimated for depths of 2,000, 4,000, 8,000, and 12,000 feet.

The direct annual operating expenses are those that are essential to the production of oil and gas, such as cost of labor, power, surface and subsurface equipment repair and maintenance, fluid injection, treatment of oil and gas for sale, etc. These operating expenses were estimated by formulating a set of assumptions and conditions whereby total annual cost was computed by summing the cost of small component items considered to be representative of oil production, in the geographic area considered, and from each of the assumed depths. Although these annual expense estimates will not be identical to those incurred in a particular field, during a par-

ticular year, or for a particular oil producer, they are considered to be representative of the expenses that may be incurred over the life of an enhanced oil recovery project. These costs were estimated on an annual basis for each item and then proportioned as if for individual wells.

The fuel or power expenses for producing oil from a well will vary considerably, depending primarily upon the type of, and depth at which, production equipment is installed. It was assumed that all power requirement was electricity; this cost was estimated from prevailing area electrical rates and the estimated horsepower required for each project. Costs were allocated on a per-well basis, where many wells were served by the same facility, such as the water injection plant for a project. Scale and corrosion inhibitors and deemulsifier costs were determined on a monthly per-well basis.

Costs for surface and subsurface equipment repair, maintenance, and service were determined by assigning frequencies of occurrences for each problem and estimating the cost of correcting the problem. The cost of correcting the problem was multiplied by the frequency of occurrence to obtain an annual per-well cost. Some of the most common types of production problems considered were broken rods, tubing leaks, and pump failures. Less frequent problems were casing leaks, sanding, packer failure, and poor cement jobs.

Summation of annual costs for all items resulted in the non-process, direct annual operating expenses shown in Table 6.

TABLE 6

1976 DIRECT ANNUAL OPERATING EXPENSE FOR WATER FLOODING*
(Dollars per Producing Well)

Area	Depth (Feet) 2,000	4,000	8,000	12,000
Texas and Louisiana	14,900	19,300	24,100	25,400
California	19,300	22,600	29,100	33,000

* Estimated at mid-year 1976.

Cost of Drilling and Completing Production and Injection Wells

Geological and stratigraphic variations between areas can cause large differences in the costs of drilling and completing wells. Drilling time required for the same depth well, completion techniques, and formation evaluation will differ, not only for each area, but also for individual operators within that area.

In view of the variations that occur in drilling and completing wells, cost data developed by the *Joint Association Survey* (JAS) were considered to be the most representative for use in this study.*

For each of the five onshore areas studied, 1974 average costs of oil wells per foot drilled were compared to average depths, for each of the JAS depth intervals. Regression analysis was used to fit a curve that describes these intervals and the functional relationship between average 1974 drilling cost per foot and depth. In some areas, the average cost per foot either remained relatively constant or decreased with depth to about the 8,000-foot level due to the depth-independent costs such as roads, moving in, rigging up, pits, surface casing, etc.

The Independent Petroleum Association of America (IPAA) index of cost of drilling and equipping new wells in the United States for year-end 1975 was 120.3 (1974 = 100); it was estimated that the mid-year 1976 index would be 126.3. Therefore, the 1976 trend of drilling cost per foot was developed by increasing the 1974 index by 26.3 percent, as shown in Figures 51 through 55. These costs include drilling and completing the wells through the wellhead, including tubing.

Cost of Equipment

The costs of producing and injecting equipment were based on mid-1976 manufacturer's or supplier's list prices of new equipment, for a design considered to be the most commonly used in the areas under consideration.

Producing Well Equipment

Table 7 shows the cost of all well equipment, except tubing and wellhead, required to lift the fluid to the surface by artificial lift. For this study, it was assumed that the wells would be equipped either with rod pump or hydraulic lift, depending upon the depth.

Lease Equipment

Table 8 shows the cost of all lease equipment required to process the produced fluids prior

**Joint Association Survey*, sponsored by the American Petroleum Institute, the Independent Petroleum Association of America, and the Mid-Continent Oil and Gas Association, published March 1976 with cost data for 1974.

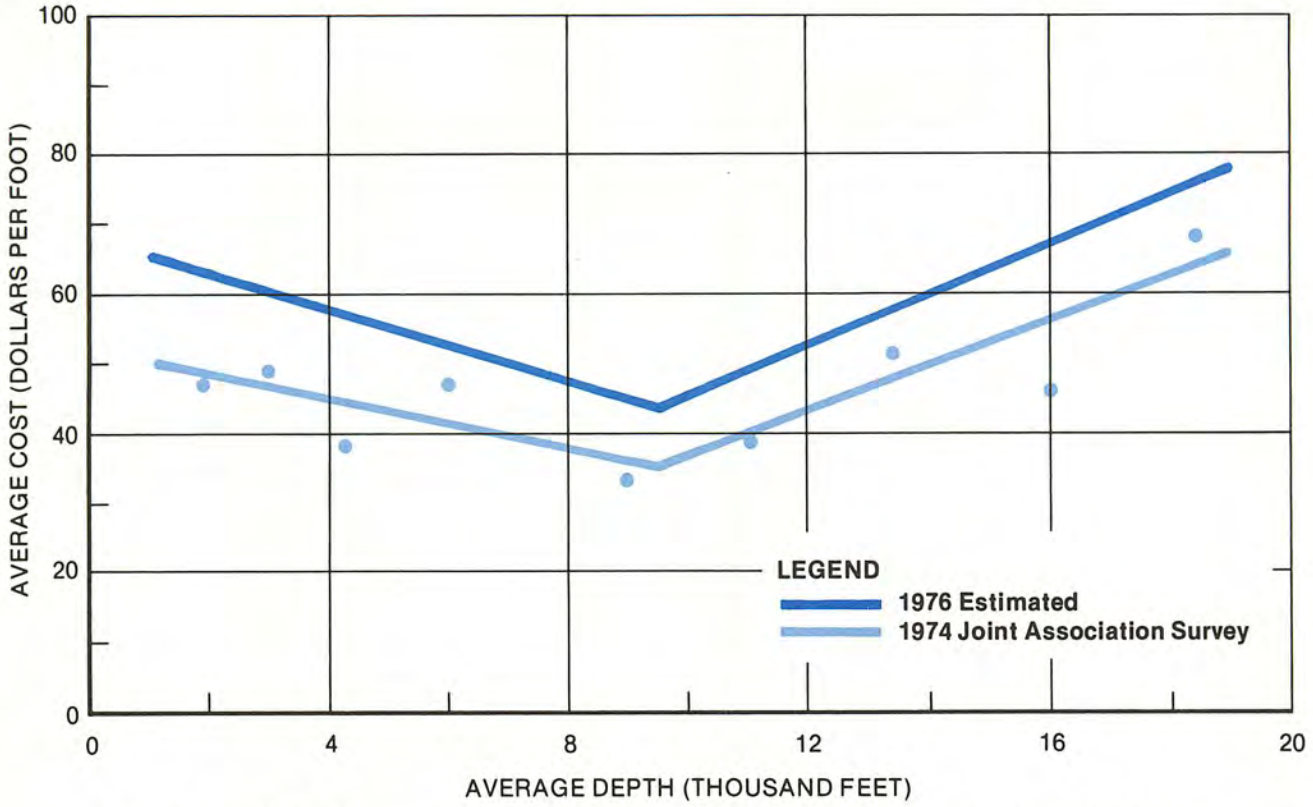


Figure 51. Cost of Drilling and Completing Production and Injection Wells—South Louisiana.

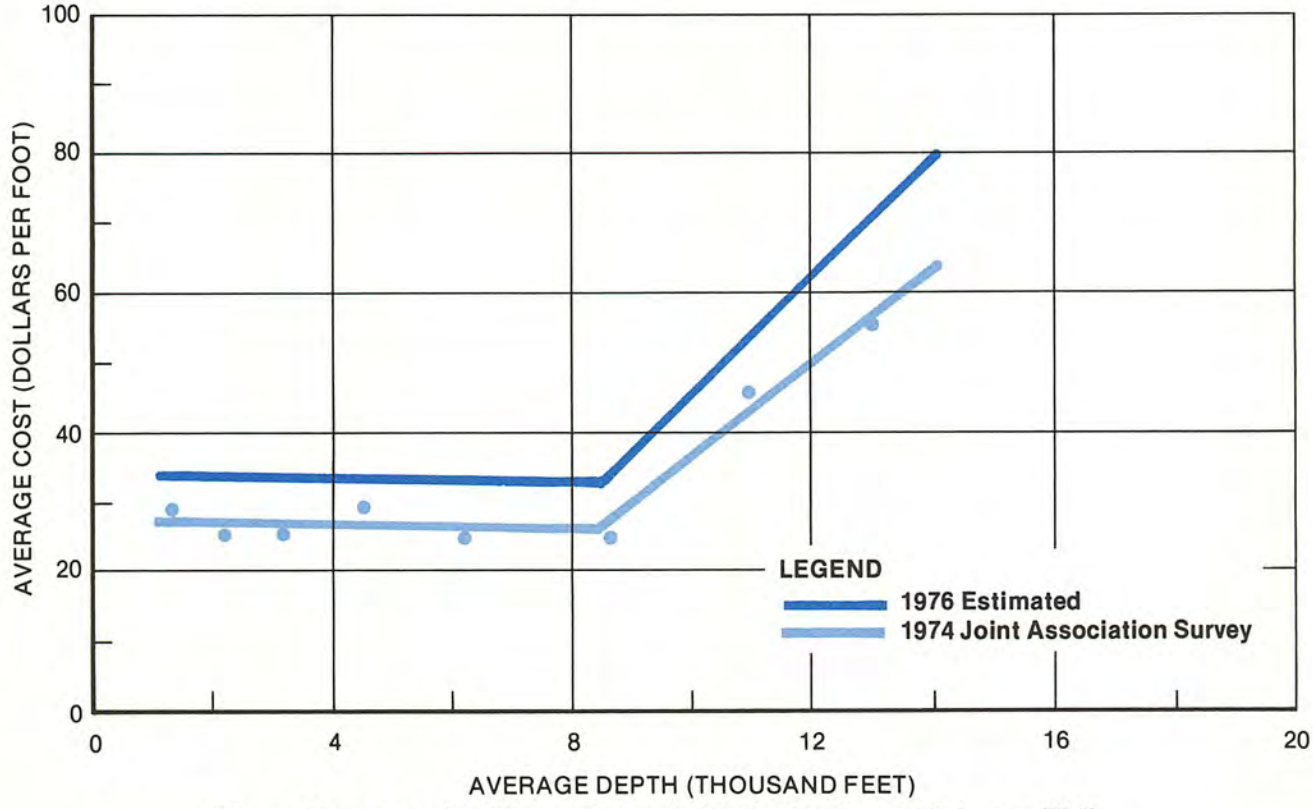


Figure 52. Cost of Drilling and Completing Production and Injection Wells
Texas Districts 2 and 3 Combined.

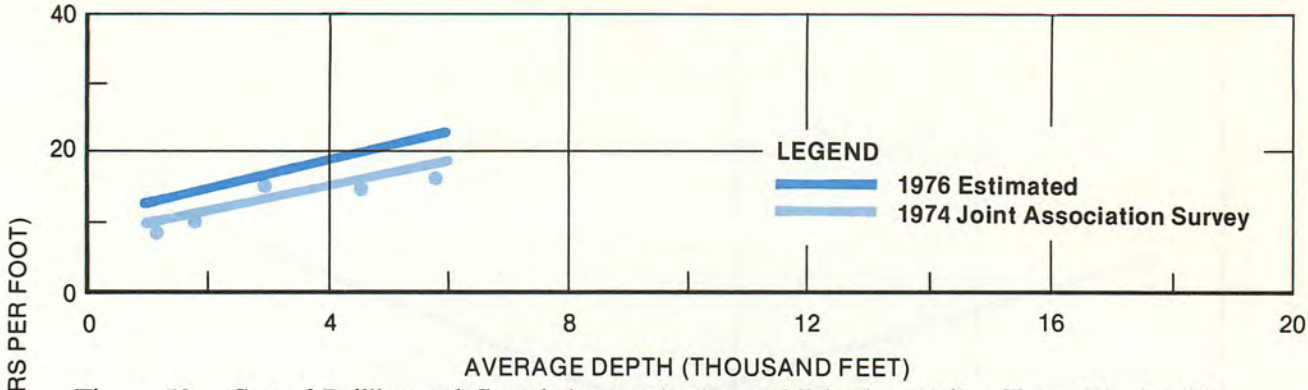


Figure 53. Cost of Drilling and Completing Production and Injection Wells—Texas District 7B.

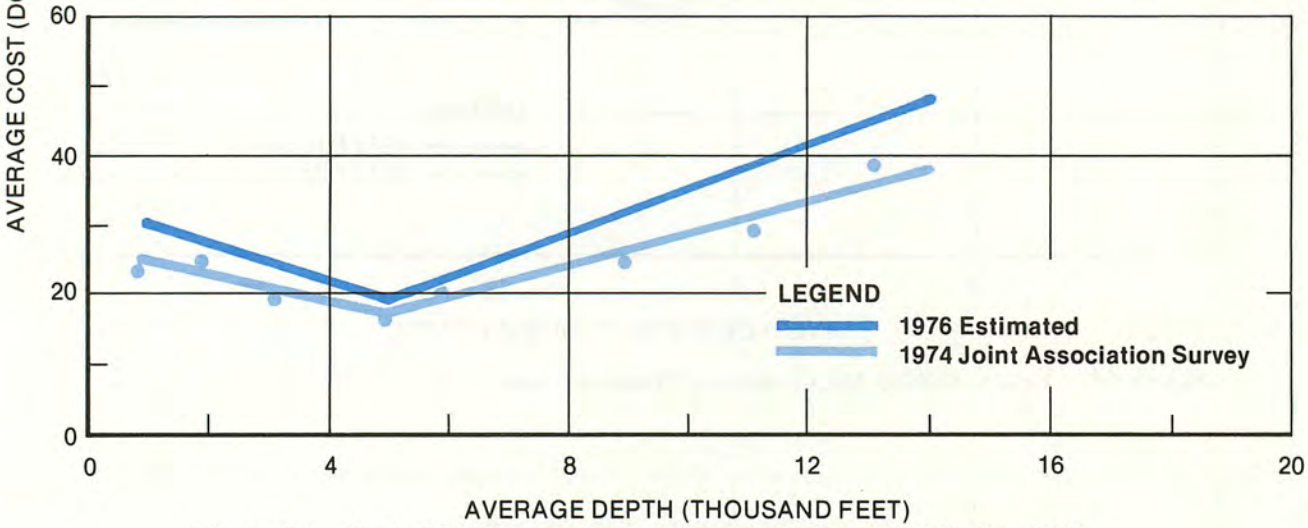


Figure 54. Cost of Drilling and Completing Production and Injection Wells
Texas Districts 8 and 8A Combined.

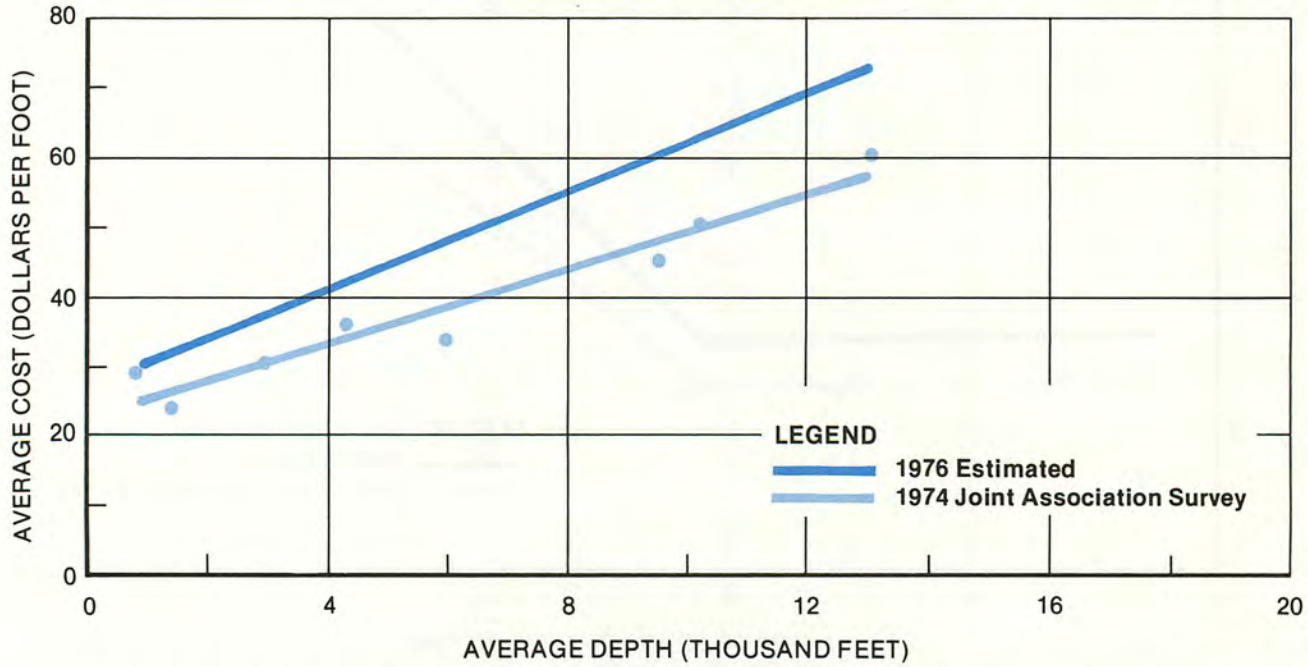


Figure 55. Cost of Drilling and Completing Production and Injection Wells—Onshore California.

TABLE 7

1976 COST OF PRODUCING WELL EQUIPMENT FOR WATERFLOOD*
(Dollars per Producing Well)

Area	Depth (Feet) 2,000	4,000	8,000	12,000
Texas and Louisiana	9,900 (Rod)	18,500 (Rod)	25,500 (Hydraulic)	25,500 (Hydraulic)
California	17,600 (Rod)	34,500 (Rod)	28,400 (Hydraulic)	32,400 (Hydraulic)

* Estimated at mid-year 1976.

TABLE 8

1976 LEASE EQUIPMENT COST*
(Dollars per Producing Well)

Area	Depth (Feet) 2,000	4,000	8,000	12,000
Texas and Louisiana	13,200	14,400	15,000	15,000
California	15,700	17,400	18,800	18,800

* Estimated at mid-year 1976.

to custody transfer. The major items include heater treaters, separators, well test systems, tanks, flowlines and water disposal systems.

Water Injection Equipment

Table 9 shows the cost of water injection equipment. These costs include all equipment necessary to install a waterflood in a depleted primary producing field. The major items included are: water supply wells, water tankage, injection plant and accessories, injection header, water injection lines, and electrification.

Cost of Utilizing Existing Wells

When installing an enhanced oil recovery project in a field, many already existing wells may be utilized as producing or injection wells. However, some wells will need workover and new equipment. Table 10 shows the assumed percentage of wells in a field that will require workover and equipment replacement.

TABLE 9

1976 COST OF WATER INJECTION EQUIPMENT FOR WATERFLOOD PROJECT*
(Dollars per Injection Well)

Area	Depth (Feet) 2,000	4,000	8,000	12,000
Texas and Louisiana	27,700	27,700	44,100	44,100
California	30,500	30,500	48,500	48,500

* Estimated at mid-year 1976.

When existing wells are to be reconditioned for further use in the EOR process, the cost of conversion depends on the age of existing equipment. Shown in Table 11 is the estimated cost of converting an existing well to an EOR producing well; Table 12 shows the cost of converting to an injection well.

Discussion of Income Tax Cases

The incentive to proceed with EOR projects and the potential volume of enhanced recovery oil is sensitive to the income tax treatment applied to these projects. In evaluating this sensitivity, each project was analyzed for two tax treatment cases: (1) a moderate case and (2) a restrictive case. Tax legislation and interpretation are ever-changing, and it is uncertain how future tax law will be applied to

TABLE 10

PROPORTION OF WELLS REQUIRING CONVERSION FOR ENHANCED RECOVERY

Number of Years Field Has Been in Operation	Percentage of Wells
26 or more	100
16 to 25	50
6 to 15	25
1 to 5	0

Source: Information obtained from discussion with company employees involved in production and conversion for secondary oil recovery projects. This data confirmed percentages previously published.

TABLE 11

COST OF CONVERTING EXISTING PRODUCING WELL TO AN EOR PRODUCING WELL
(1976 Dollars)

State	Depth	Equipment Installed Before 1950	Equipment Installed 1951-1960	Equipment Installed 1961-1970
West Texas	2,000	18,000	14,400	10,300
	4,000	30,800	23,800	16,800
	8,000	64,100	50,700	37,400
	12,000	129,100	104,300	79,400
South Louisiana	2,000	38,900	30,200	21,500
	4,000	70,400	59,800	42,200
	8,000	104,700	82,900	61,000
	12,000	130,200	105,100	80,100
California	2,000	22,500	17,500	12,400
	4,000	56,300	43,500	30,700
	8,000	115,200	91,100	67,100
	12,000	212,700	171,800	130,800

Note: Costs to workover old producing wells and install new production equipment for enhanced oil recovery were calculated based on percentages of applicable items of new well drilling costs, and equipment replacement costs as required for conversion. These costs were estimated at mid-year 1976.

TABLE 12

COST OF CONVERTING EXISTING PRODUCING WELL TO INJECTION WELL
(1976 Dollars)

State	Depth	Equipment Installed Before 1950	Equipment Installed 1951-1960	Equipment Installed 1961-1970
West Texas	2,000	13,600	11,400	9,100
	4,000	21,500	18,000	14,500
	8,000	45,400	39,000	32,500
	12,000	124,900	103,500	82,100
South Louisiana	2,000	28,600	23,800	19,100
	4,000	54,000	63,700	36,300
	8,000	74,200	63,700	53,100
	12,000	135,900	112,700	89,400
California	2,000	16,500	13,800	11,100
	4,000	39,300	32,800	26,400
	8,000	81,600	70,100	58,400
	12,000	205,800	170,500	135,300

Note: Costs to workover old producing wells and install equipment for enhanced oil recovery were calculated based on percentages of applicable items of new well drilling costs, and equipment replacement costs as required for conversion. These costs were estimated at mid-year 1976.

EOR projects. However, these cases are considered to be within reasonable interpretation of present tax laws. The moderate case assumes that, considering the energy-related nature of such projects, tax law interpretations will tend to encourage substantial expenditures of additional capital to increase domestic energy production. The restrictive interpretation is also described for purposes of testing tax policy effects. The assumptions and interpretations regarding the general tax parameters, used as the basis in evaluating these two cases, are shown in Table 13.

Intangible Development Costs

For all practical purposes, the option to expense intangible development costs (IDC) has existed since the first income tax statute. However, the first administrative ruling authorizing the taxpayer to deduct intangible expenditures incurred in drilling oil and gas wells was issued in connection with the Revenue Act of 1916. (Specific statutory authority did not exist until the Internal Revenue Code of 1954 was enacted.) Only the owner of the operating rights in a property (i.e., the working interest owner) is entitled to deduct IDC under this election. Deductible items falling within this option include any cost which in itself has no salvage value (i.e., wages, fuel, repairs, hauling, supplies, etc.) and which is "incident to and necessary for the drilling of wells and the preparation of wells for production of oil and gas." The cost of tangible equipment is not subject to this election, and it must be capitalized and depreciated. The cost to install equipment "incident to and necessary for" the drilling and preparing of wells for production is considered intangible and subject to the option; however, such costs related to the installation of production facilities (equipment installed after the casing and Christmas tree are in place) must be capitalized as equipment cost. The taxpayer's basis in capitalized installation and tangible equipment cost must then be recovered through depreciation in the manner outlined in the discussion of "Hardware."

In both tax treatment cases it was assumed that IDC is 70 percent of total new well cost. Following is a discussion of the tax treatment of IDC under the two tax cases.

Moderate Case

It is assumed that all wells included in EOR projects (injection, production, and water source)

TABLE 13

INCOME TAX PARAMETERS FOR TWO CASES

	Moderate Case	Restrictive Case
Intangible Drilling and Development Costs (IDC)*	Expense costs of all wells	Expense costs of injection and production wells
		Capitalize costs of water source wells
Hardware	Capitalize and depreciate over five years by Straight-line Method	Capitalize and depreciate over eleven years using Sum-of-the-Year's Digits Method
	Take investment tax credit based on 10 percent of two-thirds of total investment	Take investment tax credit based on 7 percent of total investment
Cost of Injected Material	Expense	Capitalize
		No investment tax credit
		Depreciate over life of reservoir by SL Method
Depletion	None	None
Federal and State Income Tax	50 percent	50 percent

* New well costs assumed to be 70 percent intangibles.

will come within the election and that all IDC incurred is deductible for tax purposes.

Restrictive Case

Costs of both production and injection wells are considered to have been incurred "incident to and necessary for" the drilling and preparation of oil and gas wells for production and, accordingly, come within the intangibles option. On the other hand, costs of water source wells incurred in connection with EOR projects would generally be considered to be incident to the maintenance of production; hence, the intangibles would not fall within the option. Therefore, all such costs must be capitalized and are depreciated under the methods established for "Hardware."

Hardware

The physical facilities that are required in an EOR project include storage tanks, pipelines and valves, water and gas separation equipment, wastewater treatment facilities, and other hardware. These items have a useful life of more than one year and may not be deducted as an expense in the year of their purchase and installation. Instead, a proportional amount of depreciation for the exhaustion, wear-and-tear, and obsolescence of this property is allowed as a deduction.

The incentive to proceed with an EOR program depends upon the type of the depreciation method, the expected life of the facilities, and the investment tax credit that are applied to the hardware. The following discussion describes the assumptions that were made for the two tax treatment cases considered here.

Moderate Case

In this case, the physical hardware is capitalized and depreciated over a five-year period, using the straight-line (SL) method of depreciation. A 20 percent depreciation credit is taken for each year. Under this quick write-off, the total cost of hardware is recovered in the first five years of its useful life. Only 68 percent of its cost would be recovered over this period using the eleven-year sum-of-the-year's digits (SYD) depreciation method assumed for the restrictive tax case. Although the total depreciation allowed is the same as under the SYD method, the earlier deduction improves the economic incentive of the EOR program.

In the moderate tax case, due to the shorter depreciation period, the investment tax credit is based on two-thirds of 10 percent of the total investment; thus, it is assumed that the present 10 percent credit would be extended beyond the current expiration date.

Restrictive Case

It was assumed that all hardware would be capitalized and depreciated under the Asset Depreciation Range (ADR) System, using the lower limit of the appropriate asset depreciation range. It was also assumed that the sum-of-the-year's digits method would be adopted to depreciate such facilities over this eleven-year period. Under the SYD method, a different fraction is applied each year to the cost of the hardware to determine the allowable depreciation. The denominator (bottom number) of the fraction, which remains constant each year, is the total of the digits representing each year of estimated useful life of the property (i.e., $1 + 2 + 3 + \ldots + 11$). The numerator of the fraction changes each year to represent the years of useful life remaining at the beginning of the year for which the computation is made. With the SYD method, a larger fraction, and hence a larger portion, of the depreciation is allowed in the early years; however, while the depreciation periods for the SL and SYD methods differ, the total depreciation allowed for equipment used in a project is the same for any depreciation method.

The investment tax credit is assumed to be 7 percent of the total qualified investment. This 7 percent was the investment tax credit allowed prior to an increase to 10 percent, effective with the Income Tax Reduction Act of 1975. This higher tax credit was due to expire at the end of 1976 at the time these cases were specified; thus, restrictive tax case analyses reflect reversion to a 7 percent tax credit in 1977.

Cost of Injected Material

In many of the enhanced oil recovery processes it is necessary to inject high-cost materials into the oil formation. In all such projects, some of the injected material remains in the production formation and is never recovered. The varying tax treatment assumptions applied to the unrecoverable portion of this material are described in the following discussion.

Moderate Case

The total cost of purchased material injected and lost in the reservoir is treated as an expense

item and is deducted in the year in which it was injected.

Restrictive Case

The costs of the unrecoverable material, which has been purchased and injected into the reservoir, is capitalized and depreciated over the life of the reservoir, using the straight-line method. However, 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. These expenditures would not constitute qualified investment for purposes of claiming investment tax credit.

Depletion

Federal income tax law takes into account the distinctive nature of the mineral producing industries, including production of oil and natural gas, and, therefore, provides a percentage depletion allowance. The percentage depletion deduction recognizes that the producer's capital—the value of his oil, gas, or other mineral in the ground—has no necessary relationship to the cost of its discovery. This procedure was adopted as a method of avoiding taxation of capital (the value of the oil or other mineral in the ground) as if it were part of the producer's income.

Generally, the percentage depletion provision for oil and gas production was disallowed for major oil companies by the 1975 Income Tax Reduction Act; but it remains for the production of other minerals. For this study, it was assumed that no percentage depletion would be allowed, either in the restrictive or the moderate tax case.

Federal and State Income Tax Rate

The federal income tax rate on corporate profits presently is 48 percent. The state income tax rate varies, but is, on the average, approximately 2 percent (after federal offset). An assumed total federal and state income tax rate of 50 percent was applied in both the restrictive and moderate tax cases.

Crude Quality Price Differentials

This study provides estimates of enhanced recovery production that would be economically attractive at oil equivalent prices of $5, $10, $15, $20, and $25 per barrel (constant 1976 dollars). Each price case selected for analysis in this study represents a single average price for a mixture of potential enhanced recovery crude oils. It is recognized, however, that in some cases individual crude oil prices currently vary significantly from the average. Following is a discussion of the reasons for these variations and their likely impact on the study results.

The most important factor currently contributing to variance of crude price from an average is the three-tier pricing structure, imposed by government price control regulations. Other contributing factors to price differences are field location, resultant transportation costs to point of consumption, and crude quality characteristics, including gravity, sulfur content, asphalt level, etc.

The current spectrum of prices paid for crude oil in the United States is illustrated in Table 14. Current price differentials are particularly burdensome to thermal projects already underway, because thermal production is primarily low-gravity oil. As illustrated in Table 14, the combination of government price control and quality price differentials results in some low-gravity crudes (especially in California) currently being priced considerably below the lower end of the price-case spectrum assumed for this study. Continuation of this pricing environment would have a significant impact on future EOR project economics, since a large proportion of enhanced recovery production is expected to be heavy oil, especially in the near term.

Distortions in quality price differentials caused by price controls would be eliminated before most EOR projects are expected to come on stream, if the control legislation expires on schedule. Also, these distortions may be corrected to some extent within existing law.

The API gravity of a crude provides some indication of a crude's initial product yield. Generally, a relatively light 35° API crude will yield a greater proportion of lighter, more valuable products, such as gasoline, per dollar of processing than a heavier 20° API crude; and, therefore, it is more valuable to refiners. This greater value is reflected in gravity differential adjustments in the crude price paid to the producer. Current adjustments in the United States can range from $.02 per degree API for higher gravity crudes to $.06 per degree for lower gravity crudes.

The foregoing discussion does not imply that quality price differentials are generally distorted. In a free market, these differentials are rationally determined and reflect the cost of converting crude to a desired mix of products of acceptable quality. This conversion, or processing, cost is different for each crude type. For example, it is more costly to make

TABLE 14

CRUDE OIL PRICES AS OF JUNE 1, 1976

Crude Type	Gravity (°API)	Lower Tier ($/Bbl.)	Upper Tier ($/Bbl.)	Imports* ($/Bbl.)
California				
— San Ardo	11	3.85	9.81	
— Long Beach	25	4.78	10.50	
— Kettleman Hills	34	5.24	10.86	
Mid Continent				
— West Texas Sour	16	4.85	11.07	
— West Texas Sour	40	5.33	11.55	
— Wyoming Heavy	29	4.92	11.82	
— Wyoming Sweet	40	5.31	12.45	
Nigerian	37			14.00
Arabian Light	34			12.50

* Estimated laid down cost at the Gulf Coast

lighter products, such as gasoline, from relatively heavy crudes and to convert high-sulfur crudes to low-sulfur products.

Ignoring gravity differentials in this study introduces a margin for error of about $1.00 per barrel for some crudes. This difference is not regarded as critical, considering the number and magnitude of other uncertainties that are associated with enhanced recovery.

Project Economics Calculation

Economic evaluations of all processes, except CO_2 miscible flooding, were calculated through a computer system named PLANS.* The system includes a standard discounted cash flow rate of return (DCFROR) analysis and has the additional capability of saving selected operational data, such as oil production, amount of injected material by process, well drilling and workover activity by years. The PLANS system was modified to incorporate the economic criteria discussed earlier in this appendix and to facilitate ready access and usage by the Technology Task Group.

The basic unit of evaluation was the individual reservoir; considerations included projected production, operating expense, investments, and injection material quantities for the applicable recovery process. Figure 56 is a flow diagram, which shows the sequence of calculations in the analysis. Each reservoir was evaluated by computing the present worth of the net cash value of its production at specified DCFROR's of 10 percent, 15 percent, and 20 percent for each of the five oil prices and two income tax cases.

To facilitate aggregating individual reservoir results for each process, as well as for extrapolating the results to a U.S. total, base case and sensitivity case computer files were developed for storage of selected vector and scalar quantities for each reservoir evaluation (see Table 15).

An additional computer program, named RESSUM, was developed for the specific purpose of interrogating, aggregating and extrapolating data from the files. Figure 57 shows a flow diagram of the RESSUM computer program.

*The PLANS system was provided and supported by Cities Service Company. The system was resident on the General Electric Time-Sharing Service.

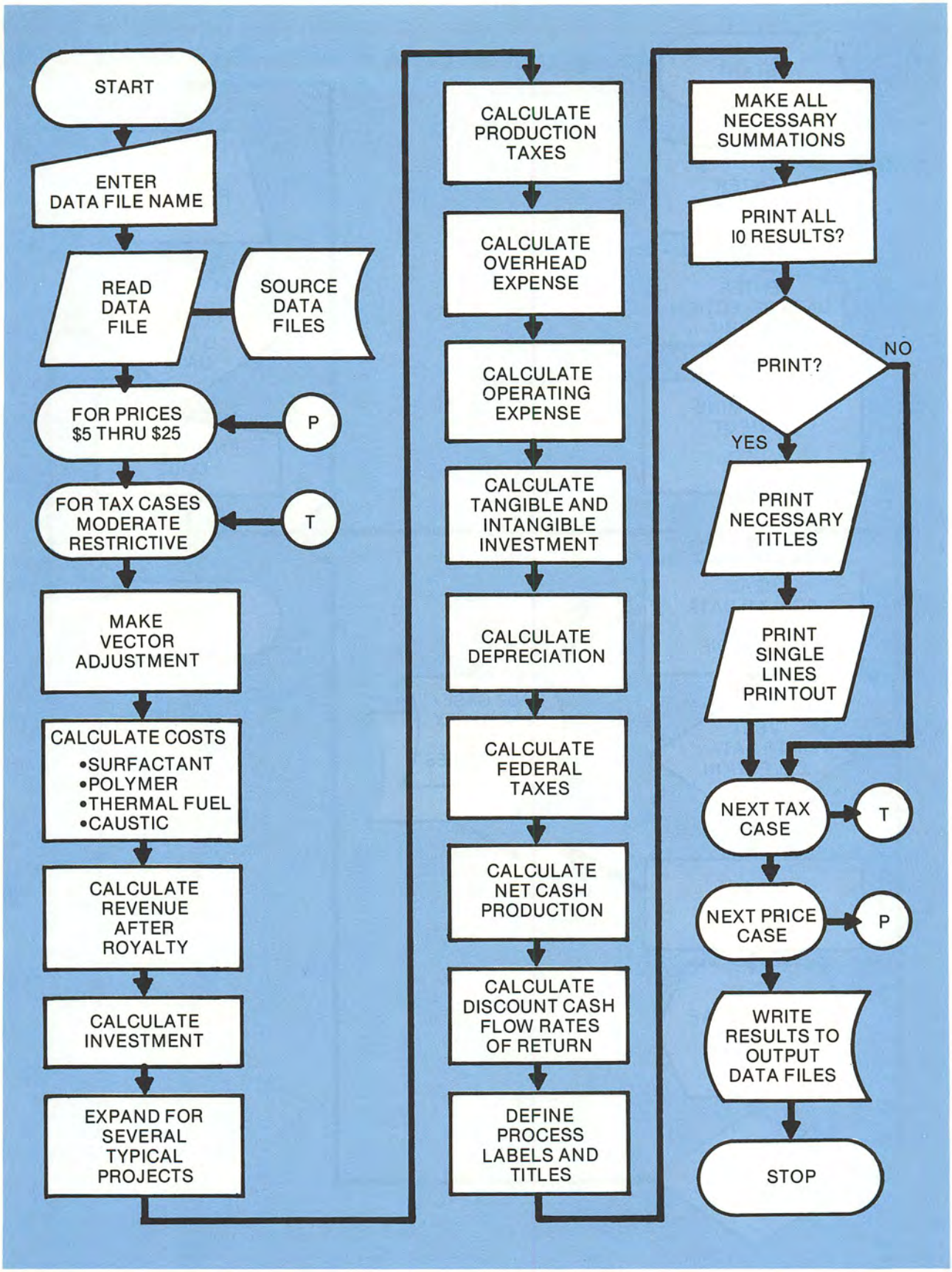


Figure 56. Economic Analysis Flow Diagram.

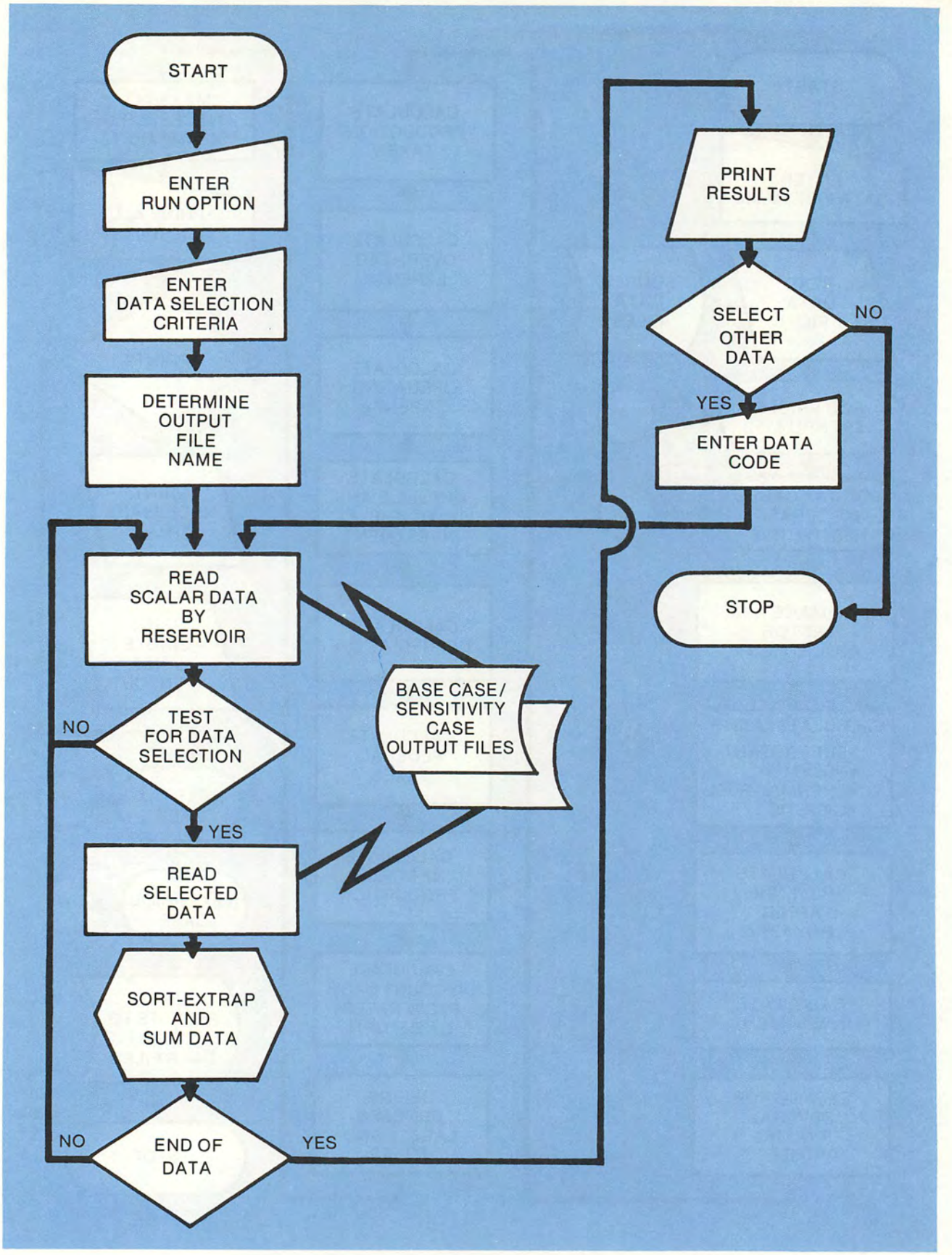


Figure 57. RESSUM Flow Diagram.

TABLE 15

BASE CASE AND SENSITIVITY CASES OUTPUT DATA FILE STORED VALUES

Scalar Quantities:

1. NPC Reservoir Data Base Page Number
2. Input Data File Name
3. Process Code
4. Starting Year
5. Starting Month
6. Life of Project
7. Rate of Return for Each Price and Tax Case
8. Ultimate Oil Production
9. Total Investment
10. Total Undiscounted Net Cash Production for Each Tax and Price Case
11. Total Oil Reserve Additions
12. NPC Screen and Performance Case Code
13. Project Description
14. Total Net Cash Production Discounted at 8, 10, 15, 20 Percent for Each Price and Tax Case

Yearly Data:

1. Undiscounted Net Cash Production for Each Price and Tax Case
2. Oil Production
3. Oil Reserve Additions
4. Annual Cash Outlay

Yearly Data: (Base Case Files Only)

1. Wells Drilled Less Than 4,000 Feet
2. Wells Drilled Greater Than 4,000 Feet
3. Injection Wells Drilled Less Than 4,000 Feet
4. Injection Wells Drilled Greater Than 4,000 Feet
5. Wells Worked Over
6. Surfactant (Thousand Barrels)
7. Polymer (Thousand Pounds)
8. Alkaline (Thousand Pounds)
9. CO_2 Purchased (Million Cubic Feet)

Appendix D
Chemical Flooding Processes

Introduction

The purpose of this appendix is to define the potential additions to crude oil ultimate recovery and producing rate from application of chemical flooding to known reservoirs in the United States. The chemical flooding processes studied were surfactant flooding, polymer flooding, and alkaline waterflooding. The results provide the best available measure of level of impact, but they should not be considered a precise measure or value for two reasons:

- The engineering data needed to describe the reservoir geology, reservoir fluids, and producing characteristics of target fields were not available; thus, it was necessary to draw broad analogies between fields with similar characteristics in making the performance assessments.
- These methods (particularly surfactant and alkaline flooding) have not demonstrated success on the field scale adequately to permit projection of process performance on a broad basis.

Given these limitations, the study can be expected to provide only an assessment of the "level of impact" of chemical flooding, together with a study of the sensitivity of results to selected variables. For example, a projection of the ultimate recovery from surfactant flooding for the United States was made for the following assumptions: (1) a crude price of $15 per barrel; (2) a discounted cash flow rate of return (DCFROR) requirement of at least 10 percent; and (3) moderate tax treatment. The projected recovery is about 2 billion barrels of oil; the projected producing rate under these assumptions is approximately 0.35 million barrels per day by 1990. This projection constitutes what may be a reasonable measure of the possible level of impact of surfactant flooding, given these economic premises. Yet, the currently unresolvable uncertainty is so great that the producing rate projected for these conditions could be negligible or, *although unlikely,* more than *double these* projections. Nevertheless, with proper focus on the uncertainties, the projections of the study should be of value in assessing the possible size and probable cost levels of this energy source.

In this appendix surfactant flooding is treated in one section, while polymer flooding and alkaline waterflooding are treated together in a separate section. Each section contains a state-of-the-art summary, a description of analysis procedures, cost data, and analysis results. A combined summary of environmental considerations for chemical flooding processes is also included.

The contribution of each of the three chemical flooding processes to projected enhanced oil recovery are put in perspective by comparing recoveries assuming base case performance and costs, a 10 percent minimum DCFROR requirement, $15 per barrel oil prices and the moderate tax case. Ultimate recovery by surfactant was estimated at 2.1 billion barrels, polymer about 500 million barrels and alkaline 400 million barrels for a total of 3 billion. Projected producing rate by the year 1990 by surfactant flooding is 310 thousand barrels per day, polymer is 60 thousand barrels per day and alkaline 10 thousand barrels per day for a total of 380 thousand barrels per day. Production was projected to peak

about the year 1995 with 350 thousand barrels per day by surfactant, 50 thousand barrels per day by polymer and 30 thousand barrels per day by alkaline for a total maximum chemical flooding production rate of 430 thousand barrels per day.

Surfactant Flooding

State-of-the-Art Assessment

For this study, surfactant flooding is defined as any of several processes that utilize injection of surfactant solutions or dispersions into underground oil reservoirs to enhance crude oil recovery. The composition of the injected mixture (chemical slug) normally includes some or all of the following components: water; hydrocarbons; alcohols; polymers; and inorganic salts. Mechanisms for this method of oil removal include reduction of oil-water interfacial tension, oil solubilization, emulsification, and mobility enhancement.

Efficient displacement generally requires that the mobility of the displacing fluid be less than that of the fluids being displaced. The chemical slug must therefore have a higher effective viscosity than that of the oil-water bank it is pushing through the reservoir. Since this slug contains expensive chemicals, the volume injected must be a small fraction of the total pore volume of the oil reservoir. This small surfactant slug in turn is displaced by a drive water. In order to achieve an efficient displacement, water-soluble polymers are normally added to the drive water so that its effective viscosity, or resistance to flow, is at least equal to that of a surfactant slug; otherwise the drive water tends to overrun the surfactant slug as it traverses the reservoir. In addition to water-soluble polymers, various combinations of other components (alcohol, hydrocarbons, etc.) may also be used to produce the required viscosity of the surfactant slug and drive water.

As summarized in Table 16, field experiments with surfactant flooding have been conducted in reservoirs with temperatures ranging from 55°to 169°F. Some tests shown in Table 16 have not been technically successful, and many have not been underway long enough for evaluation. Tests planned but not initiated have not been included in Table 16. Laboratory studies indicate that surfactant flooding should be applicable at temperatures of at least 170°F. For this study, it was assumed that this limit will be extended by future improvements in the process to about 250°F by 1995.

The salinity range of field tests have been from 2,400 to 160,000 parts per million (ppm) total dissolved solids (TDS). Most field expansions to date appear to have been limited to reservoirs of lower salinity levels (or to reservoirs that can be preflushed to lower salinity levels). Although it may be possible to preflush some reservoirs to decrease the original salinity level and thereby reduce process costs and increase recovery efficiency, this may be feasible only in a limited number of reservoirs. Thus, the trend in research is toward development of systems applicable at higher salinities without requiring a preflush. Application at salinity levels of 150,000 ppm (15 percent) may be possible within a few years, and at salinities of 200,000 ppm (20 percent) or more by 1995.

Surfactant flooding should be feasible over a fairly wide range of reservoir permeabilities. The average permeability of the reservoirs given in Table 16 ranges from 52 to 2,500 millidarcies (md). However, surfactant flooding could be applicable for a wider range of permeability. Surfactant flooding becomes less attractive at lower permeabilities, because individual injection and production well rates are reduced and because larger amounts of chemicals are frequently required to compensate for increased surfactant retention on clays, etc. A lower limit of 20 md was considered reasonable for general screening purposes; however, in exceptional cases where high oil saturations are present and clay content is not excessive, reservoirs having a permeability lower than 20 md might be suitable candidates.

The crude oil viscosity range of field tests has been 0.36 to 17.0 centipoise (cp), as shown in Table 16. The higher the reservoir oil viscosity, the less attractive the reservoir is for surfactant flooding. The most important criterion is the effective viscosity of the oil-water bank, which depends on both the relative permeabilities and the viscosities of the oil and water.

Reservoir geological and rock characteristics desirable for surfactant flooding candidates include vertical and lateral uniformity of rock properties, high levels of porosity and permeability, and low clay content. Undesirable factors are fractures, large gas-cap or bottom water drive, unusually low residual oil saturations, and pay zones that are vertically stratified or laterally discontinuous. A successful waterflood is a good indication of a reservoir's suitability for surfactant flooding. However, if the residual oil saturation in the water-swept zone is low, the potential for chemical flooding may also be low.

In practice, the most successful surfactant flood tests have been conducted in low-temperature, low-salinity, sandstone reservoirs, having a moderate-to-high permeability and containing relatively low-viscosity crude oils. This assessment was made from

TABLE 16

SUMMARY OF SURFACTANT FIELD TESTS

Field	State	County	Operator	Process Type*	Area (Acres)	Start	Pay	Porosity (%)	Perm. (Md)	Depth (ft)	Reservoir Oil (°API)	(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 (119-R)	6 tests
	Ill.		Marathon	MSF	4.3	5/70	Aux Vases			3,000					
Bingham	Penn.	McKean	Pennzoil	MSF	0.75-45	12/68	Bradford	18	82	1,860		5	68	2,800 Cl^-	2 tests
Goodwill Hill	Penn.	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	Tx.	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	Tx.	Wichita	Mobil	LTWF	209	7/73	Gunsight	22	53	1,750	42	2.2	89	160,000 TDS	
Borregos	Tx.	Kleberg	Exxon	Aqueous Solution	1.25	mid 60's	Frio	21	±400	5,000	42	0.36	165	33,000 TDS	
Guerra	Tx.	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	Tx.	Jones	Conoco	SF	2.5	/63	Flappen	21.7	457	1,900	38				
Montague	Tx.	Montague	Conoco	SF	2.5	/63	Cisco	24.2	394	1,200	27			150,000 TDS	
Loma Novia	Tx.	Duval	Mobil	SF	5.0	mid 60's									4% kaolinite 5.5% Na Montor
Salem	Ill.	Marion	Texaco	LTWF	5.8	4/74	U. Benoist	14.8	87	1,750	38.0	3.6	0.85	40,000Cl^-	
Sloss	Neb.	Kimball	Amoco	SF	10.0	1/75	Muddy J.	17.1	93	6,250	34.0	0.8	165	2,457 TDS	
West Ranch	Tx.	Jackson	Mobil	LTWF	2.5	6/74	41A	31.0	950	5,700	31.8	0.7	169	60,000Cl^-	
La Barge	Wyo.	Sublette	Texaco	SF	1.7	1/75	Almy	26.0	450	700	26.0	17.0	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 water flood normally similar to aqueous systems.

reported field tests summarized in Table 16.

Field experimentation results have also shown that surfactant flooding will require more chemicals, more careful chemical formulation and handling, and perhaps more wells, than were anticipated 10 to 15 years ago, when significant field experimentation began.

As field tests have shown, it is difficult to prevent a small chemical slug from losing its oil recovery capability as it traverses the reservoir and encounters reservoir heterogeneities and other unknown geologic conditions. Although over 400 thousand barrels of incremental oil have been produced in various tests of this process, field development on a successful commercial scale has not been demonstrated thus far. Current attempts at field expansion are limited to low-temperature and low-salinity reservoirs.

Screening Criteria

The process and reservoir geology parameters listed on Table 17 were developed as screening criteria for use in assessing the potential suitability of oil reservoirs for surfactant flooding. Future developments that will extend the applicability of the surfactant flooding process will largely affect the range of conditions under which the chemical slug may be effective. To account for these improvements, the screening criteria incorporate changes with time. The current (1976) screening criteria limits represent surfactant flooding technology that has undergone some field testing and might be ready for field development. The limits defined for the future are a projection of the time that each technological advance might be ready for field development.

This screen was applied to 175 fields (245 reservoirs) in the states of Texas, Louisiana, and California. (This data base is described in Chapter Two.) The descriptors contained in this data base were quite limited, so the full value of the screening criteria was not realized. However, by supplementing the original data base, a reasonable application of the screening criteria could be made. For example, reservoir temperatures and oil viscosities were frequently unknown;

TABLE 17

SCREENING CRITERIA — SURFACTANT FLOODING

	Limit by Year				
Process Parameters	**1976**	**1980**	**1985**	**1990**	**1995**
Temperature (°F) Max.	120	170	200	225	250
Salinity (wt. % TDS) Max.	2	15	15	15	20
Viscosity (cp) Max.	10	20	20	20	30
Permeability (md) Min.	50	20	20	20	20

General Reservoir Parameters	**1976-1985**	**1985-2000**
Geologic Criteria	Only sandstone reservoirs	Only sandstone reservoirs
	Uniform and continuous sands	Minor variations in uniformity, if good well-to-well correlations exist
	Exclude reservoirs with extensive faulting, conglomerate rock, or lense-type deposits interbedded with shale	Exclude reservoirs with extensive faulting, conglomerate rock, or lense-type deposits interbedded with shale
	Carbonate reservoirs excluded	Carbonate reservoirs excluded
Other Considerations	No bottom water-drive reservoirs	No bottom water-drive reservoirs
	No reservoirs with gas caps, unless waterflooding has been successful	No thin oil column overlain with gas
	No reservoirs where fluid movement is primarily through fractures	No reservoirs where fluid movement is primarily through fractures

those parameters were assigned to the data base fields, using published correlations. Reservoir salinity data were rarely available and had to be estimated to the degree possible. Although a well-defined geologic model is crucial to the appropriate design of a surfactant flood, no such individual field studies were possible for this analysis. Consequently, screening for geology and reservoir performance was applied by drawing on the study group's knowledge of the geology and reservoir characteristics of the data base reservoirs, or other fields in similar geologic settings. This type of assessment was an important consideration in the ranking of fields as "good," "fair," or "poor" candidates for surfactant flooding. This good, fair, or poor ranking was employed to determine chemical requirements for flooding the respective reservoirs and to aid in assigning individual reservoirs to either surfactant flooding or to a competing EOR process (see the discussion under "Dominance Determination," Chapter Two).

As a result of applying the screening criteria (Table 17) and the good, fair, and poor reservoir rankings to the data base fields, 67 reservoirs were selected as candidates for further study. After applying the economic and dominance criteria discussed in Chapter Two, 9 of these reservoirs were considered more likely candidates for another recovery process.

Process-Dependent Economic Parameters

Process-related costs for surfactant flooding were developed, in addition to the process-independent cost data described in Appendix C. These include the costs of surfactants (typically, petroleum sulfonates), alcohols, polymers, crude oil and inorganic chemicals used in the process slug, and viscosity buffers. Costs of these materials were determined for each crude price used in this study.

1976 cost levels for the specific chemicals of interest were obtained from Gulf Universities Research Consortium (GURC) studies and from chemical suppliers. The chemical costs used are shown in Tables 18 and 19. Factors to adjust chemical cost with oil price are also shown in these tables. An average cost for a 50-50 polymer blend of polysaccharides and polyacrylamides was used for the polymer slug. Costs for the surfactant slug are given in Table 20.

As another cost aspect of surfactant flooding, the cost level of pilot testing in the field was broadly estimated. This cost, although a major hurdle to the start of a project, will be small on the basis of cost per barrel of enhanced oil produced, if the recovery process proves generally successful. The number of chemical flood pilots required between now and the year 2000 to enable commercial-scale application, consistent with the NPC screening criteria, is highly speculative. However, the small relative costs of this activity compared to value of potential production can be shown, using the following assumptions:

- Ten pilots will be required to define and extend the range of process parameters, primarily temperature and salinity.
- Ten pilots will be required to evaluate commercial potential in different reservoir types.
- Twenty additional pilots might be required to develop the approximately 2 billion barrels of incremental ultimate recovery projected for the $15 per barrel crude oil price.

TABLE 18

PRICE ESTIMATES OF PETROLEUM BASED CHEMICALS FOR DIFFERENT CRUDE PRICES

Crude Oil Price (Dollars per Barrel)	Price Adjustment Factor for Converting to Different Crude Prices	Polyacrylamides (Dollars per Pound)	Isopropyl Alcohol (Cents per Pound)	100% Active Sulfonates (Cents per Pound)
5.00	.82	1.14	13	29
Base Case: 10.00	1.00	1.40*	16†	35‡
15.00	1.23	1.72	20	43
20.00	1.45	2.04	23	51
25.00	1.68	2.35	27	59

* Base Case price of $1.30 per pound (GURC report of March 1976) plus 10¢ per pound for freight and state sales tax.

† Base Case price of 14¢ per pound (GURC report of March 1976) plus 2¢ per pound for freight and state sales tax.

‡ Base Case price of 32¢ per pound (GURC report of March 1976) plus 3¢ per pound for freight and state sales tax.

TABLE 19

PRICE ESTIMATES OF POLYSACCHARIDES FOR DIFFERENT CRUDE PRICES

	Crude Oil Price (Dollars per Barrel)	Price Adjustment Factor for Converting to Different Crude Prices	Polysaccharides (Dollars per Pound)
	5.00	0.96	2.30
Base Case:	10.00	1.00	2.40*
	15.00	1.04	2.49
	20.00	1.08	2.58
	25.00	1.13	2.70

* Base Case price of $2.25 per pound (GURC report of March 1976) plus 15¢ per pound for freight and state sales tax.

TABLE 20

ESTIMATED COST OF SURFACTANT SLUG FOR VARIOUS CRUDE OIL PRICES AND SURFACTANT COSTS
(Dollars per Barrel)

Crude Price	Sulfonate Costs			Alcohol Cost	Oil Cost	Total Surfactant Slug Costs		
	Low	Central Value	High			Low	Central Value	High
5	3.81	5.08	6.34	.68	0.50	4.99	6.26	7.52
10	4.59	6.12	7.65	.84	1.00	6.43	7.96	9.49
15	5.64	7.52	9.41	1.05	1.50	8.19	10.07	11.96
20	6.69	8.92	11.16	1.21	2.00	9.90	12.13	14.37
25	7.74	10.32	12.91	1.42	2.50	11.66	14.24	16.83

Note: Low and High values of chemical costs were used to define study sensitivity to these costs. ±25% variance in cost of surfactants was used to develop the high and low value.

- The average cost of each pilot will be $3 million. Thus about 40 pilots, costing $120 million, might be required at a cost of about $.06 per barrel of oil recovered.

The costs of pilot testing appear small, but only sandstone reservoirs without complicating features of geology or reservoir character, as indicated by the NPC screen, were considered. In reality, other, less desirable candidates for surfactant flooding will also be tested. However, even if the number of pilots were doubled, the cost would still be much less than the uncertainty in the cost of each barrel of surfactant flood oil recovered. For the purpose of this study, it was assumed that pilot costs were included in the overhead cost, along with the cost of laboratory research.

Description of Process Analysis Procedures

As a result of applying the screening and process dominance criteria to the 245 reservoirs in the data base, 58 were selected as candidates for surfactant flooding.* This section describes: (1) the method used to calculate the swept zone water and chemical

*Reservoirs included in the data base developed by Lewin & Associates, Inc. in connection with their study for the Federal Energy Administration.

flood residual oil saturations; (2) the estimation of the ultimate incremental recovery that might be achieved; (3) the hypothetical chemical system selected as being representative of those used in many surfactant floods; and (4) the model developed to project oil production rate versus time for economic calculations.

Calculation of Surfactant Flood Recovery from Water-Flushed Zone

Since the economics of surfactant flooding are extremely sensitive to the volume of oil that can be recovered by a surfactant system, special emphasis was placed on estimating the oil saturation (S_{orw}) in the water-flushed zone that would likely be contacted during surfactant flood and the oil saturation (S_{orc}) remaining in the same region after the flood.

Reservoir characteristics (rock type, etc.) and production method are generally recognized as the principal factors affecting S_{orw}, and were used as the basis for assigning S_{orw} values to the candidate reservoirs. These characteristics were established by drawing upon the study group's general knowledge of the data base reservoirs or fields in similar geologic settings. Only reservoirs having residual oil saturations in the water-swept porton of the reservoir (S_{orw}), of 20 percent pore volume or more were accepted as surfactant flood candidates. Candidate reservoirs in California, Texas, and Louisiana were then individually assigned S_{orw} values of either 20, 25, or 30 percent pore volume.

The method used for assigning S_{orw} relied upon drawing an analogy through rock and fluid type to better known examples and was chosen for the following reasons:

- Estimates of original oil in place, particularly those made with sparse data, are uncertain and may be overstated for any specific field due to inability to quantify net pay, areal extent, reservoir irregularities and original oil saturation. As producing historical data is accumulated and injection projects begun, the value of OOIP must frequently be revised.
- The primary target for surfactant flooding is the final waterflood swept residual. Values for ultimate primary plus waterflooding recovery are not known for specific fields to the degree needed to confidently determine waterflood residuals, particularly considering the uncertainty in value of OOIP.
- Extensive studies to determine waterflood residuals for a few selected fields have been conducted and results published. This information, plus knowledge of laboratory determinations of water flood residuals for various reservoir rock and fluid types, was used to assign residuals to the data base fields based on analogy to the rock and crude oil characteristics of those fields. This procedure was judged to provide the best estimate of the amount of oil that can be recovered (unit oil recovery) from the water-flushed zone by surfactant flooding. However, in recognition of the magnitude of the uncertainty associated with this or any other method of assigning a target residual oil saturation, a saturation interval of 5 percent pore volume was used when assigning the value of S_{orw} to each surfactant flood candidate. For example, a reservoir believed to have an S_{orw} of between 22.5 and 27.5 percent would be given an assigned value of 25 percent.

Another method that could be used to estimate the target residual oil saturation is the "material balance" approach. This method was judged to be inadequate to define the unit oil recovery used for the economic calculations because of the uncertainties in the data and the following considerations:

- The material balance value represents all the oil estimated to be left in the reservoir after waterflooding; some of this oil is left in the unswept or poorly swept portions of the reservoir at high saturation, while the rest is left in the water-swept portion at saturations much lower than the material balance average saturation.
- If the OOIP estimate is too high, the estimate of material balance oil saturation will be correspondingly high. In general, the higher the waterflood sweep efficiency, the closer the agreement between the assigned S_{orw} values and material balance saturations will be.

In a few cases, comparisons of the assigned S_{orw} values used in this study with the total average reservoir oil saturation after waterflood, or "material balance" oil saturation, were possible. In some instances the assigned values were only slightly smaller, but in other cases, they were significantly less than material balance estimates.

The amount of oil that can be recovered by a surfactant flood is proportional to the difference between the S_{orw} and the residual oil saturation (S_{orc}) remaining in the swept zone after the surfactant flood.

The surfactant flood residual oil saturations (S_{orc}) in laboratory tests using large slugs (25 to 50

percent of pore volume at typical chemical concentrations of 4-5 percent) are typically less than 5 percent. For very small slugs (5 to 15 percent of pore volume) the injected slug frequently loses its effectiveness, even in laboratory tests using long (16- to 32-foot) cores, because of dispersive mixing between the various slugs and adsorption of the surfactants. In these tests, the residual oil saturation is frequently between 5 and 10 percent pore volume.

When a surfactant slug is injected into a reservoir, it will encounter large-scale heterogeneities, which tend to destroy its integrity, and thereby its displacement efficiency. This tendency may be unimportant in fairly homogeneous reservoirs, if displacing fluids have sufficiently favorable mobility ratios; but it could be significant in many reservoirs. It is anticipated that the average residual saturation left behind the surfactant slug in field applications will normally be more than that typically observed in laboratory floods. Lower residuals will remain in better quality rock (high permeability, high porosity, and low clay content) and higher values in the poorer quality rock. Therefore, for a typical surfactant flood target reservoir and for economically sized chemical slugs and polymer drives, a value of 10 percent pore volume was used for the average residual oil saturation left in the swept portion of the reservoir.

Calculation of Incremental Ultimate Recovery

An estimate of the incremental ultimate recovery was made for each candidate reservoir. The assumptions required before this estimate could be made included estimation of the original oil in place, the average initial water saturation in the reservoir, and an overall sweep efficiency.

In accord with the sparsity of reservoir descriptors in the data base, the following simple equation was employed to calculate the incremental ultimate oil recovery from each candidate reservoir.

$$\text{incremental ultimate recovery} = \left[\frac{\text{OOIP} \times B_{oi}}{(1-S_{wi})}\right](S_{orw}-S_{orc})\,\frac{E}{B_o}$$

where:

- OOIP = original oil in place (stock tank barrels)
- B_{oi} = original oil formation volume factor (reservoir barrels per stock tank barrel)
- B_o = current oil formation volume factor (reservoir barrels per stock tank barrel)
- S_{wi} = original water saturation
- S_{orw} = residual oil saturation by waterflood in swept zone
- S_{orc} = residual oil saturation by surfactant flood in swept zone
- E = waterflood and chemical flood volumetric sweep efficiency

This equation provides an estimate of the incremental volume of oil that might be recovered by surfactant flooding over that which could ultimately be achieved by conventional waterflooding.

In addition to the uncertainties in the values to be used in the above equation for S_{orw} and S_{orc}, there are uncertainties in the values for each of the remaining terms for OOIP, S_{wi}, and the value used for E.

Reservoir thickness and areal extent information available from the reservoir data base were frequently in conflict with the estimates given for the OOIP volumes. Although the data base values for OOIP and S_{wi} data judged best were used for estimating the reservoir pore volume (the bracketed quantity), there can be considerable uncertainty in the reservoir pore volume for any given reservoir. A surfactant flooding sweep efficiency was likewise assigned to each surfactant flood candidate based on broad analogy of reservoir rock and fluid type. When the assigned sweep efficiencies for a number of reservoirs were compared with material balance estimates for the same group of reservoirs, it appeared that the assigned values were possibly too high—by about 15-20 percent in Texas and Louisiana, and possibly as much as 33 percent in California. If so, the estimates of the incremental ultimate recovery will be correspondingly high. *However, since the volume of chemicals injected was determined as a fraction of swept pore volume, rather than total reservoir pore volume, the economics are not highly sensitive to the sweep efficiency used.*

This difference in the estimates for Texas and Louisiana is generally within the range of uncertainty in the calculations of incremental ultimate recovery. Additional factors which may contribute to the apparent discrepancy, especially in California, are as follows. API reserves statistics do not include potential waterflood reserves from a given field until the waterflood has been implemented and an economic production response at existing economic conditions demonstrated. At higher crude prices, additional waterflooding projects may become economically attractive. Hence, additional waterflood reserves from some reservoirs, particularly in California, could increase the overall waterflood sweep efficiencies experienced in such reservoirs. To the extent that such increased waterflood sweep efficiencies

may not be possible, the projections of the incremental ultimate oil recovery may be high.

The reservoir description and performance data needed to resolve the uncertainties in enhanced recovery projections will undoubtedly be collected by the individual field operators when the sizable costs of data collection can be justified. Such data are not now available on numerous fields, including those in the data base used in this study.

Surfactant System Design

The volumes of the surfactant slug and polymer drive water required for a surfactant flood depend upon the reservoir volume that can be contacted by the surfactant system and, hence, on reservoir type and quality. Thus, the amount of chemical required to process the swept pore volume of each surfactant flood candidate was adjusted according to the ranking given that reservoir for surfactant flooding.

An idealized, or base case, chemical system design was used in this study to represent a mid-range estimate of industry experience, as described in published field test data. A summary of the system design follows:

- **Chemical Slug**
  - Size: 8 percent of swept pore volume for good reservoirs
    10 percent of swept pore volume for fair reservoirs
    14 percent of swept pore volume for poor reservoirs
  - Surfactant Concentration: 5 percent by weight of active ingredients
  - Alcohol and Other Components: 1.5 percent by weight
  - Oil Content: 10 percent by volume
- **Mobility Drive (Water-Polymer Slug)**
  - Bank Size: 50 percent of swept pore volume
  - Polymer Average Concentration: 600 ppm.

The amount of chemical used in the economic calculations for each barrel of oil produced is given in Table 21 for reservoirs rated as good, fair, or poor candidates for surfactant flooding. The dependence of the assumed chemical requirements for different residual oil saturations (20, 25, and 30 percent pore volume, corresponding to reservoir types A, B, and C), is also given. Table 22 presents an example of chemical costs for fair surfactant flood candidates, for the same values of residual oil saturation and for crude prices of $5, $10, $15, $20, and $25 per barrel.

TABLE 21

CHEMICAL REQUIREMENT PER BARREL OF OIL PRODUCED
(Pounds per Barrel)

EOR Code	S_{orw} (% PV)	Polymer	Surfactant Reservoir Quality Rank		
			Good	Fair	Poor
A	20	1.05	14.00	17.50	24.50
B	25	.70	9.33	11.67	16.33
C	30	.52	7.00	8.75	12.25

TABLE 22

EXAMPLE TOTAL CHEMICAL COST FOR "FAIR" SURFACTANT FLOODING CANDIDATES
(Dollars per Barrel of Oil Produced)

Crude Price	Reservoir Type		
	A	B	C
5	8.07	5.38	4.03
10	9.96	6.64	4.98
15	12.28	8.19	6.14
20	14.56	9.71	7.28
25	16.89	11.26	8.44

Economic Model

Projected oil producing rates, development capital requirements, operating expense and chemical costs as a function of time were developed for use in a simplified economic model. (The component costs were discussed in Appendix C.)

The basic assumptions used in preparing development and production projections for a single pattern area and then for the overall project development, as illustrated in Figure 58, were:

- Individual chemical flooding projects would require two years to drill new wells, work over old wells, and install new field facilities prior to starting surfactant injection.
- The flood life of each pattern area would be 10 years, during which 1.5 swept pore volumes would be injected.
- All projects in a technologic advancement segment (see "Screening Criteria") would be developed uniformly over the following 15-year period.
- Oil production and cash flow projections from

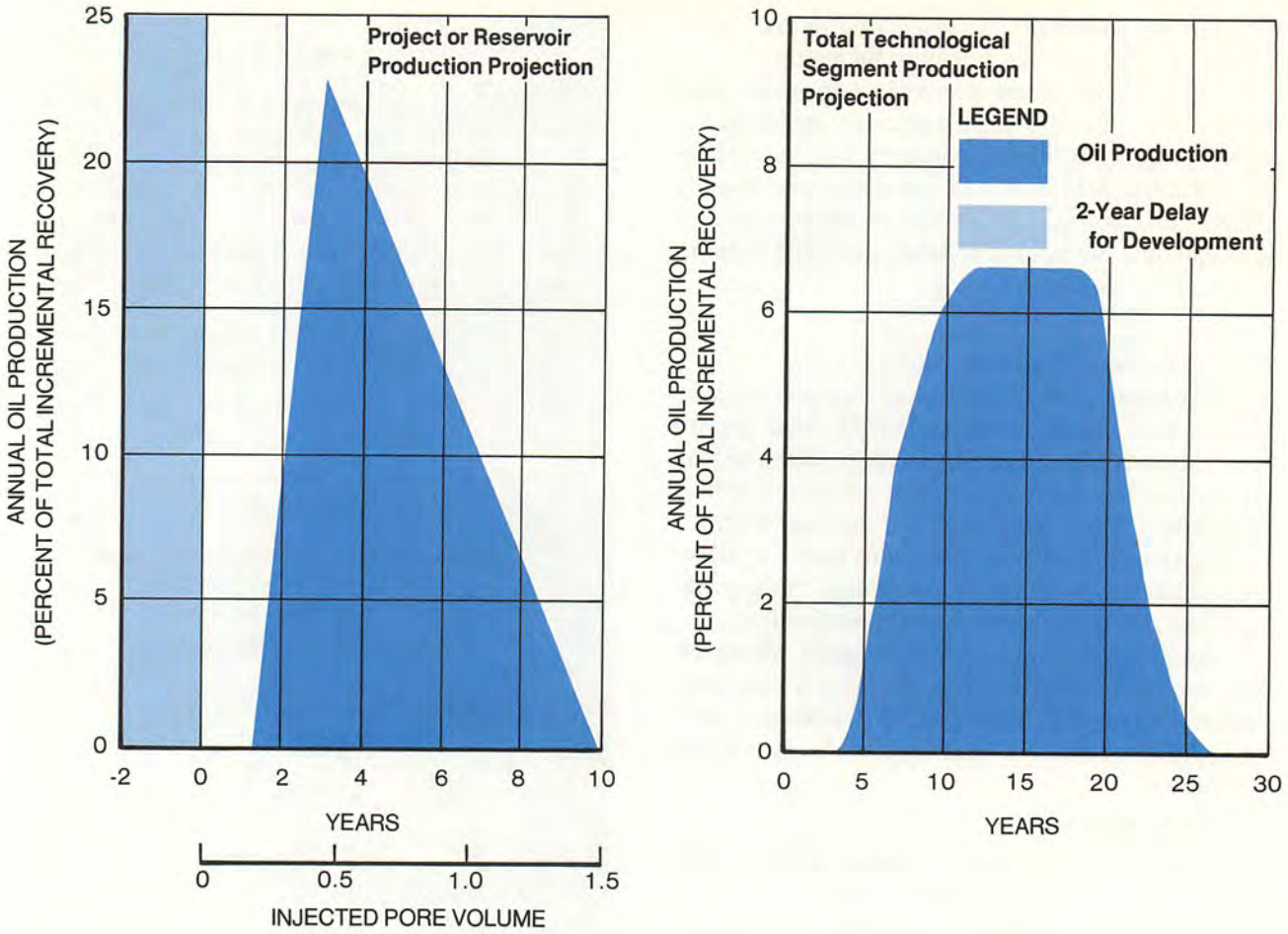


Figure 58. Production Development Schedule.

reservoirs with positive profitabilities under any assumed economic criteria are additive.

This development and production program was used to project oil production rate, capital expenditures, and operating costs. It was assumed that development drilling and facility costs would be expended during the two years before injection starts. Direct operating costs were spread uniformly over the 10-year injection life of the project. Injection costs, including chemical costs, relate directly to the time each type of injection (chemical slug, polymer drive, etc.) is scheduled.

It is anticipated that, in practice, a large reservoir or group of reservoirs can be developed sequentially; this sequential development should permit improvements in flood system design as the flood progresses, thereby saving material and resources. This type of sequential development concept was utilized in this study by assuming that 1/15 of each reservoir (or group of similar reservoirs) would be developed each year for 15 years. This 15-year development scheme is arbitrary and could vary, depending on the economic climate. However, a revision in the development program would not alter ultimate recovery, even though it could affect the rate of production, development expenditure and other variables.

The number of wells required in any specific field development is also essential to an economic analysis of surfactant flooding. This number is a function of assumed project flood life, production and injection well capacities, reservoir permeability, oil viscosity, swept pore volumes (which directly affects total quantity of injection), pattern of injectors and producers, and pressure drop from injector to producer. Assumptions used in the study are summarized as follows:

- New wells were drilled for all injectors.
- Five-spot patterns were used (for purposes of establishing well requirements).*
- Well spacing was selected consistent with the assumption that a total of 1.5 pore volumes

*See Glossary, "flood pattern."

of the swept zone could be injected in a 10-year project life. The well spacing estimate was subject to the following constraints:

- Maximum production and injection rates would be less than or equal to 2 thousand, 1.5 thousand, and 1 thousand barrels per day per well in South Louisiana, California, and Texas and North Louisiana, respectively.
- The well rates will be less than or equal to that calculated using the steady-state pressure-rate equation for five-spot flooding, assuming an effective viscosity of 20 times the viscosity of water and a pressure differential from injector to producer of one-half pound per square inch per foot of reservoir subsurface depth.
- Well spacing will not exceed 80 acres per production well, or 40 acres per well.

These assumptions, the desired project life, plus information in the reservoir data base, were used as the basis for determining number of wells drilled and operated for the surfactant flooding economic model.

Extrapolation Process

Incremental ultimate recovery and potential producing rates for surfactant flooding were extrapolated from the candidate reservoirs to a larger geographic base. This extrapolation was based on ratios of OOIP (from API data) in sandstone reservoirs in the geographic areas considered; the sequence was first to obtain a total for the three data-base states, and then for the total United States. This simplistic method was used because insufficient reservoir data were available for a rigorous appraisal of the total potential from surfactant flooding over a wide geographic base, and some subjective judgments were necessary to establish extrapolation factors. The following discussion describes the sequence of assumptions used to estimate the total surfactant flood response for the three states and the entire United States.

Three-State Totals

An extrapolation factor, based on the ratio of the OOIP in each district (Texas), area (California), or state (Louisiana) to the OOIP of the data base reservoirs in the same region, was used as a multiplier of incremental ultimate recovery, production rate, net cash flow, etc. The extrapolation factor, which is unique to any given region, was used for each reservoir in the specified region. The rationale for using specified geographic areas for the scale-up base is that the geologic setting, and therefore, the character of the reservoirs, is similar over a narrow geographic base. For California and Texas, the subdivision by area and district for extrapolation was justified by the adequate representation of reservoirs and original oil in place in the data base. It should be particularly noted that offshore California is adequately represented by the data base reservoir file; the data base includes five Wilmington field reservoirs, three Rincon reservoirs, and the Dos Cuadras field.

Louisiana, however, was rather poorly represented for scale-up by geographic area. Offshore Louisiana was not represented in the data base, although significant surfactant flooding candidate reservoirs are known to exist, particularly in the more prolific, less geologically complex reservoirs not far from an operating base. The scale-up factor selected for Louisiana data base fields includes the North and South onshore plus 70 percent of the offshore OOIP. The 70 percent factor was judged to include that portion of the total offshore oil volume which is near enough to an onshore operating base to be a target for surfactant flooding. Table 23 lists offshore fields that are in about 100 feet or less of water and shows that much of the offshore oil volume is near shore. These nine fields contain about 60 percent of the offshore OOIP used in the Louisiana extrapolation, and about 42 percent of the total offshore. As a whole, the quality ranking of these offshore reservoirs was judged to be more favorable than many of the Louisiana reservoirs included in the original data base.

TABLE 23

QUALITY RANKING OF LOUISIANA OFFSHORE RESERVOIRS

Field	API Estimated Original Oil in Place (Millions of Barrels)	Approximate Water Depth (Feet)
South Pass Block 27	818	100
South Pass Block 24	975	30
Main Pass Block 41	453	100
Bay Marchand Block 2	1,558	40
West Delta Block 30	640	50
Grand Isle Block 43	575	100
Ship Shoal Block 207	288	100
Ship Shoal Block 208	261	100
Cote Blanche Bay, West	451	20
Total 9 Fields	**6,019**	

Total United States

The extrapolation of three-state EOR results to the total U.S. potential is, at best, only a reasonable estimation of the probable level of EOR volumes. Changes in the following key assumptions may significantly affect the results of the extrapolations: (1) the data base reservoirs were assumed to provide a representative sample of the reservoir characteristics and crude oil properties of reservoirs in the remaining states; (2) the average drilling and operating costs used in the standard economic model were assumed to be representative of those in other locations and reservoirs; and (3) production rate versus time was assumed to be consistent with that represented by the data base reservoirs, despite varying geologic settings in other states.

The mechanics of the scale-up employs a ratio of sandstone original oil in place volumes. The extrapolated U.S. total oil volume is comprised of: (1) the three-state data base OOIP; (2) the total OOIP from five midcontinent states (Illinois, Kansas, New Mexico, Oklahoma, and Wyoming) with broad-ranged surfactant flooding potential; and (3) 50 percent of the OOIP from the remaining states in the United States, excluding North Slope, Alaska. The 50-percent factor was obtained simply as an estimate of the relative number of reservoirs that might be amenable to surfactant flooding, compared to reservoirs in the three data base and the five midcontinent states.

The volumes used in the scale-up factor are shown in Table 24. The extrapolation factor is used as a multiplier for each reservoir, along with the district, area or state factor previously described. Table 25 illustrates the method selected for going from the data base to a national total for one set of base case reservoir and economic parameter assumptions.

TABLE 25

EXAMPLE EXTRAPOLATION OF INCREMENTAL ULTIMATE RECOVERY (Millions of Barrels)

	Data Base Only	Extrapolated to State Total	Extrapolated to Nation Total	Ratio of Nation Total to Data Base
California	433	558	777	1.79
Texas	107	122	170	1.59
Louisiana	354	819*	1,139	4.19
Total	**812**	**1,499**	**2,086**	**2.57**

* For the described method of extrapolation, the portion of this volume from offshore fields is 261 million barrels. The same evaluation at $25 per barrel includes 394 million barrels from offshore Louisiana.

Note: Assumptions are a 10 percent rate of return requirement, $15 per barrel crude oil price, and moderate tax case.

Results for Louisiana, Texas and California, and for Total United States*

The results of the profitability calculations outlined above are presented for the data base results

*All values extrapolated to state or U.S. totals on all figures in this appendix were calculated from base case performance and costs, a minimum DCFROR requirement of 10 percent, moderate tax case, constant 1976 dollars, and oil price of $15 per barrel unless otherwise noted.

TABLE 24

EXTRAPOLATION OF SURFACTANT FLOODING RESERVES THREE-STATE TO TOTAL UNITED STATES

Volume Component	Original Oil in Place (Millions of Barrels)	Brief Description
3-States	191,021	Cal. + Tx. + La. (with 70% offshore)
Midcontinent (5 states)	58,598	Ill. + Kan. + N.M. + Okla. + Wym.
42-States	16,329	One-half of remaining OOIP in U.S.
Total	**265,948**	

Extrapolation Factor = $\frac{265,948}{191,020} = 1.392$
(3-State to Total U.S.)

extrapolated to the totals for individual states of California, Texas, and Louisiana, and to the three-state total in Figures 59 and 60.

As shown in Figure 59, the incremental ultimate oil recovery for the three-state total increases from about 1.5 billion barrels for a crude price of $15 per barrel to about 6 billion barrels at $25 per barrel (assuming the moderate tax case and a DCFROR of 10 percent). California contributes the major portion (about ⅔) of this potential recovery. The corresponding potential producing rate versus time (Figure 60) peaks in 1995 at about 0.25 million barrels of oil per day at a crude price of $15 per barrel, and at about 1.0 million barrels per day at $25 per barrel.

The projections at $15 and $25 per barrel oil prices for the entire United States are 2.1 and 8.4 billion barrels of incremental ultimate recovery and peak production rates of 0.35 and 1.4 million barrels of oil per day in 1995 (see Figure 61).

The incremental ultimate recovery projected for the United States decreases from 2.1 billion barrels for a minimum DCFROR requirement of 10 percent at $15 per barrel crude price, to essentially zero at a minimum DCFROR requirement of 20 percent (see Figure 62).

The sensitivity of the base case projections to uncertainty in chemical costs and process performance is illustrated in Figures 63 and 64. The base case chemical costs were varied by ± 25 percent in the calculations for Figure 63. This range for chemical costs realistically reflects the uncertainty in projecting future costs, which are influenced by type of surfactant used, scale of production, availability of raw materials, etc. Uncertainty in process performance was characterized by the uncertainty in the reduction in waterflood residual oil saturation achieved by the surfactant slug. This saturation reduction ($S_{orw}-S_{orc}$) depends both on the waterflood residual oil saturation in the swept region and upon the average oil saturation left in the region swept by the surfactant slug. An uncertainty of ± 5 percent pore volume (PV) in the base case values for ($S_{orw}-S_{orc}$) was examined in the calculations for Figure 64. The ± 5 percent PV variation is well within the current ability to characterize waterflood and chemical flood residual saturations.

Another variable studied was the effect of reduced pattern life. For this study a 10-year production model was used to represent surfactant flood pattern life. This flood pattern life was judged to best represent the limited field experience available. However, since chemicals required at project start are the most significant cost factor, alternative development models merit consideration for an actual project. To explore the impact of pattern acceleration by infill drilling, a project life of 5 years was evaluated. It showed that for those reservoirs that were economically attractive candidates (using the 10-year pattern life assumption) infill drilling could be beneficial (providing a 5-year pattern life). Although the simple production model used in this study cannot be considered to be best for representing any particular field, it indicates that infill drilling can improve project economics, and undoubtedly will be considered in actual field implementation of the surfactant flooding process.

Various of these sensitivity studies are shown in Table 26.

Estimated well workover and drilling requirements for surfactant flooding projects in the United States are shown in Figure 65 as related to oil price and in Figure 66 as related to time for a $15 per barrel oil price. Cumulative and yearly cash outlays are illustrated in Figures 67 and 68.

Polymer and Alkaline Flooding

State-of-the-Art Assessment

Polymer Flooding

Polymer flooding is essentially an improved waterflooding method, in which high molecular-weight, water-soluble polymers are added to the injection water to improve the mobility ratio of the water-flood. The polymers are added at low concentrations (250 ppm to 1,500 ppm); increased sweep efficiency may result from the improved mobility ratio. This method has its greatest potential in reservoirs containing viscous oils, and where the mobility ratio of ordinary waterflooding is adverse.

Currently, two types of polymers are commercially available: (1) a synthetic polymer (polyacrylamide); and (2) a biologically produced polymer (polysaccharide). In addition to increasing the water viscosity, polyacrylamides may also decrease the permeability of the formation to water. When this occurs, the polymer concentration necessary to achieve a given mobility ratio improvement is reduced.

The magnitude of mobility ratio improvement achievable with polyacrylamides decreases with water salinity and divalent ion concentration. Thus, a source of relatively fresh water (total dissolved solids less than approximately 10,000 ppm) is desirable for the most effective use of polyacrylamides.

The ability of polyacrylamides to decrease permeability of the formation to water may be severely reduced by shearing as the polymer is injected. Very high injection rates, especially through perfora-

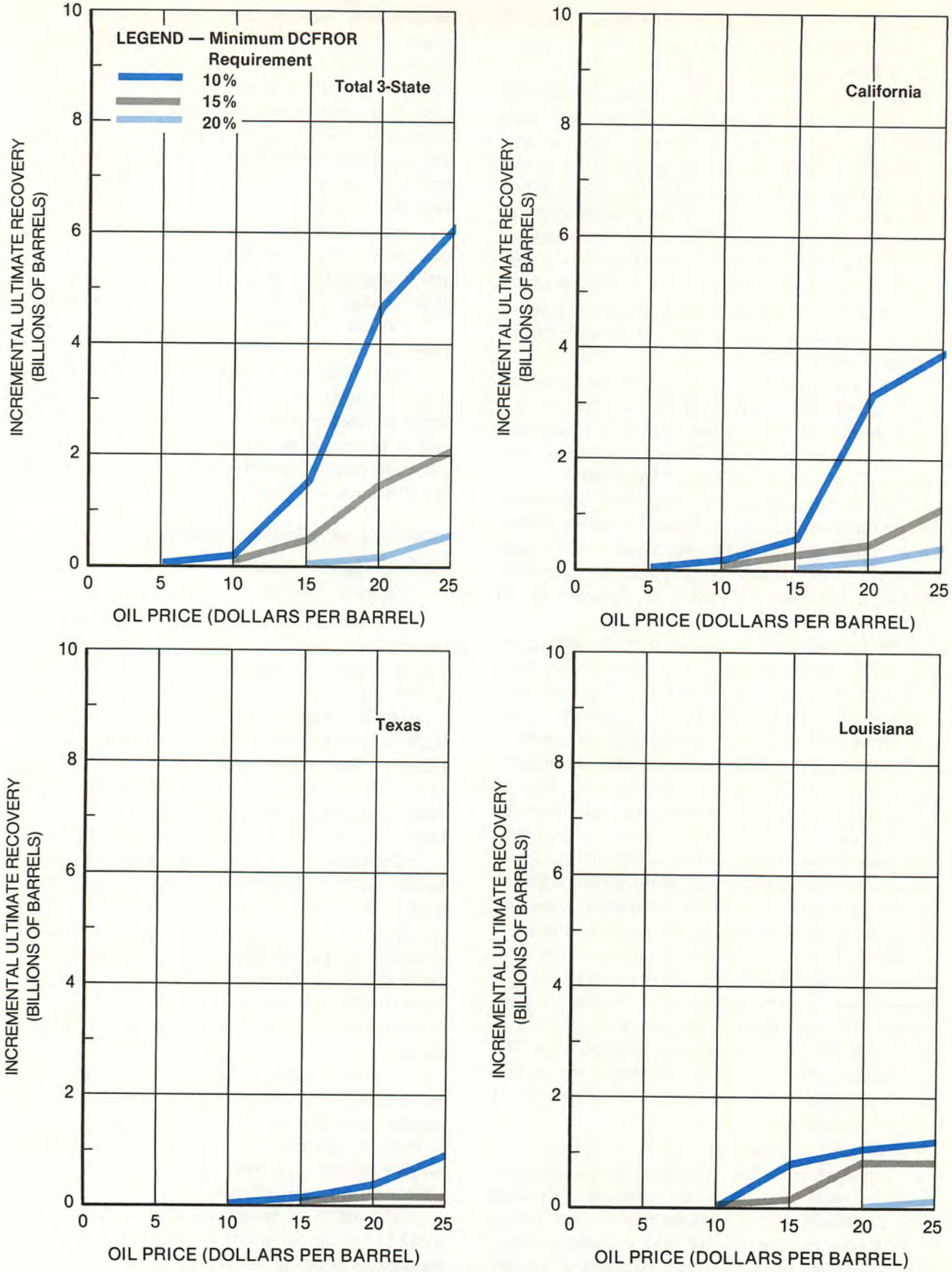


Figure 59. Incremental Ultimate Recovery—Surfactant Flooding—
Base Case Performance and Costs.

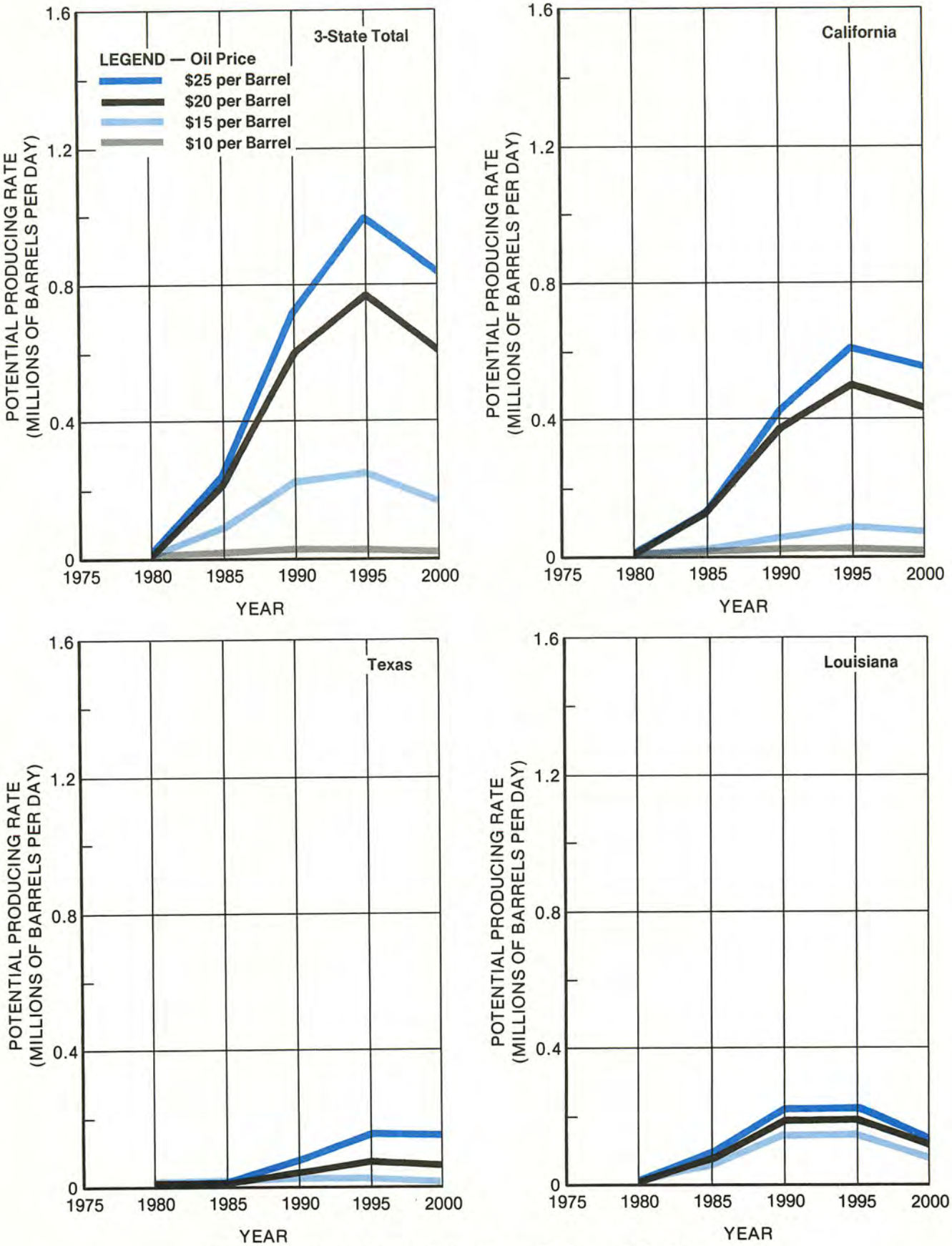


Figure 60. Potential Producing Rate—Surfactant Flooding—
Base Case Performance and Costs.

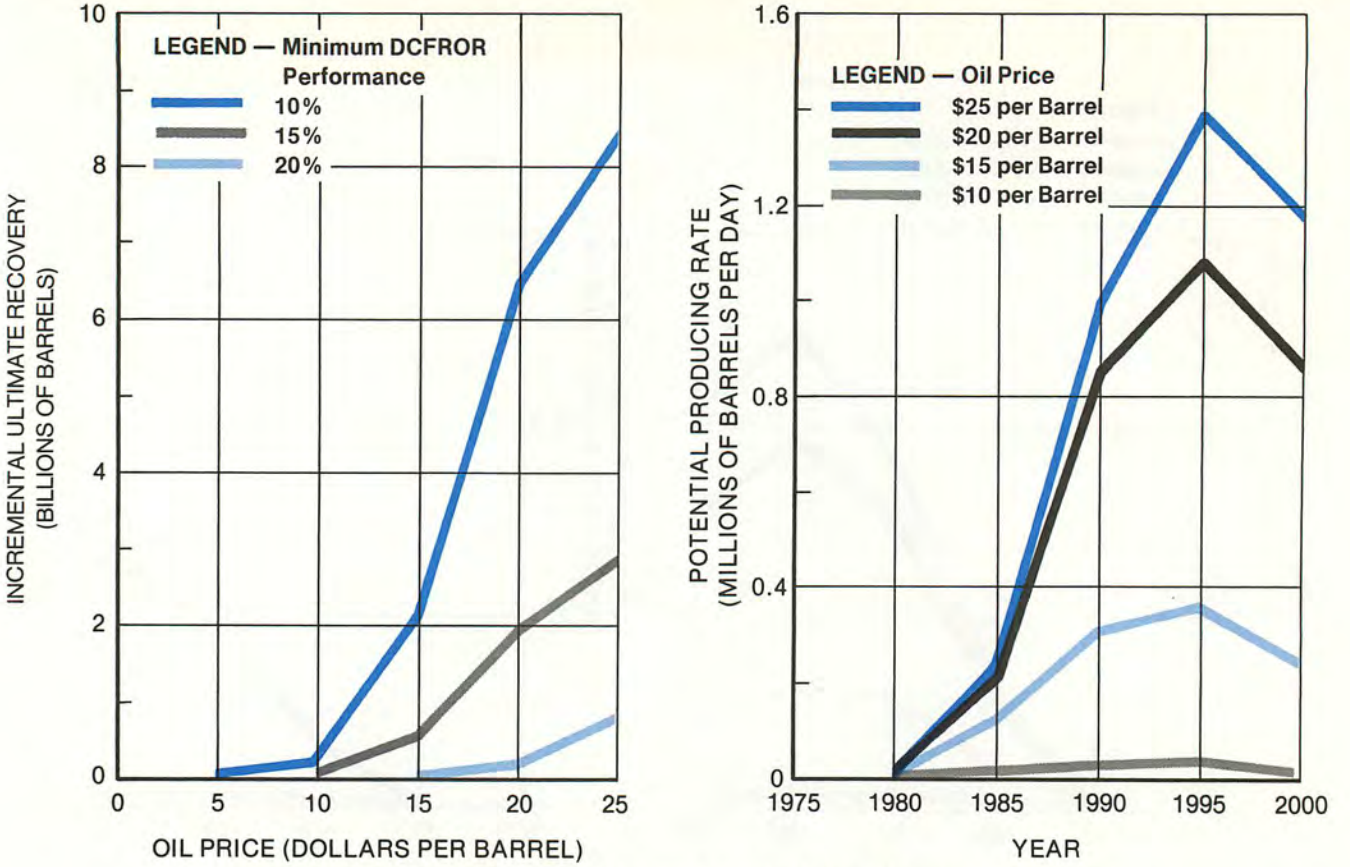


Figure 61. Incremental Ulitmate Recovery and Potential Producing Rate
Surfactant Flooding - Base Case Performance and Costs - Total U.S.

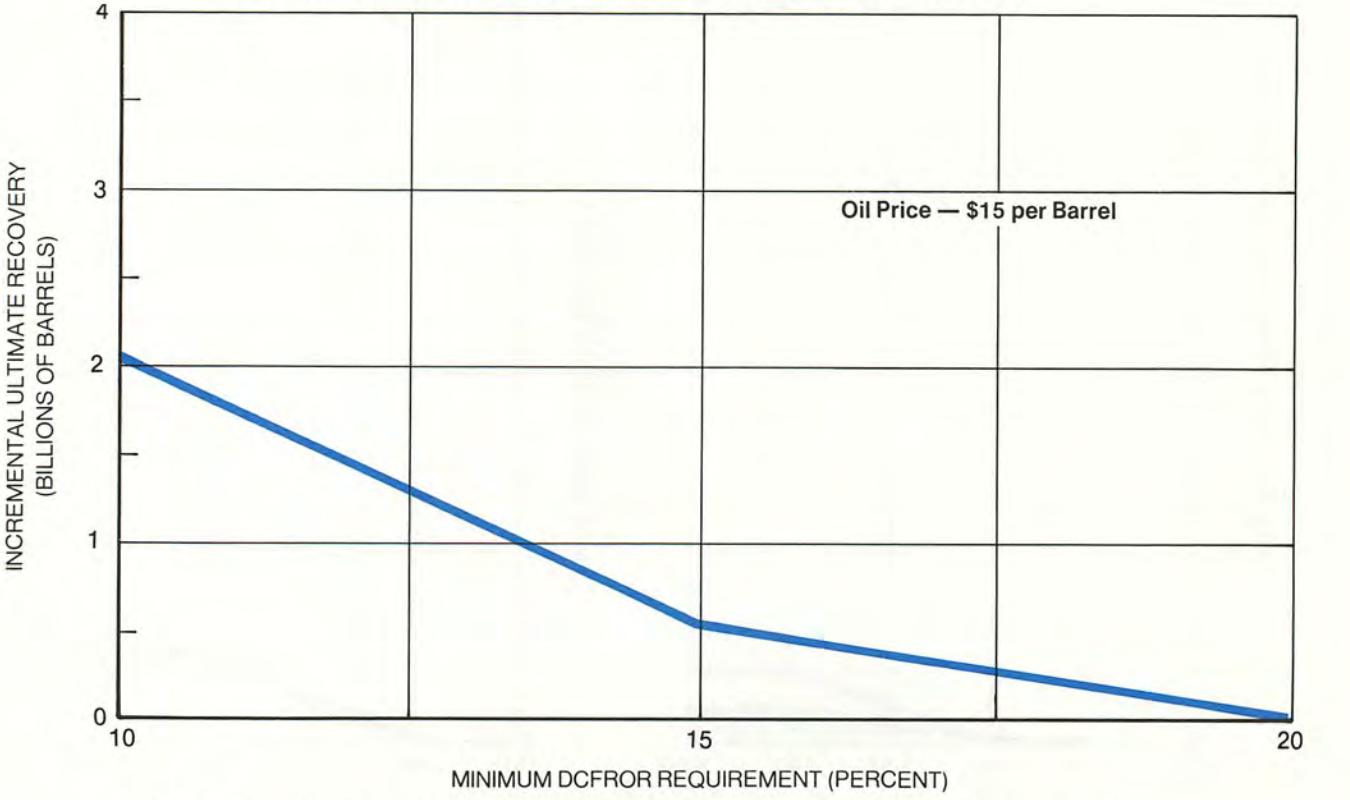
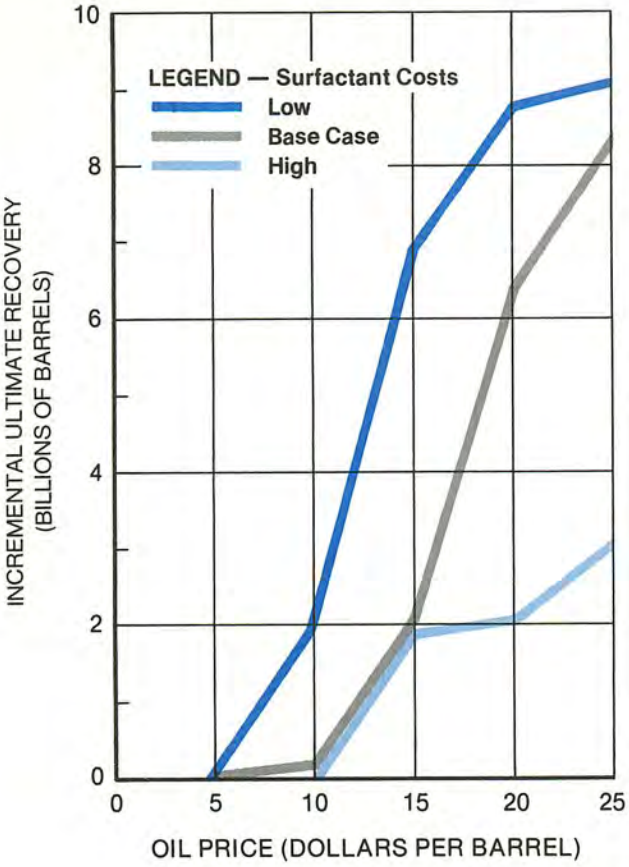


Figure 62. Surfactant Flooding—Variability of Incremental Ultimate Recovery with Minimum DCFROR Requirement—Total U.S.



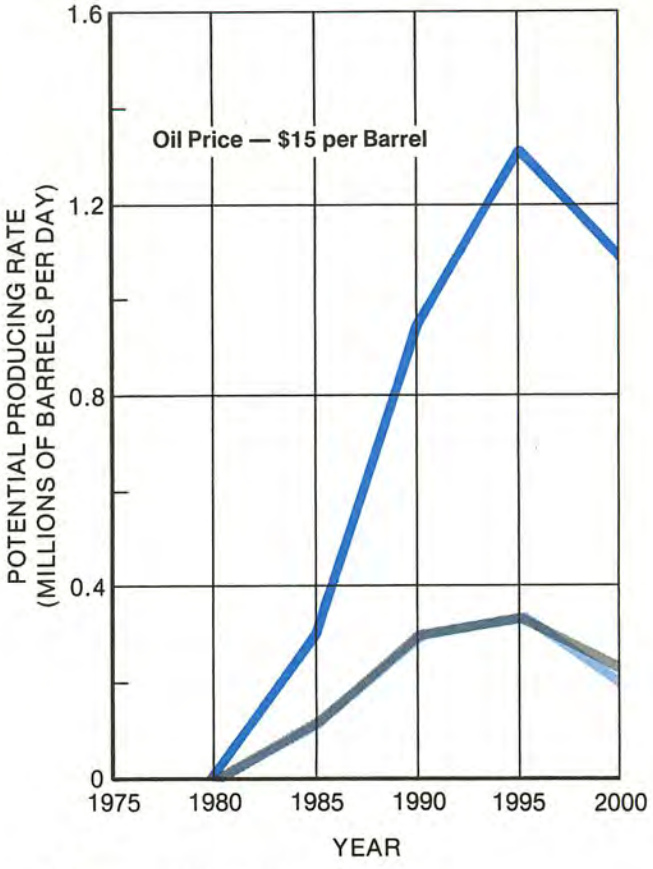
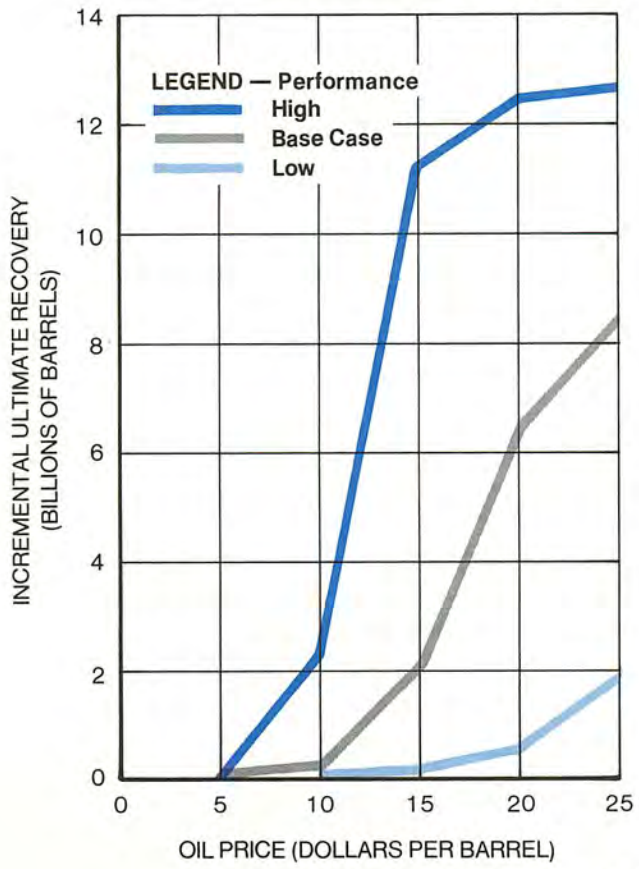


Figure 63. Surfactant Flooding—Variability of Incremental Ultimate Recovery and Potential Producing Rate with Surfactant Costs—Total U.S.



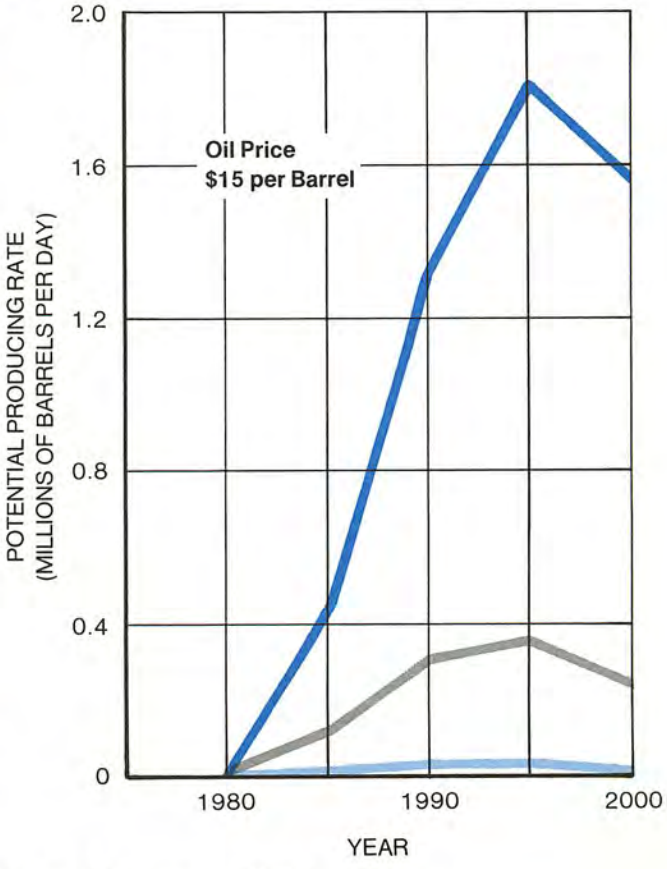


Figure 64. Surfactant Flooding—Variability of Incremental Ultimate Recovery and Potential Producing Rate with Recovery Performance—Total U.S.

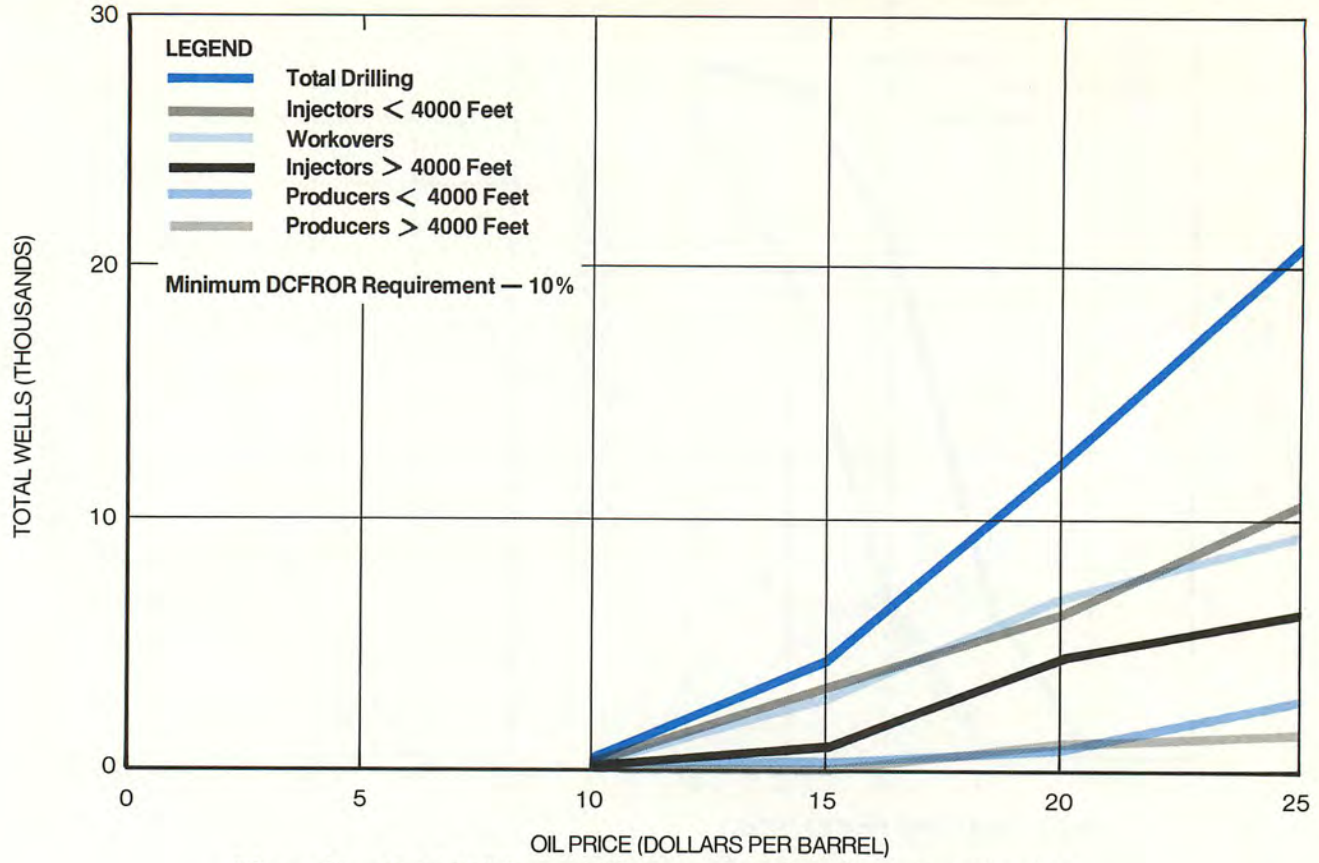


Figure 65. Total Drilling and Workover Activity—Surfactant Flooding.

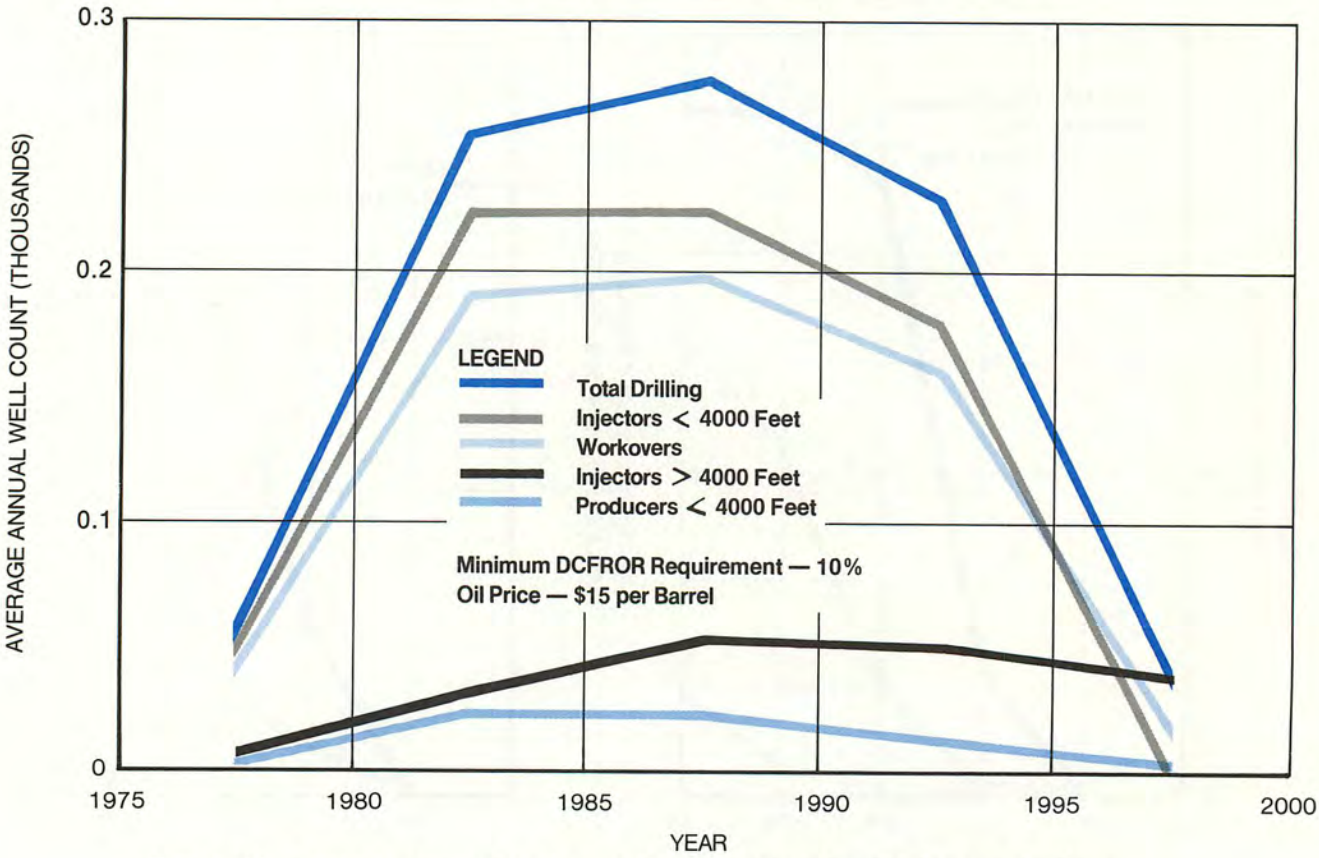


Figure 66. Average Annual Drilling and Workover Activity—Surfactant Flooding.

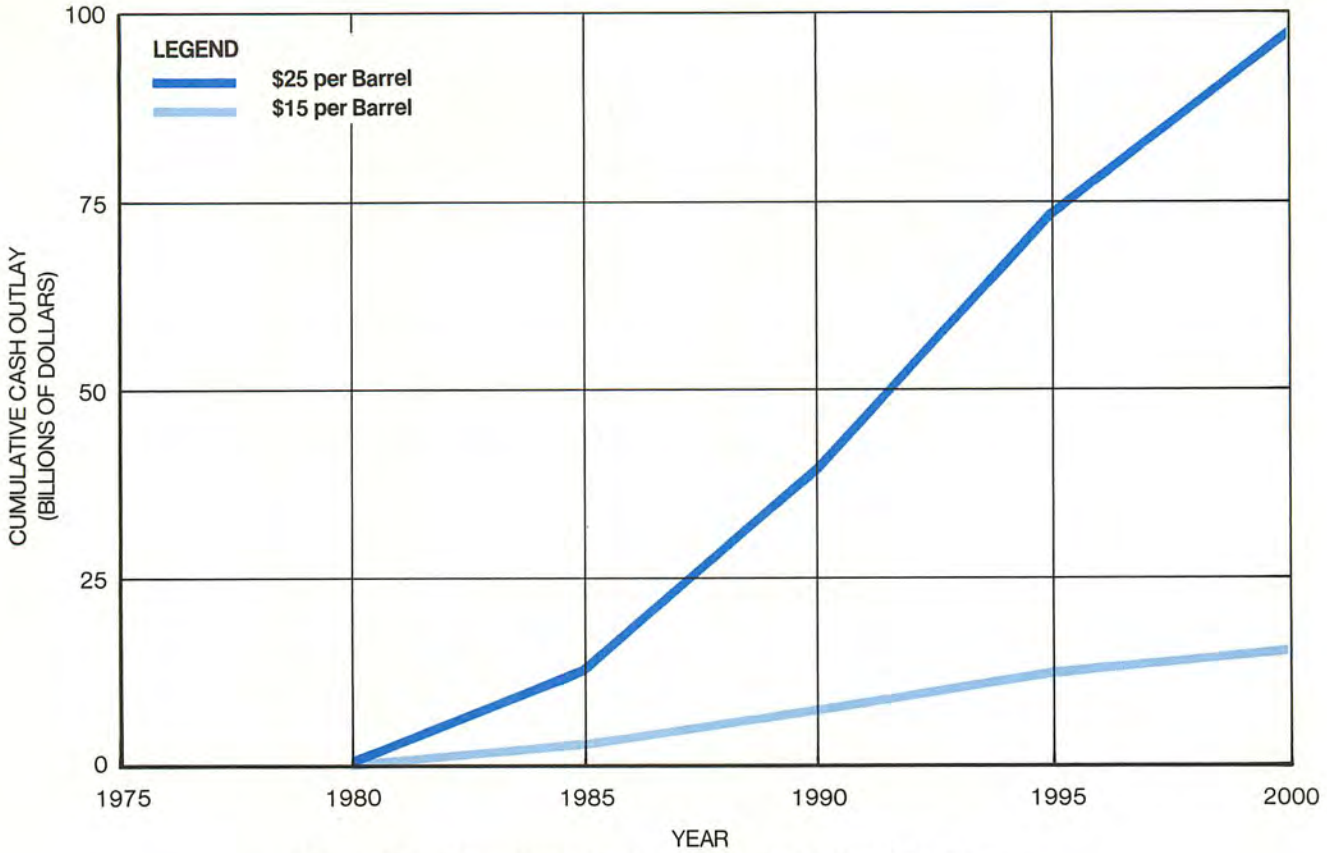


Figure 67. Cumulative Cash Outlay—Surfactant Flooding.

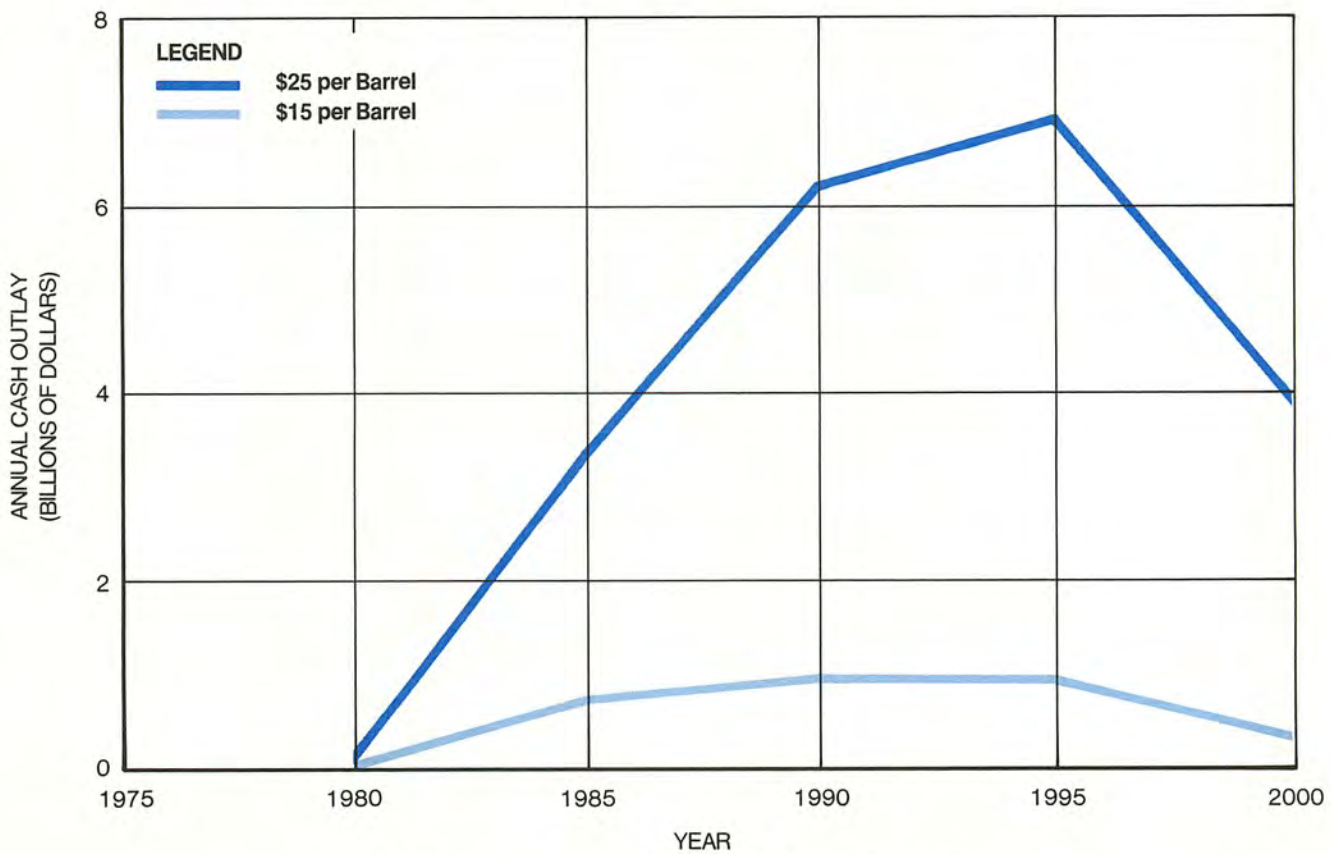


Figure 68. Annual Cash Outlay—Surfactant Flooding.

TABLE 26

SURFACTANT FLOODING SENSITIVITY STUDY RESULTS (Billion Barrels)

Case*	Crude Price	Incremental Ultimate Recovery $15	$20	$25
Base		2.09	6.480	8.380
Base, restrictive taxes		0.00	0.186	0.816
5-year project life		5.60	9.040	9.220
Low surfactant cost		7.86	8.780	9.220
High surfactant cost		1.93	2.090	3.150
Low recoverable oil saturation change		0.14	0.520	1.890
High recoverable oil saturation change		11.20	12.500	12.700
Small chemical slug		8.78	9.490	9.940
Large chemical slug		0.19	2.270	2.430

* Moderate taxes, minimum DCFROR requirement of 10 percent, and 10-year project life unless noted. All volumes are extrapolated to U.S. totals.

tions, may be harmful; hence, moderate injection rates as well as care in surface handling are required to minimize shearing.

Polysaccharides are less sensitive to salinity and divalent ion (calcium and magnesium) concentration and are less likely to shear during injection. However, these polymers, as currently manufactured, may need to be filtered through micron-sized filters to prevent well plugging. Bactericides are normally required to prevent bacterial attack and oxygen scavengers are required to maintain effectiveness. Their long-term stability in higher temperature ($\geq$160°F) reservoir environments has not yet been demonstrated. Polysaccharides currently are more expensive per pound than polyacrylamides.

High clay content in reservoirs is undesirable because the consumption (loss) of polymer is increased.

Polymer flooding with polyacrylamides has been extensively field tested, while testing of polysaccharides has been limited. Several field tests are in operation which should contribute significantly to the state of the art. The incremental ultimate oil recovery achievable by polymer flooding is expected to be modest.

Alkaline Flooding

The first patent on alkaline flooding to improve oil recovery was issued in the United States in 1927. Numerous publications of laboratory and field tests of alkaline flooding have appeared since that time. Alkaline chemicals, such as sodium hydroxide, sodium silicate, and sodium carbonate, when added to flood water, are reported to enhance oil recovery by one or more of the following mechanisms: interfacial tension reduction; emulsification of oil; and formation wettability alteration. These mechanisms result from the in-situ formation of surfactants as the alkaline flood neutralizes petroleum acids. Interfacial tension reduction and wettability reversal can reduce oil saturation below the S_{orw} saturation. Oil emulsification appears to reduce the mobility of the injected water.

The effectiveness of alkaline flooding usually improves as the acid content of the crude increases. The potential for alkaline flooding will normally be highest for recovery of viscous, naphthenic, low API-gravity crudes, since the acid content of crude oils generally increases as the API gravity decreases. Reported laboratory experiments and field test results have indicated that the primary mechanisms responsible for increased oil recovery in this process may differ from one application to another, depending on the particular oil-water-rock system investigated. Therefore, the screening criteria in several categories (such as lithology, salinity and hardness of formation water, and temperature limitations) are ambiguous. However, reservoirs with low-salinity water, a low divalent cation content, and a low clay content are preferred for the process.

Field experience has been limited; information from seven alkaline flooding field tests reported to date are summarized in Table 27. One of the tests reportedly has been successful enough to be considered for commercial expansion. A few of the other tests were considered to be technologically encouraging.

Several unreported field tests are known to be in progress, but results are not available either for technical or economical assessment. Because the potential for this process appears to be greatest for recovering higher viscosity crude oils, polymer flooding and some thermal methods might be alternative EOR methods. However, the alkaline flooding process, unlike polymer flooding, has an advantage in that it can reduce the oil saturation below the S_{orw}; in some laboratory experiments, it has reduced the oil saturation to near zero in the swept region.

Although oil emulsification in alkaline flooding has improved the mobility ratio measured in some laboratory experiments, the emulsification mechanism alone may not be sufficient to achieve significant incremental recovery of highly viscous crude oil. One method proposed for improving sweepout of the

TABLE 27

ALKALINE WATERFLOODING FIELD TRIALS

Field	State	Operator	Acres	Start	Pay Sand-Lith.	Depth (Ft.)	Ø,%/k,md*	Res. Oil °API/cp/Acid†	T, °F‡	Salinity (TDS-ppm)§	Chemical Used	Comments
Harrisburg	NEB	Pan Am	40	1960	Muddy J Sandstone	5,900	15/119	— — —	200	8,500	2%NaOH, 40,000 lb	Wet. Rev. (O/W)¶
Midway-Sunset	CA	Chevron	100	1962	Top Oil & Kinney Sandstone	1,500-2,000	34/450	16/180/1.5	87	15,062	1%NaOH, Crude oil-water (70/30)	Emulsification
Singleton	NEB	Sinclair	40	1966	J-1 Sandstone	—	—	—/1.5/—	160	—	2%NaOH, 8% PV	Wet. Rev. (O/W)¶
Whittier	CA	Chevron	63	1966	2nd and 3rd Sandstone	1,500-2,100	—/410	20/40/—	120	—	0.2%NaOH in softened water	Emulsification
South East Texas	TX	Exxon	2 wells	—	Miocene Sandstone	1,250	—	low/70/1.0	—	—	0.3 M Na_2CO_3	Wet. Rev.(W/O)**
North Ward Estates	TX	Gulf	5	1974	Queen Sand	3,140	21/20	34/2.4/0.22	—	—	5% NaOH, 15% PV	Wet. Rev. (O/W)¶
Orcutt Hill	CA	Union	420	1974	Frac. Shale Sand	2,950	23/71	22/11/—	168	14,300	NaOH, Na-Silicate, $CaCl_2$	Mobility Control

* Porosity in percent; permeability in millidarcies.

† Residual oil: Gravity in degrees API; viscosity in centipoises; acid number.

‡ Reservoir temperature, degrees Fahrenheit.

§ Salinity -- total dissolved solids, parts per million.

¶ Wettability reversal -- oil to water wet.

** Wettability reversal -- water to oil wet.

alkaline injection fluids is the combination of alkaline chemicals and polymers. Another method is the alternate injection of small slugs of sodium silicate and calcium chloride. As they mix in the reservoir, the two materials react to precipitate calcium silicate particles, which partially plug the various strata as they are flooded out. This method has had limited field testing.

Screening Criteria

The development of quantitative screening mechanisms for polymer and alkaline flooding proceeded in three phases: (1) analysis of published polymer and alkaline field test data; (2) review of the literature on the applicability of polymer and alkaline flooding; and (3) consultation with authorities from industry, government agencies, and universities. The screening criteria for polymer and alkaline flooding shown in Table 28 are compilations of the technical factors that approximate the decision parameters currently used by the oil industry in selecting reservoirs for further consideration as polymer or alkaline recovery projects. These screening criteria were used as the first screening for reservoirs in the data base. API gravity, crude viscosity and reservoir temperature data were supplemented or corrected as necessary.

TABLE 28

SCREENING CRITERIA FOR POLYMER AND ALKALINE FLOODING

Polymer Flooding

1. Natural Water Drive: None to Weak
2. Gas Cap: None to Minor
3. Fracture: None to Minor
4. Reservoir Temperature (°F): $\leqslant 200$
5. Crude Viscosity (cp): $\leqslant 200$
6. Average Reservoir Permeability (md): $\geqslant 20$
7. Mobile Oil Saturation* (%PV): $\geqslant 10$
8. Lithology: Not Critical in this screen

Alkaline Flooding

1. Natural Water Drive: None to Weak
2. Gas Cap: None to Minor
3. Fractures: None to Minor
4. Reservoir Temperature (°F): $\leqslant 200$
5. Crude Oil Acid Number (mg KOH/g of oil): $\geqslant 0.2$
6. °API Gravity: $\leqslant 35$
7. Crude Oil Viscosity (cp): $\leqslant 200$
8. Average Reservoir Permeability (md): $\geqslant 20$
9. Lithology: Sandstone

* Mobile oil saturation calculation: $S_o = S_{oip} - S_{orw}$

where:

S_o = Mobile oil saturation (%PV)

S_{oip} = Current oil saturation (%PV)

S_{orw} = Waterflood residual oil saturation (%PV)

Thirty-three reservoirs passed the first screening for polymer flooding, and 18 reservoirs passed for alkaline flooding processes. Additional screening of these reservoirs was performed by geologists and reservoir engineers from the participating companies. Factors such as depositional environment, general lithology, degree of heterogeneity, past waterflooding performance, and the likely influence of gas caps, natural water drives, and fractures were considered whenever possible. The geological and engineering review was used to reject some reservoirs on the basis of unfavorable properties. The remaining reservoirs were ranked as good, fair, or poor candidates for polymer and alkaline flooding. Factors such as the magnitude of mobile oil saturation, viscosity, permeability, and reservoir temperature were also considered in making the rankings. Only 13 reservoirs remained as candidates for polymer flooding and 5 as candidates for alkaline flooding processes after the second screening.

Crude oil acid numbers were used only in the second screening. Acid numbers were obtained from the correlation shown in Figure 69 and from other public sources, when available.

Since polymer and alkaline flooding processes can be applied to reservoirs having crude oil viscosities ranging from 5 cp to 200 cp, many candidates were also selected for other enhanced recovery processes. Therefore, the dominance rules discussed in Chapter Two were applied to those reservoirs suitable for more than one process. There was one exception to the dominance rules; some large fields were divided into several areas, with different processes applied in each area. After the application of dominance rules, only 7 reservoirs remained as final polymer candidates, and 4 reservoirs remained as alkaline flooding candidates.

Process-Dependent Cost Data

There are two categories of cost data in polymer and alkaline flooding processes: process-independent costs, described in Appendix C; and chemical costs and some special treatments related to alkaline flooding. Only this second cost category is discussed here.

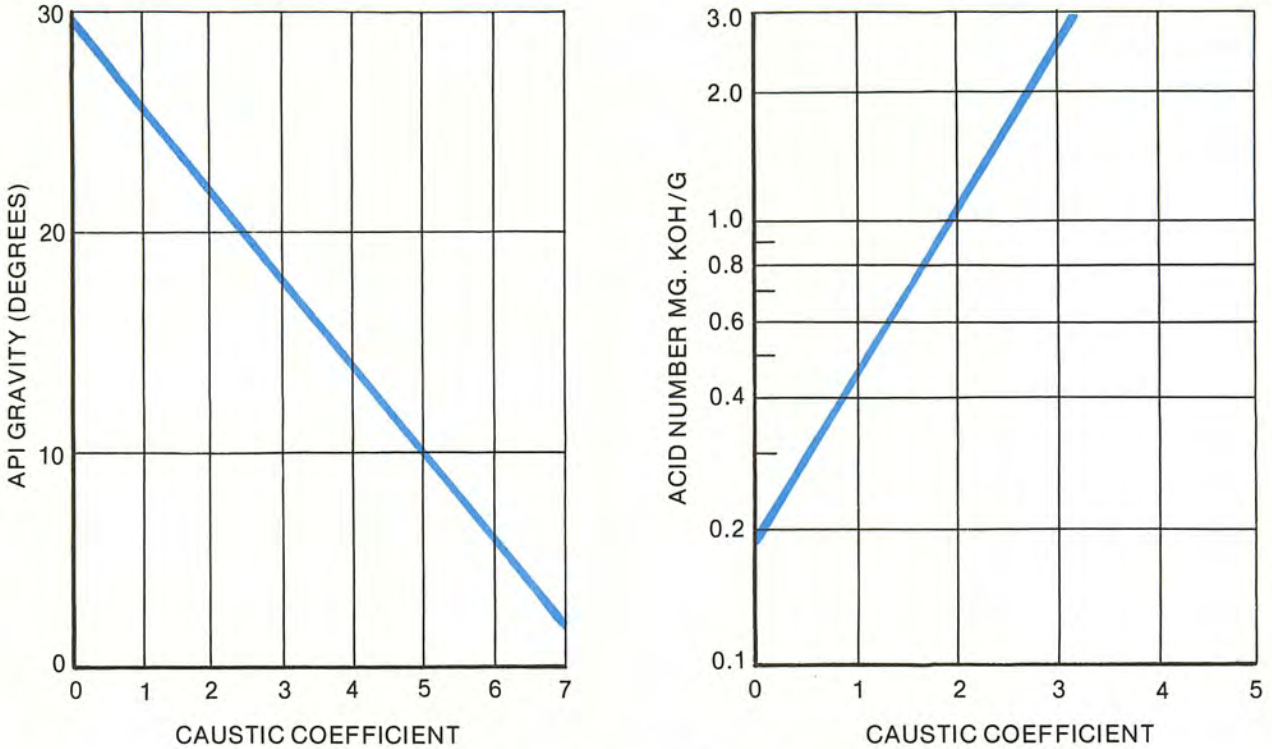


Figure 69. Determination of Crude Oil Acid Number from API Gravity Data.

Note: Reference 16 -- Alkaline Water Flooding.

Polymer

Average prices of polysaccharide and polyacrylamide polymers were used in economic computations. These prices, versus crude oil price, are shown in Table 29.

Sodium Hydroxide

Although several chemicals, such as sodium carbonate, sodium silicate, and sodium hydroxide, have been tried in field tests, sodium hydroxide (NaOH) appears to have the greatest potential in the alkaline flooding process. Therefore, the chemical costs used in this analysis are based on the cost of sodium hydroxide. Because of the high energy consumption in the production of NaOH by electrolysis, its cost was assumed to be sensitive to crude oil price, as illustrated in Table 30.

TABLE 29

AVERAGE PRICE OF POLYMER MIXTURE AT DIFFERENT CRUDE PRICES
(50% Polysaccharides: 50% Polyacrylamides)

Crude Oil Price (Dollars per Barrel)	Polysaccharides (Dollars per Pound)	Polyacrylamides (Dollars per Pound)	Average Price (Dollars per Pound)
5.00	2.30	1.14	1.72
Base Case: 10.00	2.40 *	1.40 *	1.90
15.00	2.49	1.72	2.10
20.00	2.58	2.04	2.31
25.00	2.70	2.35	2.52

* See Notes - Tables 18 and 19.

TABLE 30

COST OF SODIUM HYDROXIDE VERSUS CRUDE OIL PRICE

Crude Oil Price (Dollars per Barrel)	Cost of NaOH* (Dollars per Pound)
5	0.103
10	0.117
15	0.127
20	0.143
25	0.165

* These costs include the cost of transportation and a sales tax of $.03 per pound.

Acidizing of Injection Wells

Injectivity reduction has been experienced in the alkaline flooding process. Acidizing of injection wells once a year appeared to be frequent enough. The average cost of acidizing was estimated to be $10,000 per well. Therefore, total acidizing cost per pattern was assumed to be $20,000 (two treatments per injection well).

Demulsification

In alkaline flooding, the production of oil-water emulsions may be expected. Therefore an emulsion treatment cost of $.10 per barrel of crude oil produced was used in the economic calculations.

Pilot Tests

Pilot testing costs were not treated explicitly in the economic evaluation of individual reservoirs and were assumed to be included in overhead costs, along with the cost of laboratory research.

Description of Process Analysis Procedures

Process analysis procedures included the calculation of ultimate recovery, the estimation of chemical slug size and concentration, the determination of pattern size, flood life and field-wide expansion schedules, and the application of cost data to candidate reservoirs.

Calculation of Incremental Ultimate Recovery—Polymer Flooding

The addition of polymers to water increases the effective viscosity of water and thus results in a more favorable mobility (decreased) ratio than is present in an ordinary waterflood. The principal benefits of the improved mobility ratio are an improved areal sweep, improved vertical sweepout in permeability-stratified reservoirs, and, possibly, some crossflow of oil from low-permeability to higher-permeability strata. Although polymer flooding of reservoirs containing high viscosity oils will not reduce the oil saturation in the swept regions below the waterflood irreducible residual oil saturation, the oil saturation in the polymer-swept regions can approach irreducible values with less cumulative volume injected than is possible in ordinary waterfloods.

Although, in principle, the same ultimate recovery can be achieved by prolonged waterflooding as can be achieved by polymer flooding, in practice, an uneconomic water-oil ratio may be reached by ordinary waterflood before this recovery level is achieved. Thus, the incremental oil recovery attributable to polymer flooding in any individual reservoir depends strongly upon the economic conditions affecting the performance of an ordinary waterflood, as well as upon the properties of the reservoir oil and the nature of reservoir heterogeneities. Detailed evaluations require information not available in the data base.

Incremental oil recovery was estimated by an approximate method. The total oil that remains to be recovered by polymer flooding in each candidate reservoir was estimated by determining the current oil saturation in the reservoir and by assuming an average of 50-percent volumetric sweepout. This estimation of remaining oil recovery included both oil that could have been recovered by continued waterflooding and the incremental recovery attributable to polymer flooding.

Published field experience suggests that the incremental recovery attributable to polymer flooding is approximately 25 percent of the remaining oil recovery; therefore, this percentage was used to separate the incremental recovery from the total remaining recovery for all candidate reservoirs. When this procedure was applied to the candidate reservoirs, the average incremental oil recovery was calculated to be about 3 percent OOIP.

These calculations were used to develop base case estimates of incremental recovery for the candidate reservoirs, regardless of the good, fair, or poor rankings of the reservoirs. There is a degree of uncertainty associated with the reservoir rankings and the individual reservoir recovery estimates. To approximate the impact of this uncertainty on the total incremental ultimate recovery projected for polymer flooding, calculations were made for two more cases: (1) assuming that all reservoirs were good flooding candidates; and (2) assuming that all reservoirs were poor flooding candidates. For the first assumption, base case recovery estimates for reservoirs rated "poor" were adjusted upward by 50 percent to estimate improved recovery if the reservoir should perform better than expected. Similarly, base case recovery for reservoirs rated "good" was decreased by 50 percent to reflect decreased recovery if these reservoirs should perform more poorly than expected. Base case recoveries for reservoirs rated "fair" were increased or decreased by 25 percent for the range of uncertainty calculations.

Calculation of Incremental Ultimate Recovery—Alkaline Flooding

The method used for estimating incremental oil recovery assumes that a reduction in the waterflood residual oil saturation will be the dominant mechanism responsible for increased oil recovery in future applications of this method. The correlation presented in Figure 70 was used to estimate the final oil saturation left in the regions of a reservoir flushed with alkaline flood water. This correlation provides the ratio of the oil saturation remaining after an alkaline waterflood to the oil saturation remaining after a conventional waterflood. Since this correlation is based on experiments in laboratory cores with various acidic crude oils, its use for field applications required that adjustments be made for each alkaline flooding candidate. This adjustment is necessary to account for the higher average oil saturations that will result in the swept zones of a reservoir due to heterogeneities, unexpected harmful minerals, dilution and reduced effectiveness of the alkaline slug, and other factors. Because of the lack of definitive field tests of alkaline waterflooding, these adjustments were largely made by analogy with other processes.

Incremental recovery was estimated by using the following equation:

$$\text{incremental ultimate recovery} = \frac{\text{OOIP} \times B_{oi}}{(1 - S_{wi})B_o}(S_{orw} - S_{ora})\,E$$

where:

- OOIP = original oil in place (stock tank barrels)
- B_{oi} = original oil formation volume factor (reservoir barrels per stock tank barrel)
- B_o = current oil formation volume factor (reservoir barrels per stock tank barrel)
- S_{wi} = original water saturation
- S_{orw} = residual oil saturation by waterflood in swept zone

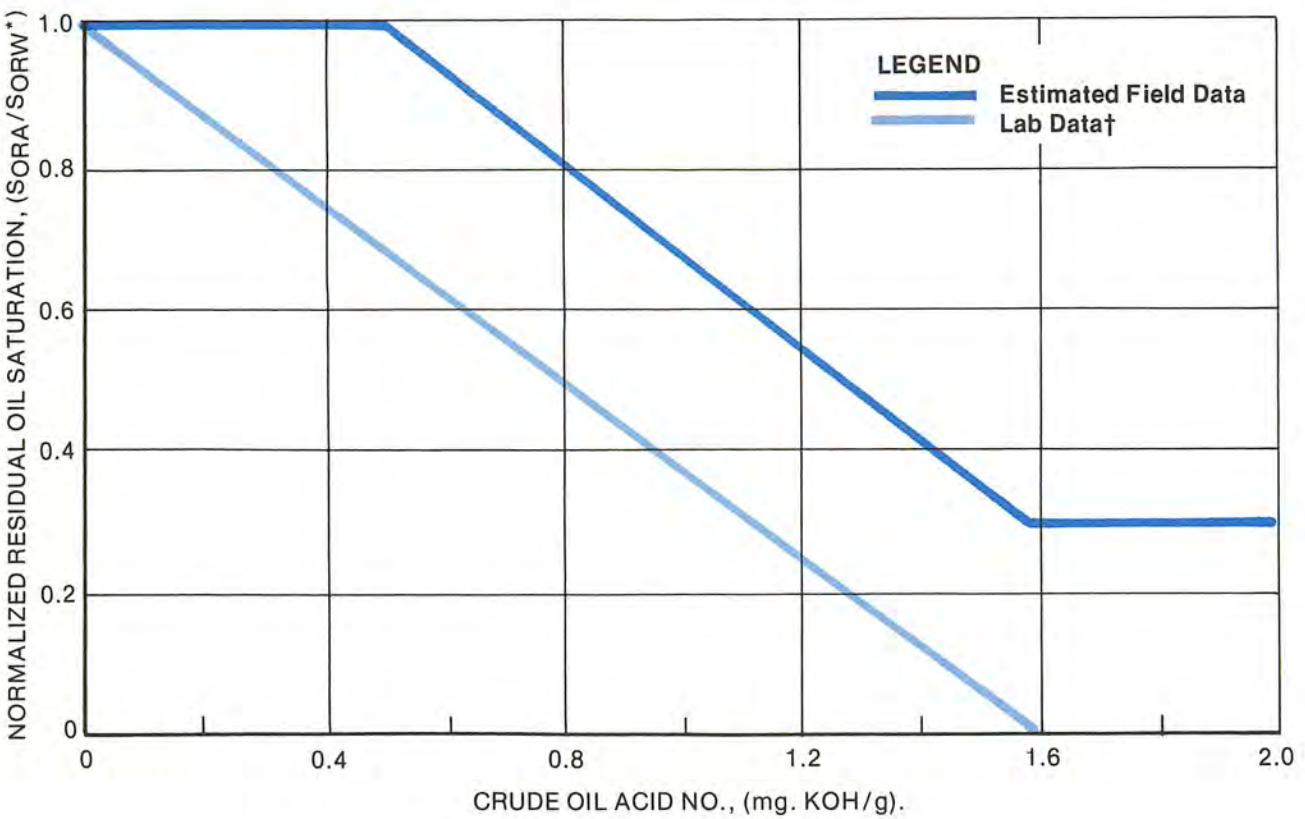


Figure 70. Correlation of Crude Oil Acid No. vs. Normalized Alkaline Flooding Residual Oil Saturation.

*S_{ora} -- Oil Saturation After Alkaline Flooding - Percent
S_{orw} -- Oil Saturation After Conventional Waterflooding - Percent.
†Laboratory Data References 38, Alkaline Flooding.

S_{ora} = residual oil saturation by alkaline flood in swept zone

E = waterflood and chemical flood volumetric sweep efficiency

The alkaline flooding candidates generally contained moderately viscous oils. For this reason the waterflood residual oil saturation values taken from the Bureau of Mines correlations shown in Figure 71 were used in the alkaline flooding projections rather than the residual oil values assumed for the surfactant projections. Formation volume factors were assumed to be 1.0 and a volumetric sweep efficiency of 50 percent was used.

Uncertainty in the recovery projections was treated in a manner similar to that described for polymer flooding.

Chemical System Design and Development Schedules—Polymer and Alkaline Flooding

Estimation of Chemical Slug Size and Concentration

Polymer slug size and concentration in the design of a polymer flood depend upon the water-oil mobility ratio, reservoir permeability, degree of stratification and other heterogeneities, type of polymer, reservoir fluid properties, polymer consumption, and economics. In this study an average of 125 ppm-PV* was assumed to be required for effective flooding with current polymers. For example, a 0.5-PV polymer slug size was assumed to contain polymer at 250-ppm concentration.

Two chemicals, sodium hydroxide and polymer were assumed to be required for the alkaline flooding process. The quantity of NaOH required for alkaline flooding was estimated to be 3,000 ppm-PV (or 1.5 weight percent and 0.2 pore volume); this figure was based on results of field tests to date (see Table 27). Although polymer requirements for alkaline flooding vary from reservoir to reservoir depending on the crude oil viscosity, an average of 600 ppm-PV was used.

*This unit is a combination of concentration (in parts per million) and slug size (in fraction of a pore volume).

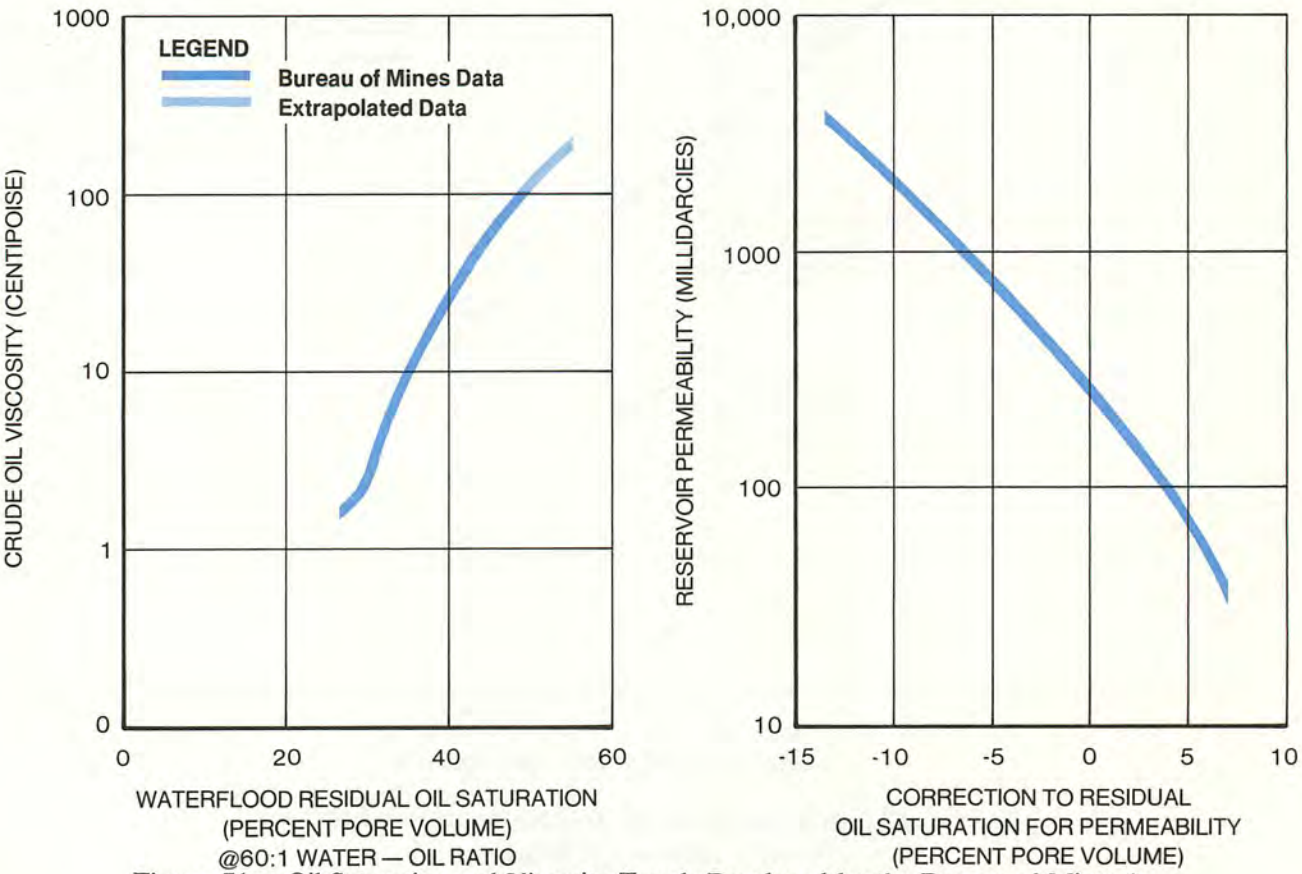


Figure 71. Oil Saturation and Viscosity Trends Developed by the Bureau of Mines.*

*Sloat, Ben. Petroleum Engineer, (May, 1971), 84.
EXAMPLE: For 10 Centipoise Viscosity and 1000 Millidarcies, S_{ORW} = 36 + (-6) = 30%

Pattern Size, Flood Life, and Field Expansion Schedules

In practice, the desired pattern size and flood life are determined from economic optimization studies. Calculations were not made in detail for this study; instead, both for polymer flooding and for alkaline flooding, a 20-acre, five-spot pattern was assumed to be approximately the pattern size that would allow a 10-year flood life, which was in turn assumed to roughly approximate the optimum flood life. For candidate reservoirs that had larger well spacings, infill drilling costs were included in the economic calculations.

Production rate schedules assumed for the incremental oil production attributable to polymer flooding and alkaline flooding are illustrated in Figures 72 and 73. In these figures, production rate is expressed as a percentage of total incremental recovery that is produced each year. Injection of the polymer and alkaline water slug was assumed to take place in the first two years.

The assumed program for staging project starts was the same for both processes. The initial stage consisted of 10 patterns. After three years for process evaluation, another 20 patterns were added. Thereafter, project expansion was scheduled at the rate of 20 patterns every two years.

The calendar year in which projects were started was determined by the current depletion status of the candidate reservoirs. Except for those reservoirs that are currently under field test or for which there are plans for tests in the near future, the project starting time was scheduled after 1980. For reservoirs currently in the early stages of waterflooding, the total estimated incremental oil recovery by polymer flooding was used. This estimated recovery was reduced by 25 percent for polymer flood projects initiated after 1980, to account for depletion up to the start of polymer flooding. It was assumed that projects in reservoirs with temperatures greater than 175° F would not be initiated until after 1985.

Extrapolation Process

Polymer Flooding

The only polymer flooding prospects identified from the data base reservoirs were located in California; they consisted of sandstone reservoirs that contained crude oils, with API gravities in the range of 20° to 30°. Therefore, results were extrapolated only for sandstone reservoirs containing crude oils in this gravity range. To reflect the influence of the screening criterion for temperature on the estimated ultimate recovery, separate extrapolations were made for reservoirs with depths less than 4,000 feet and for reservoirs with depths equal to or greater than 4,000 feet. The extrapolations were based on the OOIP contained in these depth and API-gravity categories; these were estimated for California, Texas, Louisiana, Oklahoma, Kansas, Wyoming, and New Mexico from API data and from information contained in the Petroleum Data System (PDS).

The extrapolation was made in the following steps:

- **California**—Total OOIP in the depth and API-gravity categories described above was divided by the OOIP in the data base reservoirs in these categories. The resulting ratio was multiplied by the ultimate recovery calculated for the data base polymer flood candidate reservoirs.
- **Texas and Louisiana**—No prospects were found in the data base reservoirs of these states. Potential polymer flood recovery from reservoirs not included in the data base was projected by subtracting OOIP in the data base reservoirs in these states from the total OOIP in the API-gravity and depth categories. This difference was then divided by the OOIP in the California data base reservoirs in the specified depth and API-gravity categories; the result was then multiplied by the ultimate recovery projected for the California data base reservoirs.
- **Oklahoma, Wyoming, Kansas, and New Mexico**—Recovery for each state was estimated for the separate categories by dividing the OOIP in the state by the total OOIP in the three states; this ratio was then multiplied by the extrapolated value of total ultimate recovery for the three states.
- **Total United States**—Since the seven-state total API OOIP amounted to 85.5 percent of the total U.S. OOIP, the ultimate recovery for the United States was estimated by dividing the ultimate recovery estimated for the seven states by 0.855.

Alkaline Flooding

All alkaline flooding candidates were found to be in California. The API gravity of the oil in the majority of candidate reservoirs was below 20°. Oil in the remaining candidate reservoirs had API gravities between 20° and 30°. Separate extrapolations were made for reservoirs that contained crude oils with API gravities less than 20° and for reser-

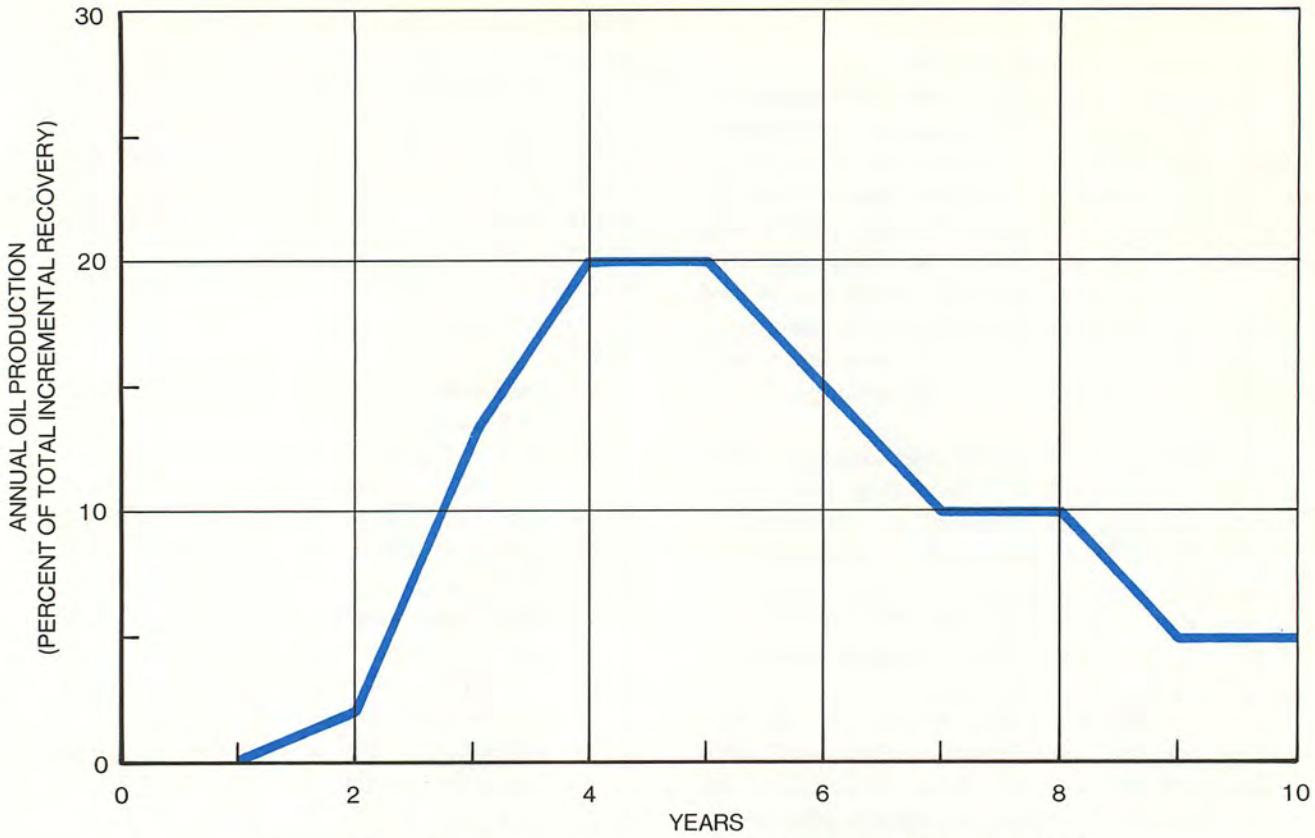


Figure 72. Polymer Flooding—Annual Production of Incremental Oil.

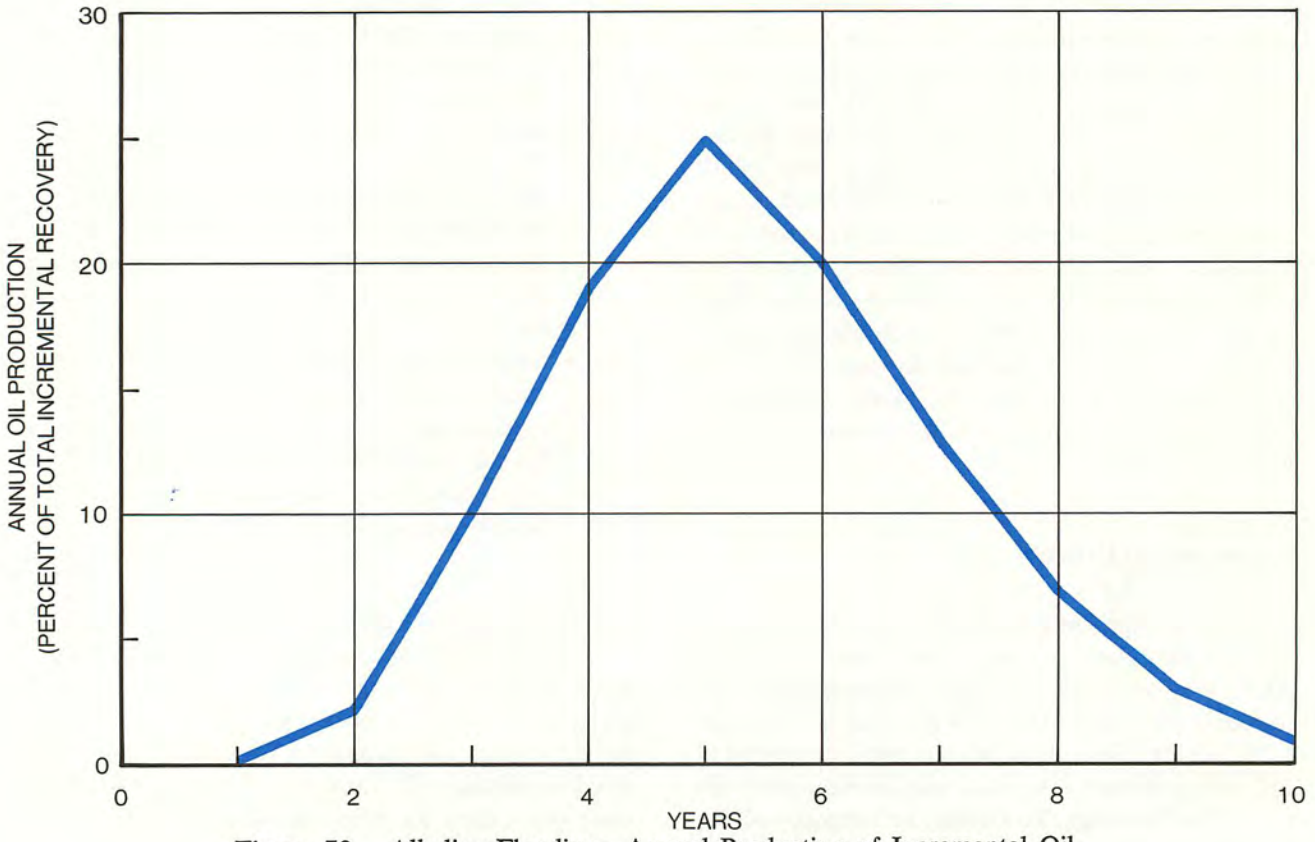


Figure 73. Alkaline Flooding—Annual Production of Incremental Oil.

voirs that contained crude oils in the 20°-30° range. The extrapolation was made in four steps in a manner analogous to that described for polymer flooding.

The results of the extrapolations for both polymer and alkaline flooding are illustrated in Table 31, for the base case performance, 10 percent DCFROR, and $15 per barrel.

TABLE 31

EXTRAPOLATION OF INCREMENTAL ULTIMATE RECOVERY*

(Millions of Barrels)

	Polymer Flooding		Alkaline Flooding	
	Data Base	Extrap-olated	Data Base	Extrap-olated
California	174	220	208	259
California, Texas, Louisiana	174	350	208	308
Seven States	174	404	208	308
U.S. Total	174	473	208	386

* Calculated at a minimum DCFROR requirement of 10 percent and a $15 per barrel oil price.

Results

Polymer Flooding

The incremental ultimate recovery projected for polymer-augmented waterflooding is illustrated in Figure 74 for the oil prices and DCFROR's investigated. Incremental ultimate recovery is estimated to be about 470 million barrels for the base case performance and costs, a minimum 10 percent DCFROR requirement, and a $15 per barrel oil price.* In this figure, the incremental ultimate recovery is relatively insensitive to DCFROR and to oil prices above $10 per barrel. This apparent lack of sensitivity is probably misleading for two reasons: (1) the small number of reservoirs in the data base to which polymer flooding was applied; and (2) the assumption of a constant quantity of polymer injected regardless of oil price. The optimum quantity of polymer to inject should increase with oil prices, thereby increasing incremental oil recovery. Because of the very small contribution of polymer flooding to enhanced oil recovery, this refinement was not incorporated into the estimates of this study.

*Under certain conditions, some reservoirs assigned to other EOR processes by the dominance criteria used in this study could become polymer-flood candidates instead, resulting in a significantly greater potential for polymer flooding.

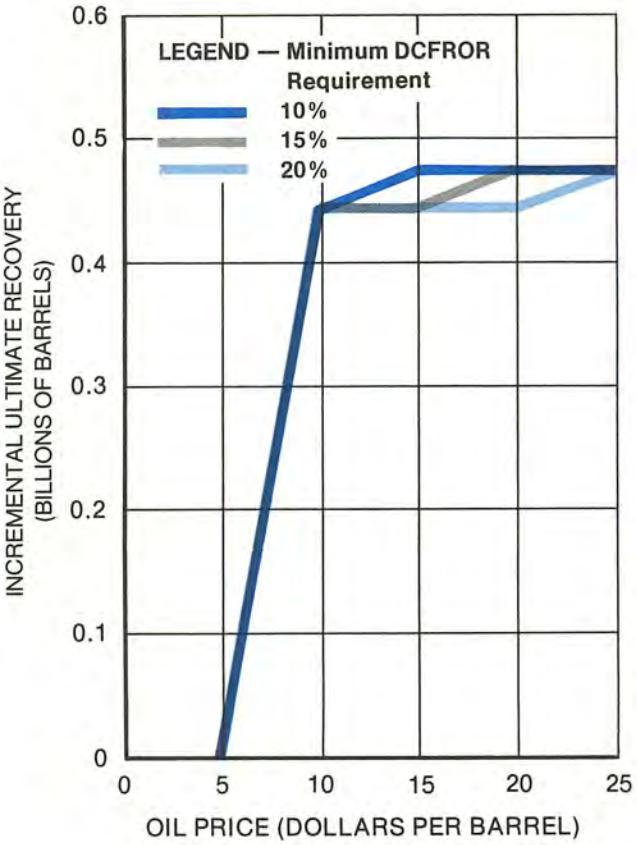


Figure 74. Incremental Ultimate Recovery—Polymer Flooding—Total United States.

Figures 75 and 76 illustrate the impact of uncertainty in process performance on incremental ultimate recovery and potential oil producing rates. Projections were developed for two cases: (1) assuming all the reservoirs show good performance; and (2) assuming all the reservoirs show poor performance. At an oil price of $15 per barrel, and a 10 percent minimum DCFROR requirement, incremental ultimate recovery ranges from 200 to 540 million barrels. In the 1990-1995 time frame, under the same economic conditions, potential oil producing rates range from 26 to 73 thousand barrels per day. Under base case performance, the peak producing rate is about 60 thousand barrels per day.

Projected drilling and well workover activity required for polymer projects are illustrated in Figures 77 and 78. Cash outlay projected to be required for polymer flooding is illustrated in Figures 79 and 80.

Alkaline Flooding

The incremental oil recovery projected for alkaline flooding is illustrated in Figure 81 for the oil

prices and DCFROR's investigated. Incremental ultimate recovery is estimated to be about 380 million barrels for the base case performance and costs, a minimum 10 percent DCFROR requirement, and $15 per barrel oil price. As with polymer flooding the incremental ultimate recovery is relatively insensitive to oil prices above a $10-$15 per barrel price level, probably for the same reasons described for polymer flooding.

Figures 82 and 83 illustrate the impact of uncertainty in process performance on incremental ultimate recovery and potential oil producing rates. At an oil price of $15 per barrel, and a 10 percent minimum DCFROR requirement, incremental ultimate recovery ranges from 280 to 400 million barrels. Under these economic criteria, peak producing rates range from 75 to 110 thousand barrels per day in 1990. Under base case performance, the peak producing rate is about 100 thousand barrels per day.

Projected drilling and well workover activity (for the base case performance and costs and a minimum 10 percent DCFROR requirement) required for alkaline flooding projects are illustrated in Figures 84 and 85. Cash outlay projected for these projects is illustrated in Figures 86 and 87.

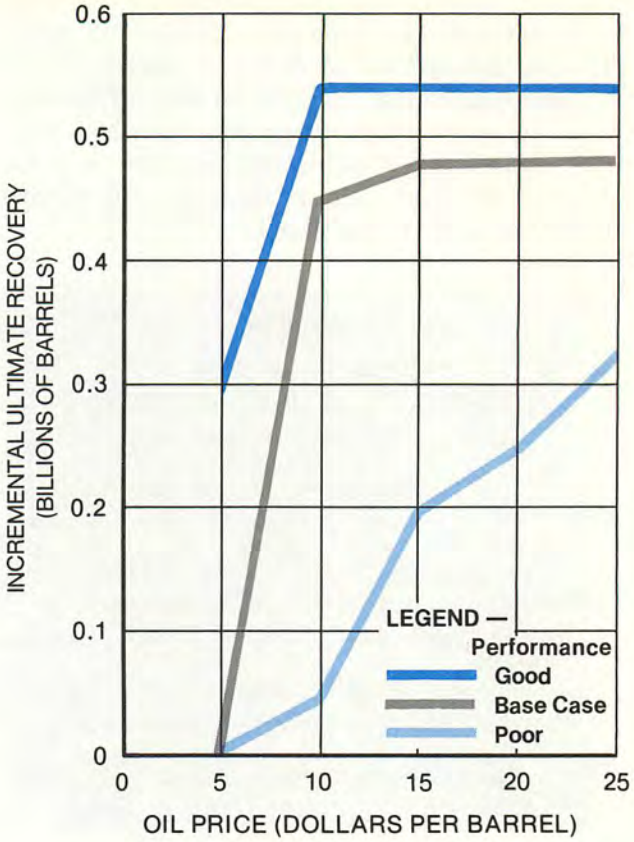


Figure 75. Polymer Flooding—Variability of Incremental Ultimate Recovery with Reservoir Recovery Performance—Total U.S.

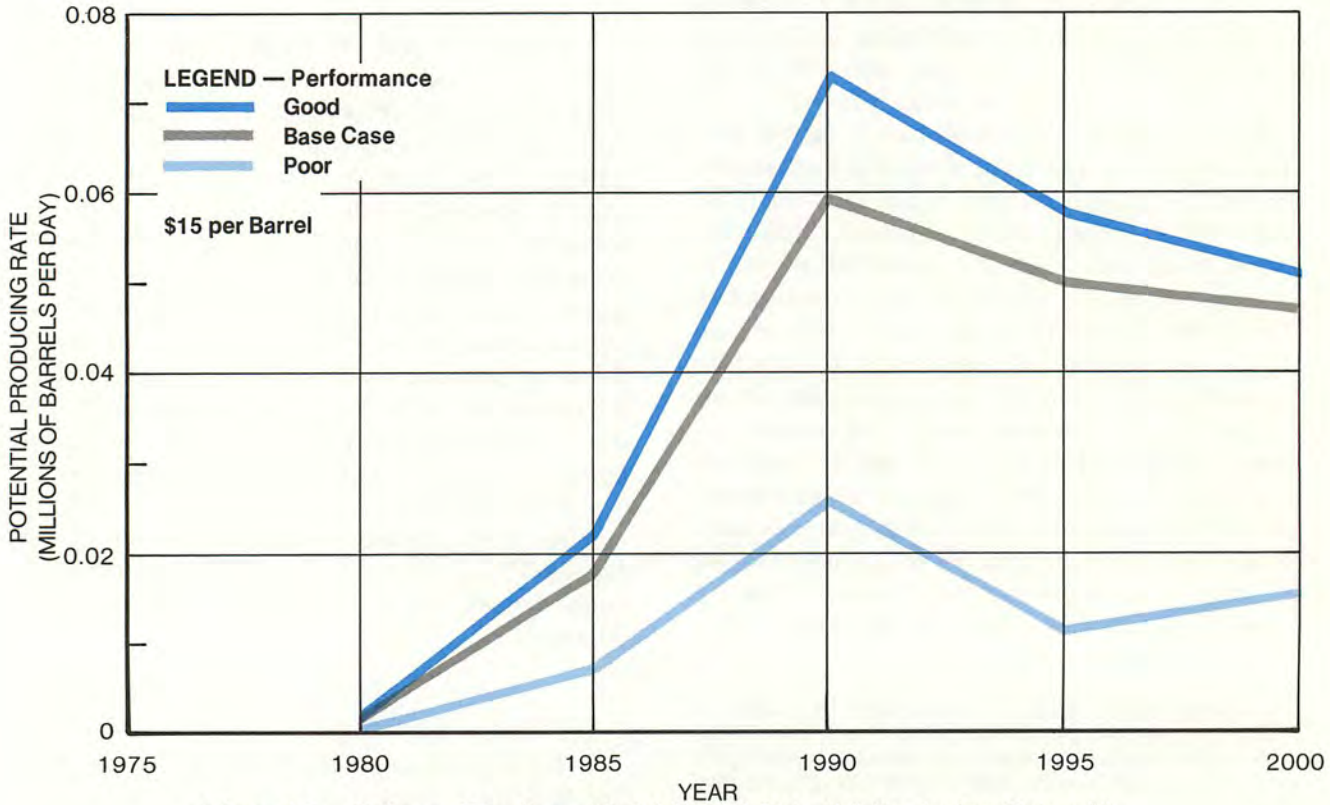


Figure 76. Polymer Flooding—Variability of Potential Producing Rate with Reservoir Recovery Performance—Total U.S.

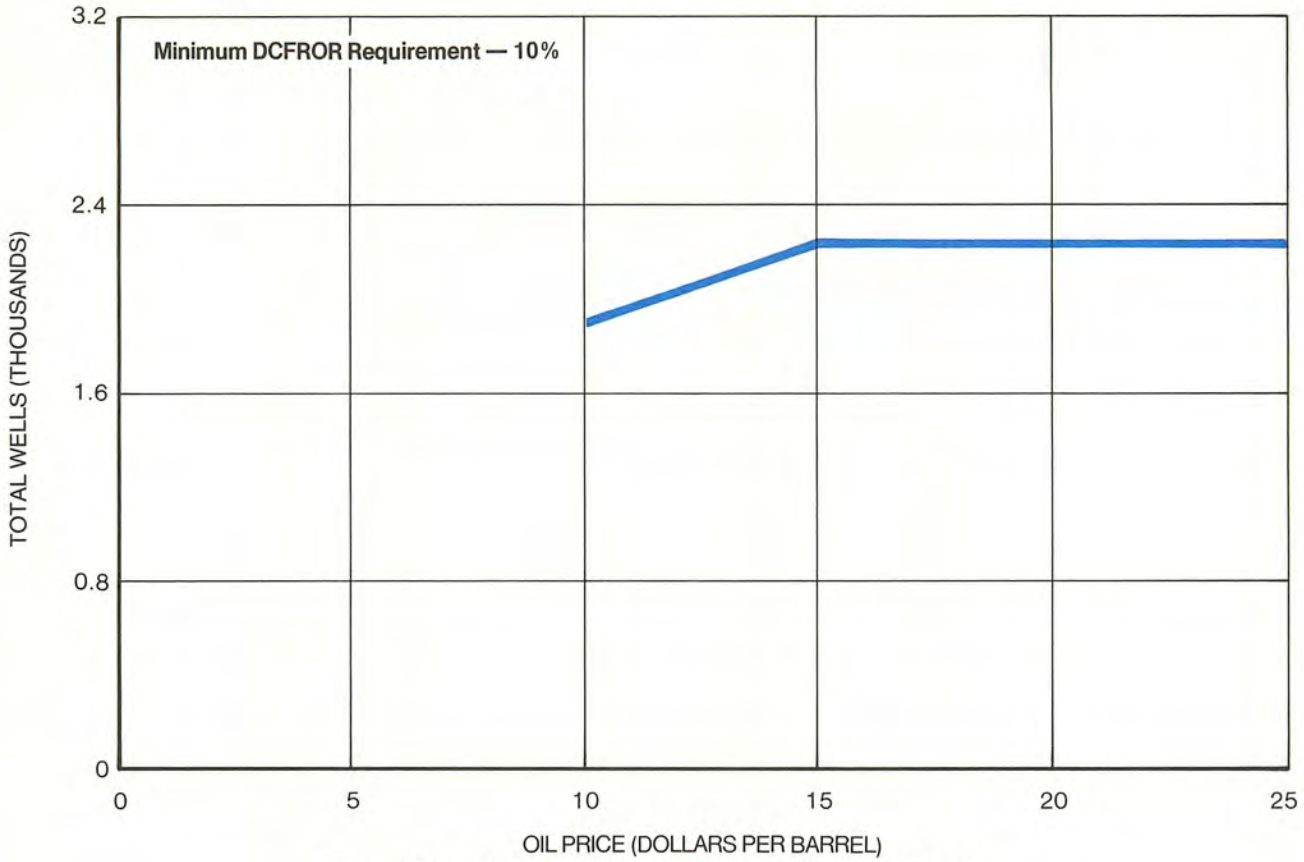


Figure 77. Total Workover Activity—Polymer Flooding.



Figure 78. Average Annual Workover Activity—Polymer Flooding.

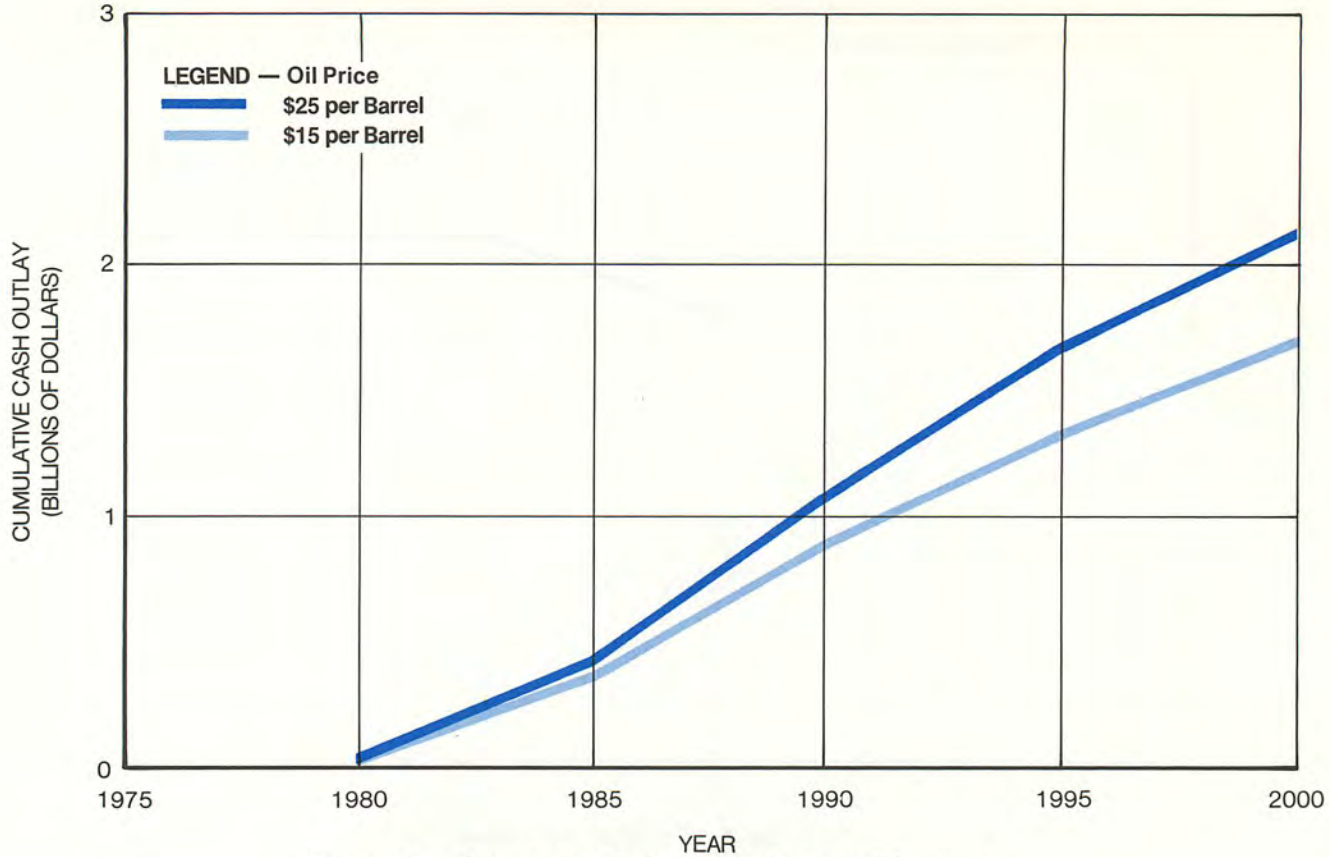


Figure 79. Cumulative Cash Outlay—Polymer Flooding.

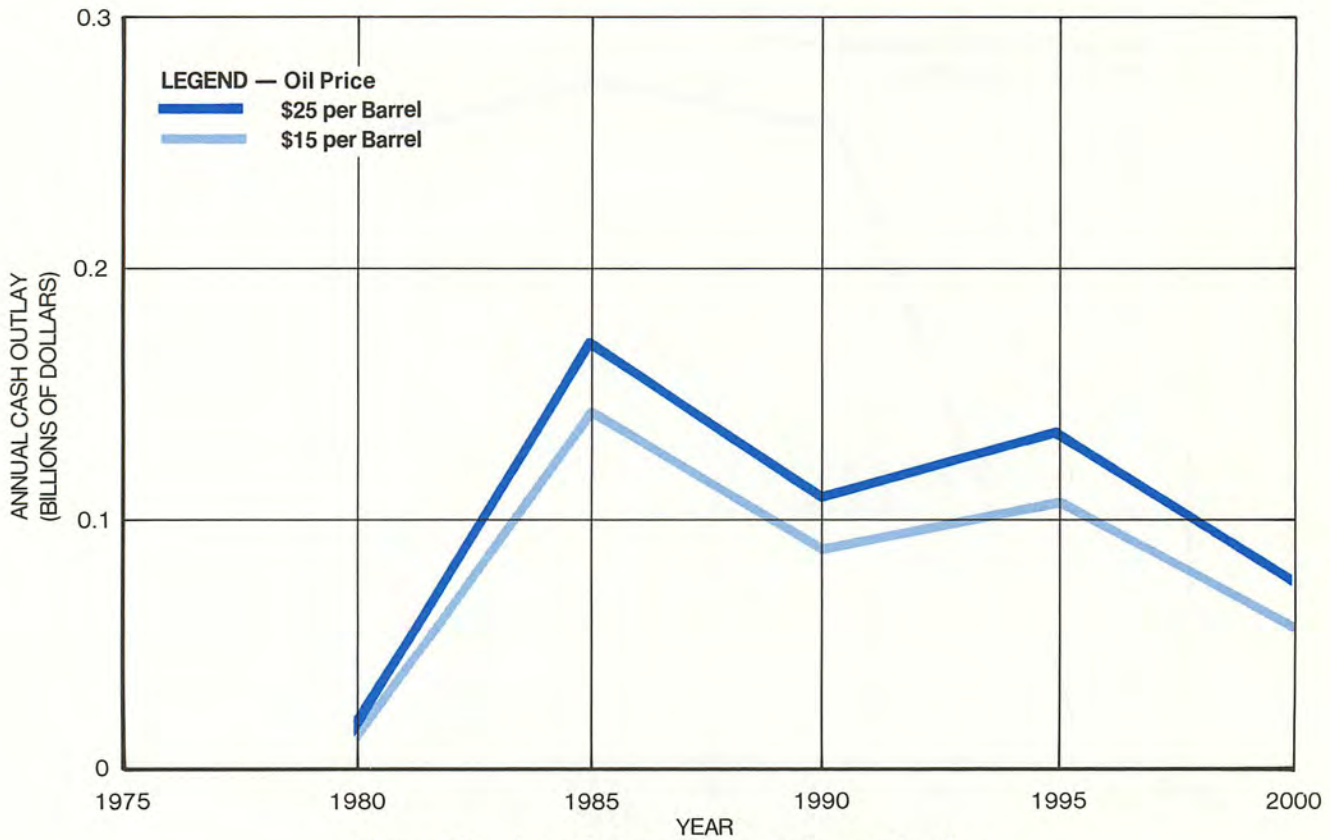


Figure 80. Annual Cash Outlay—Polymer Flooding.

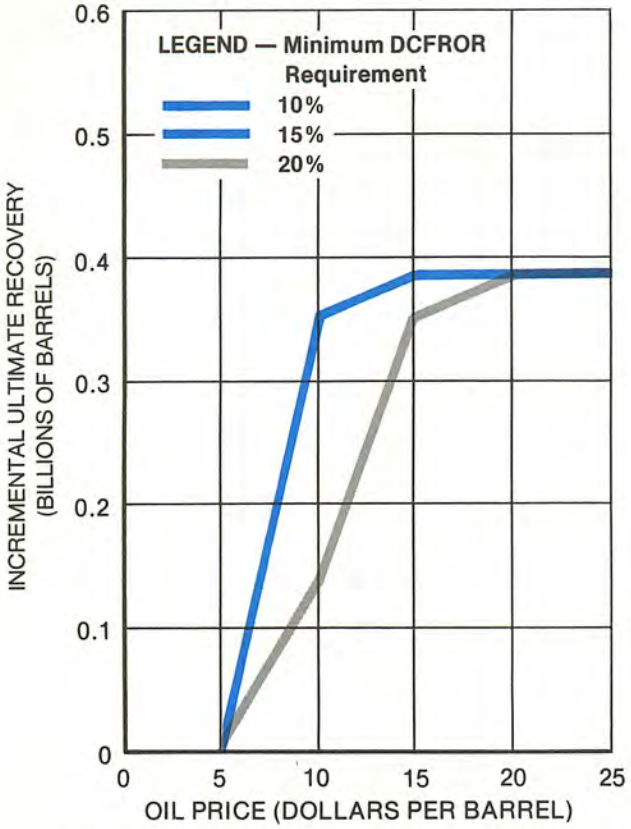


Figure 81. Alkaline Flooding—Incremental Ultimate Recovery—Total U.S.

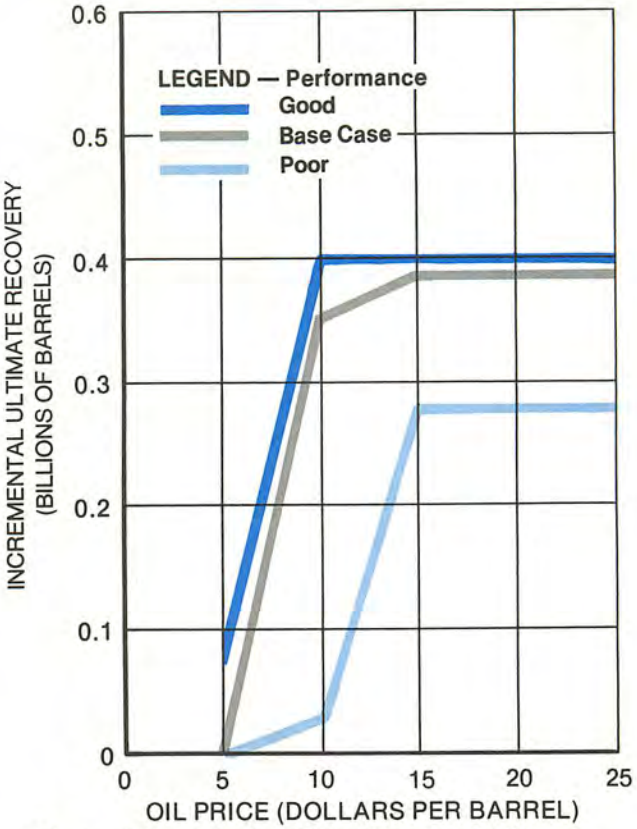


Figure 82. Alkaline Flooding—Variability of Incremental Ultimate Recovery with Reservoir Recovery Performance—Total U.S.

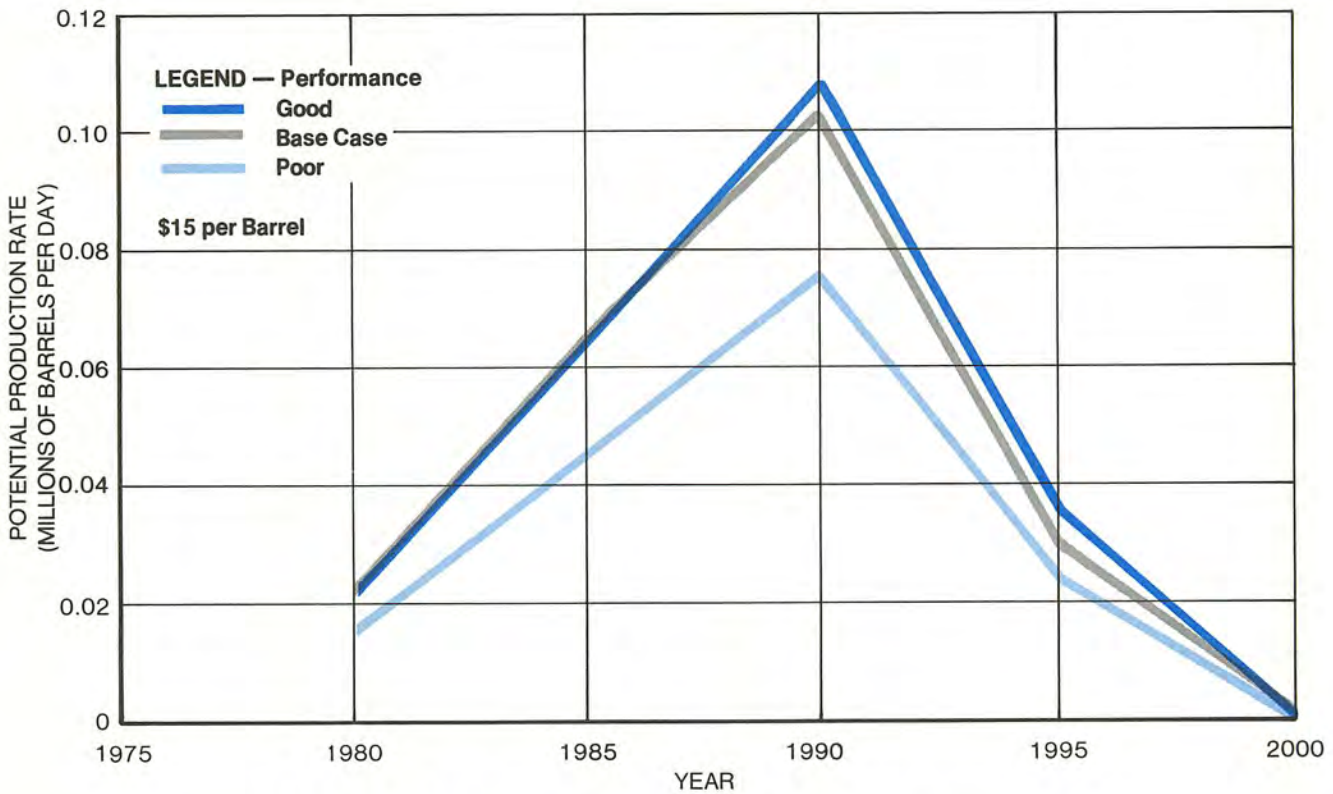


Figure 83. Alkaline Flooding—Variability of Potential Producing Rate with Reservoir Recovery Performance—Total U.S.

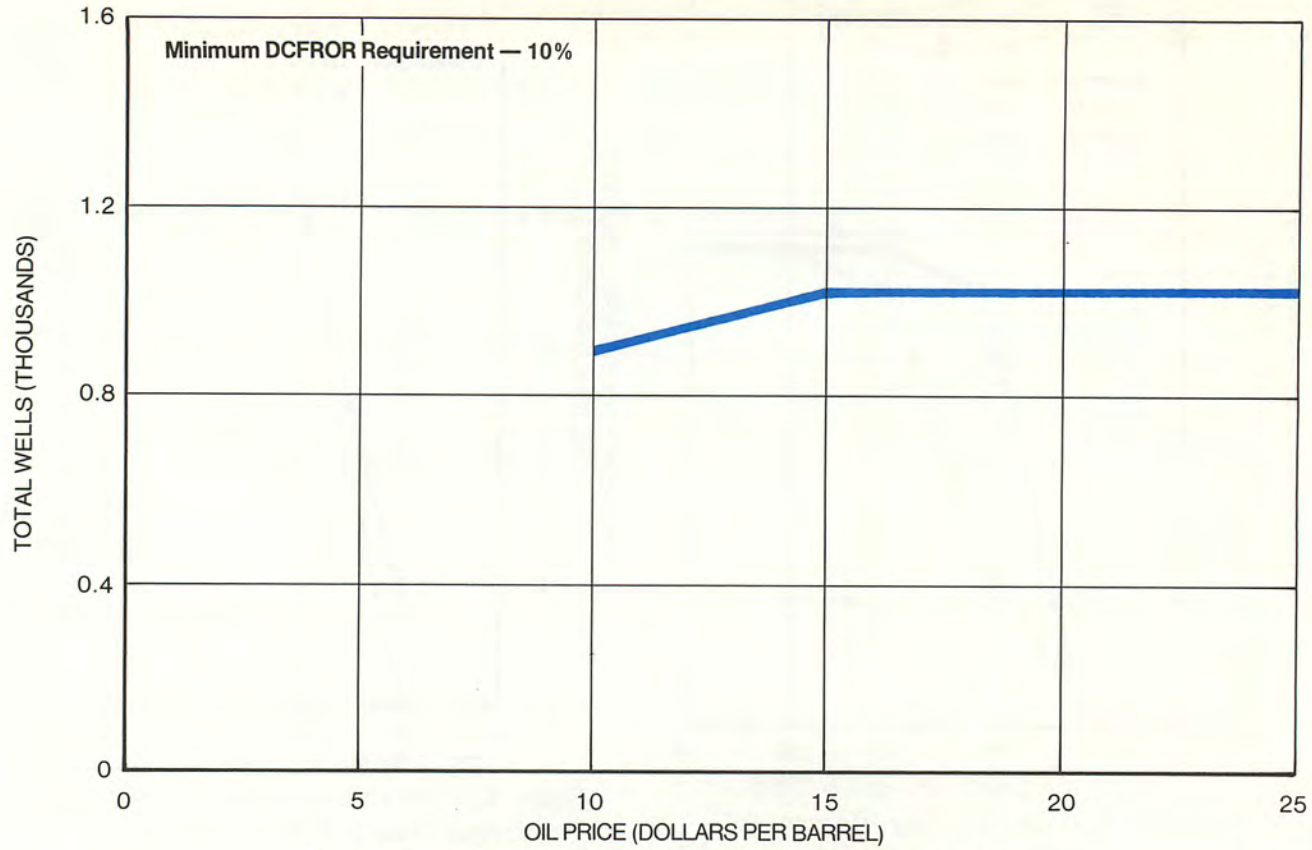


Figure 84. Total Workover Activity—Alkaline Flooding.

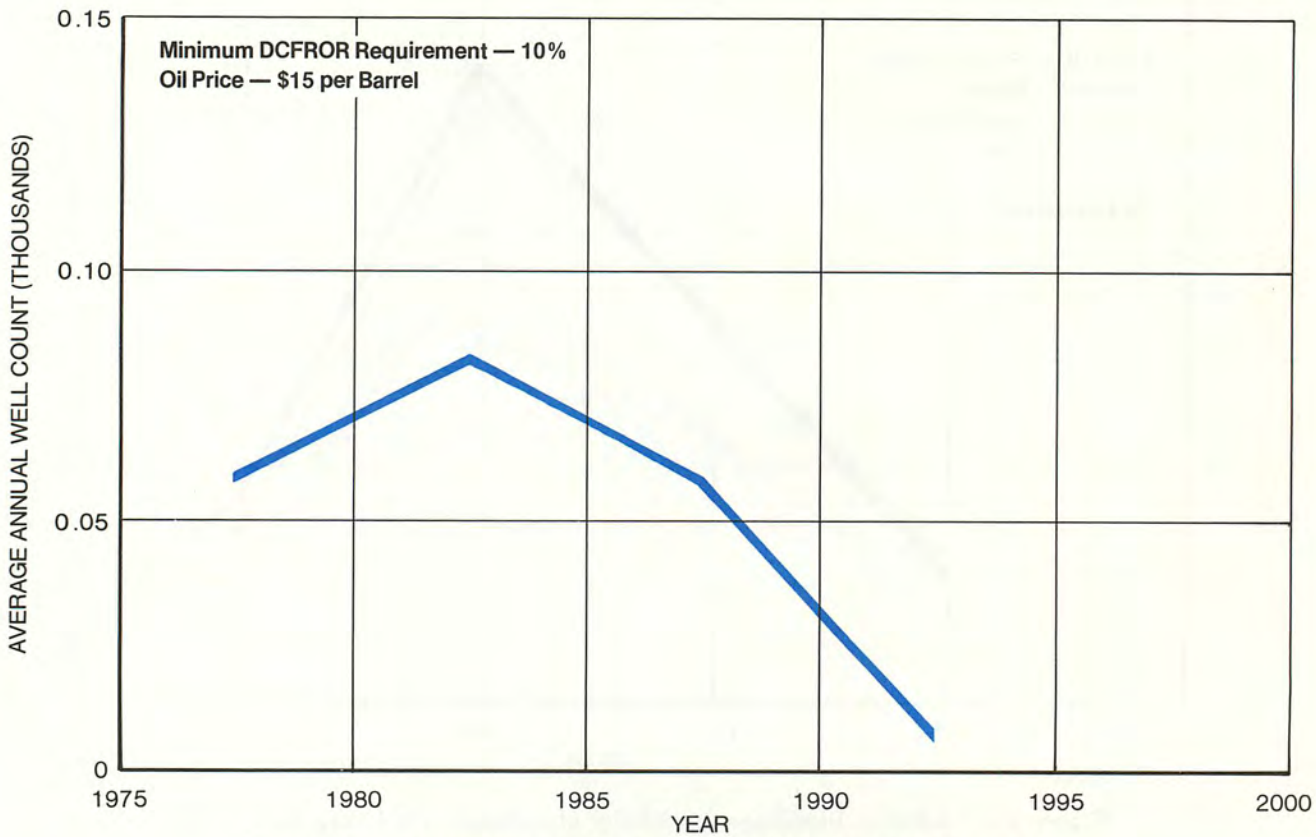


Figure 85. Average Annual Workover Activity—Alkaline Flooding.

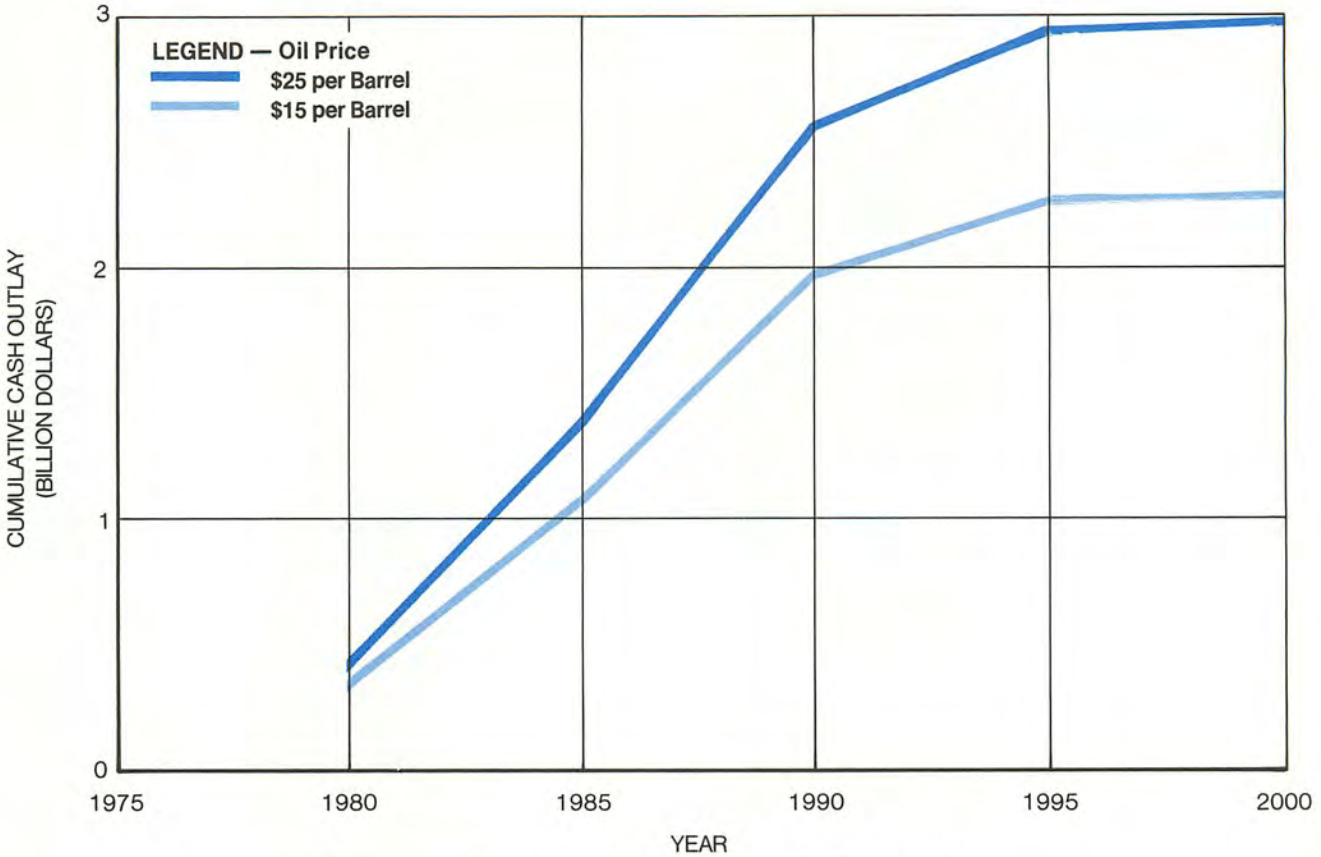


Figure 86. Cumulative Cash Outlay—Alkaline Flooding.

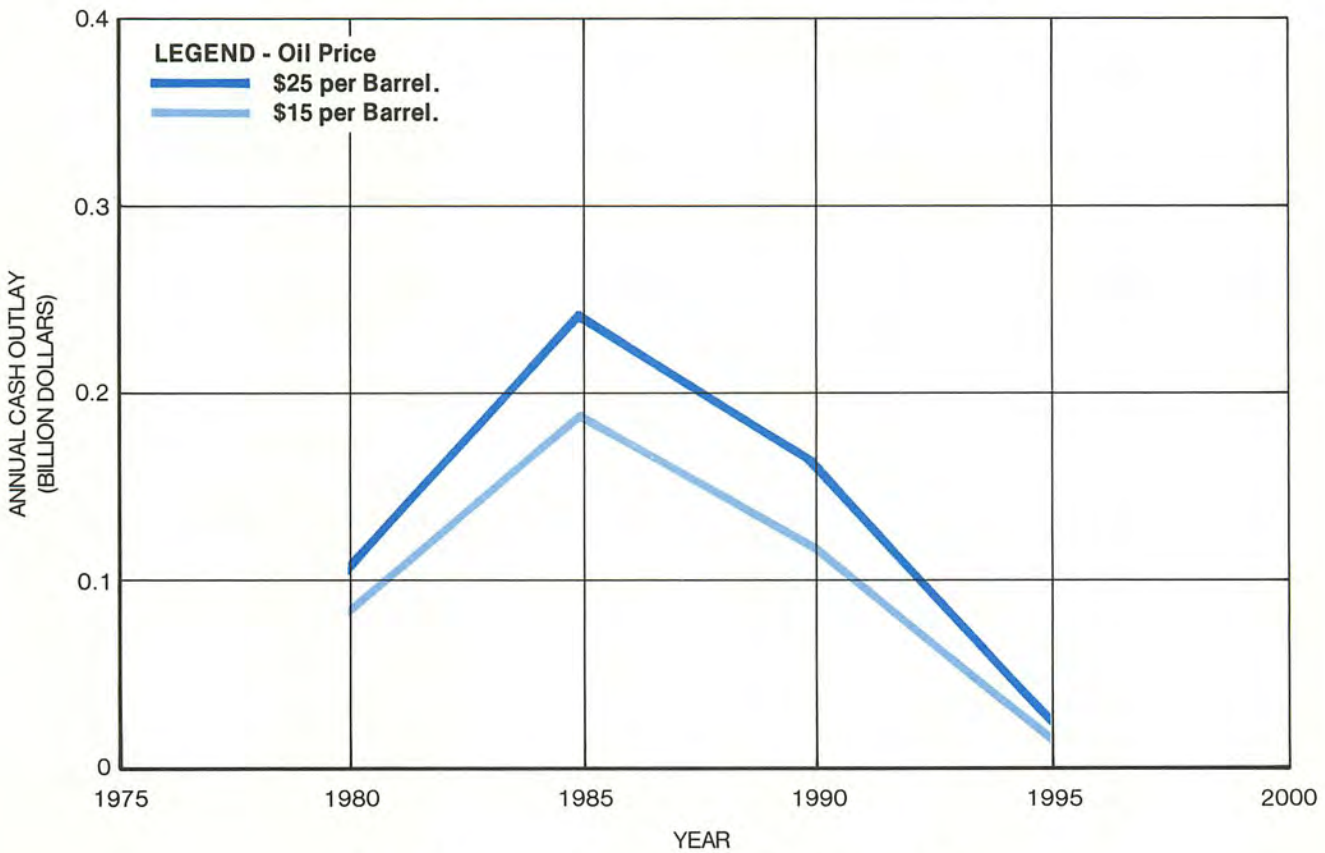


Figure 87. Annual Cash Outlay—Alkaline Flooding.

Environmental Considerations Summary

The two general areas of environmental considerations relative to chemical flooding are: (1) the application of these chemicals to oil reservoirs and the subsequent disposal of any chemicals which may be produced from such reservoirs; and (2) the manufacture of the required chemicals. Materials mentioned in patent literature for chemical flooding application are listed in Tables 32 through 36, although relatively few of these chemicals are likely to be used in practice. Properties for selected chemicals used in current chemical flooding practice are discussed in the section entitled "Health and Environmental Data for Selected Chemicals."

The injection of chemicals into an oil reservoir for enhanced oil recovery is in many ways similar to waterflooding reservoirs for secondary oil recovery,

TABLE 32

CHEMICALS PROPOSED FOR SURFACTANT FLOODING

Commonly used:
- -- Broad spectrum petroleum sulfonates
- -- Synthetic petroleum sulfonates
- -- Sulfated ethoxylated alcohols
- -- Alcohols
- -- Ethoxylated alcohols

TABLE 33

CHEMICALS PROPOSED FOR MOBILITY CONTROL

Commonly used:
- -- polyacrylamide
- -- polysaccharide

Proposed in patents:
- -- Adloses B Series
- -- Aldoses L Series
- -- Carboxymethylcellulose
- -- Carboxyvinyl polymer
- -- Dextrans
- -- Desoxyribonucleir acid
- -- Ketoses B Series
- -- Ketoses L Series
- -- Polyethylene oxide
- -- Polyisobutylene in benzene
- -- Conjugated saccharides
- -- Disaccharides
- -- Monosaccharides
- -- Tetrasaccharides

TABLE 34

CHEMICALS PROPOSED AS BACTERICIDES

Commonly used:
- -- Sodium dichlorophenol
- -- Sodium pentachlorophenol

Proposed in patents:
- -- Formaldehyde
- -- Gluteraldehyde
- -- Paraformaldehyde
- -- Alkyl phosphates
- -- Alkyl amines
- -- Acetate salts of coco diamines
- -- Acetate salts of coco amines
- -- Acetate salts of tallow diamines
- -- Alkyl dimethyl ammonium chloride
- -- Coco dimethyl ammonium chloride
- -- Sodium salts of phenols
- -- Substituted phenols
- -- Sodium hydroxide
- -- Calcium sulfate

TABLE 35

CHEMICALS PROPOSED AS OXYGEN SCAVENGERS

Sodium hydrosulfite
Hydrazine
Salts of Bisulfite

TABLE 36

CHEMICALS PROPOSED FOR ALKALINE FLOODING

Sodium Hydroxide*
Sodium Silicate*
Ammonium Hydroxide
Sodium Carbonate
Potassium Hydroxide

* Most commonly used.

since the injection and disposal of water is involved and many of the same facilities are required. Experience gained from waterflooding makes it possible to conduct injection projects in oil fields with minimum change and uncertainty in environmental impact.

Application and Disposal

Waterflooding has been used extensively for many years, and surfactant flooding will follow or replace waterflooding in existing oil fields; polymer and alkaline flooding most likely will be initiated early in the life of a waterflood, or in lieu of waterflooding. Some of the same chemicals used in chemical flooding have been used previously in waterflooding, including the addition of oxygen scavengers and biocides in the injection water to prevent corrosion and control bacterial growth. Similarly, the addition of emulsion breakers to the produced fluids is currently required in many fields. A great deal of experience already has been obtained with polymer solutions, since over 100 field tests of various sizes have been conducted.

Other chemicals required for chemical flooding but not in routine waterflooding are: the surfactants and alcohols used in surfactant flooding; and the sodium hydroxide and sodium silicate proposed for alkaline flooding. Some surfactants and alcohols are currently used in large quantities for purposes such as household detergents. Although handling of these materials prior to injection into the reservoir will require additional surface facilities, similar facilities are currently used in routine oilfield operations.

In a commercial flood, large quantities of chemicals will be injected; however, as injection will occur over a period of time, the quantity of material on-site will be limited to much smaller quantities (approximately tank car lots or less for liquid solutions). Some materials will be stored on-site as solids. Limited surface leaks or spills are possible, but major spills, resulting in significant surface contamination, are unlikely.

Currently used chemicals are relatively nontoxic. The bactericides and oxygen scavengers exhibit slight to moderate health hazard when handled at high concentration. However, the test data indicate no apparent impact on health when used at the low concentrations normally required for oilfield use.

Only a small fraction of the injected chemicals will be produced during a surfactant or alkaline flood. The amount of surfactant injected will be designed to be slightly more than that retained in the reservoir by adsorption over the large surface-area of the rock. No adverse effect of chemical retention in oil reservoirs is expected, and any produced chemicals remaining in the oil normally will be sent to a refinery and processed as a part of the crude oil. Since produced water normally will be reinjected, chemicals remaining in the produced water will usually be "recycled." Thus, essentially all water containing surfactants and other chemicals will be reinjected into underground formations.

Any surplus liquid effluent or surplus source water will be disposed of so as not to damage the environment and to be in compliance with applicable local, state, and federal laws and regulations. Subsurface disposal into brine-laden formations is a proven, environmentally acceptable technology, which requires a state permit, as does all other subsurface injection. The National Safe Drinking Water Act of 1974 requires that state injection well permit programs assure the protection of freshwater aquifers from pollution by subsurface injection operations.

Before a discharge is made into any surface waters of the United States, a permit must be obtained under the National Pollution Discharge Elimination System, administered by the Environmental Protection Agency (EPA) under the Federal Water Pollution Control Act Amendments of 1972. This Act also provides that the Environmental Protection Agency issue regulations requiring that any discharge of hazardous substances in harmful quantities into the waters of the United States be reported to the appropriate federal agency. The regulations for spills of hazardous substances other than oil have been proposed by the EPA but have not been promulgated. Neither hazardous substances nor harmful quantities have been defined, but the definitions will probably include chemicals commonly used in chemical flooding processes.

In many of the field tests of surfactant flooding conducted thus far, low-salinity or fresh water has been used as a preflush ahead of the surfactant slug, as well as with the surfactant slug and during polymer injection. In some reservoirs, the use of low-salinity or fresh water will continue to be preferred over the use of brines. However, since it is desirable to eliminate the preflush whenever possible, the trend in surfactant flooding is to design systems that will work at the same salinity as the resident reservoir brine. These brines frequently contain salt concentrations much higher than that of sea water and, thus, are unsuited for domestic uses. It is anticipated that this trend will continue, and that a major fraction of future surfactant floods will use water with about the same salinity as the formation brine. The

oil reservoir formation itself will supply much of this brine.

An undetected leak in either an injection well or a producing well provides a potential for release of chemicals and brine into shallower, freshwater sands. The potential environmental impact of such an incident does not appear to be a serious problem for the following reasons:

- Although large quantities of chemicals may be injected into a reservoir, the injection will take place for a limited amount of time (months to years) and only small quantities of injected chemicals will be produced. Thus, the potential consequences of a leak from one or more wells would be minimal.
- Moreover, any chemicals that should leak into shallower sands would rapidly decrease in concentration as they were adsorbed on the surface area of the rock, diluted, and precipitated. It is probable that chemicals from a small leak would remain near the wellbore, primarily because of adsorption of the surfactant on the very large surface areas present in a porous rock.
- Brine would be diluted as it flowed away from a wellbore leak. The consequences of contamination of shallow, freshwater sands by injected brine would be no more nor less severe for chemical flooding than they currently are for conventional waterflooding.

Chemical Manufacturing

The manufacture of chemicals for surfactant flooding will require appropriate controls, similar to the controls on the plants which currently manufacture large amounts of these same chemicals. Appreciable expansion of volume will be necessary if surfactant flooding is applied on a large scale. Large quantities will not be needed until at least the 1980's, however, so some improvement in the process for manufacture of surfactants may be anticipated. The polymers generally used at present are either polyacrylamides or polysaccharides, although other types of polymer may be developed in the future. The polyacrylamides are currently manufactured on a large scale and used for a variety of purposes, including the use of small amounts in food processing. Currently, the primary use of polysaccharide (xanthan gum) is as a food additive. Neither type is expected to introduce any environmental problems. The expansion of alcohol and polymer manufacturing facilities required is somewhat smaller, relative to current manufacturing capacity, than is required for surfactant manufacturing.

In conclusion, the environmental considerations for chemical flooding will be similar to those for existing oil fields. It will be necessary to observe standards required (1) in the manufacture of the same (or very similar) chemicals currently used for many other purposes, and (2) in the practice of waterflooding, which is already used on a large scale. The manufactured volumes of these chemicals, however, must be increased. The major application of chemical flooding will be to currently producing oil reservoirs, generally following waterflooding of these reservoirs. Therefore, many of the necessary facilities (such as pipelines) will already be in place.

Health and Environmental Data for Selected Chemicals

The information which follows describes health and environmental responses to some of the commonly used chemicals in chemical flooding, and is extracted from OSHA and other published reference material listed in the bibliography for this appendix.

Polysaccharides (Xanthan Gums)

Health: Skin and eye irritation studies indicate that xanthan gums are not an irritant or sensitizing agent. Acute oral toxicity tests showed that xanthan gums produced no mortality, signs of toxicity, or changes in the internal organs of rats and dogs which were given doses as great as 45 grams per kilogram (g/kg) of body weight for rats and 20 g/kg of body weight for dogs, respectively. Histopathological observations in rats, subjected to long-term (104-105 weeks) oral administration of xanthan gums, indicated that no distinguishable differences between the control and test groups could be observed.

Environmental: For fish and other aquatic life, the primary detrimental effect of sugar derivatives arises from their high biological oxygen demand (BOD). It has been reported that concentrations of 34 to 218 milligrams per liter (mg/1) in distilled water caused the death of minnows in 24 to 48 hours. In addition to harmful effects by deoxygenation, sugar derivatives are sometimes detrimental in industrial process waters. It has been reported that boiler feed water should contain not more than 0.5 mg/l of sugar derivatives, since they cause foaming and the deposition of a film of decomposition products on the boiler walls.

Usage Concentrations: Polymer concentrations may be varied from 250 ppm to 1,500 ppm in water for polymer flooding processes. The polymers are shipped as a liquid, at a concentration of less than

3.0 percent by weight, or as a powder, at a concentration of 80 percent or greater by weight of active ingredient.

Polyacrylamides (Molecular Weight: 2.5 to 15.0 Million)

Health: These materials, since they are slightly alkaline, may cause only minor irritation to the eyes and essentially no irritation to the skin in cases of direct contact. However, goggles should be worn when handling these polymers. Acute oral toxicity tests show that LD_{50}* for rats is greater than 4 g/kg of body weight. Estimating from these data, the lethal dose for a 100-pound person is more than 6 ounces. However, the chances of a person swallowing this quantity is very unlikely, due to gelling characteristics of the polymers.

Environmental: The polyacrylamides meet government requirements for food and potable water uses. In addition, the polyacrylamides are used for washing fruits and vegetables, and clarification of cane or beet sugar juices; therefore, their effects on crops or wildlife should be negligible.

Usage Concentrations: Polymer concentrations may be varied from 250 ppm to 1,500 ppm in water for polymer flooding applications. The polymers are shipped as a powder, at a concentration of 80.0 percent by weight or greater, or as a liquid, at a concentration of 25-35 percent by weight active ingredient.

Bactericides (Sodium Pentachlorophenate and Sodium Salts of Other Chlorophenols)

Health: Eye contact can cause moderate to severe irritation and moderate to severe corneal damage. A burn, and perhaps acne-form dermatitis, can occur with prolonged skin contact; these chemicals may be absorbed through the skin. The LD_{50} for rabbits is 100-300 mg/kg of body weight, and for rats is 210 mg/kg of body weight. The lethal dose for adults is estimated to be 8 to 15 grams. The dust from these chemicals is extremely irritating. Therefore, chemical goggles, rubber gloves, rubber aprons or jackets, and dust respirators must be worn to prevent skin contact, eye contact, or inhalation.

Environmental: The presence of these chemicals in irrigation water is not considered deleterious to crops. The chemicals may affect fish in two ways: first, by a direct toxic action; and second, by imparting a taste in the fish meat.

The following concentrations will not interfere with the designated beneficial uses: (1) domestic water supply—0.001 mg/l; (2) irrigation water—50 mg/l; (3) stock watering—1,000 mg/l; (4) fish and aquatic life—0.2 mg/l.

Usage Concentrations: The concentrations of bactericides used in polymer solutions may be varied from 25 ppm to 250 ppm. These bactericides are shipped in a flake or bead form at concentrations of 80 to 95 percent by weight active ingredient.

Oxygen Scavengers (Sodium Hydrosulfite)

Health: No LD_{50} is available; however, the amounts of chemicals which might be swallowed accidentally in industrial handling should not cause injury. Eye contact may cause pain, irritation, and slight corneal injury. Single short exposure on skin should not cause significant irritation. Several prolonged exposures may cause the development of some minor irritation.

Environmental: The effects of these chemicals have been tested extensively on animals and fish. A concentration of 15 g/l in the drinking water of rats caused no apparent injury. A lethal concentration to goldfish in 96 hours at 18-23°C has been reported to be 100 mg/l. However, concentrations up to 260 mg/l at pH of 5 to 9 have been observed to be harmless to young carp. The toxic threshold concentration of these chemicals for the flatworm was found to be 7,850 mg/l.

Usage Concentrations: The concentrations of the oxygen scavengers used in polymer solutions may be varied from 20 ppm to 100 ppm. These chemicals are shipped as a powder at 93 percent by weight active ingredient.

Sodium Hydroxide

Health: The taste threshold of sodium hydroxide in water is reported to be 1 to 50 mg/l. A dose of 1.95 grams of sodium hydroxide can cause death in man. The most serious effect of sodium hydroxide at 50 percent by weight of active ingredient is corrosion of body tissues. Eye and skin contact can cause very serious burns. Goggles, rubber gloves, rubber apron and rubber boots must be worn when handling sodium hydroxide.

Environmental: The effects on stock and wildlife have been investigated. The data indicated that the sodium hydroxide at a concentration of 5 g/l

*LD_{50} is defined as the amount of chemical that will be lethal to 50 percent of the test animals.

was almost harmless to rats. However, a concentration of 10 g/l caused nervousness, sore eyes, diarrhea, and retarded growth in rats. A toxicity study for fish and other aquatic life showed that the toxicity threshold concentration was in the range of 20-200 mg/l for all aquatic life.

Usage Concentration: The range of concentration used in alkaline flooding processes is 1,000 ppm to 50,000 ppm. Sodium hydroxide usually is shipped as a liquid at a concentration of 50.0 percent by weight (approximately 500,000 ppm).

Sodium Silicate

Health: Sodium silicate has been shown to have a moderate, single-dose, oral toxicity. The most harmful effect from ingestion is its corrosive action on the mouth, esophagus, and stomach. Eye contact causes irritation and can cause some permanent loss of vision. Skin contact can result in a burn, even on short contact. Therefore, chemical goggles, rubber gloves, rubber apron and face shield must be worn when exposure is likely.

Environmental: The Water Pollution Research Board of England has determined that sodium silicate was not lethal to fingerling Rainbow trout at a concentration of 256 mg/l. Wallen, et al., found that the 96-hour toxicity threshold limit concentration for the mosquito fish was 2,320 mg/l. Sodium silicate is strongly basic and should be handled and treated with the same precautions as sodium hydroxide.

Usage Concentration: The range of concentration used in alkaline flooding processes is 1,000 to 10,000 ppm. Sodium silicate is shipped as a liquid at a concentration of 38 percent by weight.

Broad-Based Sulfonates (Broad Spectrum Petroleum Sulfonates and Synthetic Petroleum Sulfonates)

Health: Eye contact may cause conjunctival irritation and slow-healing corneal injury. The LD_{50} for the sulfonates varies from 2.5 to 10.8 g/kg of body weight. With these values, the amounts of sulfonates which might be swallowed accidentally in industrial handling should not cause injury. Petroleum sulfonates interact with the skin to cause irritation and increase permeation or absorption by other compounds. Inhalation toxicity is not normally a problem, but care should be exercised to minimize inhalation. Chemical goggles, rubber gloves, rubber apron or jacket, and chemical respirator must be worn when handling petroleum sulfonates. The taste threshold of sulfonates in water is reported to be 0.6 to 1.4 mg/l.

Environmental: Numerous investigations show that sulfonates have lethal effects on fish at concentrations of 0.2 to 180 mg/l. Feeding studies with rats indicate that the toxic dosage of sulfonates is quite high. Adverse effects were found with 0.5 percent sulfonates in the diet. Growth of rats was retarded at 1 and 2 percent levels; however, no malformations were observed in their offspring. Toxic levels of sulfonates have not been determined for humans. However, these substances are regarded as relatively nontoxic, and, in the United States, up to 0.5 mg/l is regarded as safe for drinking water.

Concentrations: Sulfonate concentrations may be varied from 3 to 10 percent by volume for microemulsion flooding applications. The sulfonates are shipped as a liquid at 30 to 80 percent by weight of active ingredient.

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Surfactant Flooding

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Appendix E
Carbon Dioxide Miscible Flooding Process

State-of-the-Art Assessment

Background—Prior Oil Recovery Methods Employing Gas Injection

Injection of a gas into an oil reservoir to improve oil recovery is not a new idea. A traditional technique has been to inject natural gas or water to delay the pressure decline as oil is produced. In addition to delaying pressure decline, the injected gas normally displaces oil and drives it to producing wells. Some of the gas produced with the oil is reinjected. This displacement of oil by gas usually has been conducted at a pressure sufficiently low that immiscible displacement of oil by the gas occurred.

Beginning in the early 1950's and continuing into the 1960's, an improved method of recovery by hydrocarbon gas or liquid injection, called miscible displacement, was researched and pilot tested. In miscible displacement the normally gaseous material is injected either at high pressure or is of such a composition that it acts as a solvent for the oil. Under these conditions, interfaces and capillary forces between the oil and gas are essentially eliminated.

Under miscible displacement conditions, the injected solvent can displace most of the oil from the pore space of the reservoir rock contacted by the solvent. By displacing enough water to contact and mobilize the oils, a miscible injection fluid can even displace the residual oil left in the water-invaded portion of a waterflooded reservoir. Thus, miscible displacement can be used to recover tertiary oil.

Various miscible displacement processes using hydrocarbon gases and liquids have been extensively researched in the laboratory, and there have been over 75 field tests of hydrocarbon miscible flooding processes. Based upon the knowledge accumulated from these trials, it appears that hydrocarbon miscible flooding will play a very limited role in future oil recovery. The volume of oil recovered relative to the volume of hydrocarbons injected is not generally great enough to offset the current and projected high value of the hydrocarbon solvents. Hydrocarbon injection fluids also are in short supply and will not be available in the quantities required for large-scale oilfield flooding in the United States.

Oil Recovery Using Carbon Dioxide

Carbon dioxide gas is a favorable alternative injection fluid for increasing oil recovery. Perhaps the most important characteristic of CO_2 is its ability to extract, or vaporize, hydrocarbons from reservoir oils. In addition, it is soluble in oil, and the solubility increases as pressure is increased. The dissolved carbon dioxide swells the oil, increasing its volume. This results in less original liquid being left in the reservoir for a given final reservoir fluid saturation. Solution of CO_2 also can cause a large reduction in oil viscosity. These swelling and viscosity-lowering phenomena make the oil flow more readily, and can result in better recovery.

Immiscible Carbon Dioxide Flooding

Because of these characteristics, CO_2 may cause an immiscible displacement of oil that is more efficient than immiscible displacement with other gases, such as natural gas or flue gas. Immiscible displacement of oil by carbon dioxide probably is best practiced in reservoirs that have not been waterflooded; it may be considerably less efficient in recovering the

residual oil left by waterflooding. It is doubtful that in most reservoirs immiscible CO_2 flooding would significantly increase recovery over that achieved by waterflooding.

Another use of CO_2 is for the solution gas drive recovery of relatively low-gravity, viscous oils. In this method, CO_2 is injected at high pressure; it dissolves in the oil and reduces the crude's viscosity. The same well is then produced, and as the pressure is lowered, CO_2 comes out of solution, driving oil into the well. This is, in effect, a well stimulation method.

Little information has been reported on the immiscible recovery aspects of carbon dioxide flooding, and it is not expected to make a major contribution to U.S. oil production. However, a field test of well stimulation and subsequent immiscible flooding with CO_2 currently is in progress in the Lick Creek field in Arkansas.

Miscible Carbon Dioxide Flooding

The bulk of industry research and field testing of carbon dioxide has been directed toward miscible displacement, and this method of using CO_2 appears to have the greatest potential for recovery of oil that would not have been recovered by conventional producing methods. However, the potential for this method will be significant only if carbon dioxide can be found in enough quantity to treat a large number of fields, and if the carbon dioxide can be delivered to these oil fields at a low enough cost to be offset by the value of incremental oil recovery that may be attained.

Miscible displacement between oil and carbon dioxide results from hydrocarbons vaporizing from the oil into the carbon dioxide. At a sufficiently high pressure, this vaporization occurs to such a degree and so alters the composition of the invading gas front that miscibility results between the two otherwise immiscible fluids. Miscible displacement with carbon dioxide is considered to be a conditional, or dynamic, miscibility, since carbon dioxide is not directly miscible with oil on first contact. Mixing due to flow in the reservoir tends to alter and destroy the miscible composition; therefore, this composition must then be reestablished by additional vaporization of hydrocarbons. The pressure at which miscible displacement occurs depends upon reservoir temperature, oil composition, and purity of the CO_2. The presence of methane or nitrogen can drastically increase the pressure required for miscibility, whereas the presence of hydrogen sulfide or hydrocarbons of molecular weight greater than methane can reduce the pressure requirement.

In addition to defining the mechanism by which miscibility occurs and the factors that influence the level of miscibility pressure, research has demonstrated that in laboratory rocks, at pressures above the miscibility pressure, carbon dioxide will displace most of the residual oil left after waterflooding. Research on hydrocarbon miscible displacement has shown that the sweep efficiency of a miscible displacement injection fluid depends upon the viscosity ratio between the oil and solvent, upon the degree of gravity segregation of the solvent caused by density contrasts, and upon the spatial distribution of the permeability; this applies to carbon dioxide miscible displacement as well.

As oil viscosity increases relative to the viscosity of carbon dioxide, there is a greater tendency for the carbon dioxide to channel, or finger, through the oil, thereby reducing volumetric contact of the reservoir. The influence of an unfavorable viscosity ratio is compounded by heterogeneity of the reservoir rock, and the normal tendency for injected fluids to flow through the more permeable sections of the rock is aggravated.

Injection of water, either simultaneously or in small, alternate slugs with the carbon dioxide, is under field test as a potential technique for improving volumetric sweepout. The water interferes with the flow of CO_2 through the reservoir rock and, for practical purposes, causes the CO_2 to behave as if it had a higher viscosity. However, published research has also demonstrated that, under certain conditions, injection of water to improve volumetric contact efficiency may interfere with the ability of the carbon dioxide to displace oil from the pore spaces of the rock, apparently by preventing the CO_2 from contacting some of the oil-filled pore spaces. Whether or not water injection interferes with the displacement seems to depend upon the properties of the reservoir rock and upon the injection ratio of water to CO_2.

Gravity segregation of the injected fluid is another factor that is recognized to reduce volumetric contact efficiency in miscible flooding. The densities of oil and carbon dioxide are similar at many reservoir conditions; this tends to minimize segregation between these fluids in reservoirs that have not been waterflooded. In reservoirs that have been waterflooded or have had water injected with the carbon dioxide to counteract the effects of viscosity ratio and permeability stratification, the density contrast between the water and CO_2 may result in gravity segregation, which causes the CO_2 to flow preferentially in the upper part of the reservoir. Under these conditions, the severity of segregation depends upon the effective vertical flow permeability and the distribu-

tion of horizontal permeability variations of the rock, reservoir properties that are rarely known with much certainty.

Although there has been extensive research on hydrocarbon miscible displacement and considerable research on carbon dioxide miscible displacement, the effectiveness of CO_2 miscible flooding remains largely unproven. Only a few of the field tests of hydrocarbon miscible flooding have evaluated the dynamic miscibility process, where vaporizing oil components create a miscible fluid composition. Few field tests of miscible carbon dioxide flooding have been conducted, especially as a tertiary oil recovery method. A number of these tests, however, are currently in progress, and several additional tests are planned for the near future. Limited-area tests have been conducted in the Mead-Strawn and Wasson fields of West Texas, and a small tertiary oil recovery pilot test was conducted in the SACROC Unit of the Kelly-Snyder field in West Texas. Larger, secondary oil recovery floods are in progress in the SACROC Unit and in the Crosset field in Texas. Tertiary oil recovery tests are in progress or have been completed in the Little Creek field, Mississippi, and in the South Gillock and Two Freds fields in Texas.

Before the potential of current CO_2 flooding technology can be assessed fully, three rather broad questions remain to be answered: (1) which methods for practicing CO_2 miscible flooding are the most effective; (2) how many barrels of additional oil can be recovered per volume of CO_2 injected; and (3) how is this recovery ratio influenced by the stage of prior waterflooding and by reservoir rock and oil properties? Of course, in addition to these questions concerning technology, the availability and cost of CO_2 affect the potential of the method.

Because carbon dioxide is more costly than water, project designs attempt to minimize the amount used. Currently some designs call for injection of a predetermined volume of carbon dioxide injected as a slug and followed by continuous water injection. The water immiscibly displaces the CO_2, leaving part of it as a residual saturation in the reservoir. In some cases, it may be necessary to inject the water first, in order to raise the reservoir pressure to that required for miscibility. Other plans call for alternating CO_2 and water in the same injection well until the desired volume of CO_2 has been injected, in order to improve volumetric contact. After the alternating cycles of CO_2 and water, continuous injection of water is commenced. Still other plans call for alternate injection of CO_2 and water, to be followed by the alternate injection of another gas, such as flue gas or methane with water to achieve a miscible displacement at the trailing edge of the CO_2 slug, and thereby reduce CO_2 requirements.

A great deal of uncertainty remains concerning the magnitude of incremental oil recovery that will result for a given volume of CO_2 injected. In a tertiary oil recovery flood the concept of additional oil recovery is straightforward. Even when carbon dioxide flooding is used as a secondary oil recovery process, in most situations waterflooding is an alternative method for producing the oil. Incremental oil recovery above that which could have been produced by waterflooding still is a measure of the effectiveness of the process. The volume of carbon dioxide required to achieve the incremental oil recovery is critical, since the cost for carbon dioxide usually will be the dominant cost element in this method.

Numerous factors can influence the magnitude of incremental oil recovery and the volumetric ratio of oil recovered to CO_2 injected. Many of these factors will vary from reservoir to reservoir, and some may be influenced by the extent of prior waterflooding. The degree of reservoir stratification (and other heterogeneities) influence the miscible sweep, or the ability of the CO_2 to contact the reservoir volume effectively. The type and location of heterogeneities vary appreciably, both from reservoir to reservoir and within a reservoir. The degree of gravity segregation of the CO_2 from water also influences miscible sweep, and the severity of gravity segregation depends strongly upon the ratio of vertical to horizontal permeability, which also can vary appreciably among and within reservoirs.

Incremental recovery depends upon several factors: the waterflood residual oil saturation; the final oil saturation in the carbon dioxide-flushed region; the efficiency with which the displaced oil can be "captured" by the producing wells; and upon the loss of displaced oil due to resaturating low oil-saturation zones. Some disagreement also remains concerning how much CO_2 must flow through a unit volume of rock before the oil is reduced to its final saturation.

Information from field testing is still too scant to permit confident projections; and while sophisticated reservoir simulation models have been devised to project recovery performance, they are highly subject to interpretive application. Therefore, appreciable diversity of opinion exists within the oil industry concerning expected performance of carbon dioxide flooding. While a great deal is known already about the theoretical aspects of this recovery method, the effectiveness and versatility of the method in field operations remain to be demonstrated.

Screening Criteria

Process Feasibility

A screening procedure for CO_2 flooding was developed for miscible flooding; other methods using CO_2 were not analyzed in this study. The primary considerations were that the pressure required for miscible displacement be attainable in the reservoir, and that oil viscosity be low enough that severe channeling of the carbon dioxide would not occur.

Miscibility pressure is influenced by oil composition, reservoir temperature, and purity of the carbon dioxide; it is determined in the laboratory, using the actual reservoir fluid and injection gas. Whether or not the required miscibility pressure is attainable in a specific reservoir usually depends upon the limiting pressure at which the reservoir rock will fracture, or the pressure at which existing, propped, open fractures in injection wells will grow and extend. Miscibility pressure should usually be at least several hundred pounds per square inch (psi) below this pressure limit and to allow for pressure drops in the reservoir. In some reservoirs, the reservoir pressure may be the limiting pressure.

A rough formula was devised for estimating whether or not miscibility pressure was attainable, based on oil gravity (a rough measure of oil composition), reservoir temperature, and reservoir depth. These data were usually available from the Lewin & Associates data sheets. The procedure for estimating pressure required for miscible displacement was as follows:

- **Miscibility Pressure Versus Gravity**

Gravity (°API)	Miscibility Pressure (Pounds per Square Inch)
27°	4,000
27°-30°	3,000
30°	1,200

- **Correction for Reservoir Temperature**

Temperature (°F)	Additional Pressure Required (Pounds Per Square Inch)
120°	None
120-150°	+ 200
150-200°	+ 350
200-250°	+ 500

To estimate whether or not miscibility was attainable in each reservoir, the limiting fracturing pressure was estimated by multiplying the reservoir depth by an assumed fracturing gradient of 0.6 psi per foot of depth. A safety factor of 300 psi was subtracted from this limiting pressure to estimate a likely attainable pressure.

The screening procedure applied to each data base reservoir to determine process feasibility followed this sequence:

- Calculate miscibility pressure required.
- Calculate attainable reservoir pressure. Reject reservoirs when attainable pressure is less than miscibility pressure.
- Reject reservoirs in which oil viscosity was greater than 10 centipoise.

In addition, the following criteria were considered whenever the data were available:

- No natural reservoir fractures should be present.
- No extremely high-permeability, stratigraphic, thief zones should exist.
- Only a minor gas cap would be acceptable (unless isolated by an impermeable zone).
- Bottom water drive should be weak or minor.

This initial, simple screening of the 245 reservoirs in the data base indicated that 165 might be candidates for CO_2 flooding.

Review of Fields

The reservoirs that passed the first screening were reviewed qualitatively for other factors that might influence the probable success of CO_2 flooding in those reservoirs. This second screening consisted of the following procedure:

- Review by industry geologists and reservoir analysts for factors such as geology and depositional environment, severity of heterogeneity, fractures, vugs, complex faulting, likely influence of gas caps, success of past waterflooding, etc. (These reviews were not detailed, and judgments were subjective.)
- A cursory performance review from state production and secondary recovery publications. (This resulted in additional reservoirs being screened out because of large gas caps, exceptionally good natural water drives that may have resulted in low residual oil saturations, and, in some cases, apparently poor waterflood performance.)

As a result of this second review, it was discovered that the data base for fields in South Louisiana, South Texas, and California was incomplete and

inadequate. These fields actually consist of many reservoirs of complex geologic zones, fault blocks, and lenses. Only 50 percent of the original oil in place (OOIP) was considered a likely target for CO_2 flooding in reservoirs of this description that passed the initial technical and geologic screens. A further discussion of these reservoirs is presented in the section, "Detailed Description of Process Analysis Procedures," later in this appendix.

After reviewing all the information from the first and second screenings, each reservoir remaining was classified as either a "good," "fair," or "poor" candidate for CO_2 flooding. This classification, although based on consideration of all the information in the review, was also largely judgmental. These classifications were later utilized in performance projections, discussed in the "Detailed Description of Process Analysis Procedures" section of this appendix. The second screening resulted in 109 reservoirs out of the original 245 remaining as candidates for CO_2 flooding.

Dominance with Other Processes

After completion of the second screening it was found that 37 of the 109 CO_2 flood candidates were also candidates for other processes. A final assignment of these reservoirs was made, based upon the dominance criteria discussed in Chapter Two. This resulted in 26 candidates being rejected for CO_2 flooding and being included in the estimates for other processes. The results from the complete screening process are shown in Table 37.

TABLE 37

SCREENING PROCESS RESULTS, CO_2 FLOODING

State	Number of Reservoirs			Original Oil in Place (Thousands of Barrels)
	Good	Fair	Poor	
Texas	15	20	27	34,015
Louisiana	0	1	13	4,851
California	0	3	4	2,299

While the screening procedures were felt to be the best that could be devised with the available data, undoubtedly some reservoirs included will not prove to be technically suitable, and some excluded could prove to be floodable with CO_2. However, it is thought that the sample is sufficiently large that estimated outcomes are realistic.

Process-Dependent Economic Parameters

Sources and Costs of Carbon Dioxide

The following potential sources of carbon dioxide for oilfield flooding were considered in this report:

- Naturally occurring, either associated with natural gas or in nearly pure CO_2 reservoirs
- By-products from chemical and fertilizer plants
- By-products from future coal gasification plants
- Power plant stack gas
- Manufactured CO_2.

Manufacture of CO_2 or separation from power plant stack gas and subsequent transport to the oil field appeared to be prohibitively expensive for the oil price range examined in this study. Future coal gasification plants could supply a significant quantity of CO_2 as a by-product. However, the number of plants and the time frame in which they will be built, are so uncertain that they were not considered as likely primary sources for this study. Chemical and fertilizer plants offer a limited carbon dioxide supply in relation to the needs for large-scale oilfield flooding. The most plausible source of adequate volumes of CO_2, at a cost low enough for carbon dioxide flooding, appears to be from either existing known and undeveloped sources of naturally occurring CO_2, or from future such discoveries.

There are several areas in the United States where CO_2 is known to occur naturally. Figure 88 was prepared from public sources [21,22] and illustrates locations of wells that have produced significant concentrations of CO_2. Actual CO_2 reserves that might be contained in these various geographical areas are unknown. While there is known CO_2 production from natural gas fields in the Delaware basin and Val Verde basin areas of Southwest Texas, most of this appears to be committed to the SACROC CO_2 flood,[23] with relatively minor quantities left for any additional flooding. For this study, the assumption was made that if an aggressive effort were undertaken to explore for carbon dioxide, in time, enough could be found to satisfy the national requirements for oilfield flooding. Furthermore, for cost-estimating purposes, the assumption was made that future large reserves of naturally occurring CO_2 most likely would be located in the Four Corners area, the Northeast New Mexico-Southeast Colorado area, and Central Mississippi, and would occur in reservoirs of high-purity CO_2. It is believed that future CO_2 finds in Southwest Texas will result from exploration for natural gas and that the CO_2 will be

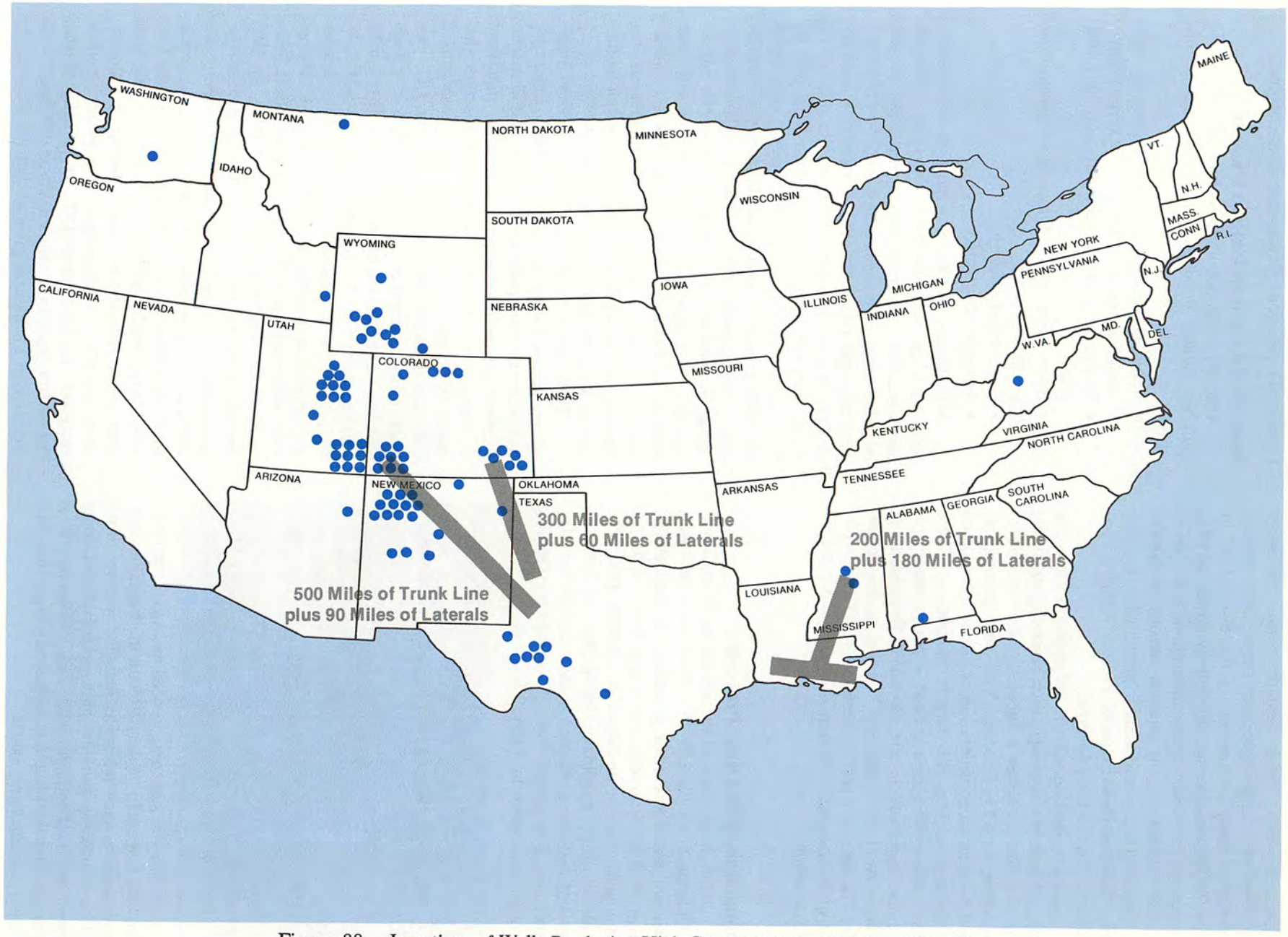


Figure 88. Locations of Wells Producing High Concentrations of Carbon Dioxide.

found as a contaminant in this gas. These discoveries will not be the result of a concentrated search for CO_2. Thus, smaller volumes in this area might be found over a longer interval of time than in the other areas.

The delivery of carbon dioxide from source to oil field can be accomplished either via pipeline or by refrigerated truck or tank car. By far the most economical delivery of the large volumes required for oilfield flooding is by pipeline. However, large projects, perhaps involving a number of oil fields committed to use a substantial quantity of CO_2, may be necessary to justify the large capital outlay required to deliver CO_2 via pipeline. The cost of CO_2 transportation via pipeline depends upon the distance and terrain the line must traverse, upon the throughput rate, and upon the life of the line. For estimating purposes, an average 20-year pipeline life was assumed.

To estimate the cost of CO_2 delivered to a particular oil field (the base CO_2 cost), the field was first classified as to mode of delivery, i.e., whether the CO_2 would be delivered via pipeline, truck, or tank car. This judgment was made after examining the scaled-up CO_2 requirements projected for various geographical areas. Based upon the scaled-up requirements and the distance to the assumed natural sources, rough estimates were made of delivered CO_2 cost. The judgment was then made whether or not a pipeline to the area was likely in view of the volume required and likely cost. If a pipeline seemed feasible, the estimated pipeline-delivered cost for CO_2 was assigned to that group of fields; if not, a truck-delivered cost estimated to be $2.75 per thousand standard cubic feet (Mscf) was assigned.

The cost for naturally occurring CO_2 delivered to various geographical areas was estimated from three components: (1) cost of capital and operating expense to develop and produce the CO_2 source; (2) cost of capital and operating expense to compress the CO_2 to pipeline pressure; and (3) cost of capital and operating expense for the main pipeline and laterals. The cost to develop a CO_2 source depends upon many factors, such as reservoir depth, location, and number of wells required to supply the demanded producing rate. The cost for compression per unit of gas depends upon the inlet pressure at which the CO_2 can be supplied to the compressors and the desired discharge pressure of the compressors into the pipeline.

Several assumed combinations of reservoir depth and pressure, producing well flow rates, and delivery pressure to the compressors were calculated. The resulting cost estimate for CO_2 produced and compressed to pipeline pressure was typically $.22 per Mscf. This cost was based on the assumption that a 15 percent discounted cash flow rate of return (DCFROR) on invested capital for field development would provide sufficient incentive to explore for and develop the CO_2 fields. The cost to transport and distribute the CO_2 from the assumed sources to various geographical areas was estimated for the various distances involved and for supply rates consistent with the demand estimated to be required for flooding. An 8 percent rate of return on the pipeline investment was required. Cost of energy required for initial compression and for pipeline booster stations was escalated with oil price. The base case costs for CO_2 used in the economic analyses for various geographical areas are shown in Table 38. Assumed locations for pipelines are shown in Figure 88. Cost elements for pipelines and compressors are given in Table 39.

TABLE 38

BASE COST FOR CARBON DIOXIDE DELIVERED TO VARIOUS GEOGRAPHICAL AREAS
(Dollars per Thousand Cubic Feet)

Geographical Area	Carbon Dioxide Cost
Texas	
Districts 2, 3, 4, 5, 6	2.75
Districts 7C, 8, 8A, 9, 10	0.65
Louisiana	2.75
	1.0± if pipeline should be built from Mississippi
California	2.75
Oklahoma	1.50 for ½ of reservoirs
	2.75 for ½ of reservoirs
New Mexico	0.65
Colorado	1.50 for ½ of reservoirs
	2.75 for ½ of reservoirs
Utah	0.50
Mississippi	1.50
Others	2.75

Oilfield Costs

To practice carbon dioxide flooding, additional costs in the oil field will be incurred above the normal costs for primary production and waterflooding. Additional wells may need to be drilled to reduce project life (thereby accelerating return on the initial investment for injected CO_2) and to achieve regularly developed patterns. Conversions of producing wells to injectors may be required for both of these purposes. Additional lines must be installed for dis-

TABLE 39

COST DATA FOR CARBON DIOXIDE FLOODING

Cost Element	Cost Basis
1. Pipeline	Investment: $330,000 per mile for a 200 million cubic feet per day capacity; investment scaled for capacity by a 0.6 exponent Operating: 1.3¢ per thousand cubic feet per 100 miles
2. Compression	Investment: $700 per brake horsepower, total installed Operating: 6¢ per thousand cubic feet plus fuel cost (fuel cost scaled directly with oil price)
3. Field Development	
Drill new CO_2 injectors	Normal cost for drilling and equipping injector (from Appendix C) plus incremental cost of $57,000 + 1.25 x depth, ft.
Drill new producer or water injector	Normal cost for drilling, completing, equipping well (from Appendix C)
Convert existing producer to CO_2 injection	Normal cost for conversion (from Appendix C) plus incremental cost of $57,000 + 1.25 x depth, ft.
Convert existing water injector to CO_2 injection	$57,000 + 1.25 x depth, ft.
4. Well Operating and Maintenance Costs	
Normal operating and maintenance costs	See Appendix C
Incremental operating and maintenance costs	$20 per day per producer
5. Separation of CO_2 from produced gas	Investment: $4,000,000 to process 25 million cubic feet per day capacity; investment scaled for capacity by a 0.6 exponent Operating: 10¢ per thousand cubic feet of CO_2
6. Hydrogen sulfide removal	Investment: $6,000,000 for plant that removes 20 tons of sulfur per day; investment scaled for capacity by a 0.5 exponent Operating: 5¢ per thousand cubic feet of CO_2

tributing the high-pressure CO_2 to injection wells, and injection wellhead equipment must be capable of withstanding high-pressure, potentially corrosive fluids. Normal well operating costs will increase. Some wells will have to bear full, rather than incremental, operating costs if the costs would not have been incurred otherwise under current field operations. Some of the injected CO_2 will be produced, and provision must be made for handling and disposing of this gas.

CO_2 flood process cost data used for economic analysis are summarized in Table 39. Whenever possible, the data were based on actual CO_2 flood tests. However, some of the operating techniques and costs are speculative, and considerable ranges in the cost estimates often resulted. In these cases judgment was exercised in selecting the appropriate data to use.

The basic costs for drilling, completing, and equipping a new well were taken from the process-independent cost data (reported in Appendix C) and varied by geographical area. Incremental costs to equip for CO_2 injection service were added to the basic data, both for new wells and for existing wells converted to CO_2 injectors. The incremental costs included high-pressure wellheads, manifolds, tubing for handling CO_2, safety equipment, and the per-well share of the separate, high-pressure distribution system required for carbon dioxide. No incremental investment was made for producing wells.

For California wells, several assumptions were made for normal costs not included in the process-independent data. A cost of one-half the drilling and completion cost of a new well was assumed for sidetracking an existing well and redrilling through the pay section. For initial workover and recompletion of producers for CO_2 service and for plugging back lower intervals to allow for flooding of shallower ones, one-sixth of new well cost was assumed.

The operating costs will increase for wells in a CO_2 flood. To account for this, an incremental well operating cost of $20 per day was included to cover such expenses as treating for additional scale deposition and corrosion, additional monitoring of flood performance by injection profile surveys, etc., and additional well work to correct injection profiles. The incremental operating cost was applied only to producing wells, to reflect the increased operating cost for each flood pattern.

For each reservoir examined, judgments were made concerning which wells should be charged full investment and operating expenses for the CO_2 project and which wells should be charged only incremental investments and expenses. When it was

judged that the CO_2 flood would be a tertiary oil recovery project, full costs were assumed. For the period of time that CO_2 flooding was judged to overlap continuation of waterflooding, incremental costs were charged unless the well would not have been necessary for continuing the waterflood.

During a carbon dioxide flood, some of the CO_2 will be produced from the reservoir. The options for disposing of this produced CO_2 include:

- Reinjection after separation from the hydrocarbon gases
- Venting after separation from the hydrocarbon gases
- Reinjection without separation from hydrocarbon gases.

Reinjection might be the preferred option in most cases since this would minimize the net volume of CO_2 required from external sources. Separation from the hydrocarbon gases produced concurrently with the CO_2 before reinjection might also be the preferred option in the majority of projects. Relatively small percentages of natural gas content might raise miscibility pressure and potentially reduce displacement efficiency should the contaminated gas contact the displacing gas-oil front as a result of channeling or mixing. Moreover, any sales value of reinjected hydrocarbon gas would have to be charged as a cost to the CO_2 project.

Investment and operating costs for separating and reinjecting carbon dioxide were included in the economic analyses, although there appears to be considerable disagreement over the method and cost for accomplishing this separation. Two types of processes are available—chemical solvent and physical solvent. The chemical solvent methods have been most widely used. Examples are the amine and the hot potassium carbonate processes. The chemical solvent processes require considerable energy for regeneration of the solvent. When energy cost escalates directly with oil price, as assumed in this study, the chemical solvent method becomes expensive. Physical solvent processes are less widely used—even untried—for some of the likely concentrations of produced gases resulting from CO_2 flooding. However, the physical solvent is regenerated by pressure reduction, and much less energy is required for regeneration than for chemical solvent processes.

The economic calculations for CO_2 flooding include rough cost estimations for separating CO_2 from hydrocarbon gas by the physical solvent method. It was assumed that gas would be delivered to the solvent plant at atmospheric pressure and compressed to 500 psi before processing. The carbon dioxide was assumed to be delivered from the solvent plant at atmospheric pressure and compressed to an average 2,500-psi reinjection pressure. Plant investment costs were scaled for gas throughput rate for the various projects by the ratio of throughput rates taken to a 0.6 power.

Produced gases from some fields, especially in West Texas, may contain hydrogen sulfide, which is lethal in small concentration and attacks and weakens steel by hydrogen embrittlement. Although hydrogen sulfide contamination in the reinjected CO_2 potentially can be handled by careful design, metallurgy, and monitoring of separation and reinjection equipment, costs were included in the economic analyses for hydrogen sulfide removal for reservoirs known to produce hydrogen sulfide.

Pilot Testing Costs

Another cost aspect of carbon dioxide flooding —the cost level of field pilot testing—was broadly estimated. To establish rough magnitude of pilot testing costs, the assumption was made that all reservoirs judged to be technically feasible for CO_2 flooding would be pilot tested at an average cost of $2.5 million per test. The total cost for testing estimated in this manner was divided by the incremental ultimate recovery projected for the various economic cases considered, resulting in a cost ranging from $.06-$.15 per barrel of oil produced. Although the cost estimated in this fashion is probably overstated, it is still much less than the total cost per barrel of oil produced by CO_2 flooding. Pilot testing cost was not treated explicitly in the economic evaluation of individual reservoirs, and it was assumed to be included in the overhead cost, along with the cost of laboratory research.

Detailed Description of Process Analysis Procedures

Overview

As discussed in the "State-of-the-Art" section of this appendix, the magnitude of incremental oil recovery that might be achieved from a given reservoir by carbon dioxide miscible flooding depends upon many factors, which may vary appreciably among reservoirs. Reservoir stratification and other heterogeneities influence the miscible sweep, as does the degree of gravity segregation of the CO_2 from reservoir fluids. The severity of gravity segregation strongly depends upon the ratio of vertical to horizontal permeability. Incremental recovery also depends upon the residual oil saturation in the waterflood-swept zone and upon the residual saturation

after the miscible flood. It may also depend upon the manner in which the miscible flood is operated, i.e., whether injection fluids can be practiced, and perhaps even whether the CO_2 slug is followed by water injection only or by gas-water injection. Incremental oil recovery also depends upon the volume of CO_2 injected into the reservoir. Injection of larger volumes of CO_2 should result in larger incremental oil recovery, but at a decreasing efficiency of CO_2 utilization and higher cost for the incremental oil produced.

To account for all of these factors requires an in-depth study of each individual reservoir, which would require many man-months of effort. Even then, a great deal of uncertainty might remain in the projection, since reservoir heterogeneity usually cannot be precisely defined and since CO_2 flood behavior under field conditions is as yet essentially untested and unproven for a wide variety of reservoir conditions.

Time and data base limitations prohibited more than a simplified examination of the reservoirs in the sample; therefore, the following analysis was applied to each reservoir passing the second screening. First, a numerical reservoir simulator was used to estimate "type" pattern flood performance, incremental oil recovery, and CO_2 requirements. Next, reservoir development models were devised for the stacked reservoirs of Gulf Coast fields, thick section reservoirs of California, and basically horizontal, moderate-thickness reservoirs of large areal extent in other geographical areas. Then, the appropriate performance and development analyses were applied to the individual candidate reservoirs, and economic outcomes were calculated. Finally, the results of the individual analyses were aggregated.

Oil Recovery and CO_2 Requirements for Individual Reservoirs

A miscible displacement numerical reservoir simulation model of the type described by Todd and Longstaff was used to generate "type" reservoir performance to apply against the reservoirs in the data base.[20] The simulator calculations were designed to investigate the influence of a range of important variables on performance, and not to calculate performance for any particular reservoir in the data base. For performance in carbonate reservoirs, calculations were made for various permeability stratifications, layering of strata, and residual oil saturations considered to be realistic. Vertical permeability was limited, but finite. Details of the performance calculations for sandstone reservoirs may be found in a paper by Warner.[24] Influence of various reservoir heterogeneities was examined in these calculations.

For sandstone reservoirs, the model was waterflooded to near-abandonment conditions before initiating CO_2 injection. For carbonate reservoirs, CO_2 injection was assumed to be initiated at about mid-life of the waterflood. These were believed to be conditions that might prevail in the bulk of the data base reservoirs. Calculations were made for the injection of 10-, 20-, and 40-percent hydrocarbon pore volume (HPV) slug sizes of carbon dioxide into flooding patterns of carbonate reservoirs; and for injection of 15-, 25-, and 35-percent HPV slug sizes into flooding patterns of sandstone reservoirs. Slug size was based on the original hydrocarbon pore volume.

The carbon dioxide and water were injected into carbonate reservoir models as small, alternate slugs in a 1:1 volumetric ratio at reservoir pressure. CO_2-water injection ratio into sandstone model reservoirs was 1:2. After carbon dioxide slug injection, water was injected continuously until floodout. For either lithology, incremental recovery over that achieved by waterflooding was computed. From the reservoir simulator calculations, performance ranges were established and ranked good, fair, or poor.

These calculations were designed to model performance of an individual flood pattern, not overall field performance. Performance of the field as a whole reflects the contributions from the edge areas, discontinuous pays, and areas that may not be subjected to pattern flooding as well as the contribution from the flood patterns. For this reason, to estimate incremental ultimate recovery for the data base reservoirs from the simulator calculations, the incremental recovery from these calculations was expressed as a percent of ultimate primary and secondary recoveries for the models. These percent recoveries were then applied to the estimated primary and secondary recoveries for the data base reservoirs. It was felt that this procedure would best account for whatever factors had influenced primary and secondary recovery in the data base reservoirs and would likely continue to influence an enhanced recovery flood.

The recovery percentages applied to the data base reservoirs are given in Table 40.

Ultimate primary and secondary recovery for the data base reservoirs was taken from the GURC[25] and FEA[26] reports, and from API statistics when available. Otherwise, it was estimated from the Lewin data sheets by adding 10 times the last reported annual production to the reported cumulative

TABLE 40

CARBON DIOXIDE FLOOD PERFORMANCE PARAMETERS

		Incremental Oil Recovery (Percent of Ultimate Primary and Secondary Recovery)	CO_2 Requirements (Reservoir Barrels of CO_2/ Reservoir Barrel of Oil)
Carbonates			
10% Slug Size	Good	15	1.5
	Fair	13.5	1.8
	Poor	12	2.2
20% Slug Size	Good	28	1.7
	Fair	22	2.4
	Poor	16	3.1
40% Slug Size	Good	44	2.2
	Fair	33	3.2
	Poor	22	4.2
Sandstones			
15% Slug Size	Good	18	1.4
	Fair	14	1.8
	Poor	11	2.2
25% Slug Size	Good	22	1.9
	Fair	18.5	2.3
	Poor	15	2.8
35% Slug Size	Good	24	2.4
	Fair	20.5	2.9
	Poor	17	3.4

production. If no information was available, ultimate recovery was taken to be 35 percent of the reported initial oil in place.

Miscible sweepout factors also were derived from the reservoir simulator calculations. This allowed the following equation to be used as an alternative method for estimating incremental recovery from the data base reservoirs:

$$\text{estimated incremental recovery} = \frac{\text{OOIP} \times (S_{orw} - S_{ore})E_M}{(1 - S_{wi})} \frac{B_{oi}}{B_o}$$

where:

OOIP = original oil in place (stock tank barrels)

B_{oi} = original oil formation volume factor (reservoir barrels per stock tank barrel)

B_o = current oil formation volume factor (reservoir barrels per stock tank barrel)

S_{wi} = original water saturation

S_{orw} = residual oil saturation in waterflood-swept zone

S_{ore} = residual oil saturation in CO_2 flood swept zone

E_M = miscible flood volumetric sweep efficiency.

This latter approach for estimating incremental recovery was followed in the Lewin & Associates study and in the surfactant flood estimates of this report.

The numerical values assigned to volumetric sweep efficiencies in Table 41 were felt to be realistic for using in the recovery equation. Only the sweep efficiencies for the 25-percent HPV slug size in sandstones and 20-percent HPV slug size in carbonates are reported in this table.

TABLE 41

CARBON DIOXIDE SWEEP EFFICIENCY AND RESIDUAL OIL SATURATION

	Waterflood Residual Oil Saturation (% PV)	CO_2 Flood Residual Oil Saturation (% PV)	CO_2 Flood Sweep Efficiency (%)
Sandstones			
Primary + Secondary Recovery ≥ 50%			
25% Slug Size	25	5	50 Good 43 Fair 36 Poor
Primary + Secondary Recovery < 50%			
25% Slug Size	30	5	40 Good 34 Fair 28 Poor
Carbonates			
Primary + Secondary Recovery = 50%			
20% Slug Size	30	10	39 Good 31 Fair 22 Poor

These two methods for estimating incremental recovery (applying percent of primary plus secondary recovery factors, and applying miscible sweep efficiency factors) resulted in incremental ultimate recovery estimates of 2.6 billion barrels and 2.9 billion barrels, respectively, when applied against the final CO_2 candidate reservoirs in the data base. The constant slug sizes of 20-percent hydrocarbon pore volume for carbonates and 25-percent hydrocarbon pore volume for sandstones were used for the comparison. The method based on percentage of primary plus secondary recovery was used to generate the estimates reported for this study.

Total incremental oil recovery and carbon dioxide requirement for each reservoir was estimated by the following procedure:

- Calculate incremental recovery using the appropriate recovery factor from Table 40 and the estimated ultimate primary plus secondary recovery
- Calculate the volume of CO_2 required, from the estimated incremental oil recovery and the appropriate ratio of (from Table 40) barrels of CO_2 injected per barrel of incremental oil produced
- Calculate the volume, in cubic feet, of CO_2 injected, from the gas conversion factor for the appropriate reservoir temperature and depth (Figure 89).

Reservoir Development Models

To aid in projecting CO_2 flood performance for the candidate reservoirs, three sets of project design assumptions were made. These designs were treated flexibly when specific reservoirs were analyzed. Assumptions were made concerning individual pattern life and staging of patterns to flood the entire field.

Since economic optimization studies were not conducted on individual reservoirs, an assumption was necessary regarding the average time that would be desired to flood-out a typical flood pattern. An injection rate of 8 percent of the original hydrocarbon pore volumes per year was chosen as a realistic target injection rate for carbonate reservoirs. An injection rate of 19 percent HPV per year was chosen as a target injection rate for the generally higher-permeability sandstone reservoirs. As an example, for the 20-percent HPV CO_2 slug size in good performance carbonate reservoirs this choice for injection rate led to a fifteen-year pattern life. For a 25-percent HPV slug size in all sandstone reservoirs, pattern life was eight years. Performance of an individual flooding pattern was derived from the reservoir simulator calculations and expressed in dimensionless form for the three slug sizes and the good, fair, and poor performance categories. Examples of pattern performance for the 20-percent HPV slug size in carbonate reservoirs and 25-percent HPV slug size in sandstone reservoirs are given in Figures 90 and 91.

Rather than flooding all patterns at once, the development of a field was assumed to occur in stages. Staging reflects the time lag in installing injection patterns throughout a reservoir and provides for injecting some of the CO_2 produced from first stage patterns into subsequent patterns; this reduces the total CO_2 demand from external sources.

The reservoirs considered in West Texas, East Texas, North Texas, and North Louisiana generally

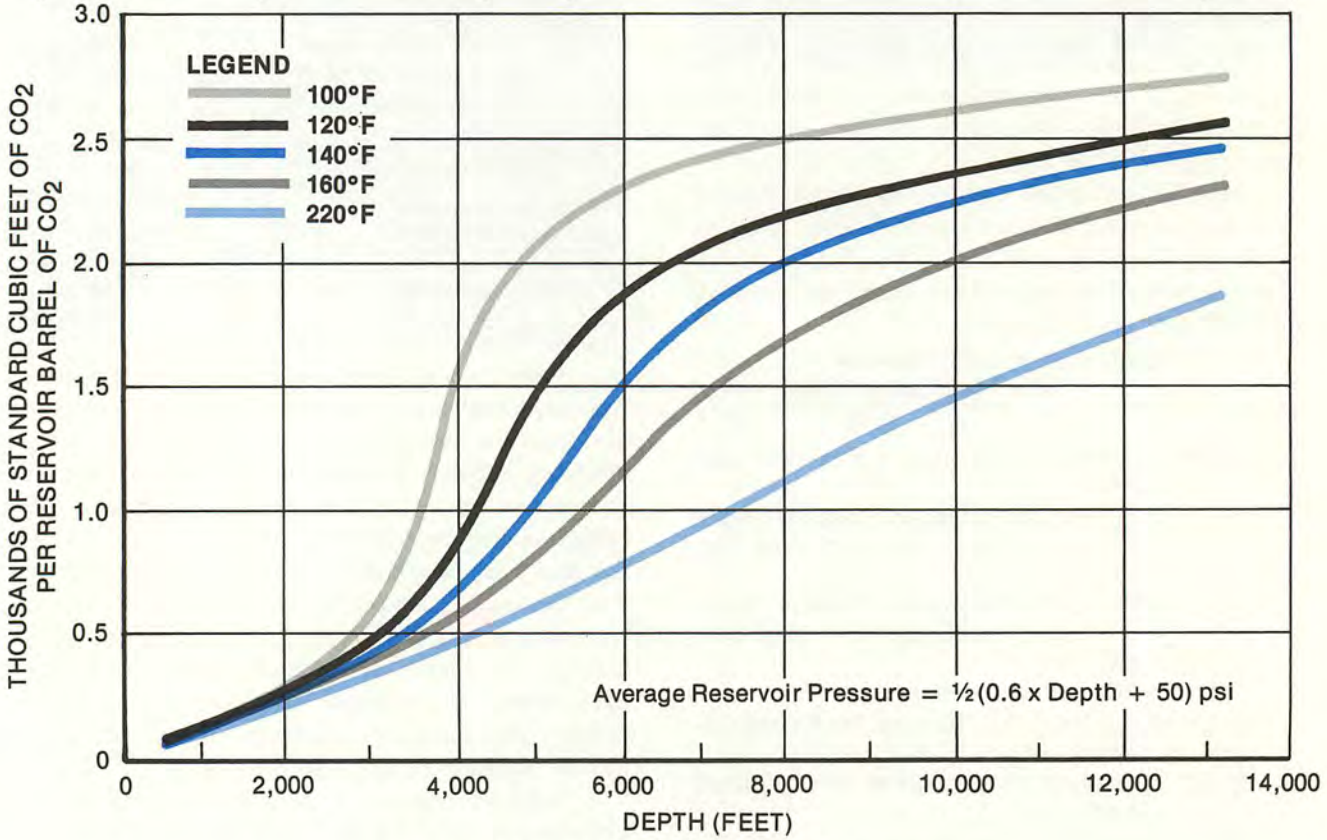


Figure 89. CO_2 Gas Conversion Factors.

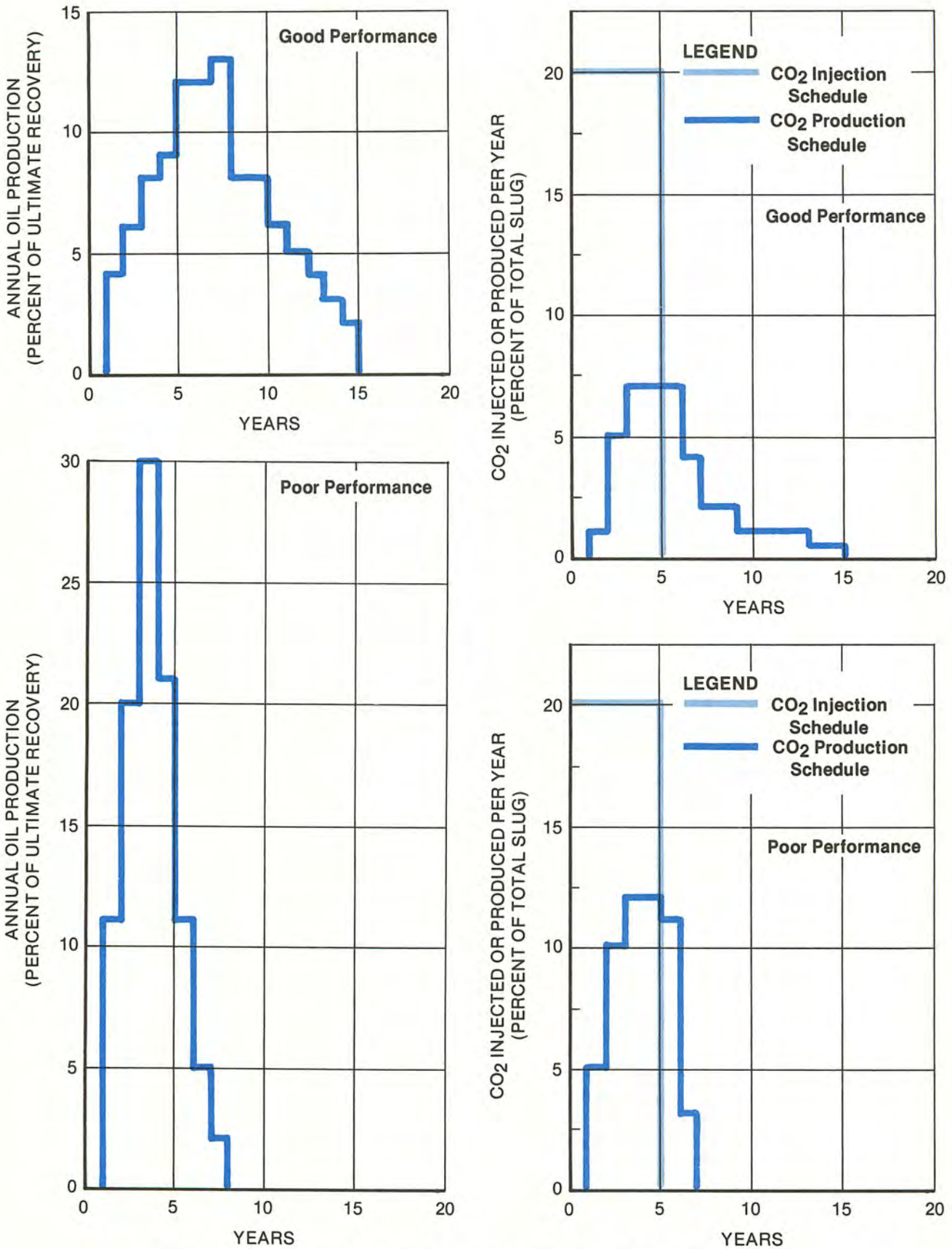


Figure 90. Examples of Single Pattern Performance—Carbonate Reservoir 20% Hydrocarbon Pore Volume Slug.

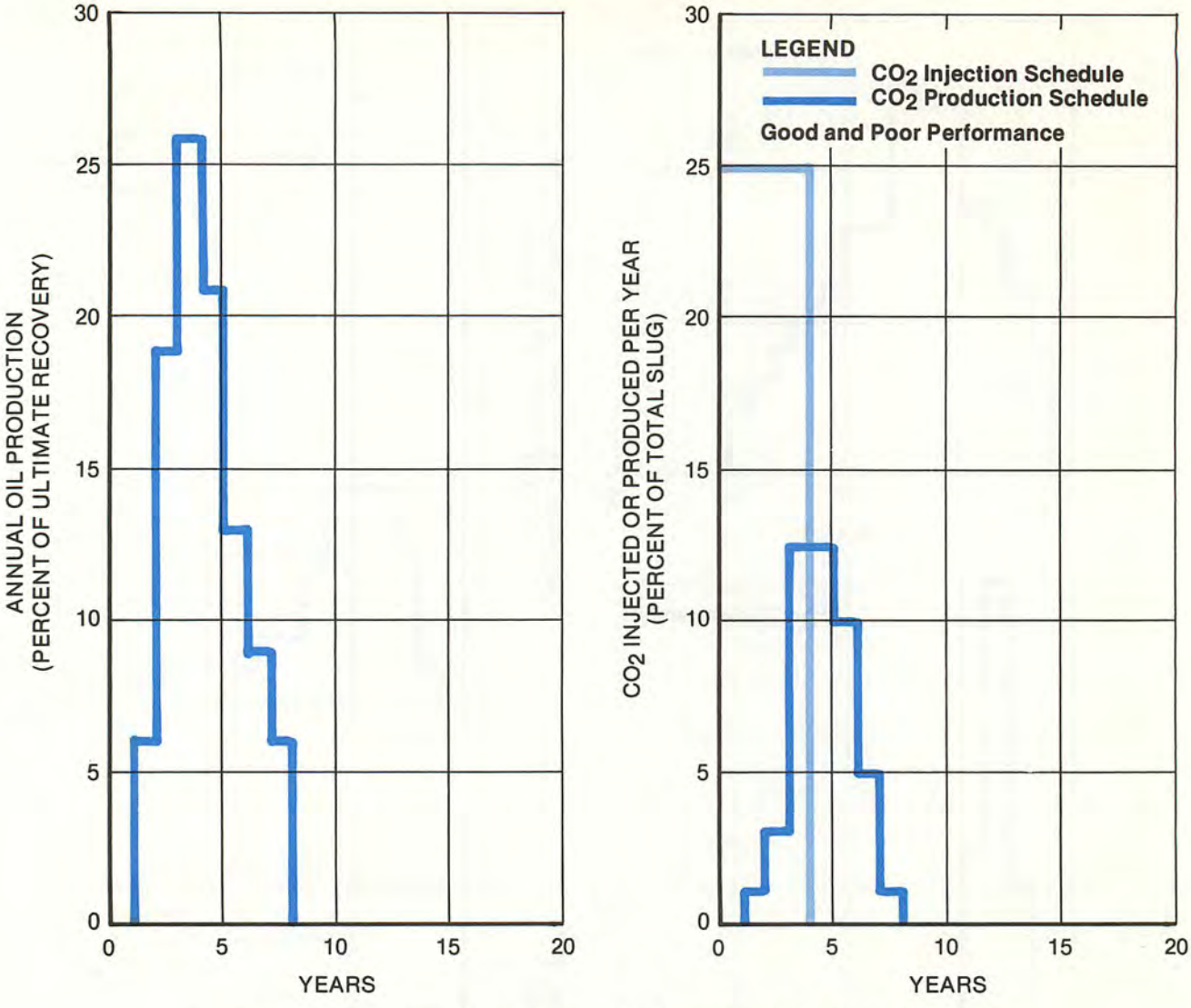


Figure 91. Examples of Single Pattern Performance—Sandstone Reservoir 25% Hydrocarbon Pore Volume Slug.

Note: For the 25 percent slug size, dimensionless production and injection performances for the good, fair and poor performance categories were sufficiently similar to warrant using the same dimensionless performance for all performance categories.

were single, horizontal oil zones of large areal extent and moderate thickness. For the small CO_2 slug sizes (10 percent HPV, carbonates; 15 percent HPV, sandstones) regular pattern development was assumed in four stages. For medium slug sizes, pattern development in two stages was assumed; and for the larger slug size only one stage of field development was assumed. These assumptions for field development led to projections of ten years of CO_2 injection for carbonate reservoirs, and eight years of injection for sandstone reservoirs. Total project lives varied from twelve to twenty years for carbonate reservoirs depending upon the slug size and performance classification, and from eleven to thirteen years in sandstone reservoirs.

From the estimated CO_2 requirement and from injection rate data or estimates of average injection rates per injection well, the required number of patterns to achieve the injection of the demanded hydrocarbon pore volumes per year was derived. Water injection data for most fields were available from state records.[27,28,29,30] If sufficient patterns did not already exist in a field, or could not be installed by conversion of producers to injectors, additional wells were drilled to meet the pattern requirement. Usually five-spot patterns were adopted, although occasionally nine-spot patterns were used.* Twenty-, 40-, or 80-acre five-spots were used most often. In this way

*See Glossary, "flood pattern."

the number of wells to be drilled and number of conversions from producers to injectors were established.

A second reservoir development model was assumed for the very thick pays, typical of California reservoirs. These thick pays may be highly interbedded with sands and shales. They may be turbidite, and highly faulted. Continuity in many zones may be questionable. Waterflooding has not worked well in some of these areas. For these reasons it was assumed that only 50 percent of the volume of reservoirs of this description would be floodable.

A crude model was devised, reflecting that these reservoirs would not be flooded as simply as single-zone, continuous reservoirs. It was assumed that the total reservoir interval could be isolated into two or three depth intervals containing equal oil volumes, each to be flooded sequentially from bottom up, using the same wells. Each floodable interval was developed in two stages, four years apart, with each stage requiring half the wells. Thus, the total project life using this design was approximately 28 years. Because of the good injectivity expected for reservoirs to which this model was applied, the producer to injector ratio was held to a range between three and six. The spacing indicated on the Lewin data sheets was maintained for the tertiary flood design. It was assumed that 90 percent of the existing wells could be utilized.

Special kinds of well work were assumed for the California model. Because of the difficulty of interval isolation within large, slotted liner completions, and recognizing the high cost of drilling new wells, all injectors were assumed to be completed by plugging existing wells to the top of the pay and sidetracking to drill a new completion through the pay section. As the lower zones were flooded out, costs were added to plug back and recomplete the next higher interval. It was assumed that all producers would require some reworking at project start, as well as subsequent plugback and recompletion to the shallower intervals as lower intervals were flooded.

The third development model was designed for Gulf Coast fields in South Louisiana and South Texas. These reservoirs are characterized by complex stratigraphy, numerous individual sands, and fault blocks. In some cases, the fields may contain over a hundred separate reservoirs. Some will contain gas caps and active water drives. In these fields, the majority of the oil may be contained in relatively few of the reservoirs. For example, 50 percent of the oil may be contained in less than 10 percent of the reservoirs. In such a case, the remaining 50 percent of the oil may be distributed among individual reservoirs so small as to be unable to support even the well costs required for an injection project. Consequently, when this model was applied to the fields in the data base believed to be of this description, only 50 percent of the reported oil in place was assumed floodable.

Because reservoirs tend to be stacked vertically in these fields, older wells often have undergone upward recompletions more than once; and it would be impractical to place them back in a depleted reservoir for tertiary oil recovery purposes. Even reservoirs with older water injection projects will have lost many of their downdip producers. Consequently, the model design considers that, on the average, only half of the existing water injectors and producers can be utilized. Further, it was assumed that at least one producer per 40 acres and one injector for each six or seven producers were required. Line-drive or peripheral flooding, rather than a five-spot pattern, was assumed for this model. New wells were assumed to be drilled to supply the needed additional injectors and producers, rather than sidetracking of wells that had been plugged back. Drilling new wells seemed to be as cost-effective as sidetracking in this area. In the Gulf Coast fields model, the development scheme was intended to simulate direct, initial completion in the few major reservoirs. No plugback and subsequent flooding of shallower zones were contemplated. Staging of CO_2 injection depended upon slug size, in a manner similar to that described for West Texas, East Texas, North Texas, and North Louisiana reservoirs.

In all the development models, waterflooding was assumed to be an alternative to carbon dioxide flooding. In those few situations where a reservoir was not under waterflood already, only the incremental costs and investments for CO_2 flooding were included in the economic evaluation, since it was assumed that these reservoirs would ultimately be waterflooded if they were not CO_2-flooded.

Economic Analysis of Projects

During the screening process, reservoirs were assigned a good, fair, or poor performance classification. These classifications were judgmental, but they were based on any information available on reservoir or formation properties, geology, or history. These classifications became the base case for performance and economic calculations. For each reservoir to be evaluated, a total project oil production history and a carbon dioxide injection-production history was calculated for each CO_2 slug size

from the following information:

- Estimated incremental oil recovery and CO_2 injection requirement
- Appropriate dimensionless pattern performance
- Appropriate staging.

Also, from applying the proper reservoir development model, the magnitude and timing of investments and operating costs were estimated. Economic evaluations were then made for the various oil prices, DCFROR's, and tax cases. The maximum slug size was selected that still attained the desired rate of return. Depending upon the economic parameters being investigated, different slug sizes were calculated to be optimum; thus, different magnitudes of incremental oil recovery were projected for the same reservoir. For a fixed set of economic parameters, increasing oil price dictated that larger slug sizes were economically attractive and larger oil recovery resulted.

Time-Rating of Oil Production—1976 to 2000

Carbon dioxide supply will be one of the major constraints of CO_2 flooding on a large scale in the 1976-2000 time frame. Potential CO_2 demand far exceeds supply from industrial sources, such as fertilizer plants, and from proved production from reservoirs containing CO_2 (see the discussion under "Results for the Three States and the Total United States," later in this appendix). To satisfy potential demand, new sources must be found and developed. Most likely, these new sources will be carbon dioxide reservoirs or carbon dioxide found as a substantial contaminant in new natural gas discoveries.

The most economical way to transport this CO_2 to the oil field will be by pipeline, but the demand generated by some oil fields or geographical areas may not justify the large investments needed for pipelines. In these cases the CO_2 will have to be transported by refrigerated truck or tank cars, if this is economically acceptable. The time required to explore for and develop an adequate CO_2 resource base for national needs, and the time required to develop the necessary distribution systems, limit the rate at which major oilfield flooding projects can be initiated.

Carbon dioxide flooding is an unproven technology, and the oil recovery performance of this method has yet to be established. The rate at which large-scale projects will be developed also will be constrained by the level of risk that operators are willing to take and by the rate at which field testing results increase confidence for making the large investments required.

To project the rate of added oil production that might be derived from carbon dioxide flooding in the 1976-2000 time period, the following assumptions were made:

- For oil prices of $10 and $15 per barrel, the earliest date for initiating any major floods supplied by pipeline would be 1985 and would probably be in West Texas. This reflects: (a) the need to complete and evaluate the present round of planned or in-progress pilot tests; (b) development time to bring on-stream the first new major CO_2 sources; (c) pipeline construction time; and (d) time to put together enough large oilfield projects to justify building a pipeline. The assumed supply rate of the first pipeline was 500 MMscfd.
- For oil prices of $20 and $25 per barrel, the incentive for the initial line would be greater. Under these conditions, the initial pipeline was assumed to be completed in 1982. This reflects less extensive pilot testing and more intensive development of sources.
- At oil prices of $10 and $15 per barrel, a second line supplying 500 MMscfd to West Texas was assumed to be completed in 1988, reflecting development of additional CO_2 sources. For $20 and $25 per barrel oil prices, this line was assumed to be completed in 1985.
- For $10 and $15 per barrel oil prices, sufficient pipelines to supply all the CO_2 requirements for West Texas and New Mexico were assumed to be completed by 1993. For the higher oil prices, these lines were assumed to be completed by 1990.
- For those fields outside of West Texas and New Mexico, where the estimated CO_2 requirements may be insufficient to justify pipelines, the CO_2 was assumed to be supplied by truck or tank car. For projects economically justifiable, at the assumed CO_2 delivered cost of $2.75 per thousand standard cubic feet, one-half are assumed to commence in 1982, and the remainder in 1985. This timing reflects a reduction in time for project initiation, since pipeline justification and construction are not necessary.

Extrapolation Process

Two separate steps were required to extrapolate

from the data base reservoirs to obtain results for the entire Nation. First, since the data base does not contain all the reservoirs in Texas, California, or Louisiana, an extrapolation was necessary to project the total recovery for each of the three states. Secondly, a procedure was developed for projecting recovery outside of the three states, using a select group of data base reservoirs as reference reservoirs.

For the three states, incremental recovery was extrapolated for each API district or area by calculating the ratio of total original oil in place (OOIP) in the district to the OOIP in all the data base reservoirs for that district. This extrapolation assumed that the mix of data base reservoirs in any district was representative of the total mix of reservoirs in the district. The CO_2 cost assigned to data base reservoirs was also assumed to be appropriate for other reservoirs in that district.

Extrapolations to the remaining states were made by estimating the total OOIP in potential candidate reservoirs, and by estimating the fraction of this OOIP that might be recovered at various economic conditions. For Oklahoma, Wyoming, Kansas, New Mexico, and Illinois, API statistics and information contained in the Petroleum Data System (PDS) were used to make separate estimations of the OOIP in standstone and carbonate reservoirs, with depths greater than 4,000 feet and containing oils with an API gravity of 30° or higher. These screening conditions were somewhat more restrictive than those applied to Lewin data base reservoirs; they were used since geological review was impractical. All of the original oil in place estimated for carbonate reservoirs meeting these criteria, and one-half of that estimated for sandstones, was assumed to be in reservoirs that would be candidates for CO_2 flooding. The other half of the oil in sandstones was assumed to be in reservoirs that would be candidates for other enhanced recovery processes, particularly surfactant flooding. For the remaining states, it was assumed that 10 percent of the total API estimated oil in place for carbonates and 25 percent of the OOIP for sandstones would be in CO_2 flood candidate reservoirs. These approximate percentages were derived from the API and PDS data for Oklahoma, Wyoming, Kansas, and New Mexico.

To estimate the fraction of the OOIP in candidate reservoirs that might be recoverable from CO_2 flooding, model reservoirs from the data base were used as guides. Estimates were made for carbonates and standstones separately. Five North and East Texas sandstone reservoirs and four West Texas carbonate reservoirs from the data base were chosen as reference reservoirs. The reference reservoirs were chosen to represent "typical" reservoirs in the remaining states. For any given set of economic parameters being investigated, such as oil price, DCFROR, and tax case, and for the CO_2 cost assigned to each state (Table 38), economic calculations were made to determine the volume of incremental oil that was economically recoverable from the reference reservoirs. This incremental oil recovery was then scaled-up to give a state total. The scaling factor was the ratio of OOIP in the state, in candidate reservoirs of that lithology, to the OOIP contained in the reference reservoirs.

Results for the Three States and the Total United States

Projections for Texas, California, and Louisiana

The potential oil recovery projected for carbon dioxide flooding in Texas, California, and Louisiana is shown in Figures 92, 93, and 94. Totals for the three states are shown in Figure 95. The projections are for incremental ultimate recovery rather than booked reserves, since some projects will not be started until after the year 2000. These results are for the base case good, fair, and poor performance rankings for reservoirs and for the base case CO_2 costs tabulated in Table 38. The base case CO_2 cost selected for South Louisiana was a truck-delivered cost of $2.75 per Mscf. However, delivery via pipeline from CO_2 reservoirs in Mississippi is an equally likely possibility and could result in lower costs, perhaps about $1 per Mscf. All results presented in Figures 92 through 95 are for the moderate tax case.

It is apparent that the bulk of oil recovery projected for CO_2 flooding is located in Texas. Moreover, the preponderance of this recovery is expected to be found in the carbonate reservoirs in API Districts 8 and 8A. These districts account for 91 percent of the recovery potential projected for the three states at a $15 oil price and a 10 percent DCFROR.

Technically recoverable incremental oil for Texas, California, and Louisiana was projected to be approximately 5.5, 0.1, and 0.3 billion barrels, respectively.* Even at the highest oil price and lowest rate of return examined in this study, some of the technically recoverable oil was not economically recoverable. Potential ultimate recovery for the three states is very sensitive to both the oil price and the DCFROR demanded for projects. No incremental recovery is projected for a $5 per barrel oil price,

*Technically recoverable incremental oil is defined here to be the total recovery for the largest slug size investigated, regardless of economic feasibility.

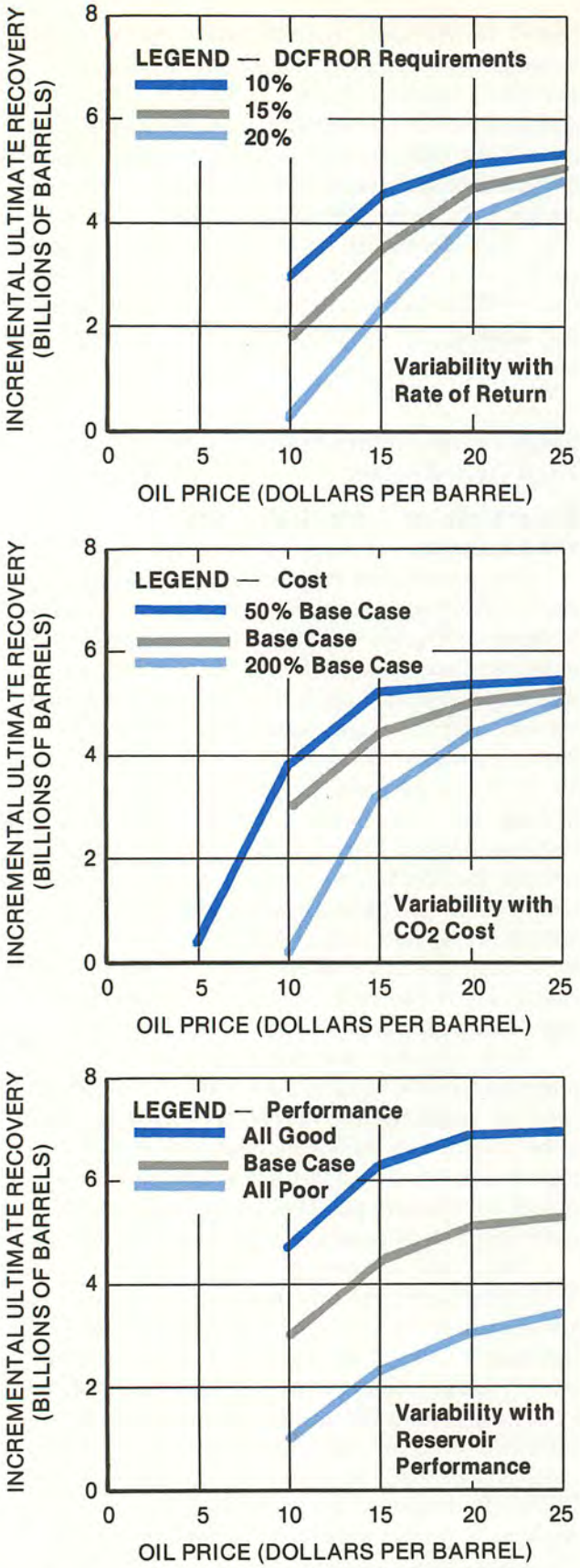


Figure 92. Incremental Ultimate Recovery Carbon Dioxide Miscible Flooding, Texas.

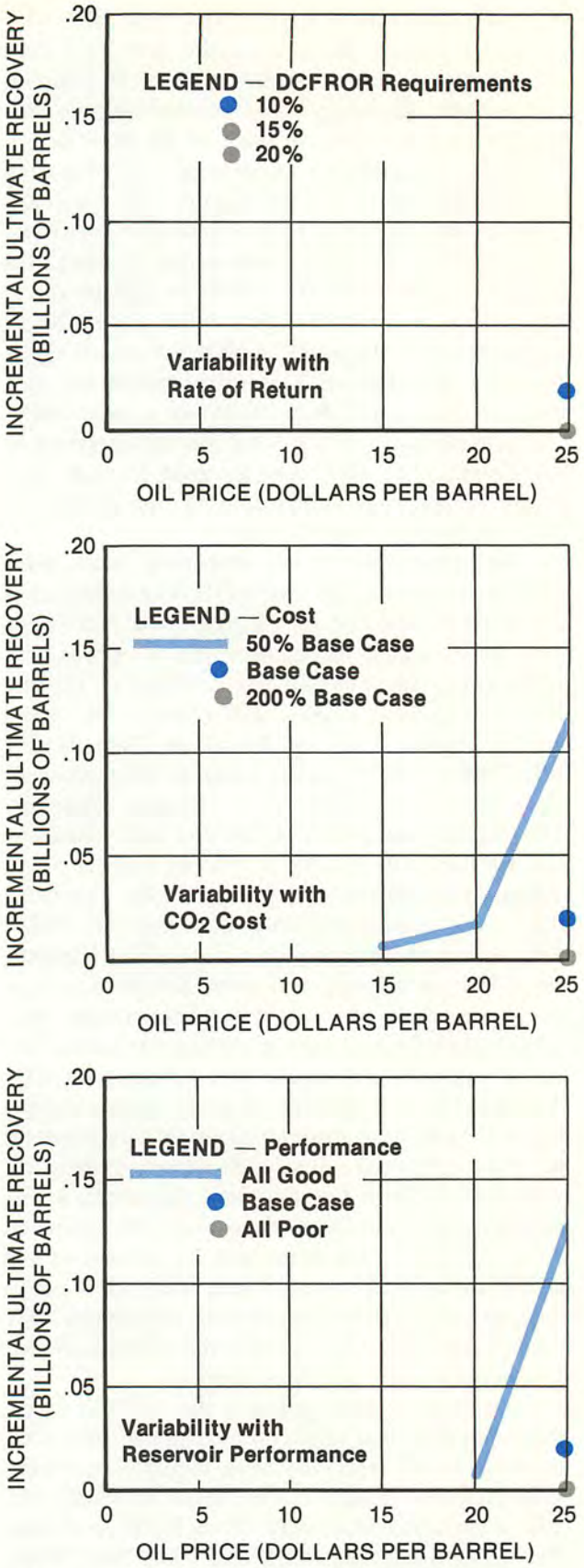
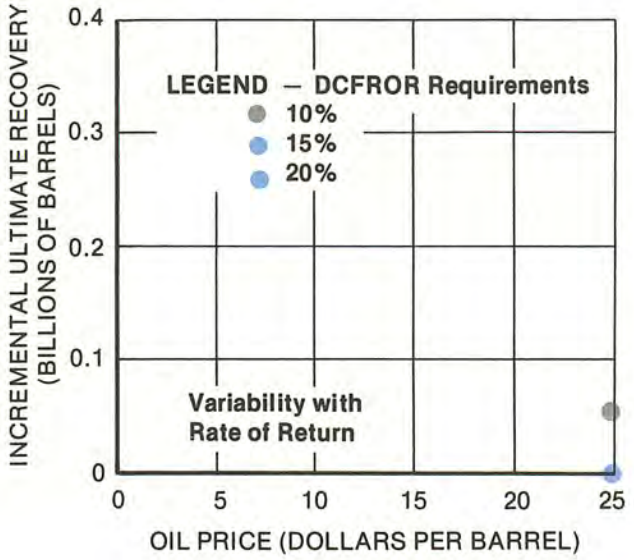
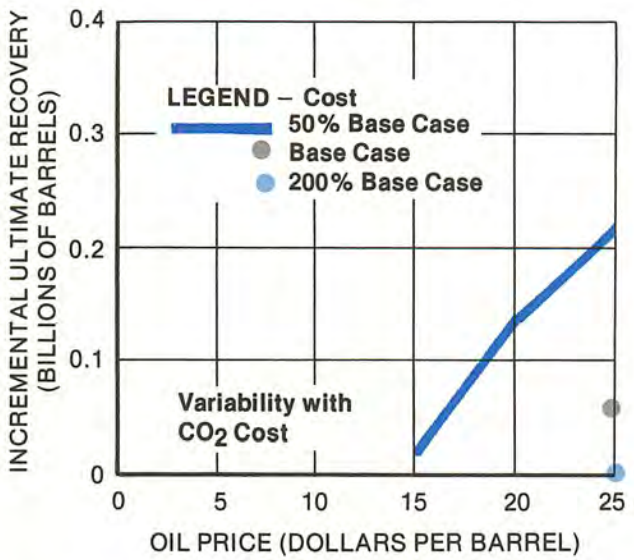


Figure 93. Incremental Ultimate Recovery Carbon Dioxide Miscible Flooding, California.





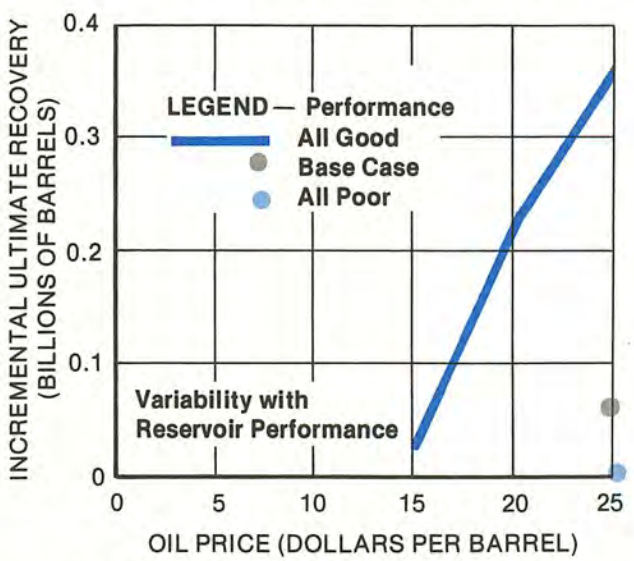


Figure. 94 Incremental Ultimate Recovery Carbon Dioxide Miscible Flooding, Louisiana.

even at the lowest DCFROR examined, 10 percent. At a $10 oil price 3.0 billion barrels of incremental ultimate recovery are projected for the 10 percent DCFROR; and at a $15 oil price a recovery potential of 4.4 billion barrels is projected. Discounted cash flow rate of return has a marked influence on projected recovery, reducing it to 2.4 billion barrels at a $15 per barrel oil price for a 20 percent DCFROR.

In CO_2 flooding, the major uncertainties affecting the outcome are the process performance and the delivered cost and availability of the carbon dioxide. These uncertainties have already been described in the preceding discussion. In this study a specific set of assumptions was used to estimate CO_2 costs, and several performance models were used to cover a range of reservoir conditions. However, these assumptions for costs and performance could be in error by a considerable margin. Figures 92 through 94 also illustrate ranges of recovery potential, at a 10 percent DCFROR as influenced by uncertainty in CO_2 costs and process performance.

To illustrate the influence of CO_2 cost, recovery potential was calculated for twice the base CO_2 cost and for half the base case cost. Base case perform-

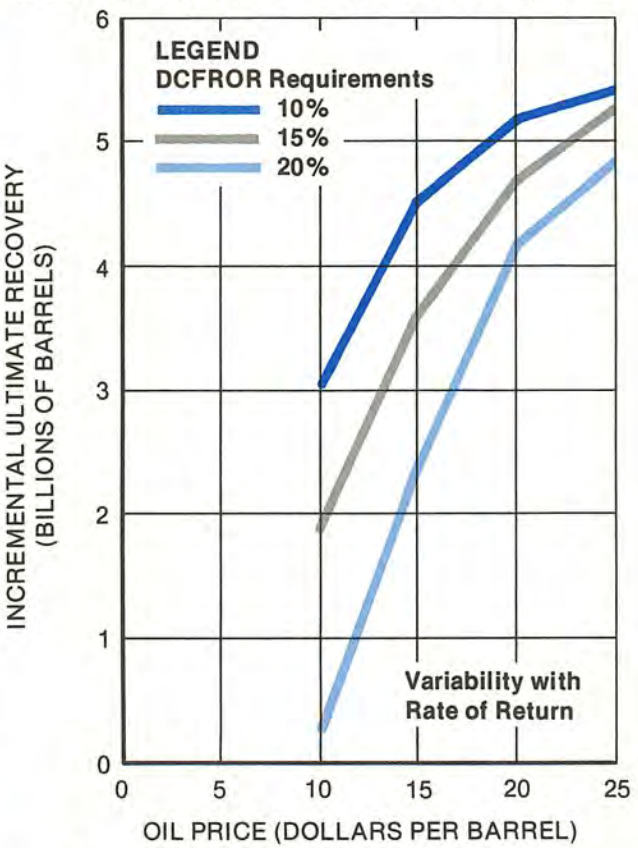


Figure 95. Incremental Ultimate Recovery Carbon Dioxide Miscible Flooding, Total for Three States.

ance ratings were used for all reservoirs. There is a high probability that most actual delivered costs will be within this range. Halving the base CO_2 cost increases recovery by less than one-half billion barrels in the \$10-\$15 per barrel oil price range. Doubling the base CO_2 cost reduces potential recovery substantially. No projects are economically feasible at the \$10 price, while potential recovery is reduced by approximately one billion barrels at the \$15 oil price.

To illustrate the influence of performance on recovery potential, base CO_2 costs were held constant, while recovery potential was calculated with all reservoirs assigned the good performance rating and with all reservoirs assigned the poor performance rating. This range of uncertainty in performance generated an uncertainty in projected recovery potential of approximately ± 2 billion barrels for the oil prices considered.

The costs for carbon dioxide flooding are heavily front-end loaded. That is, most of the investment for CO_2 and field development must be made before revenues from the incremental oil recovery are realized. An approximate breakdown of the contribution that various cost elements make to the cost of producing a barrel of oil is illustrated below:

- CO_2 purchase cost 47%
- CO_2 recycle operating expense 10%
- Well operating cost 9%
- Tangible investment * 19%
- Tangible and intangible drilling costs 2%
- Fuel cost 13%

This breakdown was derived from totals for all reservoirs that had a DCFROR greater than 10 percent at a \$15 oil price. The breakdown is based on the undiscounted cost to produce a barrel of oil. Distribution of costs for individual projects sometimes varied appreciably from this average distribution.

Projected net carbon dioxide requirements for Texas, California, and Louisiana are illustrated in Figure 96. Net requirement is the volume of CO_2 that must be purchased; the remaining CO_2 injection requirement is supplied by reinjection of produced gases. For the 10 percent DCFROR a requirement of approximately 11 to 18 trillion cubic feet is projected for oil prices in the \$10-\$15 range. The bulk of this demand is required for Texas Districts 8 and 8A.

Projections for the United States

The oil recovery projected for carbon dioxide flooding in the United States is shown in Figures 97 and 98. These results are presented for a 10 percent DCFROR requirement and moderate tax case, except where explicitly noted otherwise. Sensitivity of this recovery to tax treatment, CO_2 cost, and process performance is also illustrated in these figures. For a \$10 oil price, little additional recovery is projected from the remaining states for all DCFROR's. At a \$15 oil price about 0.8 billion barrels of additional oil recovery is projected for a 10 percent DFCROR; little additional recovery is projected for the higher DCFROR's. At the highest oil price investigated, \$25, recovery potential as high as 7.3 billion barrels was projected for the 10 percent DCFROR case, an increase of about 1.9 billion barrels over the three-state total.

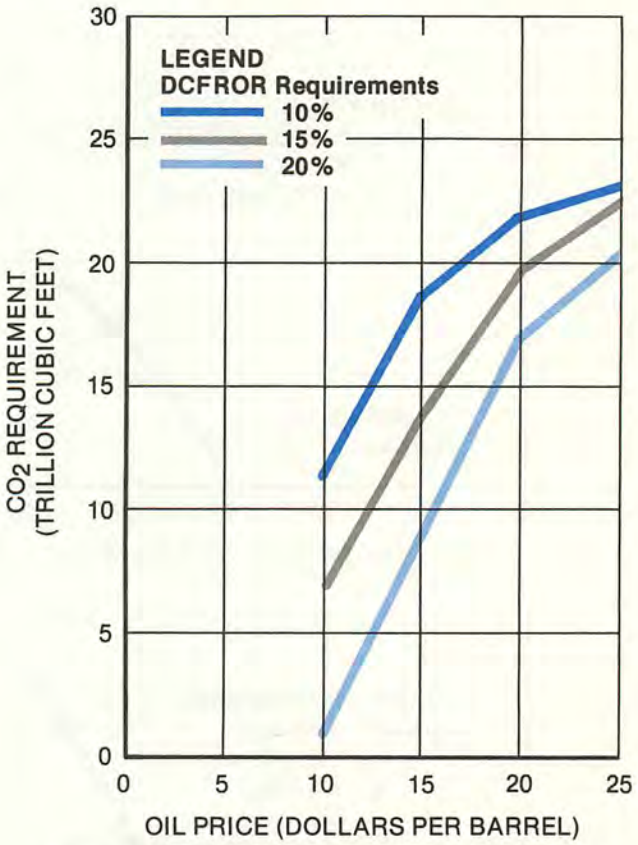


Figure 96. Carbon Dioxide Miscible Flooding Net CO_2 Requirement for Three States.

Note: Net CO_2 requirement is the difference between the gross or total volume of CO_2 injected and the volume of produced CO_2 that is reinjected.

For a 10 percent DCFROR, doubling and halving the base CO_2 costs generated an uncertainty in projected recovery potential of approximately ± 1.5 billion barrels. Again, for the higher CO_2 costs, no projects were found to be economically feasible below the \$10 oil price. An uncertainty in recovery

*Includes investments for compressors, separation equipment, well conversions, and hydrogen sulfide removal.

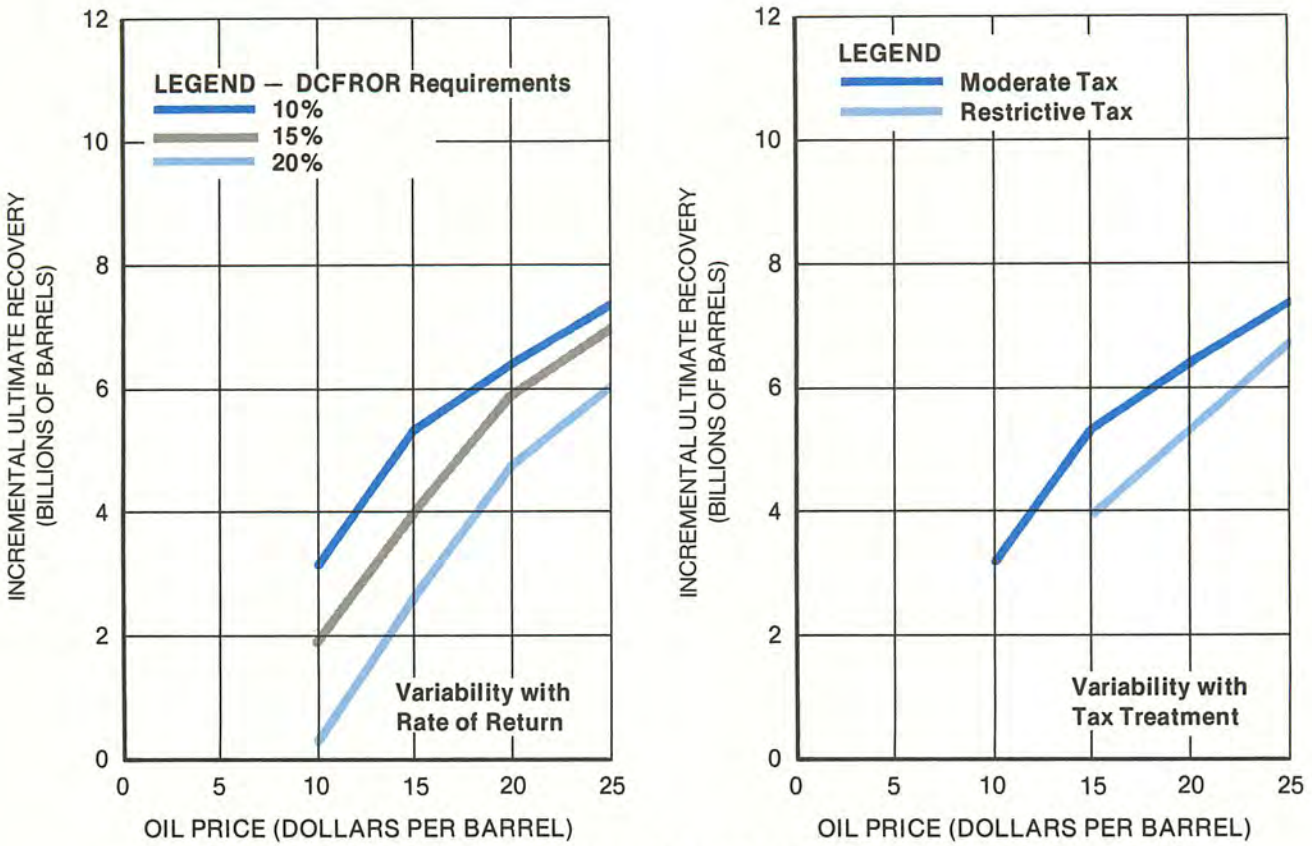


Figure 97. Incremental Ultimate Recovery—Carbon Dioxide Miscible Flooding—Total U.S.

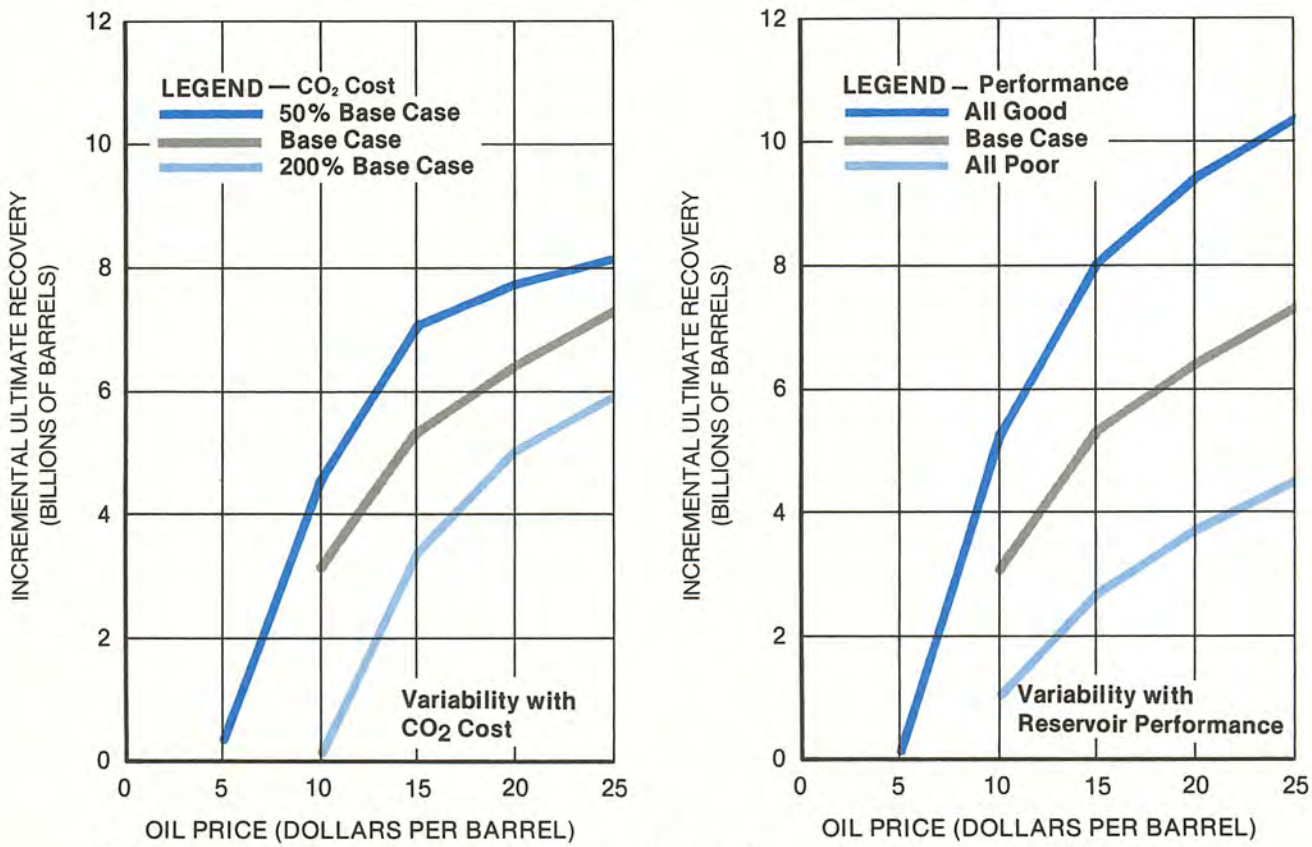


Figure 98. Incremental Ultimate Recovery—Carbon Dioxide Miscible Flooding—Total U.S.

potential at all oil prices of approximately ±2 billion barrels resulted from assigning either the good performance rating to all reservoirs or the poor performance rating to all reservoirs. At a $10 per barrel oil price, no projects were found to be economic for the restrictive tax case, whereas approximately 3.2 billion barrels of incremental ultimate recovery was projected for the moderate tax case. At higher oil prices the restrictive tax case resulted in a decrease in recovery of approximately 0.5 to 1 billion barrels over the price range investigated.

Projected net carbon dioxide requirements for the United States are illustrated in Figure 99. For the 10 percent DCFROR, approximately 12 to 21 trillion cubic feet are projected to be needed for oil prices in the $10-$15 range.

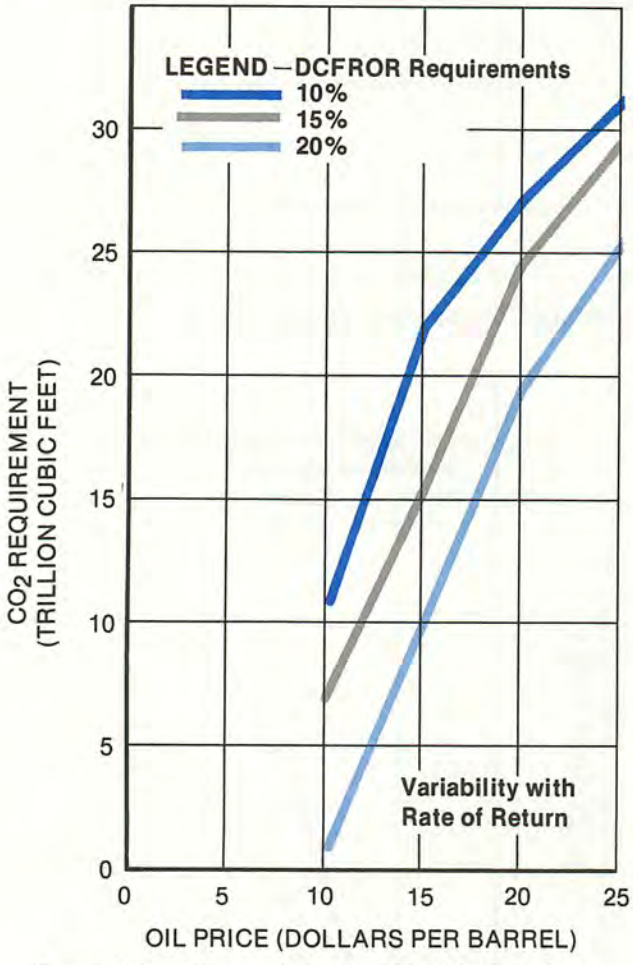


Figure 99. Carbon Dioxide Miscible Flooding Net CO_2 Requirement—Total U.S.

Note: Net CO_2 requirement is the difference between the gross or total volume of CO_2 injected and the volume of produced CO_2 that is reinjected.

The influence of oil price on producing rate for the time period 1976-2000, and for a DCFROR of 10 percent and moderate tax case, is illustrated in Figure 100. Producing rate was projected with the assumptions discussed in the "Detailed Description of Process Analysis Procedures" section of this appendix. Because of the time required for field testing, exploration and development of CO_2 sources, construction of distribution systems, and response to injection, peak producing rate is not realized until the end of this time period. By 1990 producing rates range from approximately 0.1-0.25 million barrels per day, for oil price levels of $10-$15, to 0.4 to 0.6 million barrels per day for oil prices in the $20-$25 range. By the year 2000, producing rates of from 0.9 to 1.1 million barrels per day are projected for oil prices in the $15-$25 range. At this time, a producing rate of about 0.5 million barrels per day is projected for the $10 oil price.

The sensitivity of projected producing rate to uncertainty in CO_2 cost and process performance is illustrated in Figures 101 and 102. The projections are illustrated for an oil price of $15 per barrel, for a minimum DCFROR requirement of 10 percent, and for the moderate tax case. The peak producing rate is projected to occur in the time interval from 2000 to 2005 and ranges from about 0.4 to 1.2 million barrels per day, depending upon whether all reservoirs are assigned poor performance or all are assigned good performance. When all reservoirs are assigned the base case performance, doubling or halving the base CO_2 cost causes the peak producing rate to range from about 0.5 to 1.05 million barrels per day.

Estimated well workover and drilling requirements for carbon dioxide flooding in the United States are shown in Figure 103 as related to oil price and in Figure 104 as related to time for a $15 per barrel oil price. Cumulative and yearly cash outlays are illustrated in Figures 105 and 106.

Environmental Considerations Summary

The primary environmental considerations of carbon dioxide flooding pertain to the supply and transport of the gas, its production, and its subsequent disposal.

Supply and Transport of CO_2

Carbon dioxide found in naturally occurring underground formations, either in nearly pure form or associated with other gases such as natural gas, appears to be the most likely source for large-scale oilfield use. Coal gasification plants, if these plants are ever built, are also potential large suppliers of CO_2. For the large volumes needed for enhanced

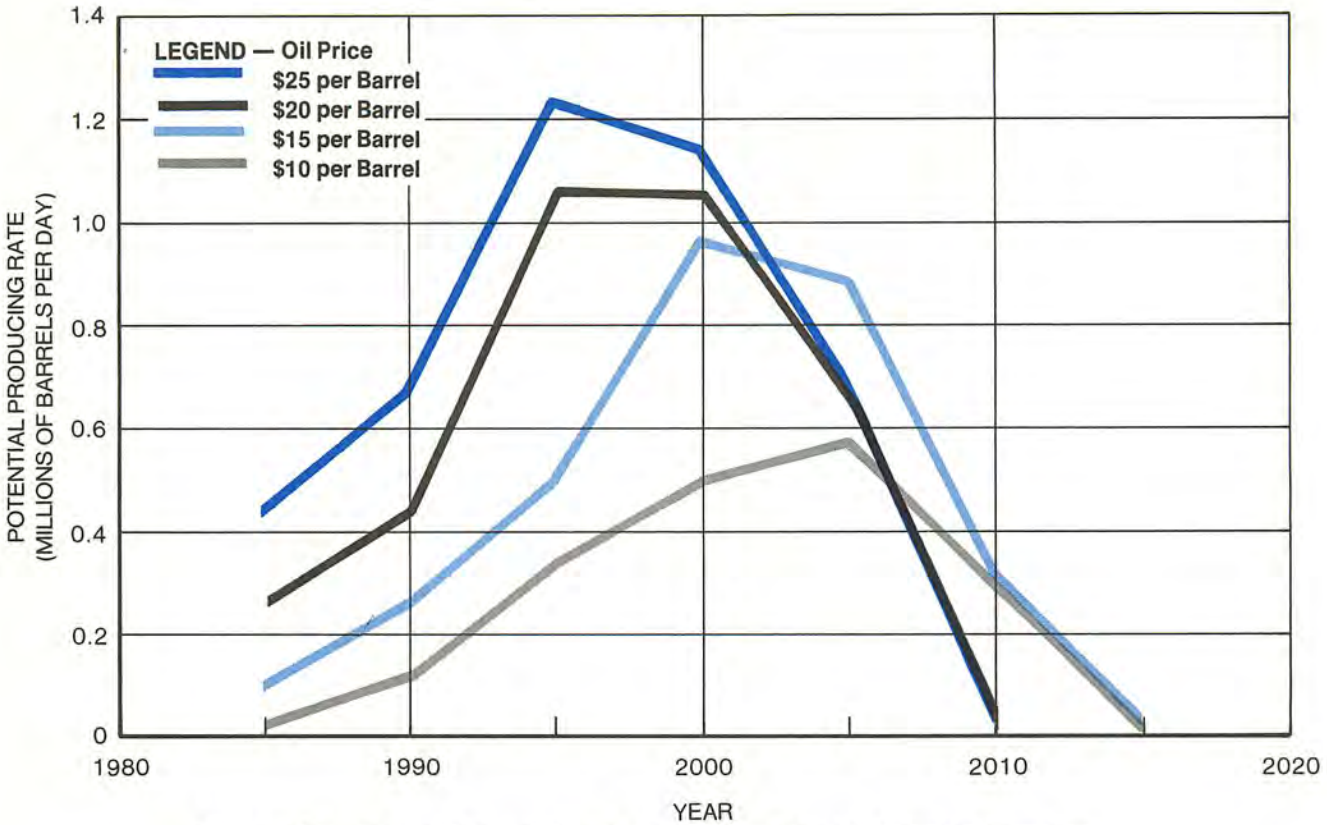


Figure 100. Potential Producing Rate—Carbon Dioxide Miscible Flooding Base Case Performance and Costs.

recovery, the carbon dioxide from these sources most probably will be transported to the oilfield by pipelines. For example, pipelines from known areas of natural CO_2 occurrences (such as the Four Corners area, the Southeast Colorado-Northeast New Mexico area, Southwest Texas, and Central Mississippi) might transport CO_2 to target oil fields. Distances involved could be hundreds of miles. Smaller lines from industrial complexes where CO_2 is emitted as a by-product might also be used for limited CO_2 delivery. Pressure of the carbon dioxide in these pipelines might be in the 1,500-2,500 pounds per square inch (psi) range. When a small CO_2 requirement makes pipeline delivery unfeasible, refrigerated trucks and tank cars may be used for transport.

For the most part, the environmental aspects of carbon dioxide transportation will be similar to the transportation of natural gas via pipeline. Right-of-way must be obtained; ditching, construction and burying of the line are necessary for completion; and river crossings will be required. Carbon dioxide is not flammable, so the danger of explosion and fire will not be present as with natural gas.

While carbon dioxide is not toxic (it is present in the atmosphere), it is odorless and heavier than air, and could be suffocating if it settled in a low spot in calm weather and were not dispersed by wind. This potential hazard could be minimized by adding odorants to provide ample warning of a leak. Also, carbon dioxide recovered from some natural and industrial sources may contain hydrogen sulfide (H_2S) at lethal levels of concentration. If hydrogen sulfide is present, it can be removed from the gas at the source.

A 200-mile long pipeline has been in operation since December 1971, to supply CO_2 for injection in the SACROC Unit in West Texas. Tests and studies were made before the line was placed in service to examine pipeline materials and operating conditions that might result in hazards. The test program and operating experience have shown that hazardous concentrations of CO_2 do not occur as a result of leaks and that safe operations can be conducted.

Production of Injected Gas

In oilfield practice of this enhanced recovery method, the carbon dioxide will be injected into the oil reservoir through injection wells to drive the displaced oil toward producing wells, where it will be captured. Because of heterogeneity of the reservoir rock and other factors related to flow of fluids in oil reservoirs, some of the injected CO_2 ultimately will

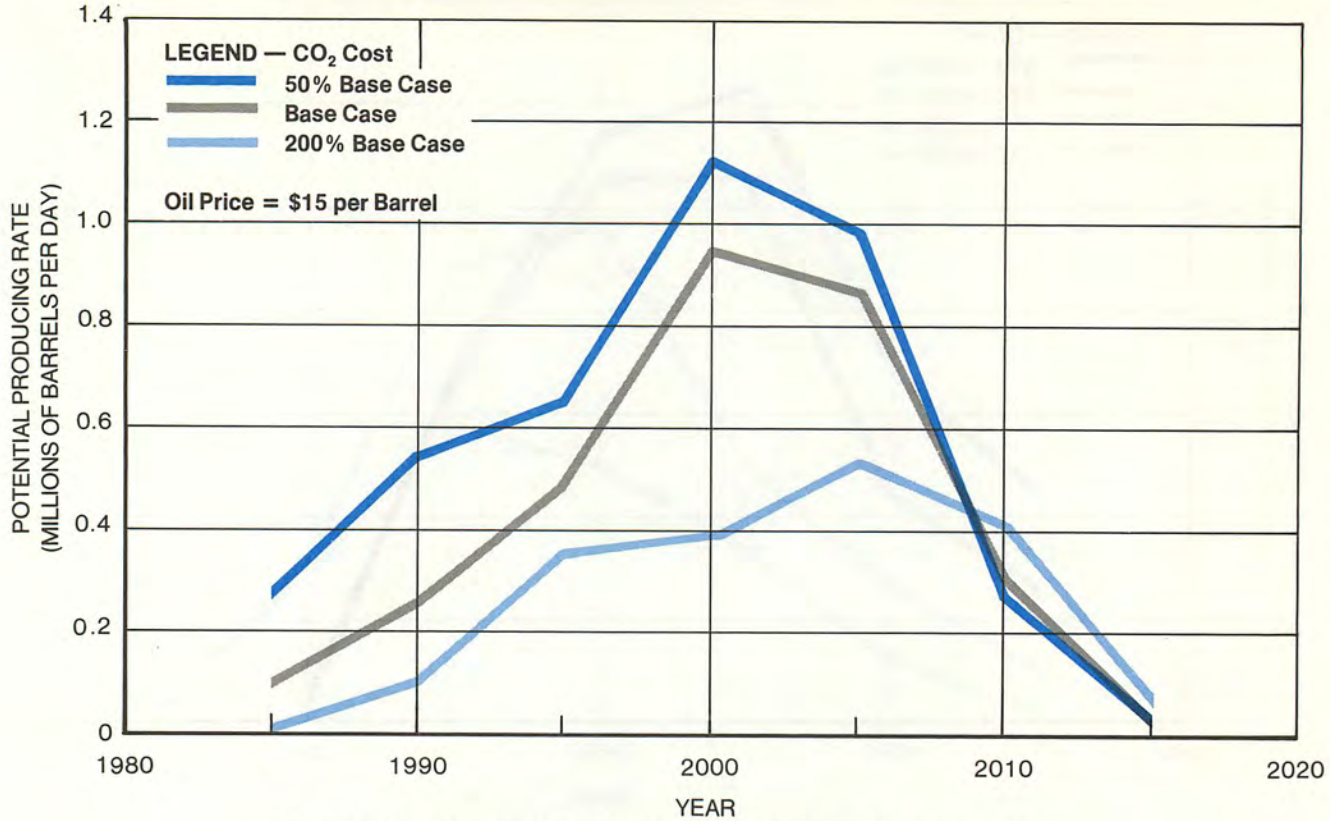


Figure 101. Carbon Dioxide Miscible Flooding—Variability of Potential Producing Rate with Carbon Dioxide Cost.

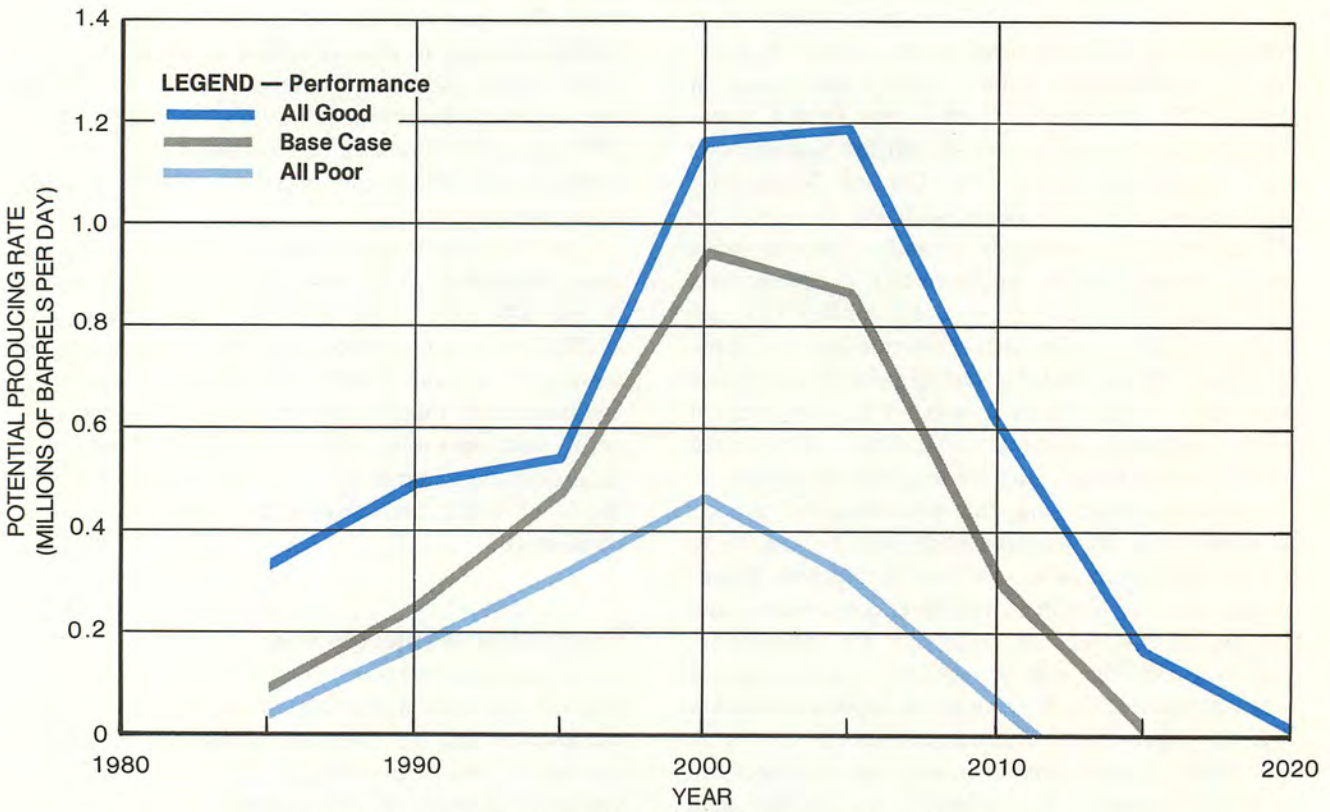


Figure 102. Carbon Dioxide Miscible Flooding—Variability of Potential Producing Rate with Reservoir Recovery Performance.

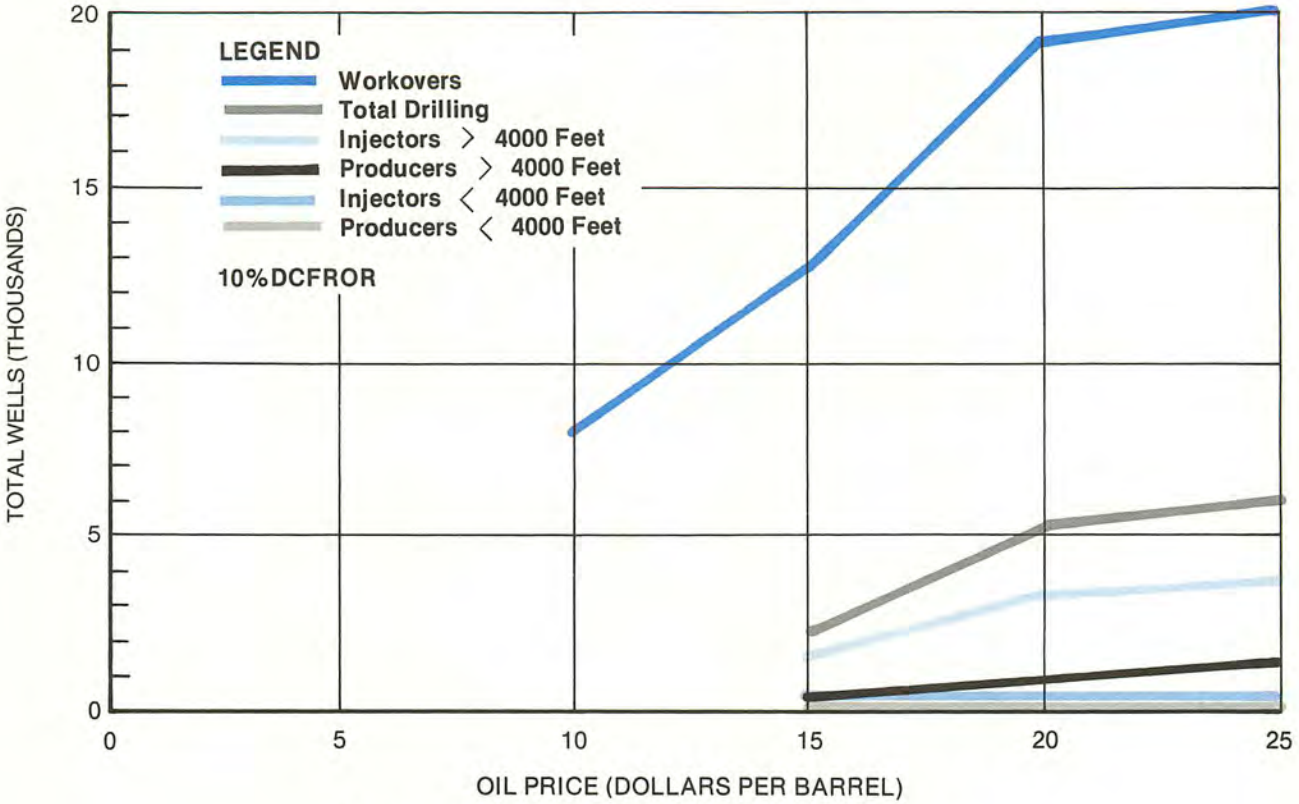


Figure 103. Total Drilling and Workover Activity Carbon Dioxide Miscible Flooding.

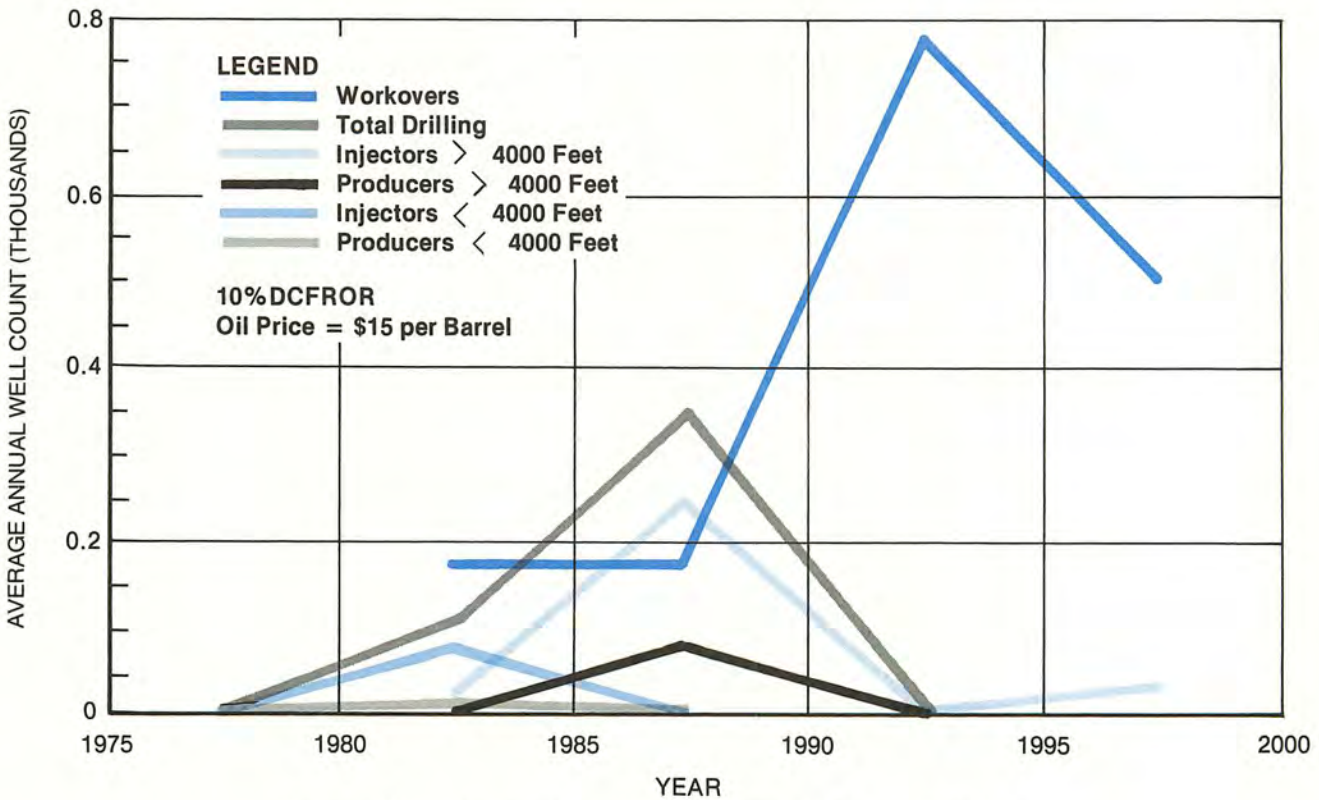


Figure 104. Average Annual Drilling and Workover Activity Carbon Dioxide Miscible Flooding.

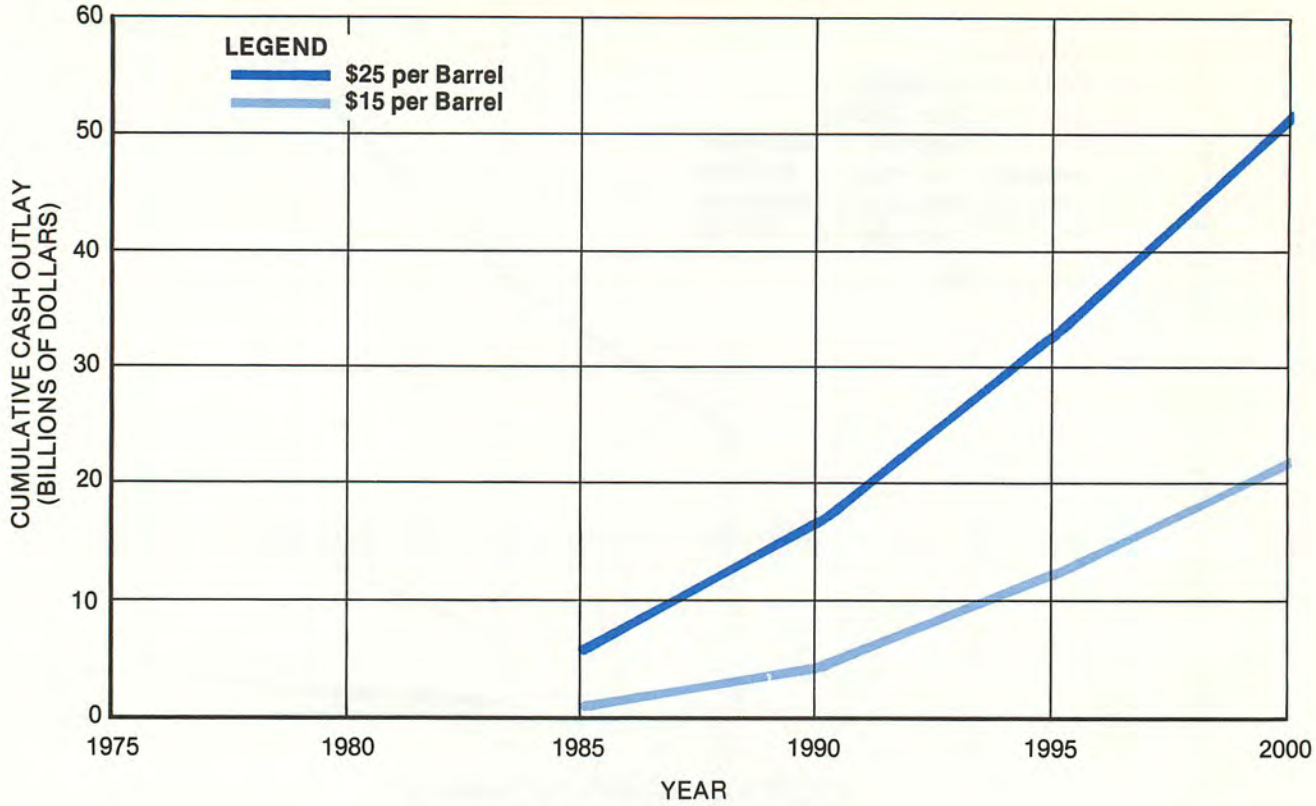


Figure 105. Cumulative Cash Outlay
Carbon Dioxide Miscible Flooding.

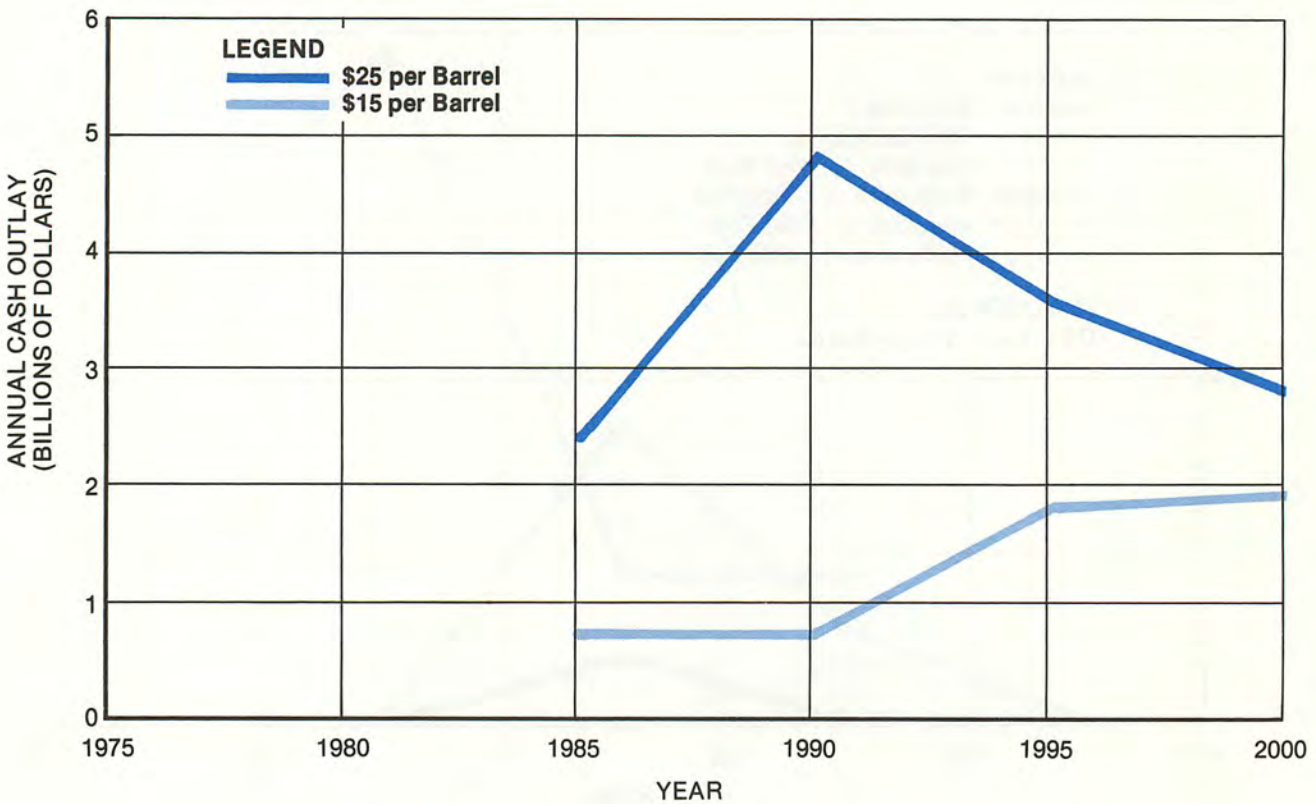


Figure 106. Annual Cash Outlay
Carbon Dioxide Miscible Flooding.

be produced from the producing wells along with oil, natural gas, and reservoir brine. In some fields containing "sour crudes," hydrogen sulfide may also be produced in the gaseous effluent from the well. This situation is not unique to enhanced oil recovery; there already are many oil fields that contain CO_2 and hydrogen sulfide naturally in the hydrocarbon solution gases that are produced. Precautions against this hazard are already standard operating procedures.

Carbon dioxide in the producing well stream can aggravate the scale formation tendency of produced water. Scale deposits in well tubing and flowlines provide sites for corrosion. Also, lowering of brine pH by CO_2 can increase acid attack on steels. Thus, production of CO_2 can increase corrosion in producing wells which, in turn, increases the danger of freshwater contamination by brines. Again, corrosion is a normal aspect of oilfield operations, and current practices and precautions for controlling corrosion should apply to CO_2 flooding. In projecting the cost for CO_2 flooding in this study, additional well operating expenses were included to allow for increased corrosion control and well maintenance.

Disposal of Produced Gas

There are several recourses for disposing of the produced carbon dioxide. It can be separated from the hydrocarbon gas and vented while the hydrocarbon gas is sold. (If the separated CO_2 contains hydrogen sulfide, this must be removed before the CO_2 is vented.) To put the venting of CO_2 in perspective, enhanced oil recovery by CO_2 flooding in any of the largest oil fields in West Texas would probably require injection of no more than 200-300 million standard cubic feet per day of carbon dioxide for that oil field. The production rate of CO_2 would not exceed half of this injection rate, i.e., a maximum of 100-150 MMscfd of carbon dioxide might be vented. This is less carbon dioxide released into the atmosphere than in the stack gas of a medium-size power plant for electricity generation.

Another alternative for CO_2 disposal is to reinject most of the produced CO_2 back into the oil reservoir. This would probably be done after separating it from hydrocarbon gas and removing any hydrogen sulfide present. In some instances, it may be more desirable to reinject both produced CO_2 and hydrocarbon gas, without separation. However, hydrogen sulfide would probably still be removed before reinjecting these gases. In calculating the economics for CO_2 flooding, investment and operating expenses were included to reinject the produced CO_2, after first separating it from produced hydrocarbon gas and after removing hydrogen sulfide (for those fields where it was recognized that hydrogen sulfide production would occur).

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Appendix F
Thermal Processes

State-of-the-Art Assessment

Recovery of heavy, low-gravity crude oils is impeded by their viscous resistance to flow at ambient reservoir temperatures. Heating of such crudes markedly improves their mobility and the effectiveness of their recovery from the reservoir by fluid injection operations. Heat may be applied by injecting hot fluid such as steam or hot water, or it may be generated directly within the reservoir, by burning of some of the crude oil in place. This latter process is termed in-situ combustion, or fire flooding.

Interest in hot fluid injection processes predates in-situ combustion, and field testing began in the 1950's, about the same time as that for the combustion process.[2,3] Field test results have been available since 1966.[4,5,6] By the early 1960's, hot water or steam injection dominated consideration. Laboratory studies indicated a distinct advantage in steam injection over hot water injection, and subsequent field trials of hot water injection have since given way to trials of steam injection.

Technical information concerning steam injection became available during the latter 1950's; many operators began serious consideration of this process in the early 1960's. This interest was quickened by recognition of the operational problems involved in in-situ combustion. Although a few continuous steam injection projects were underway or had been completed, limited information on field results had been presented. However, two significant operations were underway: a steam injection project at Yorba Linda, California; and a hot water injection operation in Kern River, California.[7] The Yorba Linda operation led to the development of the cyclic steam injection process for production well stimulation, which had a significant impact upon operations in California. Other operators began to experiment with the method. Although results were not good in every case, they were outstanding in enough cases to spur rapid development of the process.[8] Incremental production rate from cyclic steam reached about 130 thousand barrels per day in 1968. Through 1971, some 20,000 wells, of a state total of 38,000 active, had been steamed at least once in California;[9] some wells were reported to have had as many as 16 cycles of steaming and production.[9,10]

Currently, many operators in California feel that cyclic steam injection in production wells is principally a stimulation process. It will be necessary to use some continuous injection method in conjunction with cyclic steaming to achieve the high oil recoveries potentially available from thermal methods. Since 1968 there has been a large increase in continuous steam injection for steam flooding and the incremental oil production rate from steam flooding is exceeding 100 thousand barrels per day. Continuous steam injection rate for flooding now exceeds 500 thousand barrels per day (measured as feedwater input to generators) compared to somewhat less than 300 thousand barrels per day of steam used for cyclic stimulation.

Figure 107 provides a comparison of recent trends in incremental oil production from cyclic steam, steam drive and in-situ combustion in California. Cyclic steam and steam flooding require substantial amounts of fuel (usually crude oil) for steam generation. The curves labelled "Fuel Adjusted" are estimates of the net oil production remaining, after

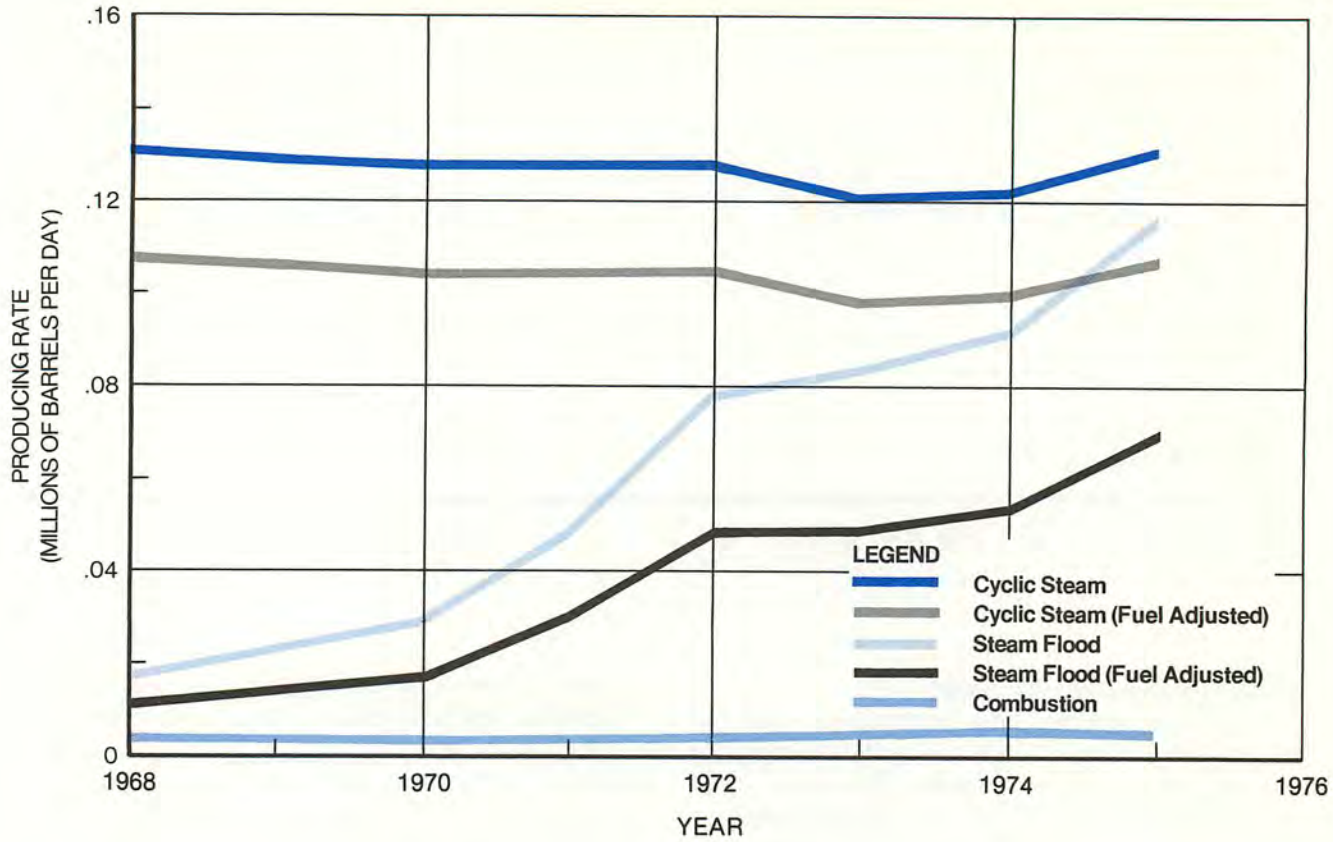


Figure 107. Historical Incremental Production—Thermal Recovery—California.

subtracting the volume of oil required as fuel from the total production.

The increase in cyclic steam production in 1974 and 1975, after a dip in 1973, is thought to be associated with an increase in drilling of new producing wells, which would be candidates for cyclic steam in the heavy oil reservoirs of the San Joaquin Valley. A total of 1,223 new producers were completed there in 1974, compared to 552 in 1973. After the production from these recently initiated cyclic steam operations declines, it is expected that the wells will be converted to steam flood production. Therefore, production from cyclic steam will decline in the next decade, while steam flood production increases.

Figure 108 provides a comparison of the trend of incremental thermal production to total oil production in California. Figure 109 shows the trend in steam usage for steam flooding and steam flooding plus cyclic steam applications.

Although detailed information on ultimate oil recovery from an entire reservoir is not yet available for steam flooding, recoveries in the range of 30 to 40 percent of oil in place at the start of operation have been reported for portions of reservoirs a number of times.[11] Recently, many papers concerning field tests of continuous steam drives have been presented.[12-16] An interesting account of mathematical modelling of steam injection has been presented by Weinstein, et al.[17]

In-situ combustion was tested in Russia in the early 1930's, but modern interest in application of the process dates from publications in the early 1950's[2,3] concerning field pilot tests in the United States. Subsequently, there have been more than 100 field trials of in-situ combustion. Currently, there are only about 30 field tests in operation in the world. Perhaps the most significant statistic concerns the duration of the current field operations. Only two current operations have been underway as long as 14 years: one project in the Midway-Sunset Field, California; and another in the West Newport Field, California. Both have been described as large-scale commercial operations.[19,20,21]

In addition to the two oldest combustion operations, at least four large in-situ combustion operations have been underway for at least nine years. These include operations in the following California fields: San Ardo; South Belridge; and Lost Hills. There have been published accounts of many other in-situ combustion projects in the United States.[22-30]

In-situ combustion requires a relatively high investment for air compressors and close monitoring

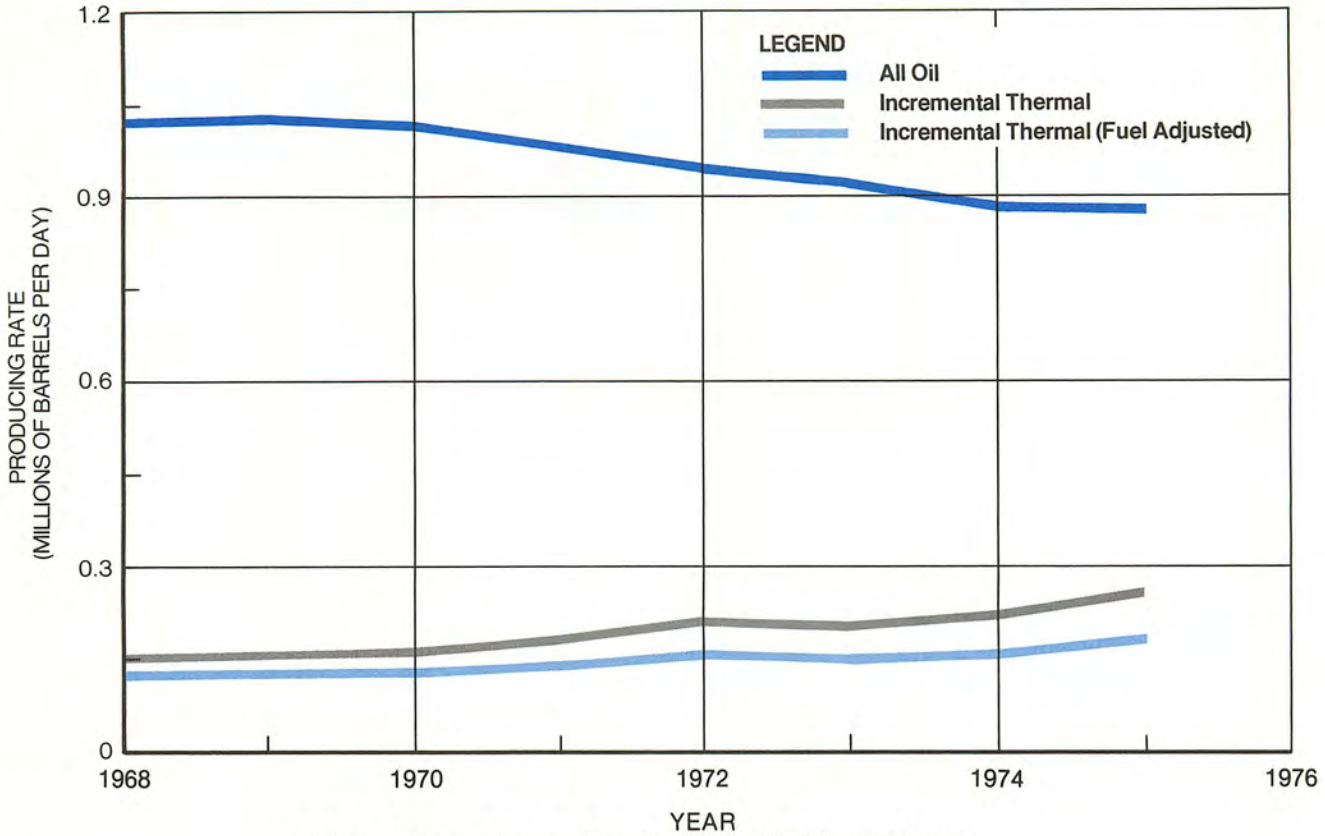


Figure 108. Historical Production—All Oil—California.

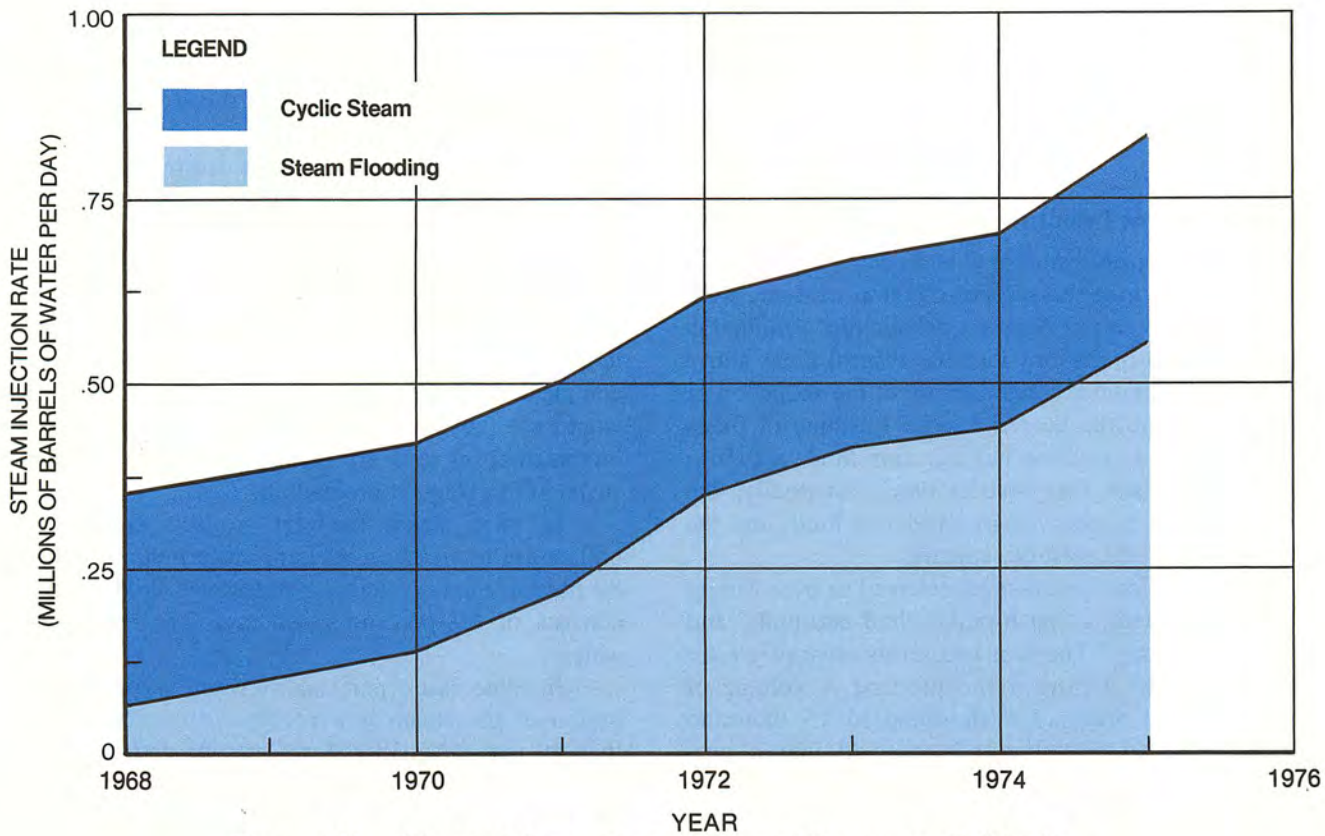


Figure 109. Historical Steam Usage—Thermal Recovery—California.

and control. In addition, the price of low-gravity crude has been significantly less than that for medium- to high-gravity crudes. This large investment/low return phenomenon has created an economic squeeze that has been an important factor in retarding expansion of commercial use of in-situ combustion for heavy oil recovery. Also, steam drive processes have the competitive edge; prior use of cyclic steam stimulation in many heavy oil reservoirs makes steam generation equipment (and experience with its operation) available for subsequent application in continuous steam injection. Thus, in those situations steam injection requires less new investment than the in-situ combustion process.

Some of the in-situ combustion field tests[25,27,28] have involved tertiary recovery of medium- to high-gravity crudes, and there is, in the long term, potential for this type of application. In this respect, in-situ combustion may be an alternative, in specific situations, to surfactant flooding or the CO_2-miscible process. For purposes of this study, it has been assumed that, where applicable, the surfactant process would generally provide a higher oil recovery and would tend to be the dominant process; therefore, the projections in this study of in-situ combustion applications have been restricted to the heavier oil reservoirs. If surfactant flooding does not measure up to expectations, it is possible that in-situ combustion, given sufficient economic incentive, will be utilized as an alternative in a number of reservoirs.

Descriptions of the major thermal processes follow.

Cyclic Steam Injection in Production Wells

Steam or hot water may be injected into production wells to heat the reservoir region near the well. The well is then put back on production. Production rates of viscous oils may increase several times above their non-stimulated rates because of the reduction of oil viscosity in the heated region. Flushing of liners or perforations with the hot injection fluids may also remove deposits that restrict flow. Eventually, the injected heat is removed by produced fluid, and the stimulation cycle must be repeated.

Cyclic steam injection is referred to by a variety of terms, including "push-pull," "huff-and-puff," and "steam soaking." The first two terms obviously refer to the general nature of the process. A volume of steam of the order of 5 thousand to 15 thousand barrels (feedwater volume) is injected into a producing well; the well is then produced for a period of time, ranging from a few months to a year. The term "steam soaking" refers to the practice by a number of operators of shutting-in the well for a period of time before placing it back on production. Many publications have described field experience with cyclic steam injection and proposed mathematical models for the process.[8,36-39]

Continuous Steam Injection for Steam Drive

Steam is injected to heat and displace heavy oil toward producing wells (Figure 110). When steam flows into the oil sand, it condenses as heat is transferred to the rock and reservoir fluids. Heat loss to adjacent formations also increases as the heated zone expands outward from an injection well. Hot water condenses from the steam accumulated at the steam front and tends to settle below the steam vapor, since it is much denser than the vapor. Thus, the steam flows in the upper part of the oil sand as the steam front moves out from the injection well.

The vertical invasion efficiency of the steam zone is dependent on the steam injection rate, well spacing, formation thickness, and permeability distribution.

Oil displacement is enhanced by the lowering of oil viscosity and possibly by increasing the relative permeability to oil with increased temperature in the hot-water-swept region. In the steam-swept region, steam stripping of lighter fractions of the crude also contributes to oil displacement. Displacement efficiencies of steam and hot water for particular crude oils and reservoir sands can be evaluated with laboratory flood studies.

During steam drive, a large fraction of the injected heat is transferred to the reservoir rock in the flooded region. In the final phase of the oil recovery operation, the process efficiency can be improved by injecting unheated water to recover heat from the flooded region and carry it forward as a hot waterflood. Generating the additional heat to provide complete floodout with steam may be inefficient; it would use fuel at a higher cost than the value of the incremental oil recovery that could be obtained with steam at this stage of production.

In most steam recovery projects, single-pass boilers are used. The boilers produce steam of about 80 percent quality; that is, the injected fluid actually consists of 80 percent steam and 20 percent hot water.

In some cases, particularly when vertical distribution of the steam is a problem, injection of less than 80 percent quality steam may be desirable. For example, the additional volumes of hot water in the injected fluid may aid recovery from the lower regions of very thick permeable zones.

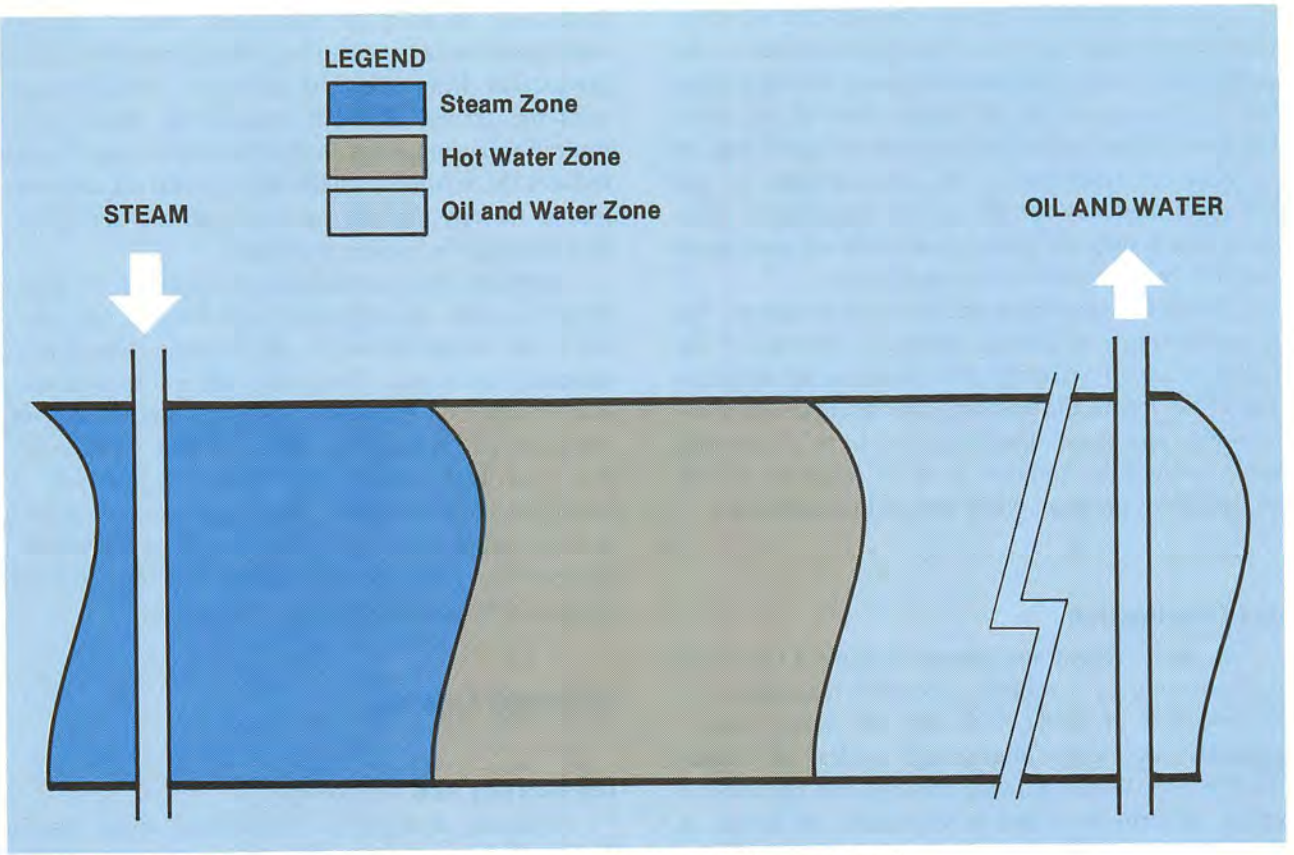


Figure F-4. Steam Drive Process (Steam Flood).
Figure 110. Steam Drive Process (Steam Flood).

In flowing through the reservoir, the hot water transfers heat to the rock and reservoir fluid, resulting in a zone of temperature transition from the temperature in the hot water zone to reservoir temperature at some distance beyond the hot water front. Cooled water flows on ahead, with the result that an ordinary waterflood precedes the warm-water- and hot-waterflooded regions. This flooding sequence results in a gradual reduction in residual oil saturation over the distance between the region of cold water flow and the region of hot water flow.

After the hot water front has progressed about half-way from the injection well to the producing well, cold water may be injected to drive the hot water bank. The cold water recovers heat from the swept region and carries it forward. The optimum time to change from hot water injection to cold water injection can be evaluated with reservoir simulation models.

Conventional In-Situ Combustion Process

The combustion process uses air injection to supply oxygen to a burning front in the oil sand. When air injection is initiated, the crude oil near the injection wellbore begins to oxidize. If the oxidation reaction is rapid (which is the usual case for heavy crudes in Venezuela and California), the oil will ignite spontaneously and begin to burn. If the oxidation reaction is slow, ignition can be obtained by lowering a heater into the injection well to heat the air. After ignition is obtained, continued air injection will cause the burning front to move out through the oil sand and away from the air injection well. Combustion gases flow on ahead and are produced with other fluids at the production well.

Heat generated at the burning front (where the peak temperature is normally in the range of 600° to 1,200°F, but in some instances might reach 1,800°F) vaporizes formation water near the front and develops a steam zone ahead of the burning front. Water formed in the combustion reaction also contributes to this steam zone. The steam mobilizes and displaces much of the heavy oil from the steamed region, leaving a relatively low oil saturation to be overtaken by the burning front. The high temperatures at the burning front vaporize and crack the oil, leaving only a coke-like residue to be burned. The light vapors from distillation and cracking flow ahead with the combustion gas and are absorbed in the oil ahead of the steam front. The coke that is burned is the least valuable, asphaltic portion of the crude.

As combustion continues through the oil zone, water condensing from the steam settles below the steam vapor and combustion gases, causing their flow to concentrate in the upper part of the zone. The combustion front also moves in the upper part of the zone, in response to the concentration of gas flow. The tendency for the in-situ combustion process to sweep only the upper part of the oil zone must therefore be recognized in its application.

When the heat front arrives at the producer, the oil production rate usually increases because of the reduction in oil viscosity with increase in temperature. However, as the burning front nears the producing well, preventive measures (such as circulating water through the annulus) must be taken to protect the well from damage, while production continues.

Wet Combustion

A more recent innovation (Figure 111), with high potential in combustion process technology, is the injection of water with the air, either simultaneously or with alternating cycles of injection.[27,28,32-35] Water, flowing through the burned-out region, absorbs heat and is vaporized; as steam, it carries the heat through the burning front to the steam zone ahead of the combustion front. Producing well operation is benefited by a longer period of warm production from the first heat-front breakthrough until the arrival of the burning front. Also, water saturation accumulates in the burned-out region and reduces the volume available for injected air accumulation, thereby causing more of the injected air to flow through the combustion front.

Perhaps the most important benefit of wet combustion is that the amount of residual oil (or coke) left to be burned as fuel by the burning front is substantially decreased. Thus, more oil is displaced and less air injection is required to burn a unit volume of the reservoir. It has been observed that water injection (usually in the ratio of 0.3 to 0.5 barrels of water per thousand cubic feet of air) can reduce fuel and air requirements by as much as 30 to 50 percent. Water-to-air ratios outside the usual range may be required for specific reservoir applications.

Screening Criteria

Oil Gravity and Viscosity

Viscous, low-gravity crudes are prime candidates for thermal recovery methods because of the

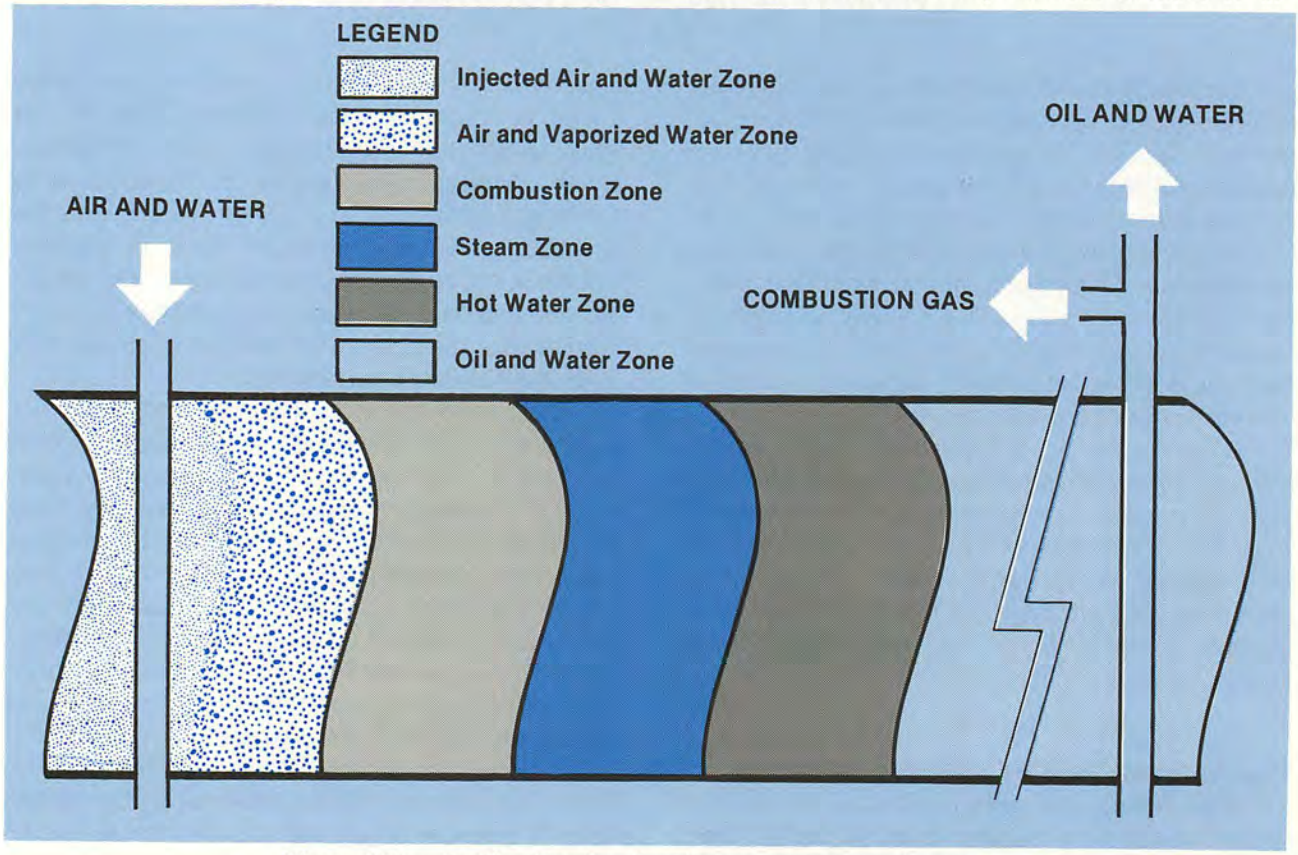


Figure 111. In-Situ Combustion Process—Wet Combustion.

effectiveness of heat in lowering oil viscosity and because of the general inefficiency of other methods for their recovery. For purposes of this study, the data base reservoirs were screened for candidates with oil viscosities higher than about 20 centipoise (cp) (reservoir conditions), and it was found that the tank oil gravities ranged downward from about 25° API.

Oil Content

A minimum average oil content of 500 barrels per acre-foot was selected as necessary to sufficiently exceed fuel requirements for steam generation or for in-situ combustion and permit significant recovery of additional oil.

Depth

The depth of overburden must be great enough to permit use of sufficient injection pressures to obtain practical rates of frontal advance. About 200 feet is the minimum for steam injection and about 5,000 feet is the maximum to avoid excessive heat loss and steam generation pressures and temperatures. About 500 feet is the minimum for in-situ combustion, and greater depths are not a technical limitation. Where zone thickness and transmissibility were satisfactory for application of steam drive, it was given dominance over in-situ combustion for use at depths of less than about 5,000 feet. This dominance of steam drive over in-situ combustion, where conditions are suited to either process, is in recognition of the trend of industry practice in California.

Thickness of Individual Zones

The minimum pay zone thickness for practical use of combustion is about 10 feet, and that for steam or hot water drive is about 20 feet, to avoid excessive loss of heat.

Transmissibility (Permeability x Thickness/Viscosity)

Sufficient transmissibility is needed to permit frontal advance at high enough rates that heat losses to adjacent formations do not become untenable. The minimum acceptable transmissibility for in-situ combustion is about 20 millidarcy-feet per centipoise (md-ft/cp), and for steam or hot water is about 100 md-ft/cp.

Rock Type

Limestone reservoirs were excluded from consideration for in-situ combustion because of generally low oil content due to low porosities. Rock type is not a limitation with steam, except for formations containing swelling clays, which might limit transmissibility.

Geological Screen

Candidate reservoirs from the data base that passed the above process screening criteria were further screened as to the suitability of the general geologic characteristics for application of a thermal process. Information was obtained from literature and from discussion with industry personnel familiar with each reservoir. Reservoirs with thin oil zones under large gas caps; those with thin, discontinuous sand, interbedded with thick shale; and those considered non-floodable due to very complex geology were excluded. Reservoirs considered to have some degree of geologic suitability for thermal flooding were further rated as "good," "fair," or "poor," depending on the combination of geological characteristics affecting the thermal sweep efficiency and process criteria factors. The consequences of the good, fair, or poor ratings on expected recovery performance are discussed later in this appendix.

Other Considerations

Some of the candidate reservoirs were near urban areas, and special environmental problems pertaining to the necessary surface facilities were involved. One reservoir was eliminated from further consideration because of extensive residential development in progress over the surface area.

Process Cost Data

Steam drive was assumed to be utilized primarily for steam processes, with hot water injection selected for a few special cases with very thick zones. Also, a final phase of water injection alone was included in each pattern to utilize heat previously developed in the formation. Wet combustion was assumed for combustion applications, with a final phase of water injection only. Development in all cases was assumed to be carried out in a number of stages, dependent upon reservoir size; it was also assumed that major injection facilities could be moved to later stages after completing injection in early stages.

Process-Independent Costs

The general cost factors for well drilling and completion, production well workovers, lease equipment for waterflooding and production handling, and for lease operation under waterflood are presented in Appendix C; these costs were used as a basis on which to add further costs specific to thermal recovery applications. All injectors were assumed to be new wells, and new producers were added as needed to fill out well patterns on a selected spacing. The additional costs specific to thermal processes are discussed below.

Specific Additional Costs—Steam Processes

An installed cost of $100 per barrel of steam capacity per day for steam generation equipment and associated stack gas scrubbers was used for medium-pressure generators suitable for injection depths to about 2,500 feet.* A cost of $120 per barrel of steam capacity per day was assumed for high-pressure generation equipment for depths greater than 2,500 feet. Steam generator maintenance and extra treating cost for water was assumed to cost $.08 per barrel of feedwater throughput.

Lease crude was assumed to be used for fuel, with an average use of one barrel of crude per 12 barrels steam generated. Oil used for steam generation was subtracted from the total production to obtain the net oil delivered by the project, which is the net oil recovery for the overall process.

Extra water injection equipment for high-rate water injection after discontinuing steam injection was assumed to cost $10,000 per thousand barrels per day of capacity. Extra operating cost for the additional water injection was estimated at $.03 per barrel. Moving of injection facilities was expensed at 30 percent of the initial investment cost.

An extra investment cost of $4,000 per producing well was added to provide for gathering the casinghead gas and recovering condensible liquids. In basin areas where the steam plume must be eliminated from scrubbers, an additional investment of $10 per barrel of steam per day generator capacity was added, and an additional operating expense of $.034 per barrel of steam generated was included. A further cost of $36,000 per year per project in the critical basin areas was added for pollution monitoring.

A contingency fund of 10 percent was added to total investment costs to cover other special costs, which might be incurred in particular locations.

*In this discussion the phrase "barrel of steam" refers to a barrel of water converted to steam.

Specific Additional Costs—Wet Combustion

An installed cost of $400 per horsepower was assumed for electric motor driven air compressors. Extra cost for high-pressure air injection lines was $10,000, $15,000, and $20,000 per injector for 10-acre, 20-acre, and 40-acre size patterns, respectively. Air compressor maintenance cost was estimated to be $.60 per Mscf of air. Power cost for compressor operations was $.023135 per horsepower-hour at a $5 per barrel oil price, and was increased by 25 percent for each $5 increase in oil price.

Extra water injection equipment for a higher water-injection rate after discontinuing air injection was assumed to cost $10,000 per thousand barrels per day of capacity. Extra operating cost for the additional water injection was estimated at $.03 per barrel. Moving of injection facilities was expensed at 30 percent of the initial investment cost. An oil treating cost of $10 per thousand barrels was added to the basic operating expense.

An extra investment cost of $4,000 per producing well was added to provide for gathering and incinerating the casinghead gas. A corrosion treatment cost of $.02 per Mscf of gas handled was provided for protection of the gathering system. In basin areas, where the vent gas must be scrubbed to reduce sulfur emissions, a scrubber investment of $5,680 per million standard cubic feet per day (MMscfd) of gas handled, plus $2,500 per MMscfd of gas for heaters to eliminate the steam plume from the scrubbers was included. An operating cost of $8.47 per MMscfd of vent gas processed was also added. A further cost of $36,000 per year per project in the critical basin areas was added for pollution monitoring.

A contingency fund of 10 percent was added to total investment costs to cover other special costs, which might be incurred in particular locations.

Economic Sensitivities

The economically critical parameters with thermal processes are basically the oil recovery and process cost. On the average it is expected that oil recovery might vary by ± 25 percent from the initial estimate, which means that in individual cases the variance could be much larger. One problem in this study was the lack of detailed information on candidate reservoirs. This information would be essential to a pattern-by-pattern analysis of projected performance, which might vary substantially from an assumed "average pattern" performance applied over

the total project area. Another problem was that an actual operation as carried out may vary substantially from prior assumptions of the schedule in terms of the distribution of injection to various patterns and unforeseen well problems which alter areal withdrawals.

Costs were predicated on the basis of average cost factors. There is normally a continuing effort to improve procedures and techniques to reduce costs, and there is a possibility that some reduction can be achieved as projects are developed from stage to stage. However, costs are not expected to be reduced by more than about 10 percent on the average. On the other hand, there is substantial latitude for costs to increase with unforeseen well problems with hot wells and workovers, equipment failures, added regulations concerning environmental restrictions, etc. It is not unlikely that costs could average as much as 25 percent more than initially estimated.

Detailed Description of Process Analysis Procedures

Estimation of recovery performance with the thermal processes was based on consideration of the individual factors that influence performance in a single pattern, with average reservoir characteristics. The results of the single pattern analysis were then multiplied by the number of patterns to be developed and scheduled, according to the expected pattern development schedule. Finally, an adjustment factor was applied to reduce the recovery, to account for expected reduced sweep effectiveness in multi-pattern development due to regional variations in reservoir properties.

Steam Processes—Single Pattern Analysis

In a single pattern swept by a steam flood, oil will be displaced from a steamed zone and a hot-water-swept zone. Assumptions regarding the performance were derived from reported results of field tests,[4,5,6,14,40,41,42] which utilize temperature logs and/or coring to evaluate intervals invaded by steam and hot water. The assumptions are as follows:

- **Displacement Effectiveness**
  - Steam swept regions: Assume residual oil in swept zone (S_{or}) of 0.15.

    Oil displaced (barrels) = $(S_{oi} - 0.15) \times 7{,}758 \times$ area (acre-feet) swept by steam, where S_{oi} is the initial oil saturation, as a fraction, at start of process.
  - Hot water swept region: Assume S_{or} of 0.25.

    Oil displaced (barrels) = $(S_{oi} - 0.25) \times 7{,}758 \times$ area (acre-feet) swept by hot water.

- **Volumetric Sweep**
  - **Vertical Sweep**

    a. Steam Region: Assume steam will sweep the upper part of a zone to a maximum thickness of 20 feet at up to 2.5-acre well spacing, 15 feet at 5-acre well spacing, and 10 feet at 10-acre well spacing. Swept thickness at intermediate well spacings would be proportional on a linear basis.

    b. Hot Water Region: Assume that hot water will sweep an additional zone below the steam to an average thickness of up to 40 feet at 2.5-acre well spacing, 35 feet at 5-acre well spacings would be proportional on a linear Again, swept thickness at intermediate well spacings would be proportional on a linear basis.

  - **Areal Sweep**

    a. Steam Region: Assume 70 percent sweep at well spacings up to 2.5 acres, 65 percent sweep at 5-acre well spacing, and 60 percent sweep at 10-acre well spacing. Sweep at intermediate well spacings would be proportional on a linear basis.

    b. Hot Water Region: Assume 90 percent sweep at well spacings up to 2.5 acres, 85 percent at 5-acre well spacing, and 80 percent sweep at 10-acre well spacing. Sweep at intermediate well spacings would be proportional on a linear basis.

- **Capture Efficiency and Oil Recovery**

  In reservoirs that have undergone prior depletion, some of the displaced oil may resaturate unswept regions where there is gas or mobile water saturation. Capture efficiency is the percentage of the oil displaced from the swept region that is recovered from wells. It is dependent on several factors: the difference in oil saturation at the start of the process (S_{oi}) and the maximum oil saturation possible in the presence of connate water ($1 - S_{wc}$); the areal sweep for thermal processes (because the displaced oil tends to be banked above or ahead of the warm water front); and oil viscosity. The following formula can be used to estimate capture efficiency.

Capture Efficiency = 100% − f (100 − areal sweep efficiency, %) (1 − S_{wc} − S_{oi})
where: f = 2 for oils 20 to 100 cp
= 4 for oils 100 to 1,000 cp
= 6 for oils > 1,000 cp

Hot Water Injection

For the special case of hot water injection, the vertical sweep efficiency was assumed to be 80 percent of the zone thickness. Displacement effectiveness, areal sweep, and capture efficiency were assumed to be the same as for the hot-water-swept region in a steam flood.

Reservoir Development and Performance Schedule

If the steam process had not been tested in the reservoir, it was assumed that a pilot of 9 patterns of the size and type planned for full scale development would be prepared during the first year. The pilot would begin operation during the second year and continue on the schedule described for each process. If performance were favorable during the second and third years (two years of operation), the first expansion would be prepared during the fourth year and begin operation in the fifth year. If the process had already been tested and/or was being applied to a portion of the reservoir, it was assumed the first new expansion would be prepared in the first year and begin operation the second year.

The first expansion would encompass about 20 percent of the reservoir area for reservoirs of approximately 5,000 acres or more. It would cover about 25 percent of reservoir area for those of 2,000 to 5,000 acres, and about 30 percent for reservoirs of less than 2,000 acres. Subsequent expansions of comparable size would be scheduled with ultimate development of 90 percent of the reservoir area occurring within about 20 years from the start of the first expansion. This would permit some repetitive use of major capital equipment.

Existing producing wells would be used insofar as practical. If current producing well spacing approximated 5 acres, new injectors would be infill drilled to obtain 5-acre, 5-spot patterns.* If producing well spacing was 2.5 acres, selected producer locations would be changed to injectors to obtain 10-acre, inverted 9-spot patterns. Also, 10-acre, inverted 9-spot patterns would be developed by new drilling of injection and production wells if the producing well spacing was mainly greater than 5 acres.

Steam would be injected for 5 years at a rate of 0.2 pore volume (water equivalent) per year of the pattern thickness expected to be ultimately swept by steam or hot condensate. Cold water would then be injected for one final year at three times the prior rate of steam injection.

The oil recovery schedule in fraction of total oil recovery expected from the pattern is shown in Table 42.

TABLE 42

PROJECTED OIL RECOVERY SCHEDULE FROM STEAM PROCESSES

Year	Oil Recovery, Fraction
1	0.10
2	0.20
3	0.22
4	0.22
5	0.16
6	0.10
Total	**1.00**

Oil required for fuel to generate steam, in the ratio of 1 barrel of oil to 12 barrels of steam, was subtracted from the produced oil volume to obtain the net oil delivered.

Hot waterflood would be used as an alternative to steam flood where thick, continuous zones of more than about 80 feet thickness would have poor vertical sweep with steam, because of gravity overriding. Pattern development would be the same as for steam. For this study, hot water was assumed to be a mix of about 3 parts steam (80 percent quality) to 7 parts cold water.

Hot water would be injected for four years at the rate of 0.5 pore volume per year of the expected vertical thickness to be swept in the pattern. Cold water then would be injected at the same rate for two additional years. The recovery schedule, in fraction of total recovery per year, is expected to be the same as for steam flood (see Table 42). Oil required as fuel for steam generation (1 barrel of oil for each 12 barrels of steam) was subtracted from the oil produced to obtain the net oil delivered.

*See Glossary, "flood pattern."

Wet Combustion—Single Pattern Analysis

In a single pattern swept by wet combustion, oil will be displaced from a burned zone, a steamed zone, and a hot-water-swept zone. The assumptions regarding the performance are as follows:

- **Displacement Efficiency**
  - Burned zone: Assume average of 200 barrels per acre-foot fuel consumption (S_{ob}). $S_{ob} = 200/7{,}758\ \phi$, where ϕ is fractional porosity of the rock.* Change in oil saturation (barrels) $= S_{oi} - S_{ob}$, where S_{oi} = initial oil saturation at start of process.
  - Steamed zone: Assume average $S_{or} = 0.15$ for heavy oil ($<30°$ API). Change in oil saturation $= S_{oi} - S_{or}$.
  - Hot water zone: Assume average $S_{or} = 0.25$ for oils $>30°$ API. Change in oil saturation $= S_{oi} - S_{or}$.

- **Volumetric Sweep**
  - **Vertical Sweep**

    a. Burned zone: Assume average burned zone thickness of up to 12 feet at well spacings of up to 2.5 acres. Assume average burned zone thickness of 10 feet at larger well spacings. The assumed burned thickness is derived from results of combustion field tests.[2,27,43]

    b. Steam zone: Assume steam zone thickness of up to 10 feet added to that of burned zone.

    c. Hot water zone: Assume hot water zone thickness of up to 30 feet added to the combined thickness of the burned zone plus steam zone.

  - **Areal Sweep**

    a. Burned zone: Assume 60 percent sweep efficiency at well spacings up to 2.5 acres and 55 percent sweep at larger well spacings.

    b. Steam region: Assume 70 percent sweep efficiency at well spacings up to 2.5 acres, 65 percent sweep efficiency at 5-acre well spacing, and 60 percent sweep efficiency at 10-acre well spacing. Sweep efficiency at intermediate well spacings would be proportional on a linear basis.

    c. Hot water region: Assume 90 percent sweep at well spacings up to 2.5 acres, 80 percent at 5-acre well spacing, and 80 percent at 10-acre well spacing. Sweep efficiency at intermediate well spacings would be proportional on a linear basis.

- **Volume of Oil Displaced and Oil Recovery**

  The volume of oil displaced from each swept zone in a well pattern is obtained by multiplying the pattern area (in acres) by the areal sweep efficiency, the swept thickness (in feet), the oil displacement (in fraction of the pore volume), the fractional porosity of the rock, and a factor of 7,758 to convert the answer to units of barrels.

  The total oil displaced is then the sum of that displaced from the burned, steamed, and hot-water-swept zones.

  Capture efficiency of the oil displaced is calculated by the same method described above for steam processes. The oil recovery from the single pattern is then obtained by multiplying the total oil displaced by the capture efficiency.

*The assumed fuel consumption is based on laboratory experimental data.[32,34,35]

Reservoir Development and Performance Schedule

If in-situ combustion had not been tested in the reservoir, it was assumed that a pilot of 9 patterns of the size and type planned for full scale development would be prepared during the first year. The pilot would begin operation in the second year and continue on the schedule described for that process. If performance were favorable during the second and third years (two years of operation), the first expansion would be prepared during the fourth year and begin operation in the fifth year. If the process had already been tested and/or was being applied to a portion of the reservoir, it was assumed the first new expansion would be prepared in the first year and begin operation the second year.

The first expansion would be about 20 percent of the reservoir area for reservoirs of approximately 5,000 acres or more. It would be about 25 percent for those of 2,000 to 5,000 acres, and about 30 percent for reservoirs of less than 2,000 acres. Subsequent expansions of comparable size would be scheduled to achieve an ultimate development of about 90 percent of the reservoir area within about 20 years from the start of the first expansion. This would permit some repetitive use of major capital equipment.

Existing producing wells would be utilized insofar as practical. Inverted 9-spot patterns would be

developed by drilling new injectors or by converting some producers to injectors. Where production well spacing was predominately 2.5 acres, 10-acre, 9-spots would be utilized. Where usable producers were at greater spacings and depth was less than about 3,000 feet (substantial new drilling would be required), 20-acre, 9-spots would be developed. Forty-acre, 9-spots would be developed where depth was greater than about 3,000 feet.

The water-to-air injection ratio during the period of alternating air and water injection would average 1 barrel of water per 1 Mscf of air. After a period of air injection sufficient to advance the steam condensation front to the producer, water alone would be injected, in an amount of about 1 pore volume of the heated thickness, to complete the flood. Approximately 11 MMscf of air per acre-foot of burned sand, and a fuel consumption in the sand of 200 barrels per acre-foot, were estimated for the wet combustion. The estimated schedule of injection and of production of recoverable oil for the different 9-spot patterns is shown in Table 43.

Timing of the starts of thermal projects in the various base case reservoirs was related to the progress of current recovery operations. The earliest starts (1977 or 1978) were scheduled for reservoirs already nearing depletion by current methods and those where the project would be an expansion from a prior thermal application. Further phasing-in of thermal EOR operation was scheduled to coincide with conventional recovery depletion, to arrest declining production rates.

Recovery Adjustment Factors

The estimated recovery performance of a single, basic well pattern with uniform, average reservoir properties provides a basis for extrapolation to total project performance. However, an overall performance projected on the assumption that all patterns perform the same as estimated for the single pattern was considered too optimistic, and needed to be adjusted downward. A direct extrapolation implies either that the average reservoir properties are uniformly distributed or that poor performance in any pattern will be compensated for by better performance in another. Neither of these cases is true.

In fact, important characteristics such as permeability, porosity, fluid saturation, zone thicknesses, and pressure often vary significantly from one region to another within a reservoir. Variations within a pattern can result in non-uniform distribution of in-

TABLE 43

PROJECTED OIL RECOVERY SCHEDULE FROM IN-SITU COMBUSTION PROCESS

	Pattern Size								
	10 acres			20 acres			40 acres		
	Injection			Injection			Injection		
Year	Air (MMscf)	Water (MB)	Oil Produced (Fraction)	Air (MMscf)	Water (MB)	Oil Produced (Fraction)	Air (MMscf)	Water (MB)	Oil Produced (Fraction)
1	212	212	0.16	210	210	0.08	230	230	0.05
2	290	290	0.26	286	286	0.15	365	365	0.08
3	290	290	0.30	286	286	0.18	365	365	0.10
4		580	0.2	286	286	0.22	365	365	0.12
5		290*	0.08*	142*	428	0.18	365	365	0.12
6					572	0.12	365	365	0.14
7					572	0.07	365	365	0.12
8								730	0.11
9								730	0.07
10								730	0.05
11								730	0.04
			1.00			1.00			1.00

* 6 months of injection or production.

jected fluid and reduced sweep efficiency. Differences between adjacent patterns sharing a common producer may cause extensive breakthrough from one pattern, requiring the producer to be shut-in before the other pattern area served by that producer can be completely swept. This problem with multi-pattern, in-situ combustion operations has been encountered in the Sloss field.[27] Although the Sloss crude is not a heavy, viscous oil, the problem is likely to be even more pronounced with high-viscosity crude oils.

Also, in large multi-zone reservoirs (which represent the major fraction of the heavy oil data base) some zones may be too thin, discontinuous, or have too low permeability in certain areas to be included in well completions for the thermal process. Elimination of these poor parts of the reservoir would reduce the effective volume to be swept in patterns in those areas. Although zones thicker and more permeable than average may exist in other areas, thermal recovery might not increase directly with zone thickness; and it would, therefore, not be likely that the below-average pattern recovery from poor areas would be offset. All of these considerations point to a reduced recovery performance from that based on the single-pattern analysis with uniform, average reservoir properties. The degree of reduction in recovery expected from a particular reservoir is related to the degree and nature of the non-uniformities in that reservoir.

Based on rather generalized, qualitative geologic information obtained in screening the reservoirs as to suitability for thermal flooding, selected base case recovery adjustment factors of 0.7, 0.6, and 0.5 were applied to reservoirs rated good, fair, and poor, respectively. The good, fair, and poor ratings were based on judgments of the effect of the reservoir non-uniformities on the volumetric sweep that might be attained, compared to that estimated for a single pattern with uniform properties. Resulting recovery projections for some of the larger reservoirs were reviewed by industry personnel familiar with the particular reservoirs and were found to be satisfactory approximations of their independent assessments of expected recovery.

The cost/recovery ratios for the larger reservoirs have a strong influence on the composite cost/recovery ratios for thermal recovery estimated from data base reservoirs. Different areas of large reservoirs (5,000 acres or more) might be of different quality and involve different cost/recovery ratios. Thus, one area might be economically attractive for application of thermal recovery at a lower oil price than another area within the same reservoir. In recognition of these considerations, and for economic case estimates, the larger reservoirs were subdivided into two or three areas of approximately equal size, and the overall enhanced recovery estimated for the total reservoir was apportioned to the different areas in accordance with an estimate of their relative quality for thermal EOR. Thus 60 percent of the enhanced recovery potential might be in the best half of the reservoir area, and the remaining 40 percent of the recovery potential in the poorer half of the reservoir area. This procedure provided detail on the estimated cost/recovery ratios for the various areas of the reservoir, though it did not change the estimated ultimate recovery for the total reservoir.

Extrapolation Process

Estimates of thermal EOR potential were extrapolated from the data base reservoirs to the total potential in each of the three states represented (California, Texas, and Louisiana). Original heavy oil in place (25° API and below) in commercially productive reservoirs was used as the basis for the extrapolation. The information source for the original oil in place (OOIP) is the U.S. Bureau of Mines (USBM) Information Circular 8352, *Heavy Crude Oil Resource, Reserve and Potential Production in the United States* (1967). Although the remaining resource and reserve figures in that publication are outdated by subsequent production, the OOIP figures are reasonably valid for purposes of this study. The USBM publication also provided information on the distribution of the resource, at depths above 3,000 feet and below 3,000 feet, and between sandstone and limestone. This information was useful in applying thermal EOR process performance factors derived from the data base reservoirs for the three states and in extending the extrapolation to other states.

An extrapolation procedure based on American Petroleum Institute (API) production statistics, as used for other processes applicable to medium- and high-gravity crudes, was found to under-estimate the potential resource base for thermal EOR significantly. The API extrapolation procedure relates the size of the thermal EOR resource base for a state to the fraction of incremental ultimate oil recovery that consists of low-gravity oil (less than 20° API). Recovery efficiency from reservoirs with 20° API and heavier oil has been much less than that for lighter oil; and a given cumulative recovery must relate to a larger amount of the heavy oil in place than for a medium-gravity oil. Also, thermal EOR potential extends into the gravity range up to about 25° API (which further increases the potential resource base). Demonstrations of the extrapolation process based

on OOIP were applied to the three states represented in the data base. The following parameters were selected to project the incremental ultimate recoveries used in these demonstrations:

- Base case performance and costs
- Oil price of $25 per barrel
- Minimum DCFROR requirement of 10 percent
- Moderate tax case.

Example Extrapolations

California

The estimated heavy OOIP in California is 61 billion barrels. California heavy oil reservoirs in the data base had a total of 46.8 billion barrels originally in place, which amounts to 76.7 percent of the state total. Assuming that the California data base reservoirs are representative of those outside the data base, in terms of relative potential for thermal EOR, the California portion of the data base thermal EOR would amount to about 76.7 percent of the total thermal EOR potential for the state. Based on the selected set of parameters listed above, incremental ultimate recovery from thermal EOR methods for California is 5.1 billion barrels, which corresponds to an application factor of 8.35 percent of OOIP.*

The data base reservoir sample of state OOIP located at depths less than 3,000 feet was 84.44 percent; that for depths greater than 3,000 feet was 67.8 percent of the state OOIP. Use of these percentages, with the amounts of data base EOR distributed between those depths, allowed estimation of the distribution of the state thermal EOR between those depths. State thermal EOR for depths less than 3,000 feet is 3.4 billion barrels and the application factor is 10.4 percent of the OOIP. For depths below 3,000 feet, the figures are 1.7 billion barrels thermal EOR and an application factor of 6.3 percent of the OOIP.

The state thermal EOR estimated to be recoverable under the selected parameters by use of steam or hot water is 4.2 billion barrels, and by use of wet combustion, 0.9 billion barrels.

Texas

Original heavy oil in place in Texas was estimated at 33.7 billion barrels. The OOIP from data base Texas heavy oil reservoirs amounted to 11.65 percent of the state total. The data base sample involved only one reservoir, at less than 3,000 feet, which amounted to 5 percent of the state OOIP for that depth range. Seven heavy oil reservoirs in the data base were at depth ranges below 3,000 feet and amounted to 12.9 percent of the state heavy OOIP in that depth category. The total state thermal EOR potential was estimated to be 0.9 billion barrels, with an application factor of 2.7 percent. The depth distribution is estimated to be about 0.6 billion barrels from depths less than 3,000 feet, with an application factor of 11.2 percent OOIP; and 0.3 billion barrels from depths greater than 3,000 feet, with an application factor of 1.06 percent OOIP. All of the Texas thermal EOR is assigned to wet combustion.

Louisiana

Original heavy oil in place in Louisiana is estimated to be 6.8 billion barrels, with about 18 percent distributed at depths above 3,000 feet, and 82 percent at depths below 3,000 feet. The data base sample included only one Louisiana heavy oil reservoir, at less than 3,000 feet. It represented about 67.4 percent of the shallow OOIP for the state, but only 12.1 percent of the total heavy OOIP. The data base reservoir sample was used for estimation of only the shallow Louisiana thermal EOR, and the Texas application factor of 1.06 percent OOIP was used for the resource below 3,000 feet. Total estimated thermal EOR for Louisiana is 0.5 billion barrels, with 0.44 billion barrels allocated to the shallow resource (application factor about 35 percent), and 0.06 billion barrels to the deeper resource. Of the Louisiana thermal EOR that may be recovered, approximately 0.25 billion barrels would be by steam and 0.25 billion barrels would be by wet combustion.

Other States and Total United States

For other states, the Texas application factors of 11.1 percent OOIP for the shallow reservoirs and 1.06 percent OOIP for those at depths below 3,000 feet were used to arrive at state totals. The deeper resources and shallow resources with thin sand were mainly assigned to in-situ combustion, with the remainder assigned to steam processes. These results are shown in Table 44.

Results for the Three States and the U.S.†

The producing rates from the three states and from the total United States were assumed to be pro-

* "Application factor" is defined as the ratio of the incremental ultimate recovery to the total OOIP in the region examined.

†All values extrapolated to state or U.S. totals on all figures in this appendix were calculated from base case performance and costs, a minimum DCFROR requirement of 10 percent, moderate tax case, constant 1976 dollars, and oil price of $15 per barrel unless otherwise noted.

TABLE 44

EXAMPLE EXTRAPOLATION OF POTENTIAL OIL RECOVERY FROM THERMAL PROCESSES -- THREE STATE TO TOTAL U.S.
(Millions of Barrels)

State	Thermal EOR		
	Steam	Combustion	Total
Arkansas	634	3	637
Oklahoma	60	59	119
Wyoming	68	49	117
Kansas	25	28	53
Alabama-Mississippi	—	28	28
Other States	13	3	16
Subtotal	800	170	970
3-States (Data Base)	4,450	2,050	6,500
Total U.S.	**5,250**	**2,220**	**7,470**

Note: Assumptions are as follows --

- Base case performance and costs
- Oil price — $25 per barrel
- Minimum DCFROR Requirement — 10 percent
- Tax case — Moderate

portional to the producing rates from the data base reservoirs (for the same economic parameters). For example, the incremental ultimate recovery from thermal EOR processes for the three states was divided by the incremental ultimate recovery from data base reservoirs to obtain the recovery ratio factor. The data base production rate for incremental recovery at each point in time was then multiplied by the recovery ratio factor to obtain the producing rates of the three states.

For the three-state total of steam applications, the sensitivity of ultimate recovery and oil production rate schedule to oil price (base case with moderate tax assumptions) is illustrated in Figures 112 and 113. Similar sensitivity for the United States is shown in Figures 114 and 115. Incremental ultimate recovery generally increases with oil price. Near-term production rates increase substantially as oil price increases to $15 and to $20 per barrel.

The sensitivities of total U.S. performance to cost variations of −10 percent or +25 percent from the base case are shown in Figures 116 and 117. The sensitivities to recovery performance variations of −25 and +25 percent of the base case estimates are shown in Figures 118 and 119. These cost and recovery variations approximate the range of uncertainty that is considered to be associated with the projections of this study. Since substantial experience with steam process operations has already included efforts to decrease costs, the margin for future cost reduction appears to be limited. On the other hand, increasing requirements for environmental protection and monitoring of operations could increase costs above those based on current regulations and practice. The detail of reservoir information required for accurate predictions of recovery estimates was not available; these projections, therefore, are at best very rough approximations.

For the three-state incremental ultimate recovery from in-situ combustion, the sensitivities of ultimate recovery to oil price and of production rate schedule to oil price are shown in Figures 120 and 121. Ultimate recovery generally increases as oil price increases. The near-term oil production rate increases substantially as the oil price increases to $15 per barrel from $10 per barrel.

For the total U.S. recovery by in-situ combustion, the sensitivities of ultimate recovery and of production rate schedule to oil price are shown in Figures 122 and 123. These trends are similar to those for the three-state total.

Sensitivities of ultimate recovery and recovery rate from in-situ combustion for the total U.S. to +25 and −25 percent of the base case recovery estimate are shown in Figures 124 and 125. Sensitivities to cost variations of −10 and +25 percent of the base case are shown in Figures 126 and 127. These ranges of variation in recovery and costs approximate the range of uncertainty that is anticipated to be associated with recovery and cost projections. It may be noted, with reference to Figures 126 and 127, that a 10-percent decrease in cost from the base case does not change the expected recovery, except at the $10 per barrel oil price.

The sensitivity of recovery by all thermal processes to oil price, as extrapolated for the total United States, is shown in Figure 128; and the projected total production rate from thermal processes is shown in Figure 129. The sensitivities to +25 percent and −25 percent recovery factors, relative to the base case, are shown in Figures 130 and 131, respectively. These results illustrate the rather broad range of uncertainty in the ultimate recovery and production rate projections. The total thermal recovery sensitivity to +25 percent and −10 percent of the base case cost assumptions is shown in Figure 132. The production rate sensitivity to the same cost variation is shown in Figure 133.

The effects of restrictive tax assumptions, compared to the moderate tax assumptions, for total

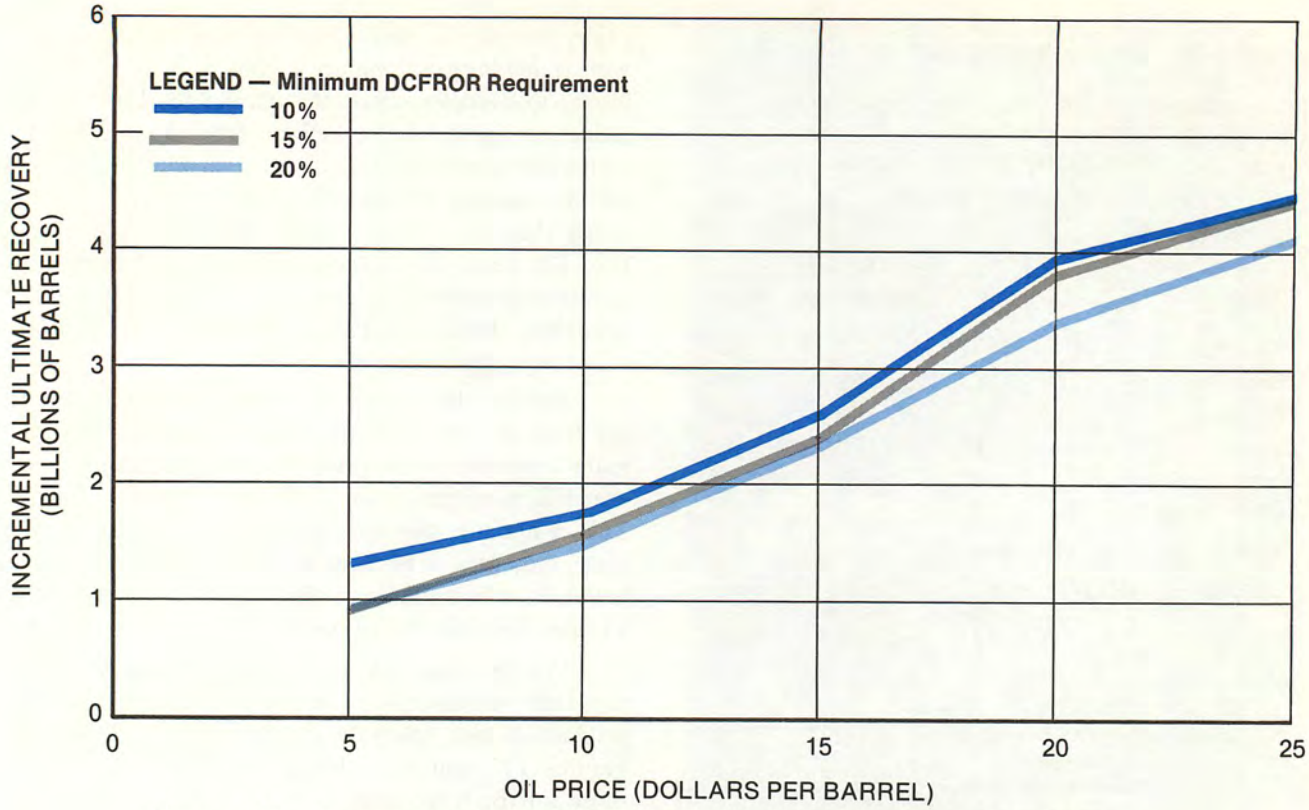


Figure 112. Incremental Ultimate Recovery—Steam (and Hot Water) Flooding—Total for Three States.

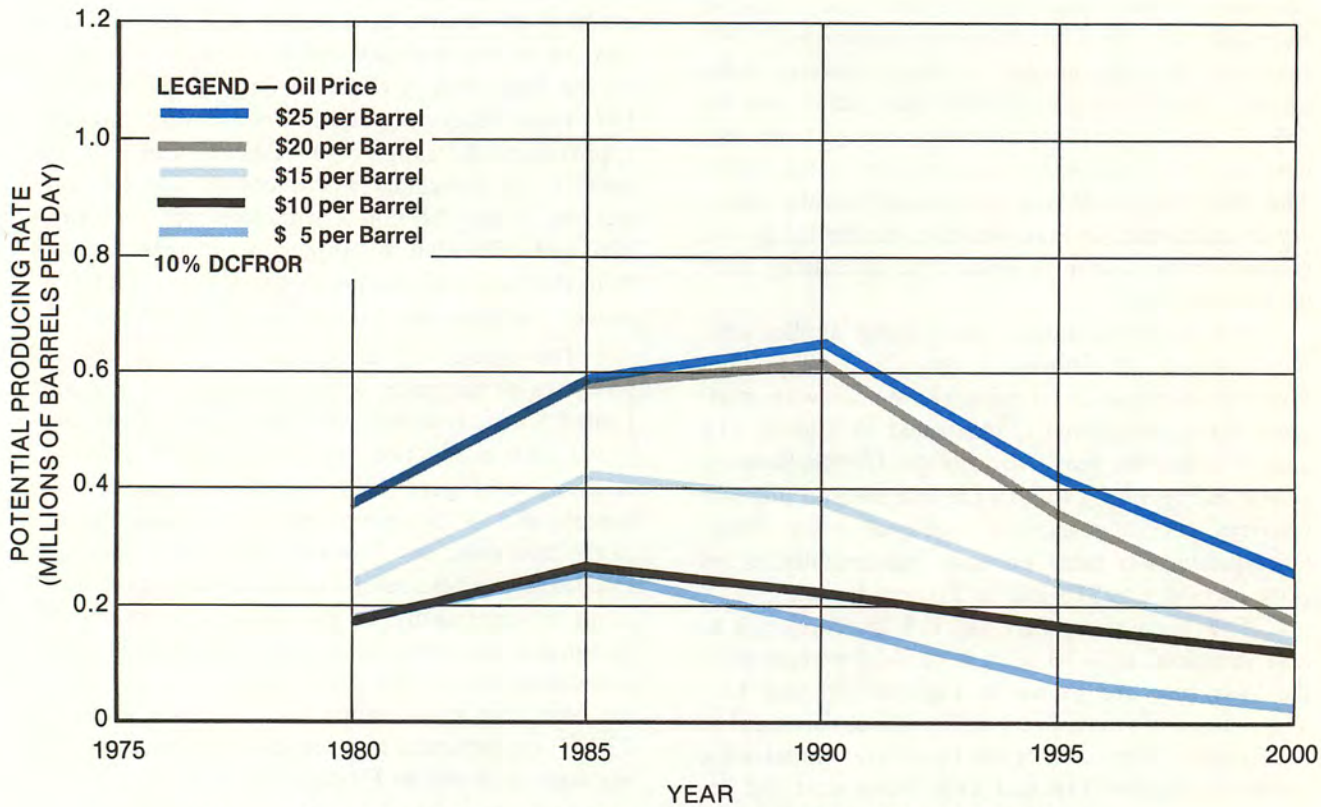


Figure 113. Potential Producing Rate—Steam (and Hot Water) Flooding—Total for Three States.

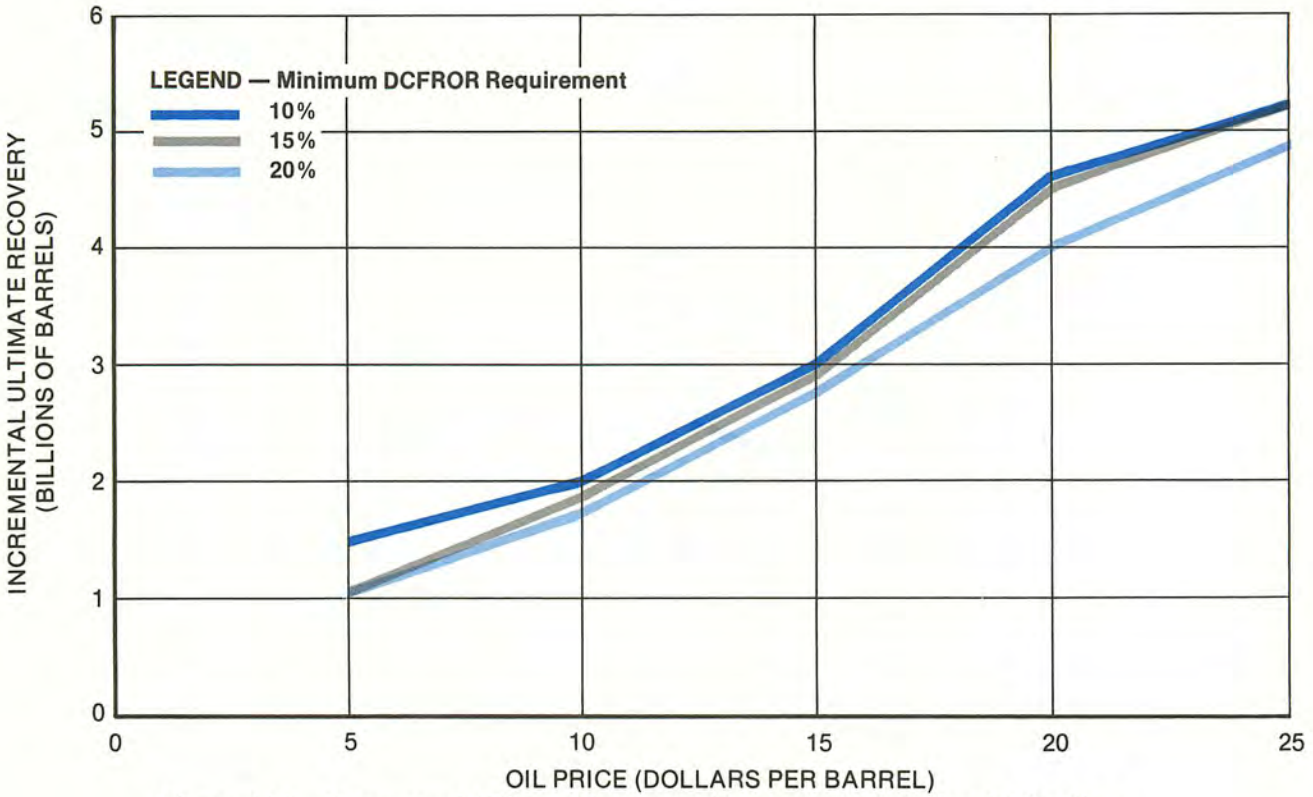


Figure 114. Incremental Ultimate Recovery—Steam (and Hot Water) Flooding—Total U.S.

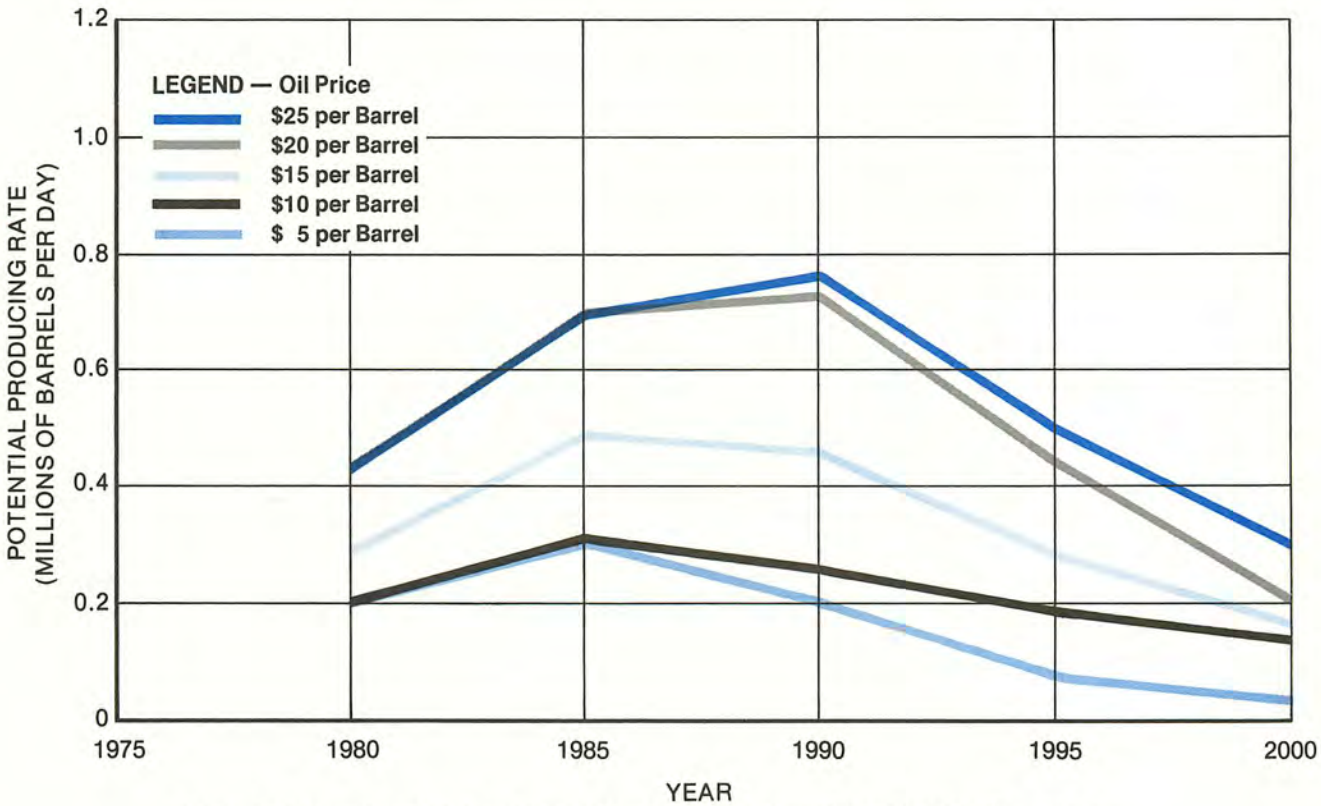


Figure 115. Potential Producing Rate—Steam (and Hot Water) Flooding—Total U.S.

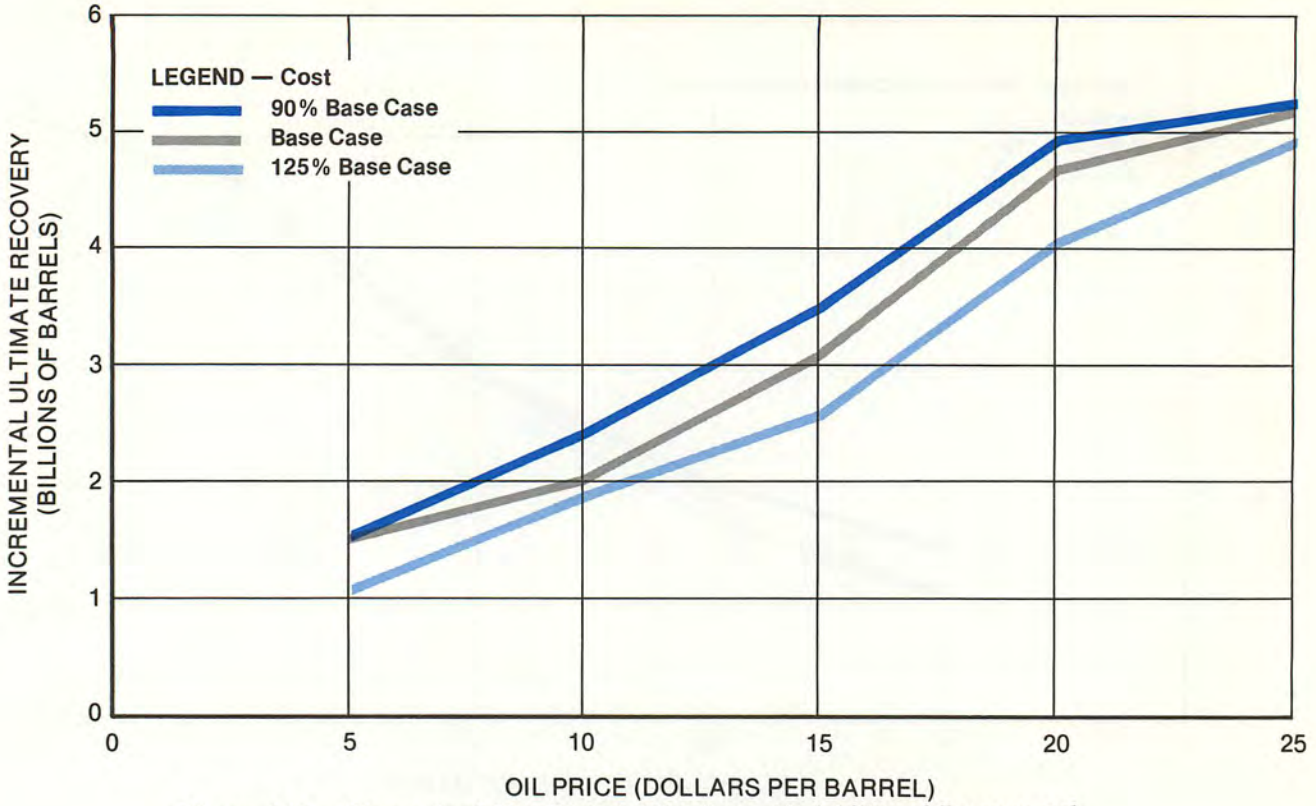


Figure 116. Steam (and Hot Water) Flooding—Variability of Incremental Ultimate Recovery with Process Costs—Total U.S.

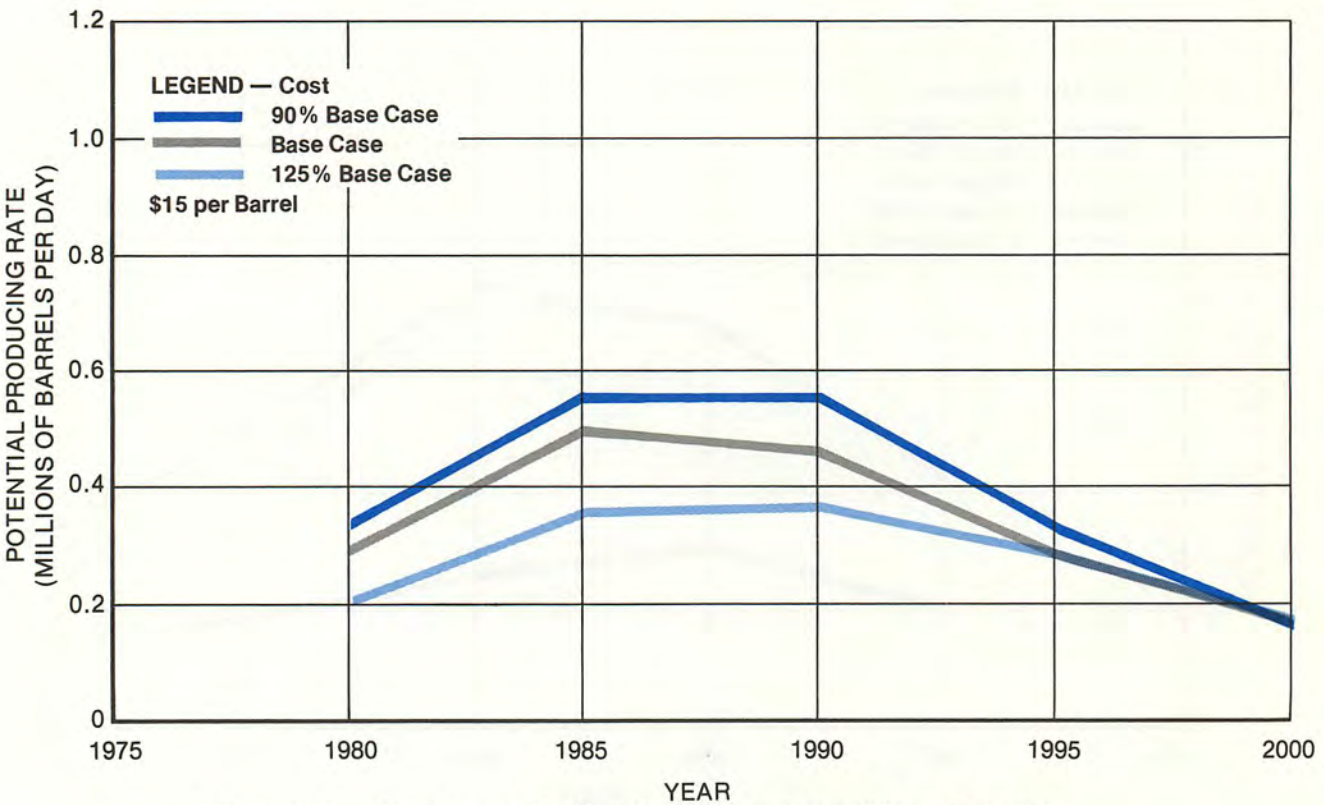


Figure 117. Steam (and Hot Water) Flooding—Variability of Potential Producing Rate with Process Costs—Total U.S.

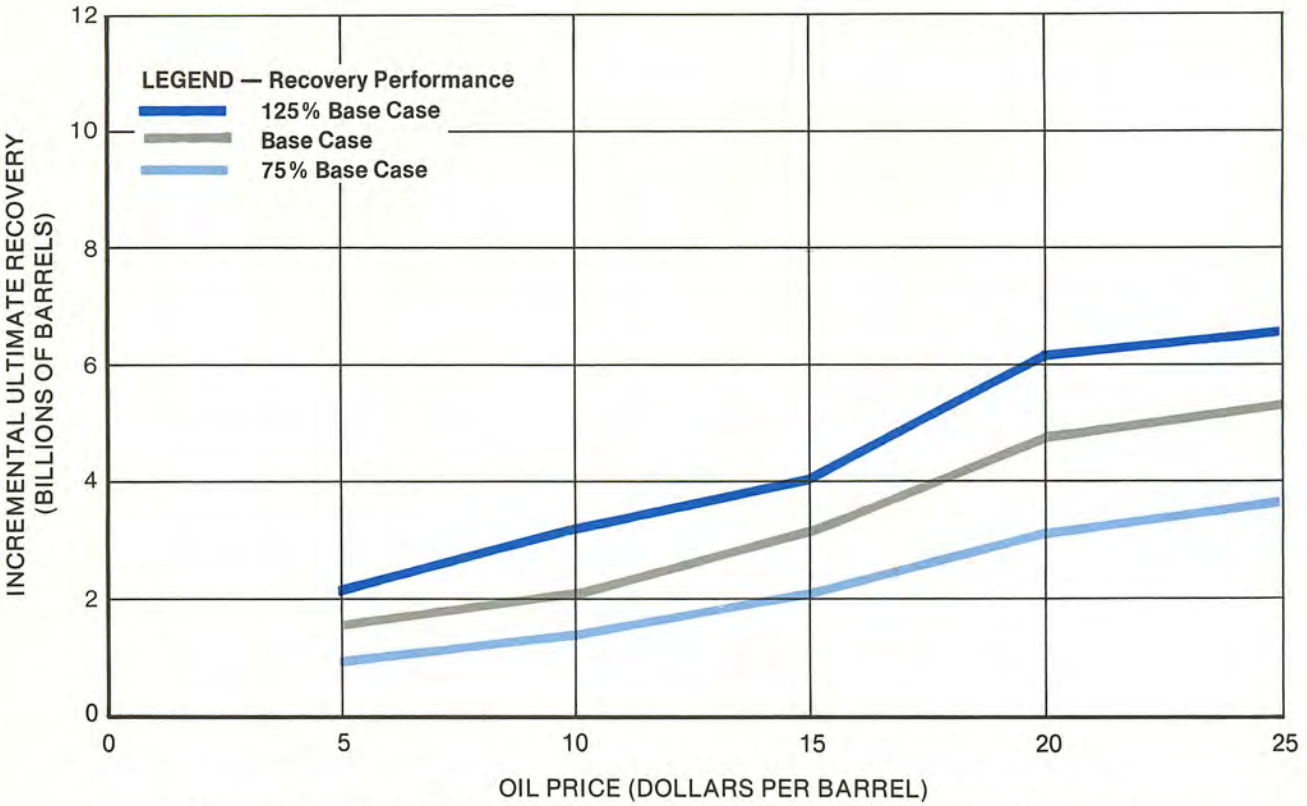


Figure 118. Steam (and Hot Water) Flooding—Variability of Incremental Ultimate Recovery with Reservoir Recovery Performance—Total U.S.

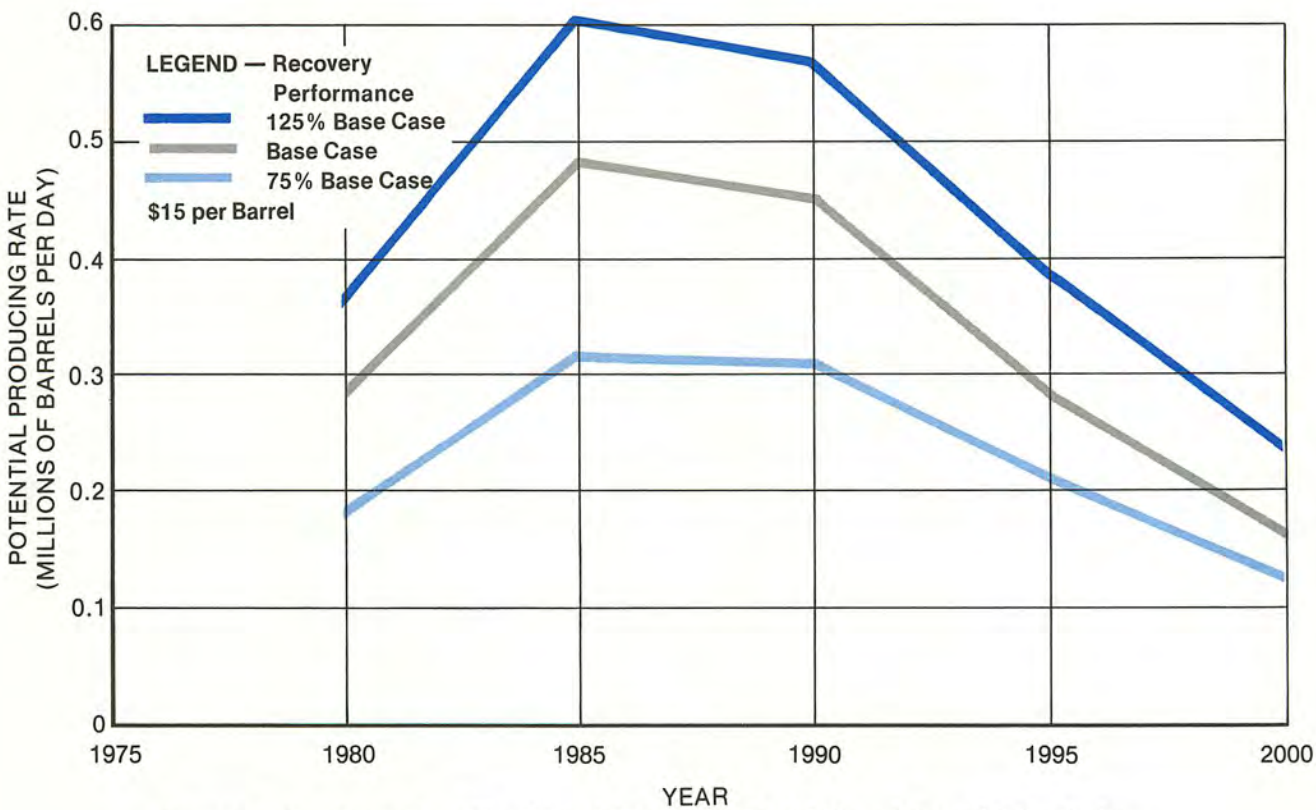


Figure 119. Steam (and Hot Water) Flooding—Variability of Potential Producing Rate with Reservoir Recovery Performance—Total U.S.

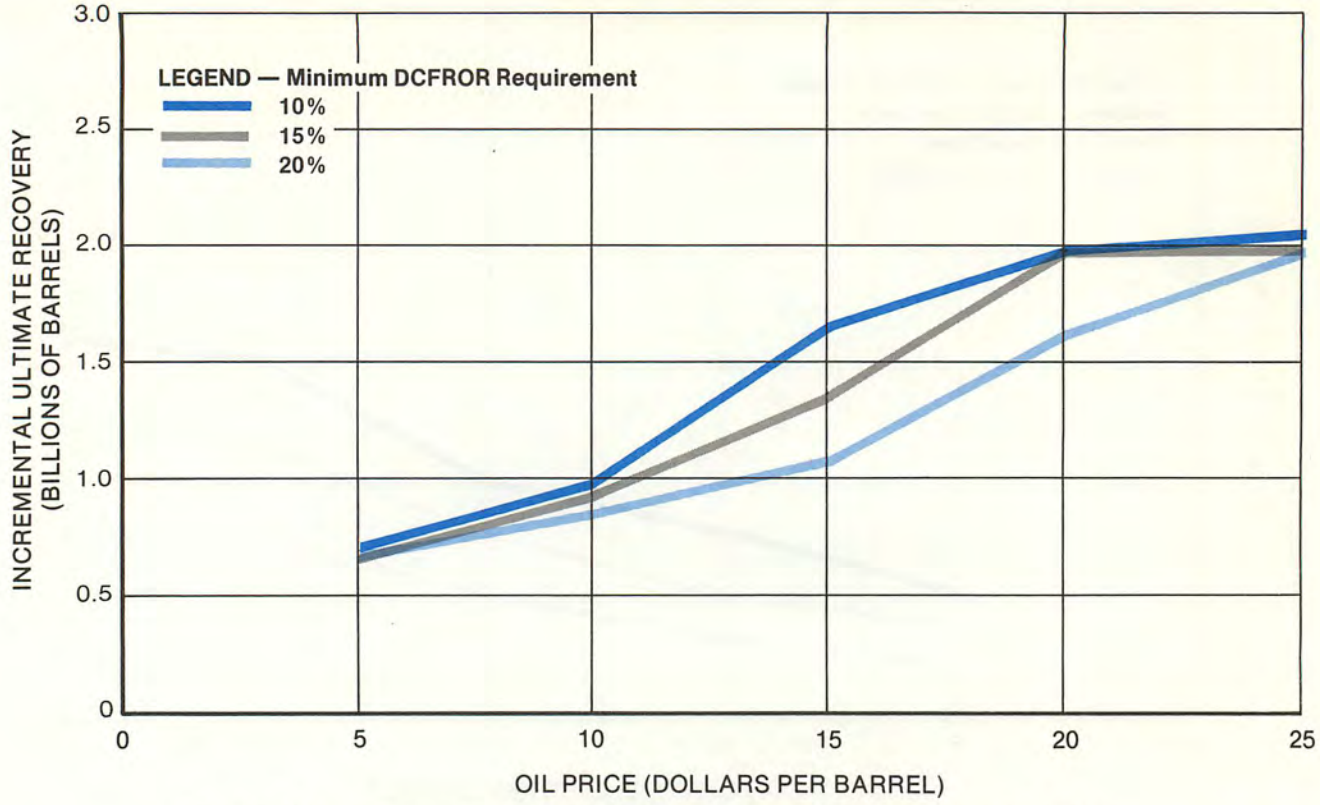


Figure 120. Incremental Ultimate Recovery—In-Situ Combustion—Total for Three States.

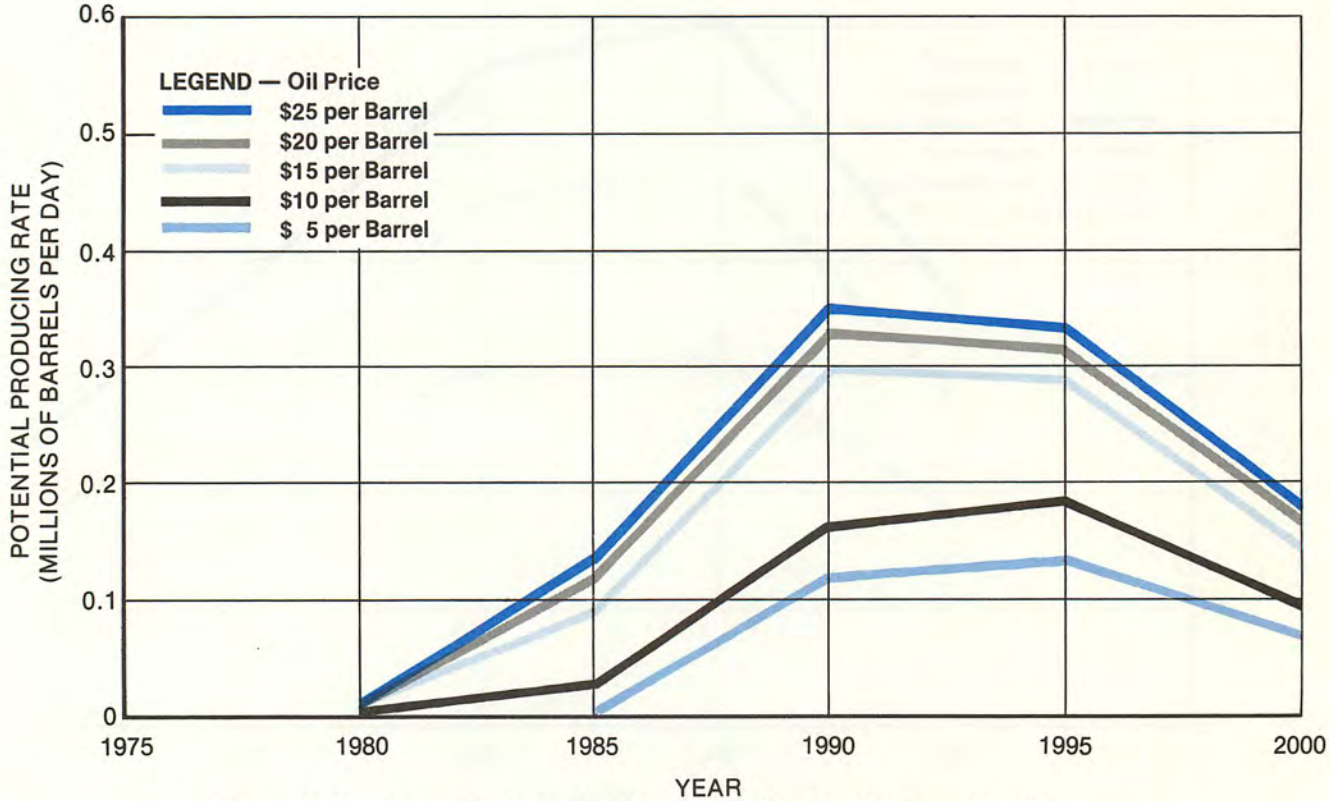


Figure 121. Potential Producing Rates—In-Situ Combustion—Total for Three States.

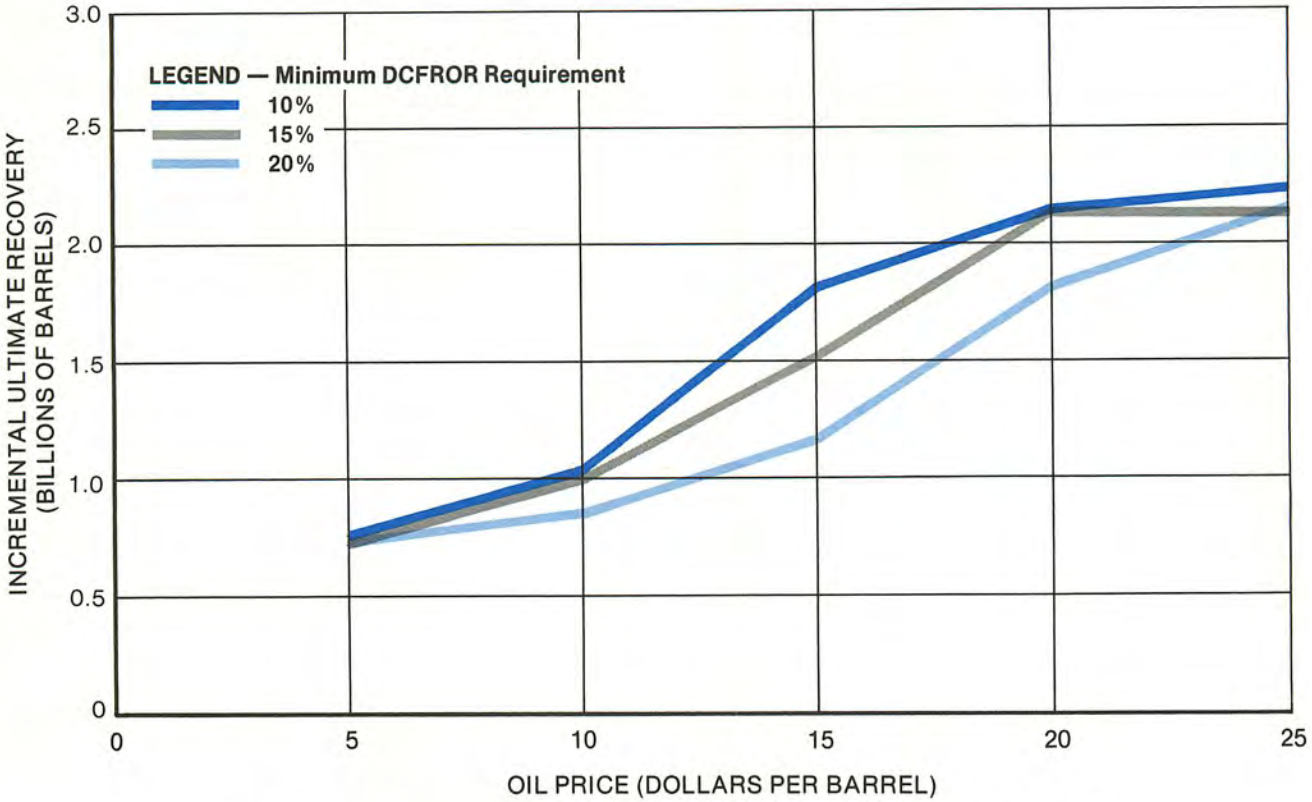


Figure 122. Incremental Ultimate Recovery—In-Situ Combustion—Total U.S.

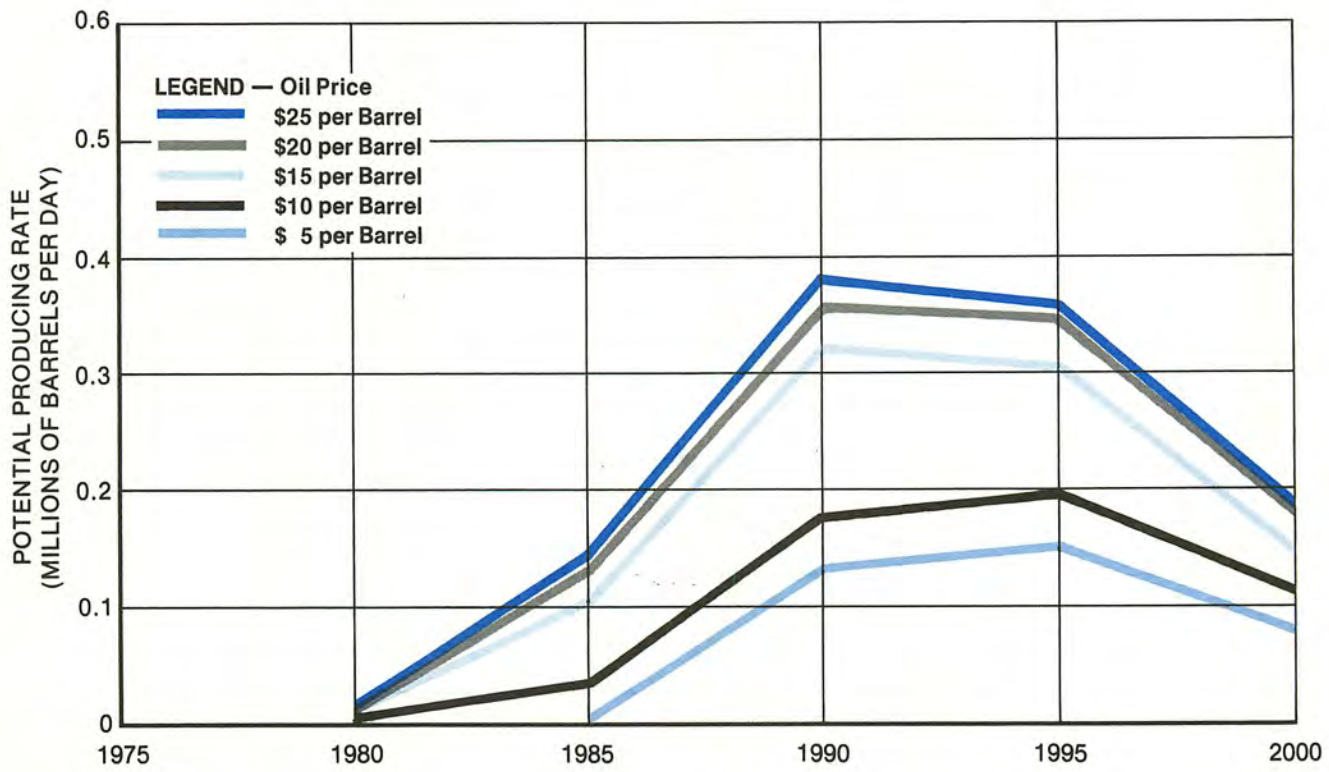


Figure 123. Potential Producing Rates—In-Situ Combustion—Total U.S.

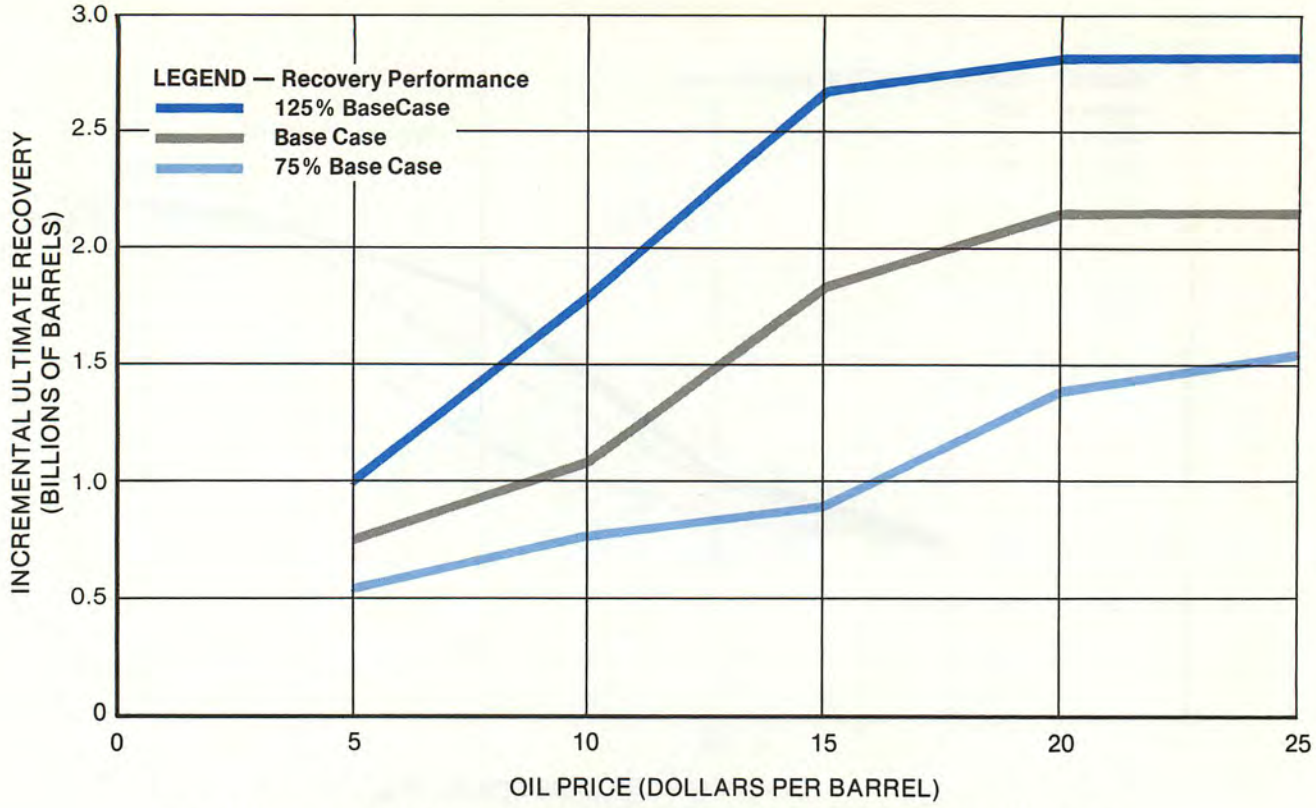


Figure 124. In-Situ Combustion—Variability of Incremental Ultimate Recovery with Reservoir Recovery Performance—Total U.S.

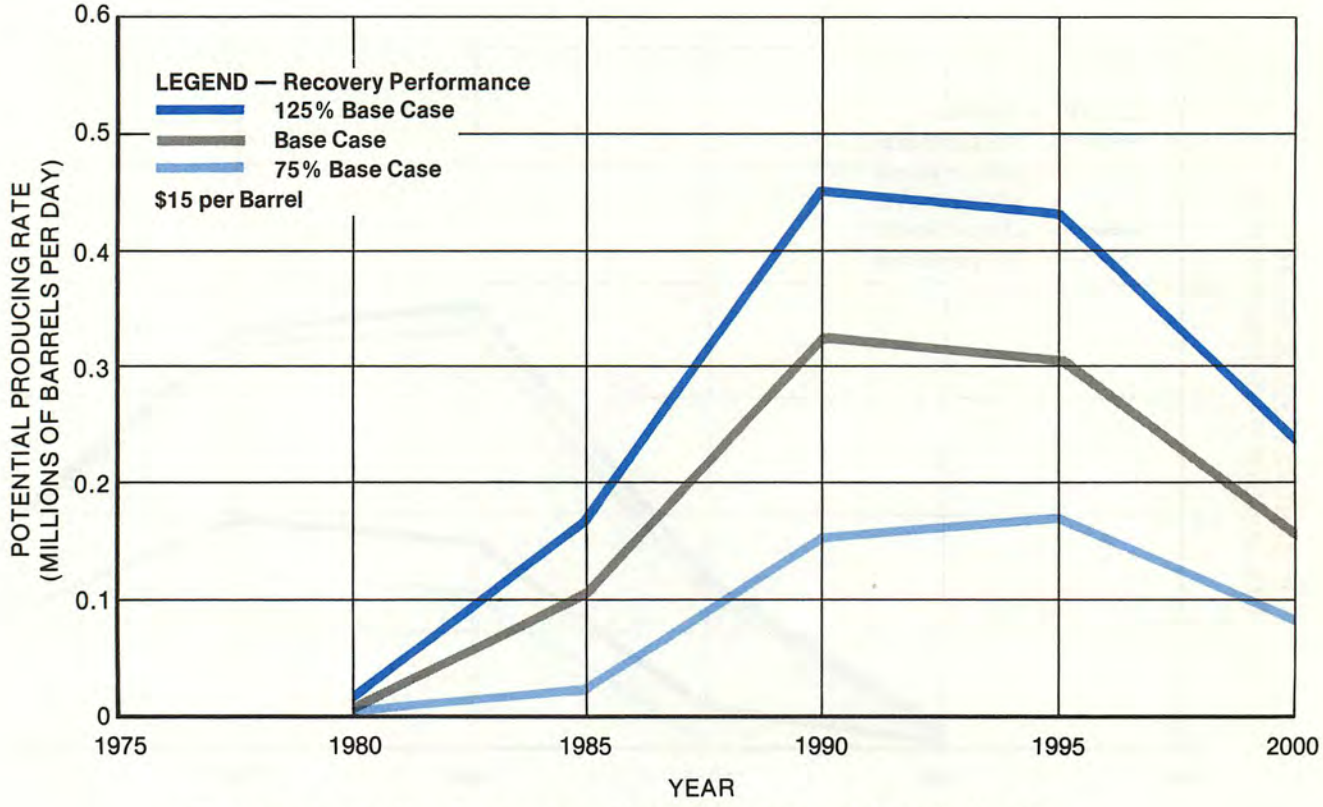


Figure 125. In-Situ Combustion—Variability of Potential Producing Rates with Reservoir Recovery Performance—Total U.S.

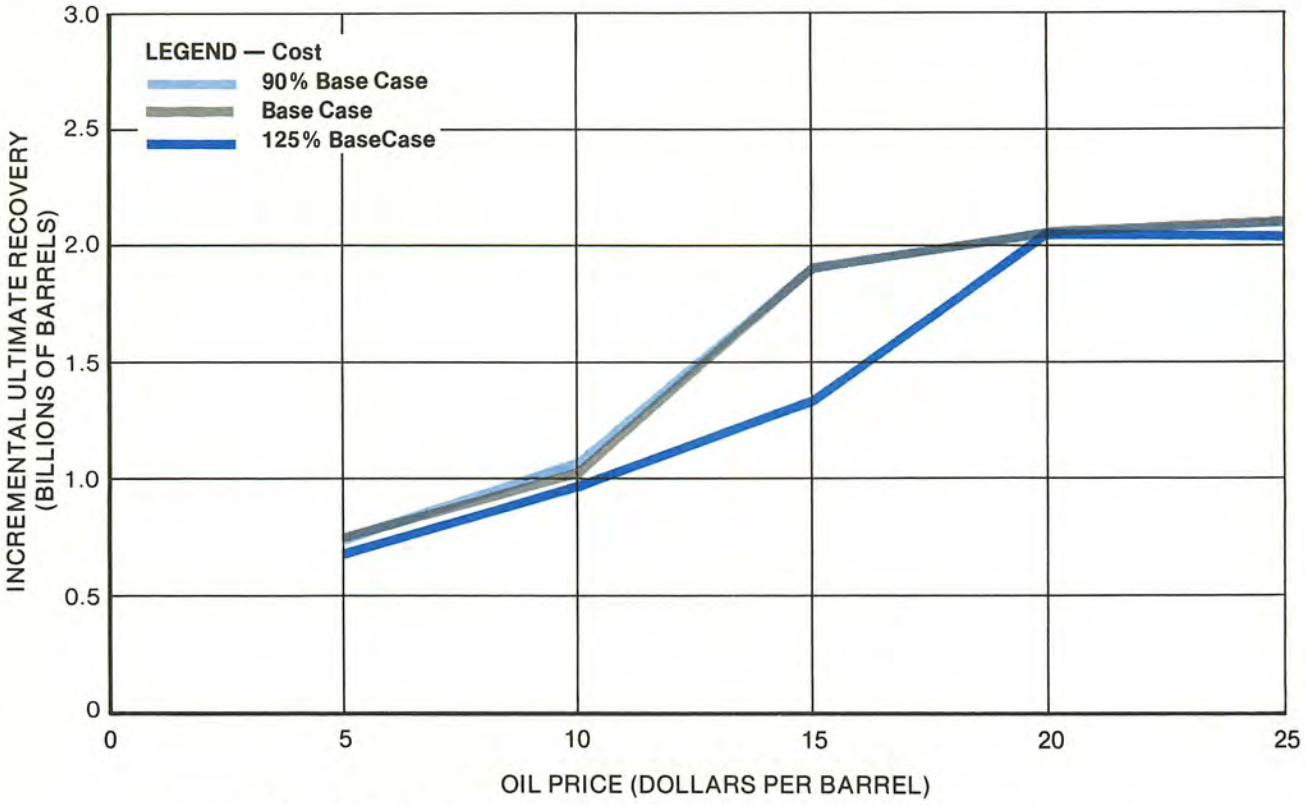


Figure 126. In-Situ Combustion—Variability of Incremental Ultimate Recovery with Process Costs.

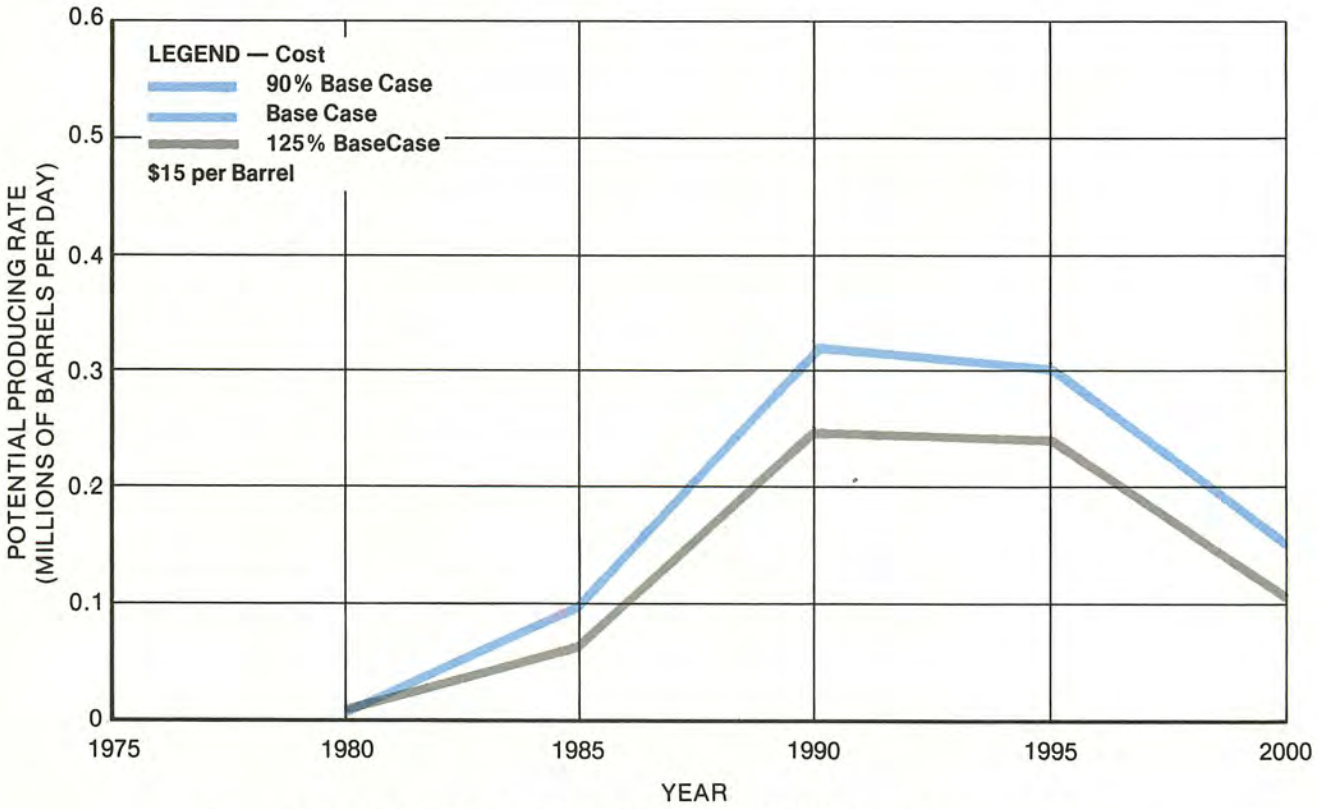


Figure 127. In-Situ Combustion—Variability of Potential Producing Rates with Process Costs.

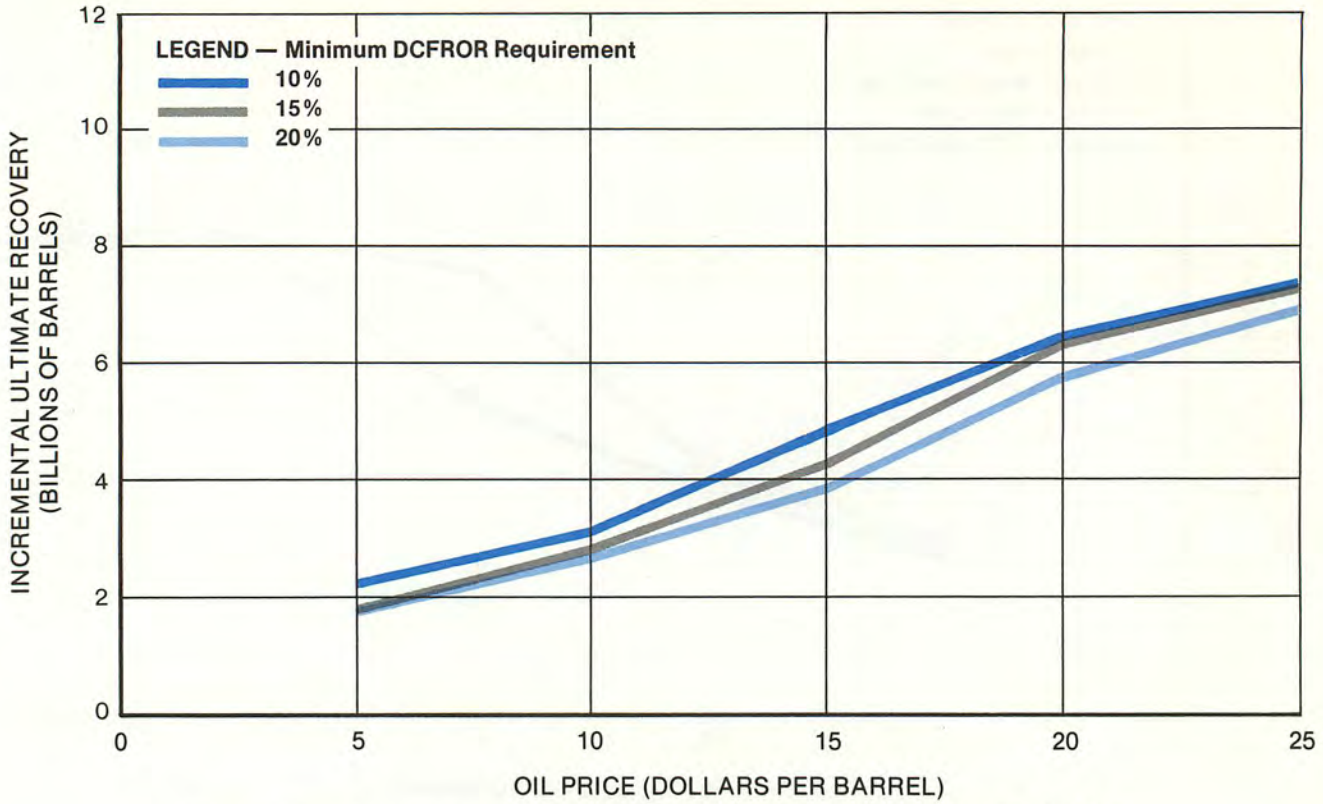


Figure 128. Incremental Ultimate Recovery—Thermal Recovery—Total U.S.

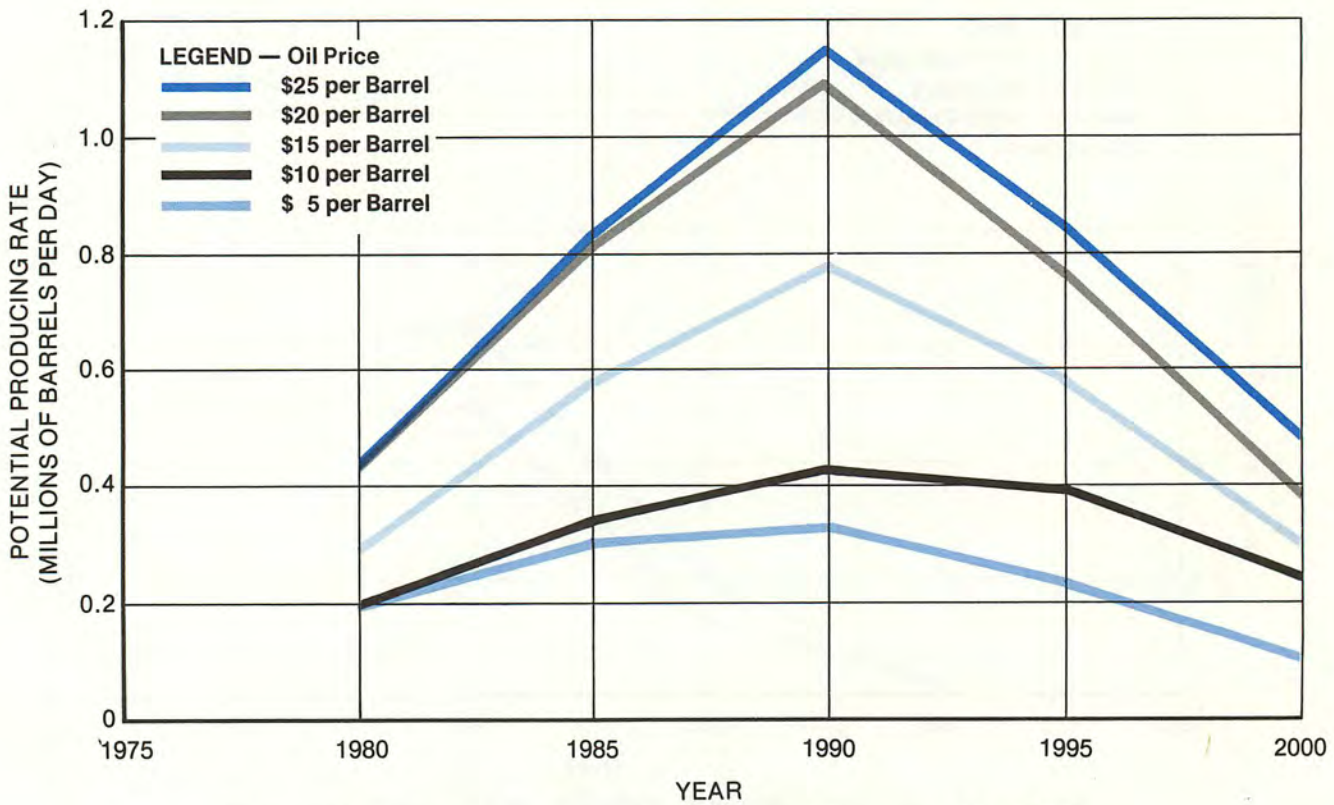


Figure 129. Potential Producing Rates—Thermal Recovery—Total U.S.

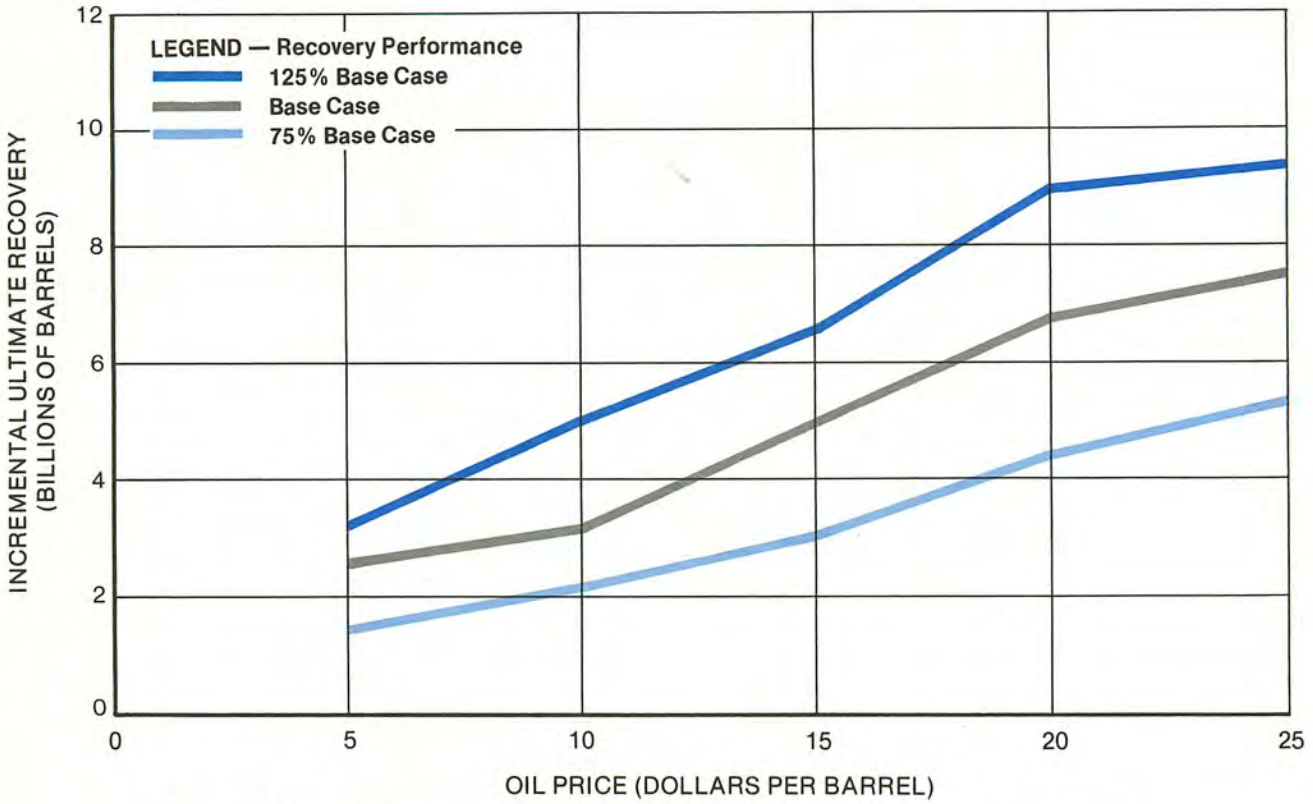


Figure 130. Thermal Recovery—Variability of Incremental Ultimate Recovery with Reservoir Recovery Performance—Total U.S.

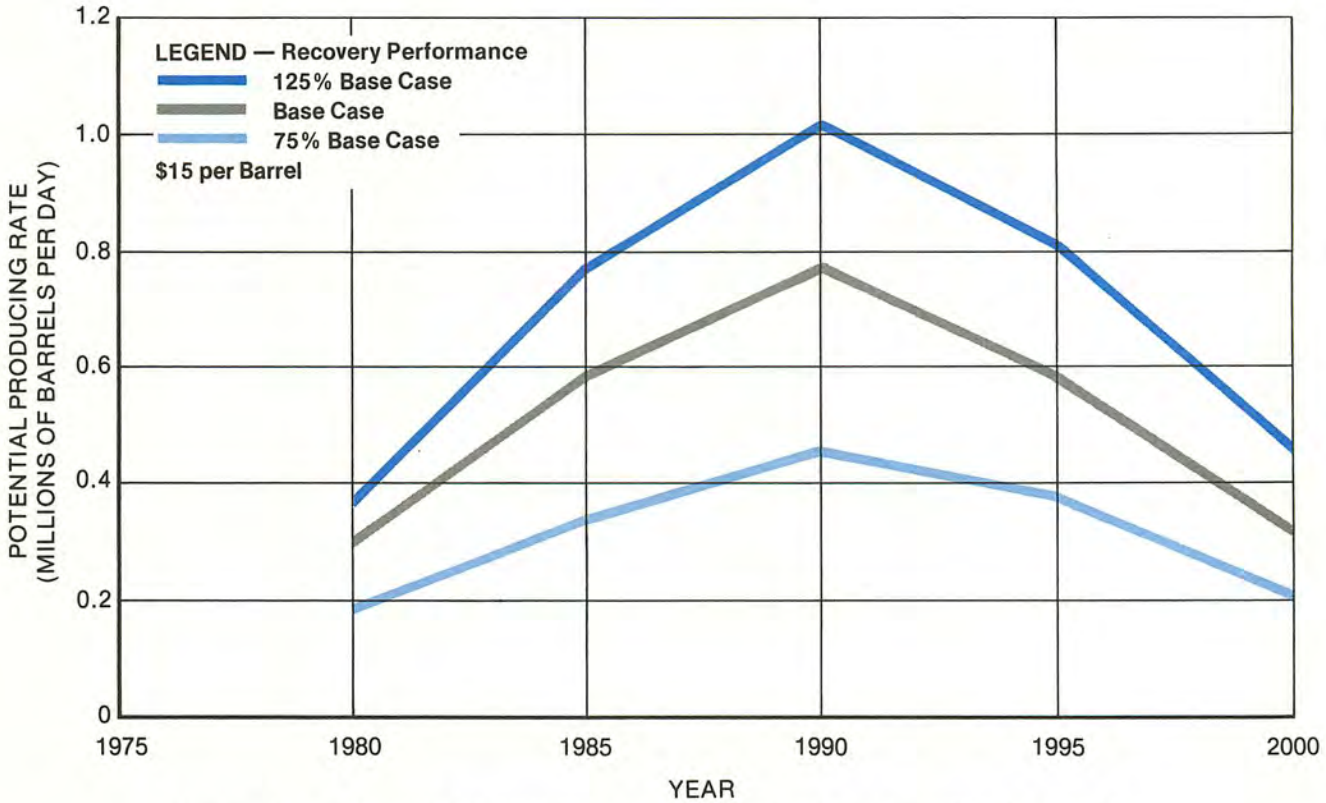


Figure 131. Thermal Recovery—Variability of Potential Producing Rates with Reservoir Recovery Performance—Total U.S.

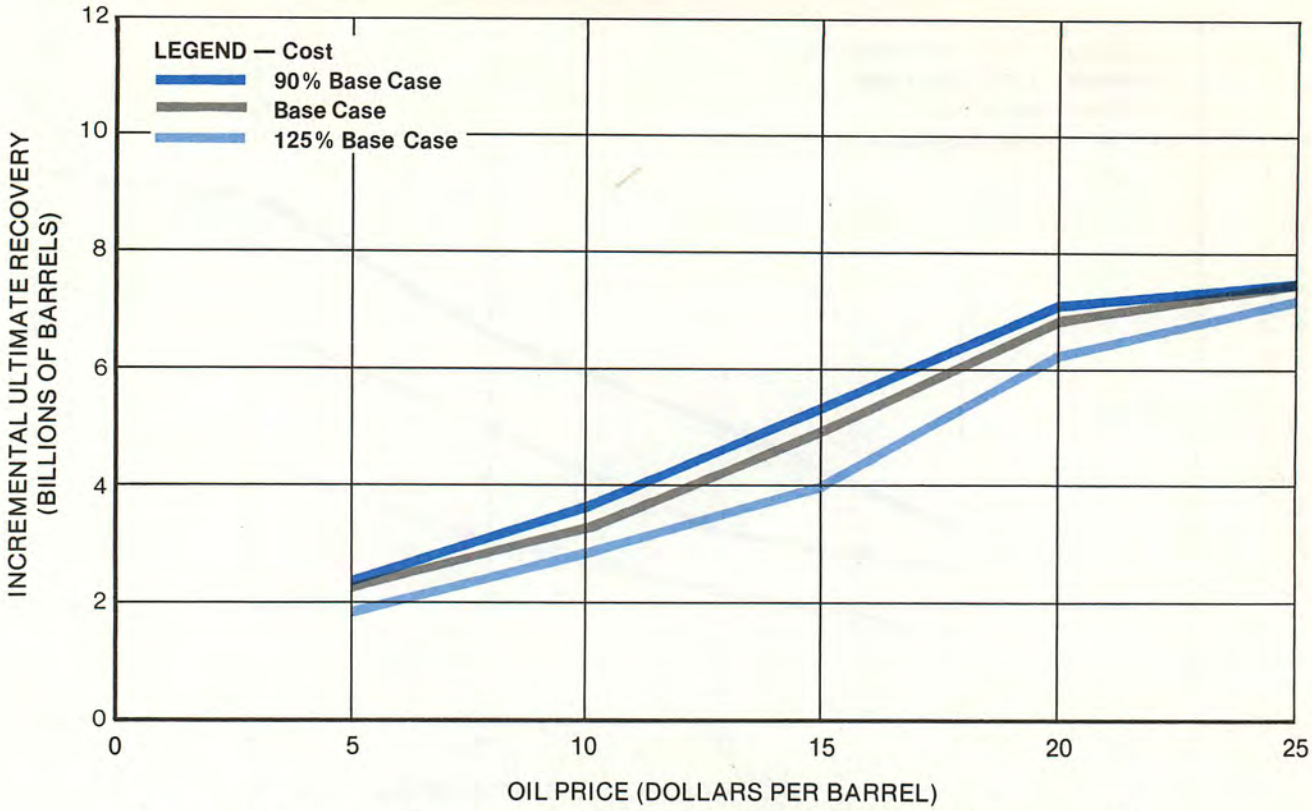


Figure 132. Thermal Recovery—Variability of Incremental Ultimate Recovery with Process Costs—Total U.S.

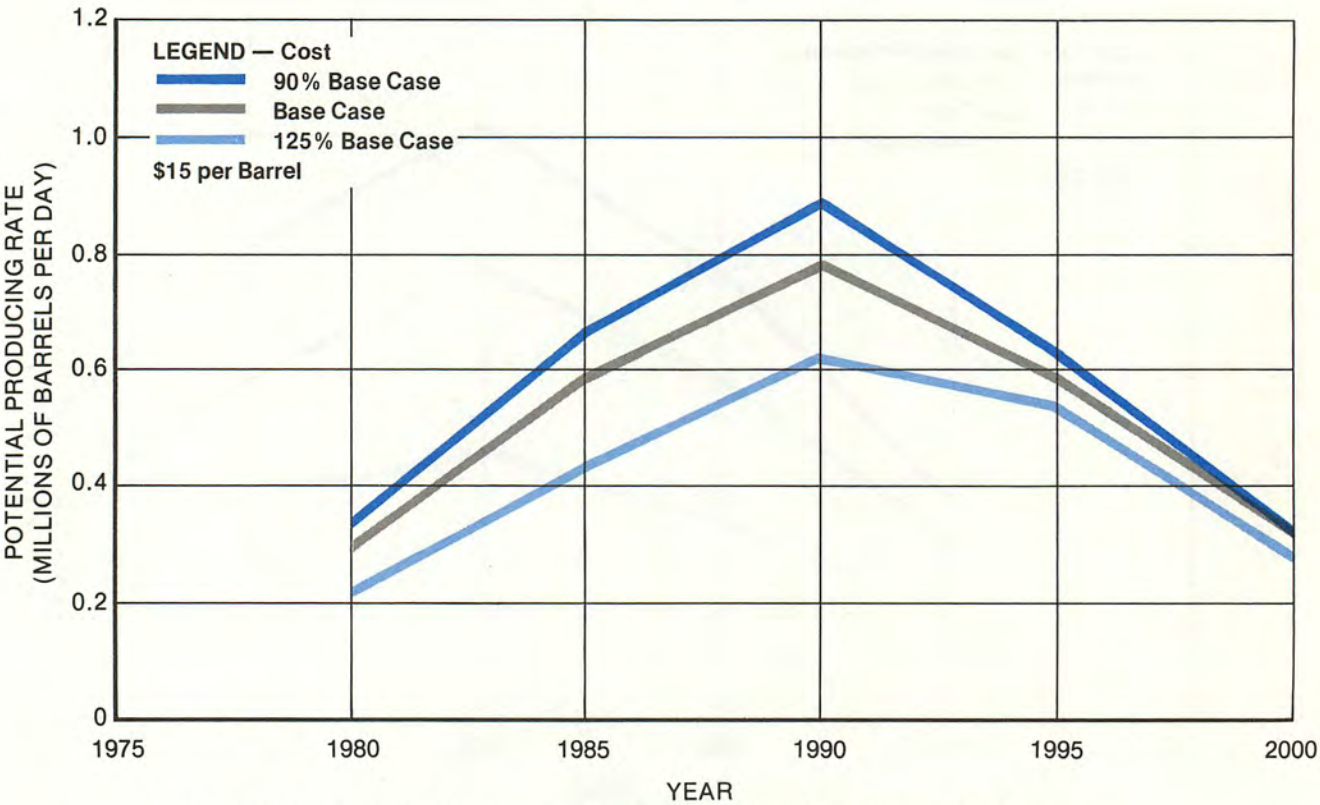


Figure 133. Thermal Recovery—Variability of Potential Producing Rates with Process Costs—Total U.S.

thermal recovery are illustrated in Figure 134 for ultimate recovery, and Figure 135 for production rate. The effect is a noticeable reduction in the projection of thermally produced crude oil under restrictive tax conditions.

Price Differential for Low-Gravity Crude

Oil prices used in all of the foregoing estimates did not incorporate any discount for low-gravity crude. The low-gravity crudes typical of most thermal recovery applications are normally discounted in price below the level for medium-gravity crudes, because of their poorer quality and poorer refining yield in product value. The average gravity of crude in the reservoirs selected for thermal recovery from the data base would currently bring about $1.20 per barrel less than a medium-gravity crude oil. The effect of such a price penalty for low-gravity oil on projected ultimate recovery for thermal recovery in the United States is shown in Figure 136. The effect of the penalty on thermal oil production rate is shown in Figure 137. The principal impact of the penalty is obtained at the lower oil prices, where the penalty constitutes a larger fraction of the base price.

Well Drilling, Completion and Workover Requirement

The projected application of thermal recovery would require a substantial effort in drilling and completion of new wells and workovers of current wells. Estimated well requirements for total thermal recovery, in the United States, as they relate to different oil prices, are shown in Figure 138; and, in Figure 139, for a single oil price ($15 per barrel), as they relate to time. A large fraction of the projected wells would be in California, where the current state total of wells producing crude oil is about 41,000.

Cash Outlay Requirements

Cumulative cash outlay is plotted in Figure 140, showing a cumulative cash outlay of more than $50 billion for the $25 per barrel case by the year 2000.

Yearly cash outlay requirements for base case total thermal recovery in the United States are plotted in Figure 141 for $15 and $25 per barrel oil price assumptions. Maximum cash outlays are incurred in the 1985-1990 period, exceeding $3 billion for the $25 per barrel case.

Environmental Considerations Summary

Environmental considerations associated with thermal recovery operations include: (1) air emissions; (2) oil and water discharge; (3) heat emission; (4) solid waste; (5) land use; (6) sound emission; and (7) occupational health and safety. Sufficient experience has been obtained in operating the processes (even in some environmentally sensitive locations) to indicate a number of potential environmental problems and provide some solutions. Environmental aspects are accorded a high order of importance in the planning and design of thermal projects, and may, in some cases, be the basis for a decision not to proceed with a project.

Air Emissions

Produced gas from combustion projects may contain malodorous and/or toxic components (H_2S, SO_2, CO) and hydrocarbons, in addition to N_2, CO_2, and O_2. This gas may be gathered in a closed system, incinerated to eliminate the toxic and combustible components, and vented from a tall stack. Facilities for these treatments were assumed for all combustion projects in this study. A further step to protect air quality may be to scrub the incinerated gas with alkaline water before venting, to reduce sulfur content. Visible plumes of condensing water vapor usually accompany the vent gas from the scrubber stacks. Where such condensation plumes are objectionable, they may be eliminated by heating the scrubber stack gases. Scrubbers and heating of scrubber stack gas were assumed for combustion projects in the California coastal basin areas.

Exhaust gas emission from gas-fueled, engine-driven air compressors has not been a significant problem in the past (with proper venting), because there has been no large concentration of such operations. The majority of future projects are expected to use electrically driven compressors as gas becomes less available and more expensive.

Steam is generated in boilers fired by lease crude and fed with formation water. It is necessary to soften the produced water, which is used to strip fly ash and sulfur oxides from the boiler exhaust gas by direct-contact, countercurrent flow of produced water in scrubbers. Such scrubbers were assumed for all steam projects in this study. Also, scrubber stack heaters to eliminate steam plumes were assumed for steam projects located in California coastal basin areas.

Gases produced from cyclic steam and steam drive projects are normally handled in closed systems. Hot hydrocarbon vapors are collected and

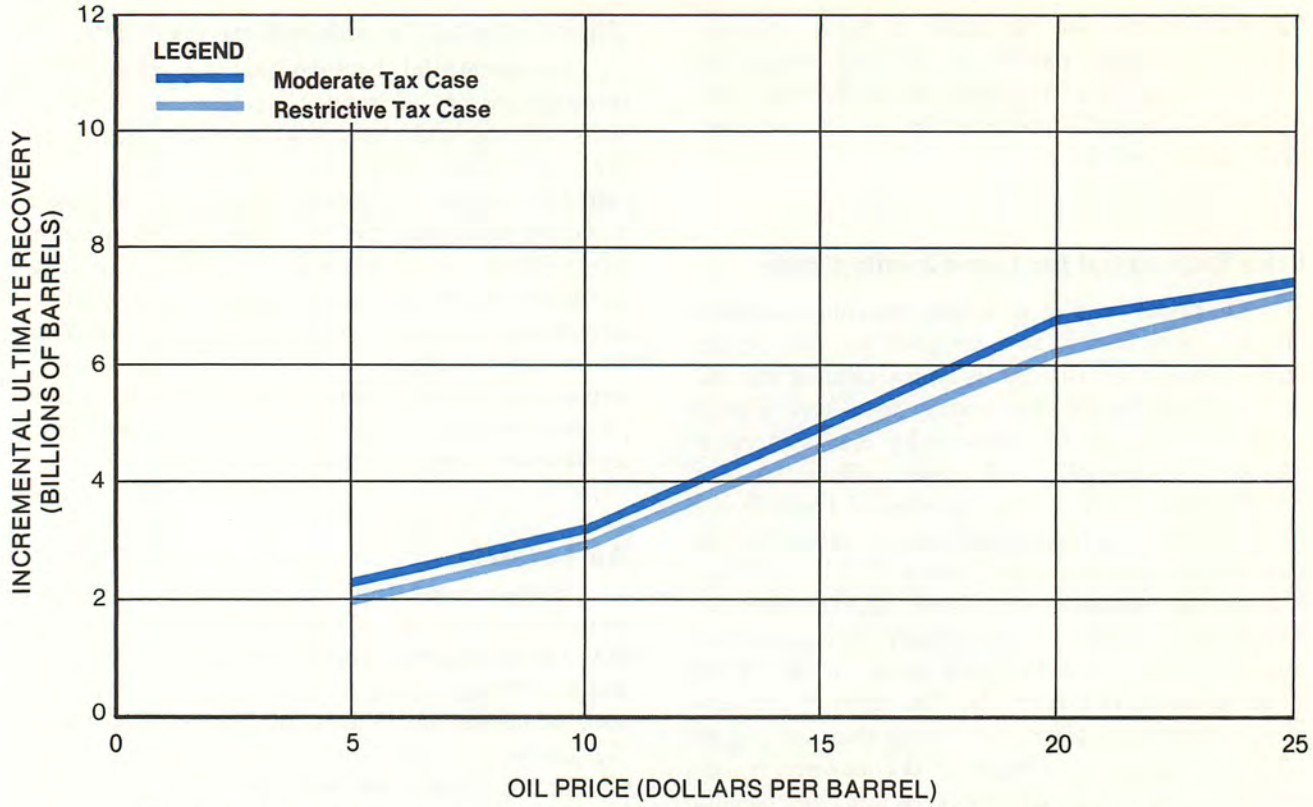


Figure 134. Thermal Recovery—Variability of Incremental Ultimate Recovery with Tax Treatment—Total U.S.

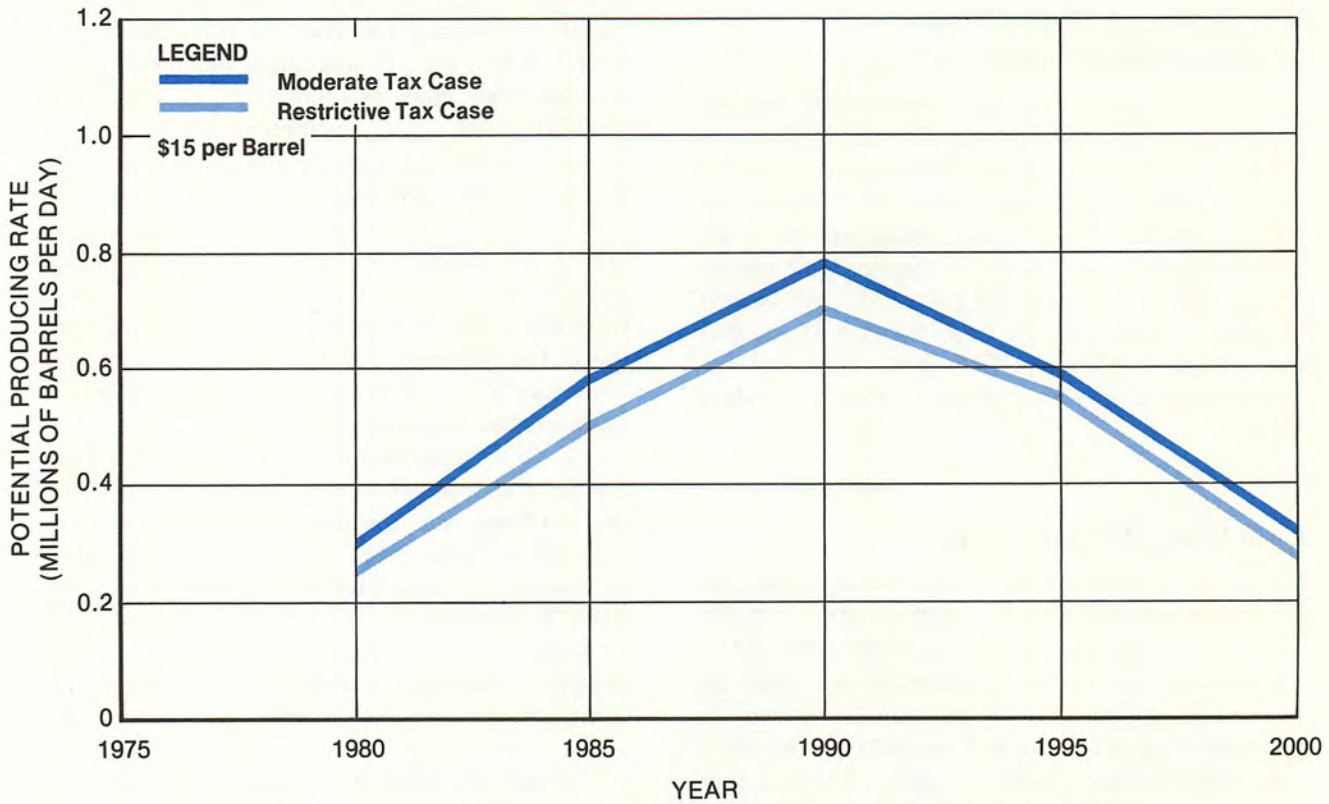


Figure 135. Thermal Recovery—Variability of Potential Producing Rates with Tax Treatment—Total U.S.

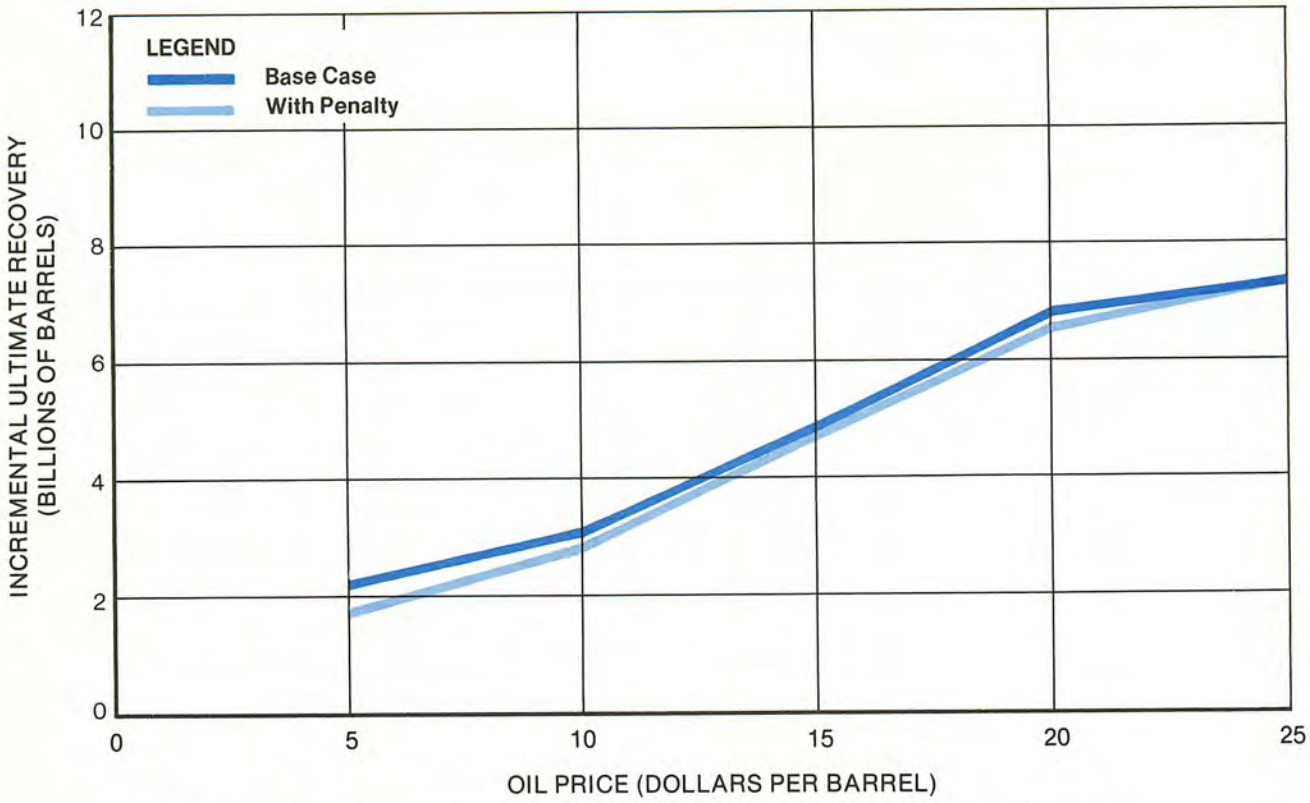


Figure 136. Thermal Recovery—Variability of Incremental Ultimate Recovery with $1.20 per Barrel Gravity Penalty.

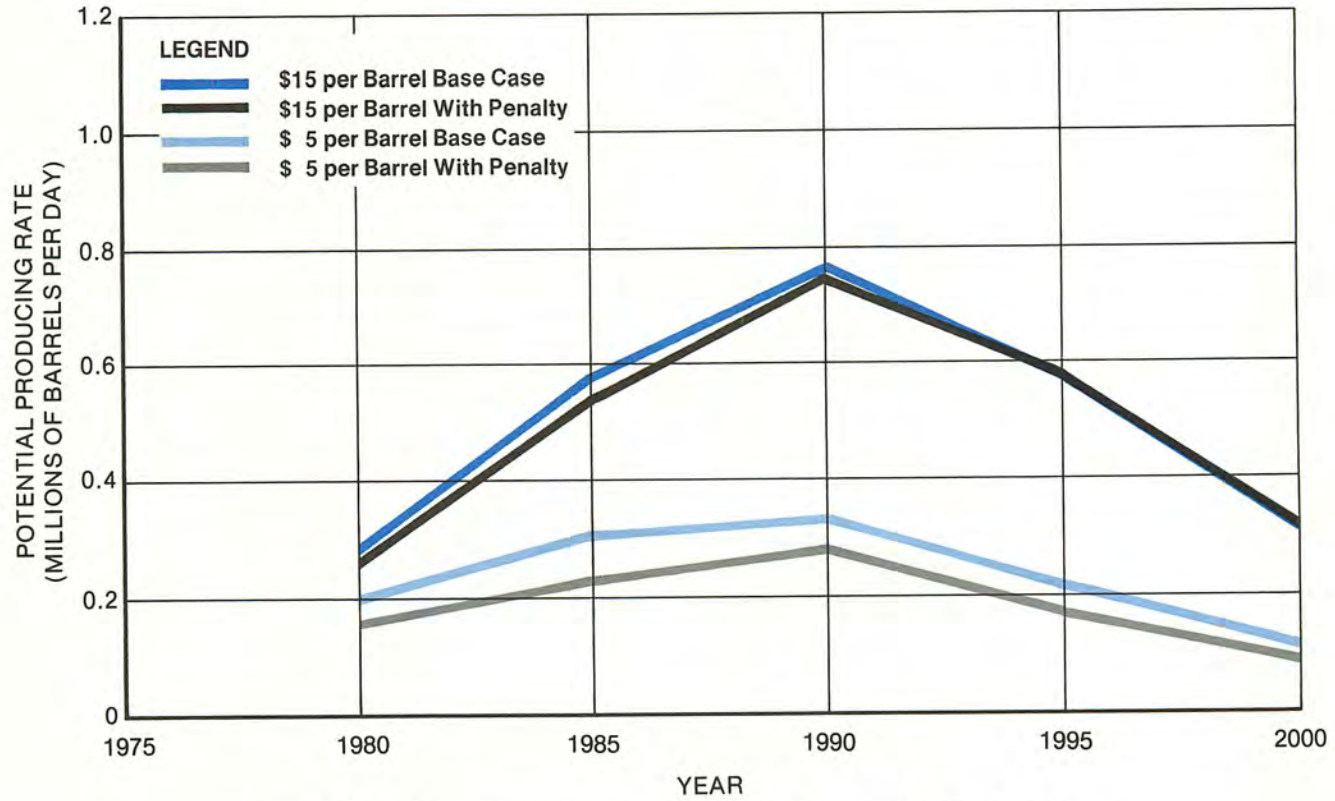


Figure 137. Thermal Recovery—Variability of Potential Producing Rates with $1.20 per Barrel Gravity Penalty.

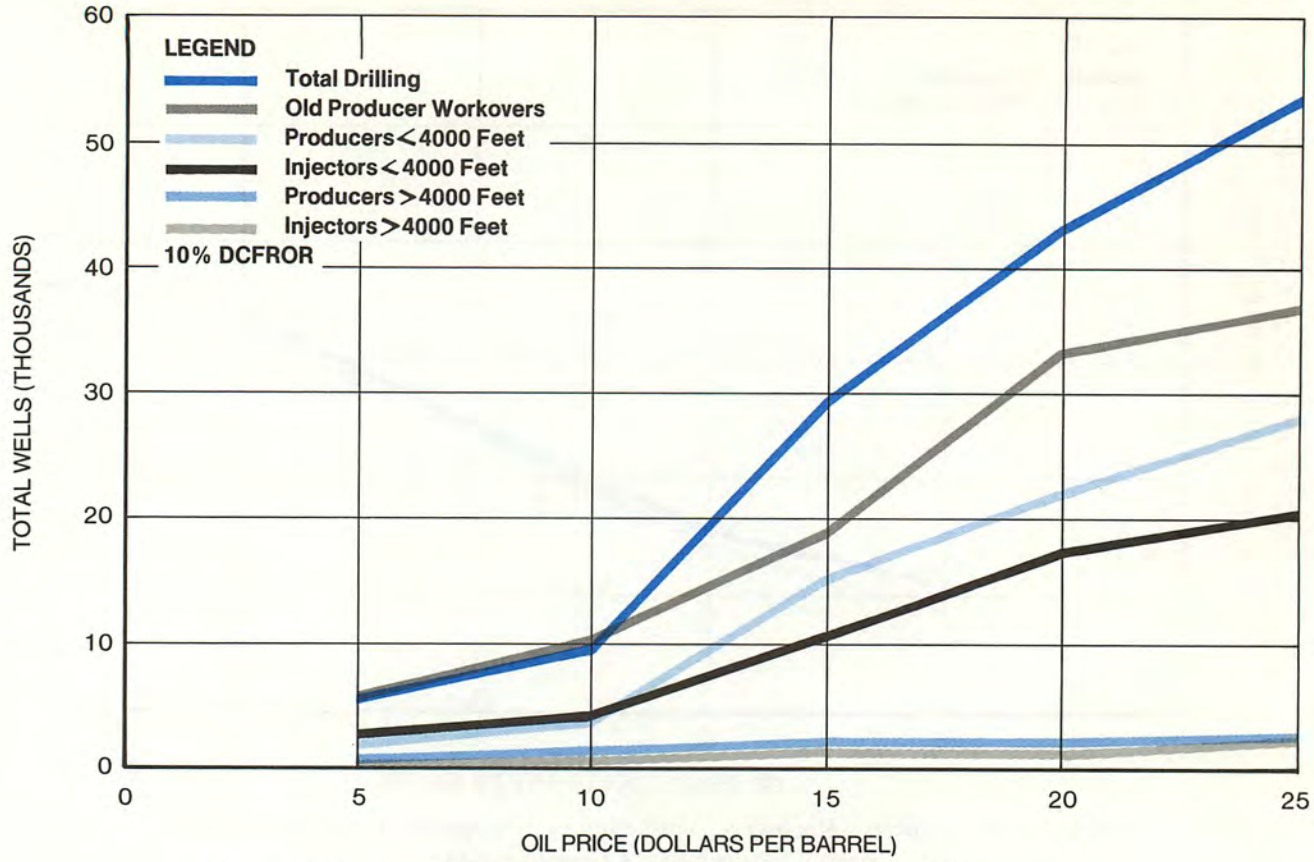


Figure 138. Total Drilling and Workover Activity—Thermal Recovery.

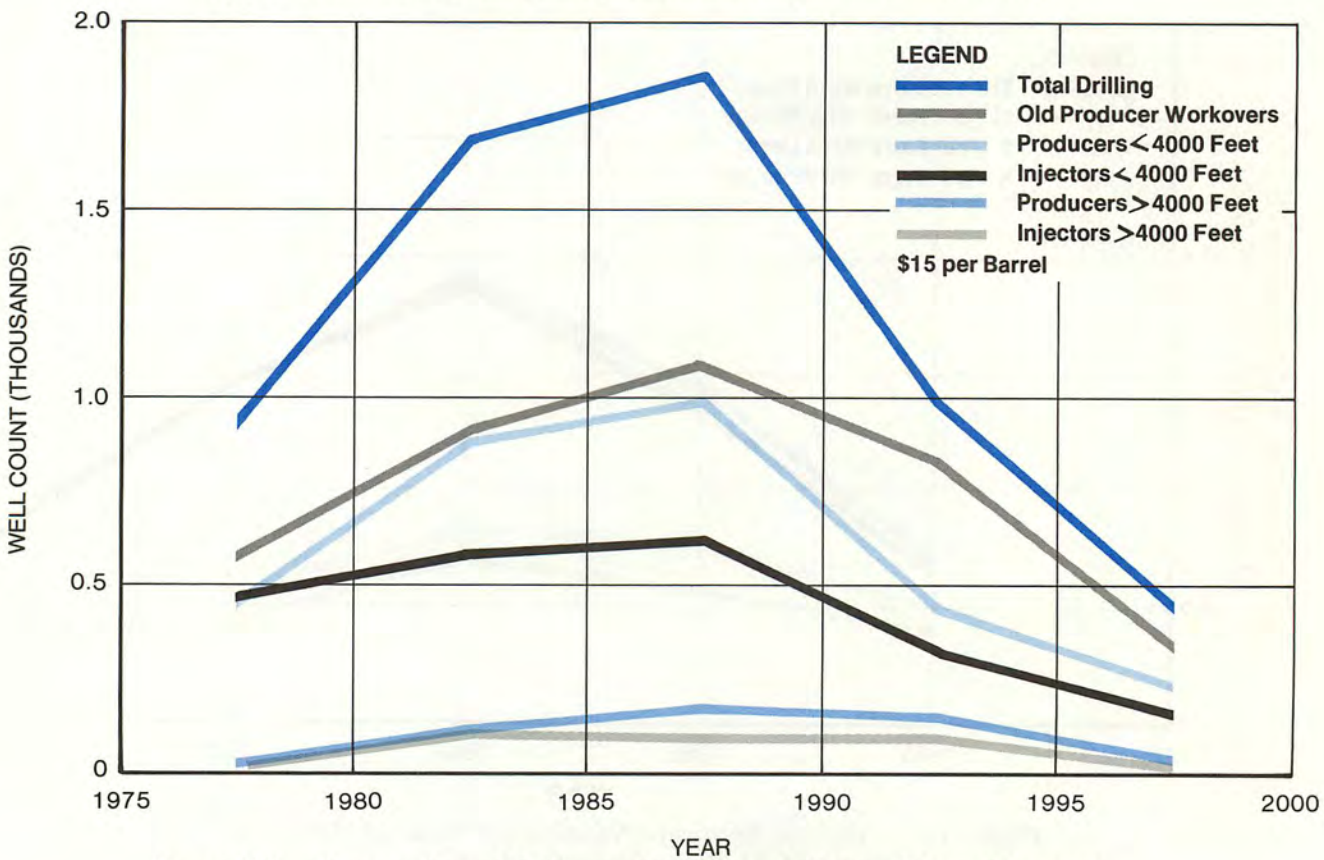


Figure 139. Average Annual Drilling and Workover Activity—Thermal Recovery.

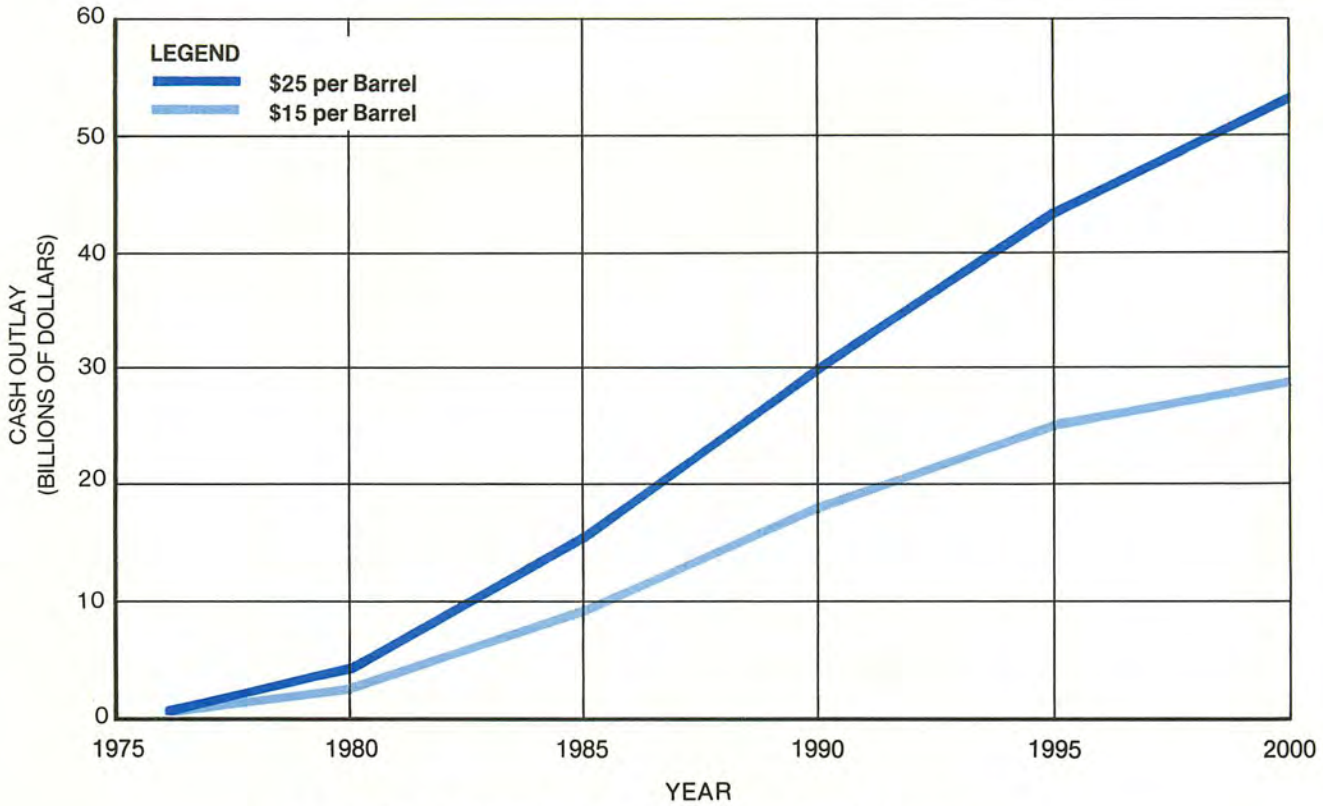


Figure 140. Cumulative Cash Outlay—Thermal Recovery.

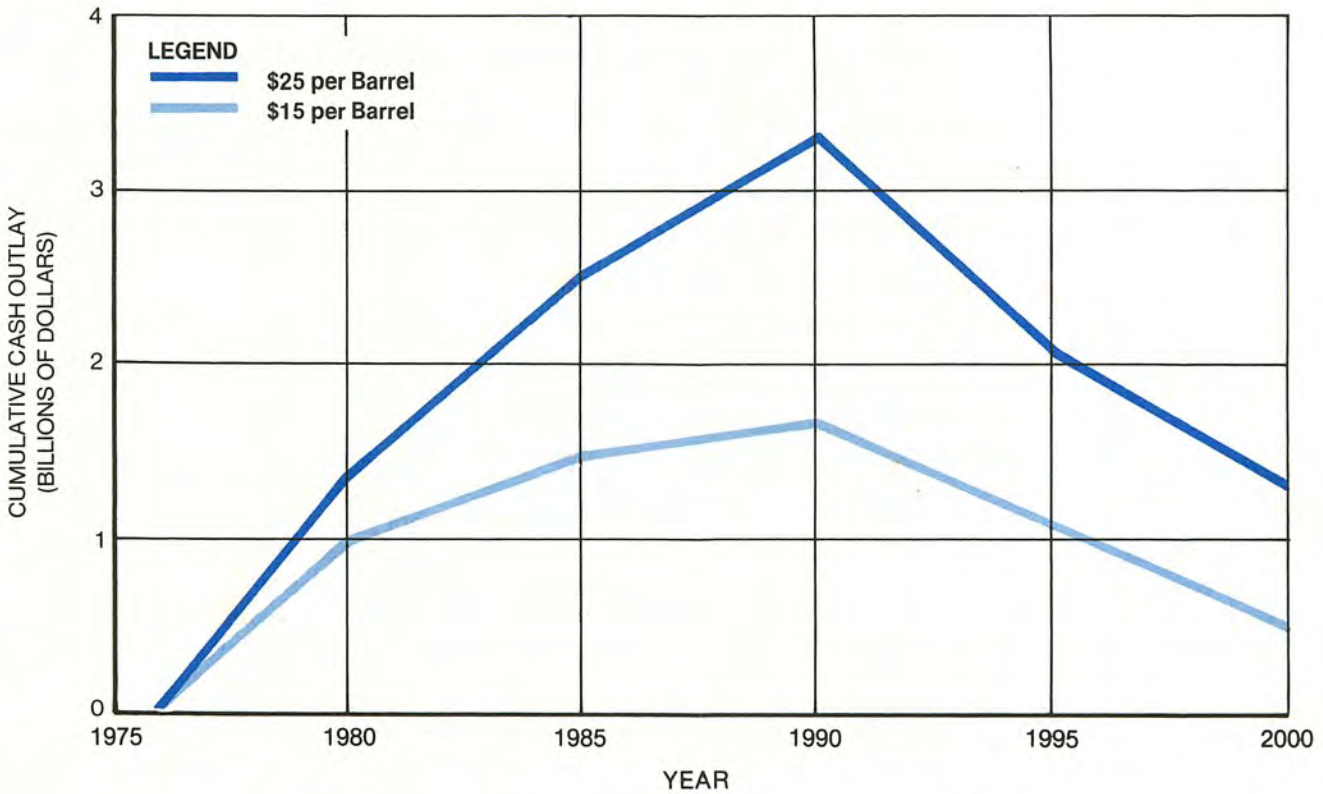


Figure 141. Annual Cash Outlay—Thermal Recovery.

condensed; toxic and explosive gas concentrations are monitored to avoid occupational health hazards; and care is used in workovers of hot wells to avoid gas accumulations. Produced gases are incinerated at vent points to eliminate traces of combustible, obnoxious, or toxic materials. These operating procedures were assumed to be employed in projects analyzed in this study.

Oil and Water Discharge

Large percentages of water are usually obtained in the production from thermal operations. The produced water must be separated, treated, and reinjected into the producing formation, or otherwise disposed of in accordance with pollution-control regulations. Heavy oil emulsions may be difficult to break and can require changes in the treatment chemicals or operating procedure from time to time. Close monitoring of the treatment operations is necessary to avoid oil carry-over with the water. Also, close attention is required for early detection and remedy of any fluid leaks in the production system, which may result from extended periods of hot production, corrosion and/or erosion by produced sand.

Heat Emission

Hot steam injection lines are insulated to protect personnel and livestock from injury, as well as to conserve heat. Large steam generation facilities may require 24-hour monitoring as a safety consideration, in compliance with local regulations.

Production of hot fluids can result in hot wellheads and gathering lines. The temperature of producers in combustion projects may be controlled to some extent by injecting cooling water in the well annulus and by controlling the production rate. In extreme cases, it may be necessary to shut-in the well. The gathering lines from hot wells should be buried, and the wellheads fenced or caged where there is danger of contact by personnel or livestock.

Solid Waste

Wastes from clean-out of scrubbers (fly ash), in addition to those associated with conventional production operations from clean-out of tanks, flowlines, etc., are taken to approved disposal sites.

Land Use

Land use is generally compatible with application of thermal operations in old, established oil fields. However, near urban areas, special monitoring, control and protection procedures may be needed to satisfy local requirements. Costs for such special monitoring procedures were included in the project economic calculations in the California coastal basin. Where urban development extends into the oil field, the potential impacts of thermal recovery operations must be carefully considered.

Sound Emission

Compressor operation for in-situ combustion can generate a high noise level. Sound-reducing measures and sound-absorbing housing can substantially reduce the emission of noise from the immediate location. However, personnel in the compressor building should always wear approved ear protection devices to avoid injury. Venting of high-pressure air, gas, or steam lines also generates high noise levels and should be avoided insofar as possible. Ear protectors should be worn when it is necessary to be in the vicinity of such venting.

Occupational Health and Safety

Thermal operations require close monitoring and control for successful, safe operation. Operating personnel must be properly trained and qualified in the special routine and emergency procedures and associated safety requirements to maintain control and minimize the consequences of any equipment failures. Air injection lines should be steam-cleaned periodically to remove any lube oil accumulation, which could result in an explosion. This procedure may be required by state regulations. Gas-gathering, treating and venting systems must be monitored for proper operation, using approved respiratory protection devices in locations where toxic gases may exist. Warm or hot producing wells must be carefully monitored and controlled within prescribed limits, or immediately shut-in if control cannot be maintained. Well workovers must be handled with contingency procedures for the possibility of encountering high temperatures and high-pressure gases.

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Appendix G
Comparison with Other Studies

There have been a number of previous estimates of enhanced oil recovery potential. The results from several of these studies are summarized in Table 45.

Caution should be exercised in comparing results from the various studies since the results are not directly comparable on a one-for-one basis. Greatly differing degrees of detail went into the various projections, and different scenarios were assumed for projecting potential recovery. Different criteria for economic parameters, such as discounted cash flow rate of return (DCFROR) probably were employed. The same improved recovery methods were not considered in all of the studies, and even somewhat different definitions of enhanced oil recovery appear to have been used.

With the exception of the Lewin & Associates study, none of the previous estimates were based on a reservoir-by-reservoir approach. The *Project Independence* projection was based on the methodology used in the earlier NPC study, *U.S. Energy Outlook* (1972). Each year a fraction of the previously discovered oil in place was added to proven reserves as a component of the potential ultimate recovery from EOR. This fraction was subjectively estimated for each of twelve different regions of the United States.

In the Environmental Protection Agency (EPA) study conducted by Mathematica, Inc., a limited data base was compiled on over 350 major domestic oil fields. Criteria for applicability of the major enhanced recovery processes were established in terms of ranges of reservoir and oil properties, such as depth, permeability, API gravity, etc. From the data base, aggregate original oil in place (OOIP) and remaining oil in place were also classified according to the criteria established for the processes. The plausible magnitudes of the percentage of incremental recovery achievable by the various methods, as well as approximate costs, were estimated from reviewing major field projects, from interviews with petroleum industry personnel and from simplified recovery models. The low-range estimate considered free market crude oil prices of $8-$12 per barrel, while the high-range estimate assumed oil prices of $12-$16 per barrel. Oil price was apparently expressed in 1975 dollars. Potential additional recovery attributable to thermal methods, surfactant flooding, and CO_2 flooding was estimated to be 7 billion barrels for the low range and 16 billion barrels for the high range. Of this additional recovery, thermal methods accounted for approximately 60 percent, CO_2 flooding for 23-36 percent, and surfactant flooding for 3-16 percent.

The Gulf Universities Research Consortium (GURC) conducted a modified Delphi survey approach to project enhanced oil recovery potential. A series of conferences, sequential questionnaires, interim report reviews, and individual discussions was used to develop an industry consensus. Twenty-two companies participated in the survey, and individual responses remained confidential. Although there was a considerable range of opinion in individual responses, averages were reported to be representative of judgments by about two-thirds of the participants, with high and low projections about equally divided. In the earlier report the "almost assured" projection for ultimate recovery potential was 18.5 billion barrels; the lowest response was 5 billion barrels, and the highest response was 60 billion barrels. The "reasonable" projection was 36.3 billion

TABLE 45

ESTIMATES OF ENHANCED OIL RECOVERY POTENTIAL

	Potential EOR Recovery (Billions of Barrels)	Production in 1985 (Millions of Barrels/Day)
NPC Study*		
-----$ 5	2.2	0.3
-----$10	7.2	0.4
-----$15 (1976 dollars)	13.2	0.9
-----$20	20.5	1.5
-----$25	24.0	1.7
GURC†‡		
-----$10 (1974 dollars)	18-36	1.1
-----$15	51-76	—
FEA/PIR§		
-----business as usual, $11	—	1.8
-----accelerated development, $11	—	2.3
EPA¶		
-----$ 8-12 (1975 dollars)	7	—
-----$12-16	16	—
FEA/Energy Outlook**		
-----$12	—	0.9
FEA†† (3 states)		
-----upper bound, $11.28 (1975 dollars)	30.5‡‡	2
-----lower bound, $11.28	15.6§§	1

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

† *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.

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

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

¶ *The Estimated Recovery Potential of Conventional Source Domestic Crude Oil,* Mathematica, Incorporated for the U.S. Environmental Protection Agency, May 1975.

** *1976 National Energy Outlook,* Federal Energy Administration.

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

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

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

barrels with a low response of 15 billion barrels and a high response of 100 billion barrels. Also, the consensus of estimates was that surfactant flooding would account for 58 percent of total recovery by enhanced methods, followed by thermal methods with 29 percent, carbon dioxide flooding with 8 percent, and hydrocarbon miscible with 5 percent. The GURC consensus projection of 423 million barrels for annual production in 1985 by all enhanced methods was conditional on a large-scale, cooperative industry/government field test program being undertaken immediately to assess the economics and range of applicability of the various processes.

A later GURC survey continued to support these findings and attempted to relate recovery potential to oil price. At an oil price of $10 per barrel, enhanced oil recovery potential was again projected to be 18-36 billion barrels. At an oil price of $15 per barrel, this potential was projected to be 51-76 billion barrels. There is no way of judging the degree of detail that went into the individual responses to GURC.

The Lewin & Associates projection followed a methodology similar to that used in the NPC study.

The same data base on 245 reservoirs in California, Texas, and Louisiana was used as the starting point for both analyses. Individual reservoirs were screened for enhanced oil recovery process suitability by applying screening criteria for reservoir and oil properties, such as depth, temperature, oil viscosity, API gravity, brime composition, etc. When two or more processes appeared to be candidates in the same reservoir, dominance criteria were applied to select the one process to be considered for each reservoir. The amount of oil recoverable by the enhanced process and the rate at which this oil would be produced were estimated for each reservoir from simple process models. Each reservoir was subjected to an economic analysis that attempted to account for the cost of injected materials, operating expenses, costs for drilling and completing additional wells, reconditioning old wells, and investment for capital items. Finally, the results of these analyses for the reservoirs in the data base were scaled up to reflect totals for each process in each of the three states.

Figures 142 through 144 show estimates made for each state by Lewin & Associates for ultimate recovery potential in comparison with the estimates resulting from the NPC study. The comparisons are given for the three dominant processes: CO_2 flooding, surfactant flooding, and steamflooding. All comparisons were made at an 8 percent DCFROR. No additional recovery from surfactant flooding or carbon dioxide miscible flooding was projected by this study at an oil price as low as $5 per barrel, whereas Lewin & Associates projected approximately 1.2 and 1.8 billion barrels to be recoverable by these processes at the $5 oil price. For higher oil prices substantially more oil recovery was estimated by Lewin & Associates for each of the processes than was estimated by the NPC study.

A comparison of projections of oil production rates up to the year 2000 is shown in Figure 145. These projections are for all enhanced recovery processes. An oil price of $11.28 per barrel (1975 dollars) was assumed for the Lewin & Associates projections, and "lower bound" and "upper bound" projections were made. The "lower bound" case assumed that a moderate level of federal initiative and research funding would be achieved and that enhanced oil recovery would remain a high-risk technology throughout this time period to the extent that at least a 20 percent DCFROR was demanded for projects. The "upper bound" case assumed that through a massive effort in research, development, and field testing as a result of a concerted federal initiative, enhanced oil recovery would become a proven, conventional technology by 1990 to the extent that only an 8 percent DCFROR would be demanded for projects. For comparison the production rate curves for the NPC study, shown in Figure 145, were projected for EOR projects that showed at least an 8 percent DCFROR.

For those economic conditions where the projected incremental ultimate recoveries are similar, the projected producing rates are also similar for both studies. For example, the projected ultimate recovery is about 12.5 billion barrels for the $15 oil price and 8 percent DCFROR case of the NPC study; the projected ultimate recovery is 15.6 billion barrels for the Lewin & Associates "lower bound" case, which assumes a $11.28 oil price and a 20 percent DCFROR criterion. The producing rates shown in Figure 145 for these cases are approximately the same magnitude. However, even at the $25 oil price, the oil producing rates projected by this study do not reach the levels projected for the Lewin & Associates "upper bound" case. The ultimate recovery projected by this study at the $25 oil price, 8 percent DCFROR (19 billion barrels) still is much less than that projected by Lewin & Associates at the $11.28 oil price, 8 percent DCFROR (30.5 billion barrels).

The Lewin & Associates study and the NPC study started with the same reservoir data base and used a similar reservoir-by-reservoir approach, but the conclusions differ substantially. The reasons for these differences cannot be discerned with certainty, since the identity of the individual reservoirs assigned to a particular process by Lewin & Associates was not published; nor were the exact values of some saturations and costs used for individual reservoir calculations available. However, some of the probable causes for these differences are examined in the remainder of this appendix.

The definition of future oil recovery to be attributed to the enhanced oil recovery processes was slightly different for the two studies. In the NPC study, whenever waterflooding was considered to be a realistic alternative to enhanced recovery, only the incremental oil that might be recovered in excess of waterflood recovery was considered to be enhanced recovery oil. This definition was followed even for reservoirs still undergoing primary depletion. Also, in the NPC study the estimated future production from current enhanced oil recovery projects was not included. Only projects not yet undertaken were evaluated. In the Lewin & Associates study, the estimated future recovery from current projects was included, as was all projected recovery from reservoirs not yet undergoing secondary recovery flooding. This difference in definitions could have resulted in an additional 2-4 billion barrels of ultimate recovery in the Lewin & Associates estimates.

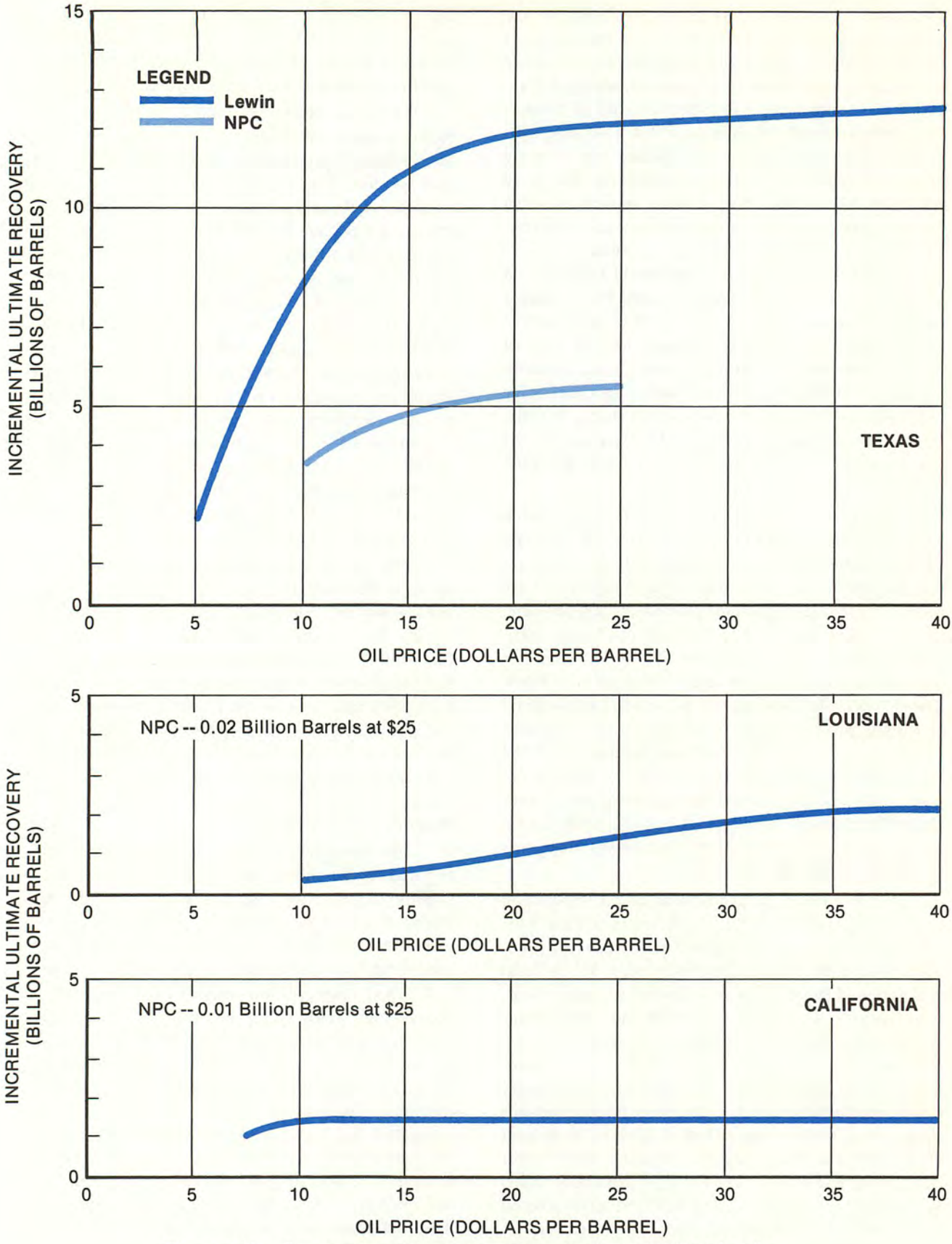


Figure 142. Incremental Ultimate Recovery—Carbon Dioxide Flooding —Minimum DCFROR Requirement—8%.

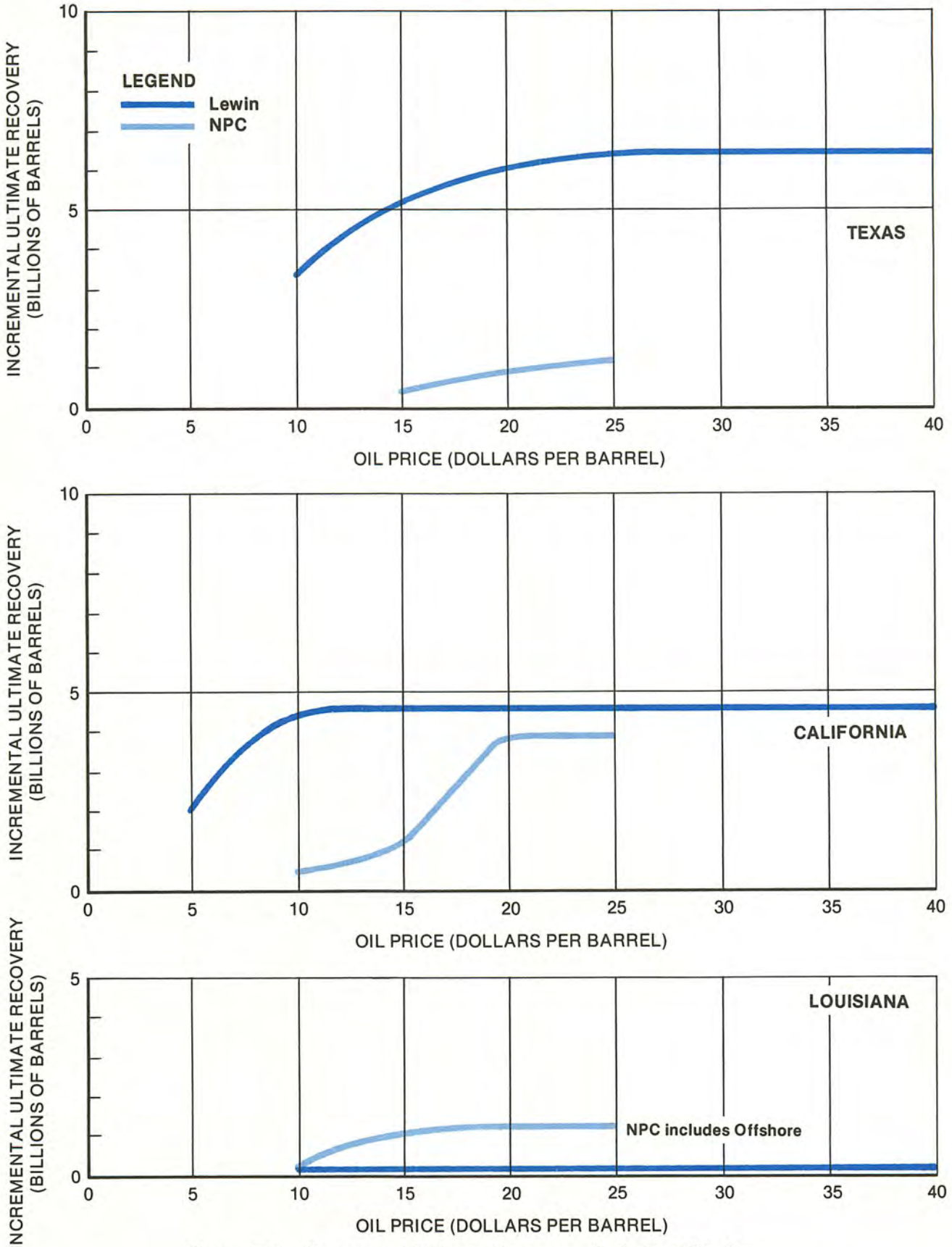


Figure 143. Incremental Ultimate Recovery—Surfactant Flooding —Minimum DCFROR Requirement—8%.

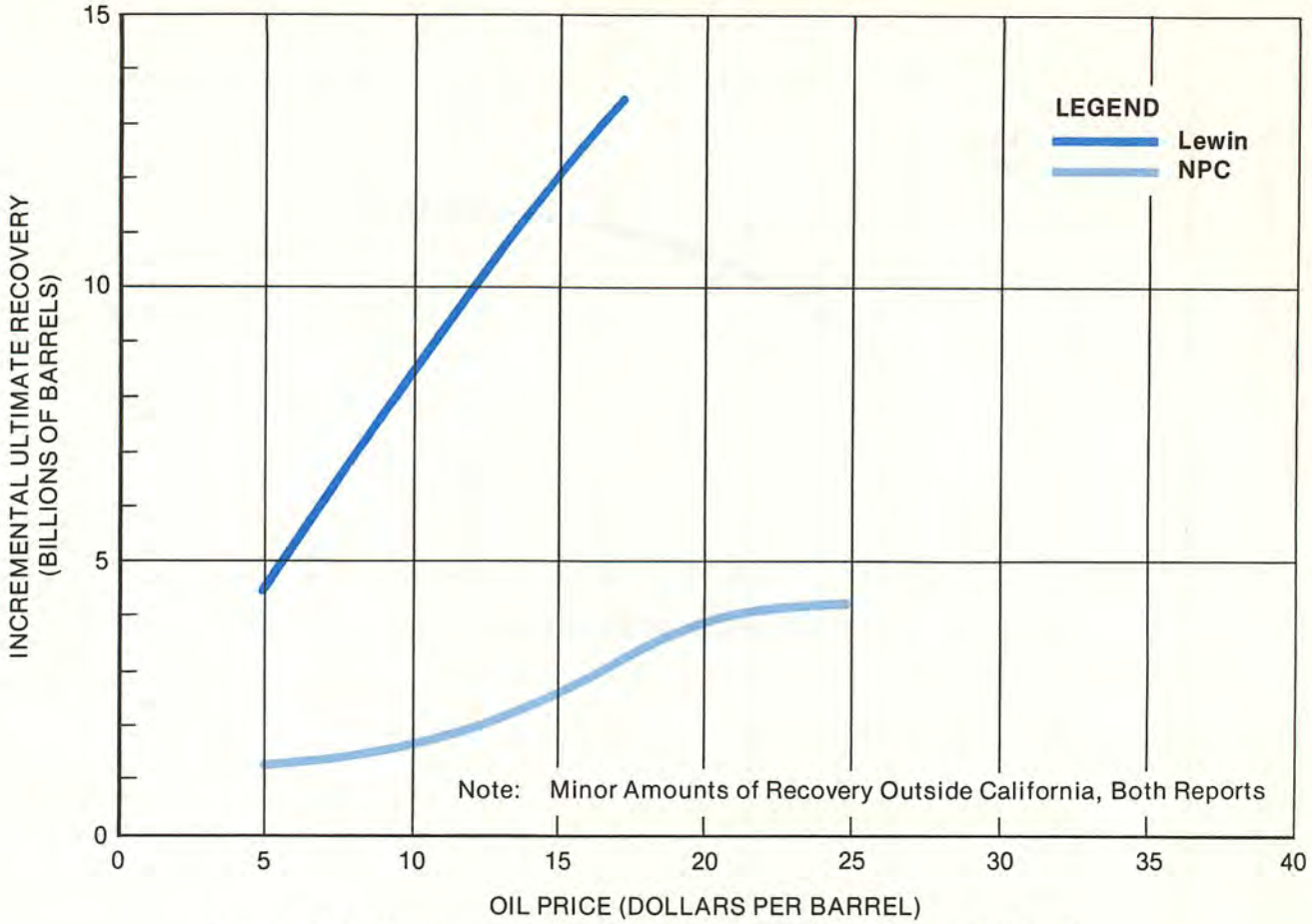


Figure 144. Incremental Ultimate Recovery—Steam Flooding, California —Minimum DCFROR Requirement—8%.

The basic screening criteria used by Lewin & Associates and the NPC study for identifying reservoirs as potential candidates for each enhanced recovery process were similar. Differences in reservoir selection caused by slightly different basic screening criteria probably did not contribute materially to the overall disagreement between the two studies.

However, the differences in dominance criteria employed in the two studies probably did cause substantial differences within individual states for the matching of reservoirs with processes, particularly between CO_2 and surfactant flooding. For example, in Louisiana most of the reservoirs in which both CO_2 flooding and surfactant flooding were potential processes would be assigned to CO_2 flooding by the Lewin dominance criteria; in that study, CO_2 flooding was assumed to dominate if API gravity was greater than 35°. In the NPC study, however, an economic dominance criterion was used as well as the technical screening criteria. In general, the Lewin dominance criteria, which were non-economic criteria, favored CO_2 flooding.

In the NPC study, those reservoirs that passed the first screening were reviewed by industry geologists and reservoir analysts for other factors that might influence the probability of the reservoir being a candidate for enhanced oil recovery. This second review was not detailed, and judgments were subjective; but factors such as geology, severity of heterogeneity, success of past waterflooding, likely influence of gas caps, etc. were considered whenever possible. For some of the processes this second screening appreciably reduced the number of reservoirs which were considered further as candidates for enhanced recovery. For example, for the CO_2 flooding process, the number of reservoirs was reduced from 165 to 109 by the second review. This reduction in the number of candidate reservoirs reduced the amount of original oil in place for these reservoirs from 84 to 47 billion barrels.

There is potential for substantial disagreement between the two studies in the manner in which incremental oil recovery was forecast for individual reservoirs. For CO_2 flooding and surfactant flooding, a basic difference in viewpoint exists concerning the effective oil saturation the injected fluids will encounter and displace in a tertiary flood. The significance of this difference perhaps can be illustrated

best with the following formula.

$$\text{incremental oil recovery} = \frac{\text{OOIP} \times (S_{orw} - S_{ore})}{(1 - S_{wi})} \left(\frac{B_{oi}}{B_o}\right) E$$

where:

OOIP = original oil in place (stock tank barrels)

B_{oi} = original oil formation volume factor (reservoir barrels per stock tank barrel)

B_o = current oil formation volume factor (reservoir barrels per stock tank barrel)

S_{orw} = effective residual oil saturation after waterflooding contacted by the enhanced recovery injection fluids in the volume of reservoir swept by the injection fluids

S_{ore} = final residual oil saturation left in that volume of the reservoir swept by enhanced recovery fluids

S_{wi} = original water saturation

E = sweep efficiency of the enhanced recovery fluids

For most of the reservoirs examined, it is unlikely that major disagreement has resulted due to any differences in the values used for initial oil in place, remaining oil in place, initial water saturation, or formation volume factors, since basically the same data base was used by the two studies. (However, the NPC study did not have available the remaining oil in place data actually used by Lewin; these were, therefore, estimated.) Although there were some differences in sweep efficiency values from reservoir to reservoir, it is unlikely that this factor resulted in major differences in aggregated recovery estimates. The most likely potential for serious disagreement lies in the term, "$S_{orw} - S_{ore}$," the effective reduction in oil saturation in the swept reservoir volume achieved by the injected fluids.

There is basic disagreement between the two studies on how to estimate S_{orw}, the effective residual oil saturation after waterflooding encountered by the enhanced recovery injection fluids in a tertiary flood, and large differences in estimated potential oil recovery can result from this disagreement. In the Lewin & Associates study, the oil remaining in place in a reservoir at the start of tertiary flooding was estimated by subtracting the anticipated ultimate

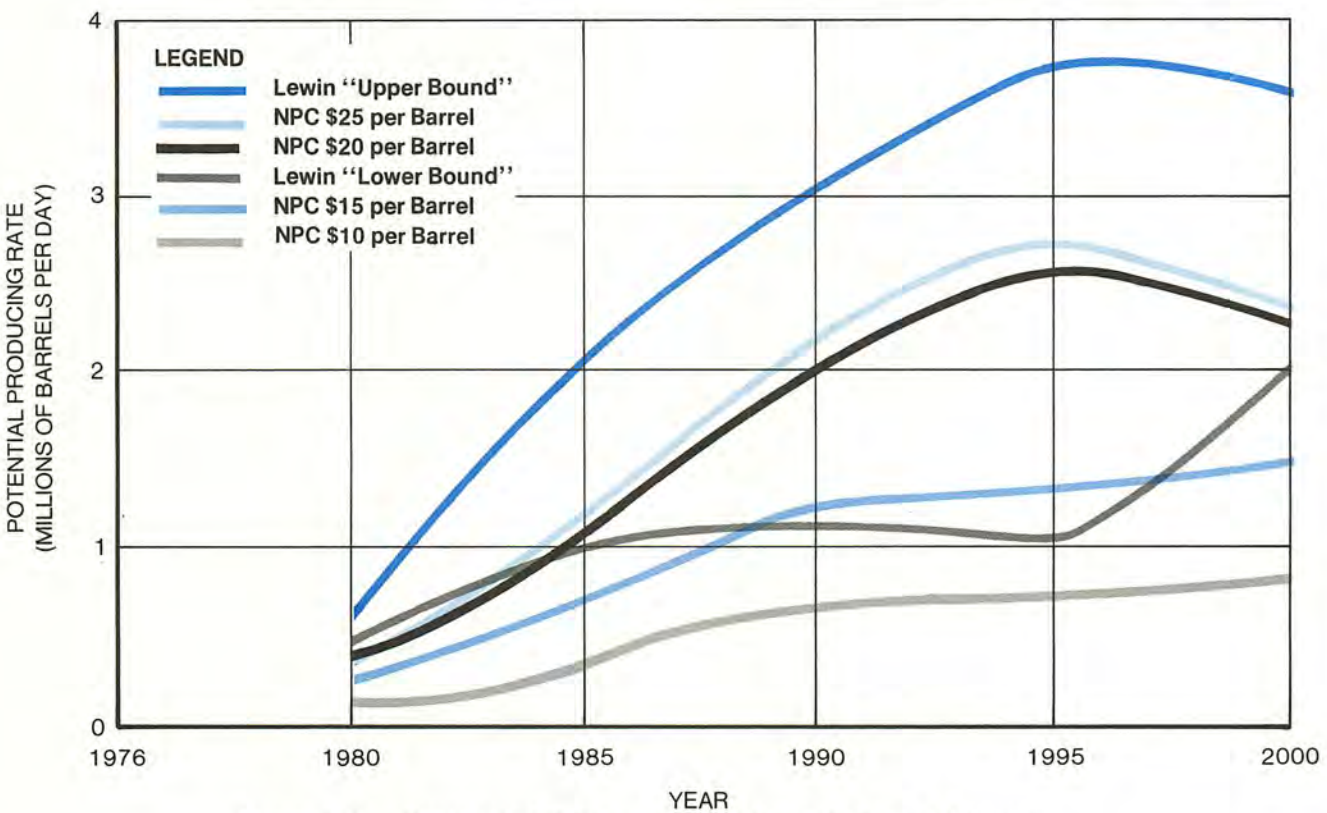


Figure 145. Projected Oil Producing Rate from Enhanced Recovery Total for Three States.

Note: All curves are based on a minimum DCFROR requirement of 8 percent except Lewin "Lower Bound" which is based on a minimum DCFROR requirement of 20 percent.

primary and secondary production from the OOIP. This remaining oil in place was then assumed to be distributed uniformly throughout the reservoir pore volume (PV) as a material balance residual oil saturation to waterflooding. In reality, the oil left in a reservoir after waterflooding will be distributed at higher saturations in regions of the reservoir unswept by water and at lower saturations in the water-swept regions; it was reasoned, however, by Lewin & Associates that additional infill drilling to closer well spacings for enhanced recovery would result in sweepout by the EOR fluids of those parts of the reservoir that had not been previously contacted by the waterflood. In their estimates for surfactant flooding, Lewin & Associates assumed a standard 2.5-acre, five-spot pattern, which in most candidate fields for this process does represent substantial infill drilling.* However, for CO_2 flooding, a standard 40-acre, five-spot pattern was assumed; for most CO_2 flood candidate fields, this does not represent a materially different well spacing for CO_2 flooding than for waterflooding.

Although infill drilling to very close well spacing may result in some improvement in sweep efficiency in a few reservoirs, the NPC study assumed that the enhanced recovery fluids would follow the flow paths already established by previous waterflooding (i.e., in the most permeable portions of the reservoir rock). Therefore, the oil saturation encountered by the enhanced recovery fluids was assumed to be in the swept, or water-flushed zone. The probability of this flow behavior was judged to be high, both for well spacings that were not drastically different from the spacing used to waterflood a reservoir and for economically realistic infill drilling in most reservoirs.

For reservoirs that have had high waterflood recoveries and high sweep efficiency by waterflooding, this difference in viewpoint is not appreciable. However, for reservoirs that achieve ultimate primary plus secondary recoveries of approximately 30-40 percent and sweep efficiencies of approximately 0.60 or less, the material balance residual oil saturation to waterflood may be on the order of 0.40 to 0.55, while the flushed zone residual oil saturation to waterflood may be on the order of 0.25-0.30. Moreover, for surfactant and CO_2 flooding, generally higher final residual oil saturations (S_{ore}) were assumed to be left to enhanced recovery flooding in the NPC study than in the Lewin study, as illustrated below:

	S_{ore} Lewin	S_{ore} NPC
Surfactant Flooding	0.05	0.10
CO_2 flooding		
Sandstones	0.05	0.05
Carbonates	0.05	0.10

For 14 reservoirs examined for surfactant flooding in the NPC report and on which comparisons were made, aggregate oil recovery was 1.6 times higher when using the Lewin sweep factors and approach for estimating saturations. For 42 carbonate reservoirs examined for CO_2 flooding, 2.2 times more oil recovery was estimated using the Lewin approach.

Different methods also were used in the two studies to project the unit pattern oil recovery from steamflooding. In the method used by Lewin & Associates, the same percentage volumetric sweep factors for steam and for hot water were applied regardless of reservoir thickness. In the NPC study, the steam and hot water each were assumed to sweep a constant vertical thickness of the reservoir, which varied with well spacing but did not vary with total reservoir thickness. The result of these different sweep assumptions is that less oil recovery would be projected in the NPC study for reservoirs with thick oil zones (approximately 100 feet or greater), and that more oil recovery would be projected for thin oil zones (approximately 30 feet or less).

Generally, the thicker reservoirs predominated among the steamflood candidate reservoirs of this study. In addition to the differences in estimating sweepout, a higher residual oil saturation in the steam-swept region was assumed in the NPC study than in the Lewin & Associates study (0.15 versus 0.08). Also, recovery adjustment factors ranging from 0.5 to 0.7 were applied in the NPC study to the basic, single-pattern performance predictions to account for heterogeneity and for quality of the reservoirs (see Appendix F). All of these factors probably account for most of the difference in projected oil recovery between the two studies. Both studies reported the net oil production, i.e., the production after accounting for produced oil consumed as fuel in the steam generators.

The unit cost to produce a barrel of enhanced recovery oil probably was different in the two studies for many of the fields examined. The higher oil recovery projected by Lewin & Associates because of the assumed material balance residual oil saturation would result in a lower unit cost per barrel of oil produced, provided the production costs were not correspondingly higher than those assumed in the NPC study. As a result, projects would be economically attractive at lower oil prices in the Lewin study, leading to further disparity between the two studies in the magnitude of recovery projected for a given oil price.

There were numerous differences in costs, and a reservoir-by-reservoir analysis would be necessary

*See Glossary, "flood pattern."

to determine the extent to which lower unit costs per barrel of oil produced were projected by Lewin & Associates. However, the cost of total surfactant fluid injected was generally higher in the NPC study as illustrated in the following table:

Oil price (Dollars per Barrel)	Relative Costs of Surfactant Injection Fluid* $\left(\frac{\text{NPC}}{\text{Lewin}}\right)$
5	0.80
10	0.89
15	1.00
20	1.10
25	1.20

*Cost of Surfactant Injection Fluid = (pore volume injected) × unit cost, dollars per barrel. Comparisons made for NPC reservoirs rated fair, 65 percent sweep efficiency.

The total cost of the surfactant slug increased more with oil price in the NPC study than in the Lewin & Associates study, because the surfactant cost was escalated with oil price in the NPC study.

Since CO_2 sources and their distances from oil fields are not identified in the Lewin study, a direct comparison of the delivered CO_2 costs could not be made. For equivalent distances, the Lewin method estimates somewhat higher delivered cost of naturally occurring CO_2 than does the NPC study. However, in the NPC study, sharply higher delivered CO_2 costs were assumed for situations where pipeline delivery seemed unlikely and trucking costs would be incurred.

Appendix H
Production Decline Curve

Introduction

Purpose

Existing crude oil reserves (excluding North Slope, Alaska) were analyzed to provide a projection of yearly producing rates to the year 2000. This provides a base curve to which North Slope production, new U.S. discoveries, and enhanced oil recovery from past discoveries can be added.

Sources of Information

The historical data used were based on the December 31, 1975, American Petroleum Institute (API) reserves statistics.* Where interpretation or judgment was necessary, additional information was drawn from NPC, Interstate Oil Compact Commission (IOCC), the *Oil and Gas Journal* industry surveys, and other publications.

Historical Primary and Secondary Reserve Statistics

It is impossible to separate API reserve figures rigorously into primary and secondary reserves. The method used was primarily based on assumptions as expressed in the 1972 NPC *U.S. Energy Outlook, Oil and Gas Availability* report:

- The 1946 reserves were allocated according to that year's production (95 percent primary) into primary and secondary reserves.
- After 1946, historical primary reserves were calculated by adding cumulative new oil reserve additions from extensions, new fields, and new reservoirs, to the 1946 primary reserves and subtracting cumulative primary production.
- After 1946, historical secondary reserves were calculated by adding cumulative net reserve revisions to the 1946 secondary reserves and subtracting cumulative secondary production.

Using this method, the first-of-the-year 1976 United States proved crude oil reserves (excluding North Slope, Alaska) were calculated to be divided among primary, secondary and enhanced as shown in Table 46.

Indicated Additional Reserves

Beyond the booked reserves, the API recognizes that current secondary and enhanced recovery reserves will increase from known sources by 5,022 million barrels. It was assumed that about two-thirds of this oil would be added to proved secondary reserves over a five-year period, beginning in 1976. This amounts to 663 million barrels per year (see Table 48).

Approximately one-third of the remaining indicated additional reserves was assumed to be future proved reserves that will be added through new enhanced oil recovery operations projected in this study; therefore, it was not included in this projection.

*API, *Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada as of December 31, 1975*, Vol. 30, May 1976.

NOTE: Data describing "existing crude oil reserves" does not include reserves in North Slope, Alaska.

TABLE 46

API CRUDE OIL RESERVES AS OF DECEMBER 31,1975
(Billions of Barrels)

Proven Reserves (Total U.S.)	32.7
Less North Slope	9.6
	23.1
Add Indicated Additional Reserves	5.0
Reserves Used in the Projection	28.1
Breakdown of Reserves in This Projection	
Proven	
Primary	11.5*
Secondary	10.6*
Enhanced	1.0†
Subtotal	23.1
Indicated Additional	
Secondary	3.3*
Enhanced	1.7‡
Subtotal	5.0
Total	28.1

* Included in projection, excluding enhanced.

† Projected as a separate add-on in Figures 5 and 47 to reflect proved enhanced recovery reserves.

‡ Included in this study as a gross estimate of projected resources from enhanced oil recovery not proved as of December 31, 1975.

Historical and Projected Production From Existing Reserves

Historical production figures were derived from an allocation of API statistics between primary and secondary production.

Projected producing rates were calculated from API proved reserves and the secondary portion of API indicated additional reserves of crude oil as of December 31, 1975. *Except for this portion of indicated additional reserves, future reserve revisions and reserve additions from extensions, new field discoveries and new reservoirs were not included in the calculation of projected production.*

Projections of annual production were calculated by multiplying the first-of-the-year primary and secondary reserves by the production-to-reserve fractions of 0.116 for primary and 0.119 for secondary. Those production-to-reserve ratios have prevailed since 1972 when the United States essentially went on maximum efficient rate (MER) capacity production.

Depletion schedules for primary and secondary reserves were calculated by subtracting annual production from the first-of-the-year reserves, as shown in Tables 47 and 48.

Figure 146 shows historical data up to January 1, 1976, and projected values from then to January 1, 2000, on daily oil rates from primary, secondary and enhanced recovery projects underway as of December 31, 1975. These projected values are listed in Table 49.

The contribution of future enhanced oil recovery projects is not addressed in this appendix. The historical enhanced production is shown on Figure 146 in the upper portion of the total production interval. This assumed some significance by 1965 and is estimated to be about 350 thousand barrels per day in 1975. The one billion barrel estimated enhanced recovery proved reserve as of December 31, 1975, was typically depleted at a rate approximating 10 percent per year.

Also, a wedge, or add-on, value to this is the estimated increased producing rate thought to be obtainable from stripper wells due to increases in

TABLE 47

DEPLETION SCHEDULE FOR PRIMARY RESERVES*
(Millions of Barrels)

Year	First of Year Reserve	Annual Production
1-1-76 Primary Reserves†	11,527	1,337
1977	10,190	1,182
1978	9,008	1,044
1979	7,963	923
1980	7,039	816
1981	6,223	721
1982	5,501	638
1983	4,863	564
1984	4,298	498
1985	3,800	440
1986	3,359	389
1987	2,969	344
1988	2,625	304
1989	2,320	269
1990	2,051	237
1991	1,813	210
1992	1,603	185
1993	1,417	164
1994	1,252	145
1995	1,107	128
1996	979	113
1997	865	100
1998	765	88
1999	676	78
2000	597	69

* Excluding North Slope.

† Primary Reserve: P/R = 0.116.

TABLE 48

DEPLETION SCHEDULE FOR SECONDARY RESERVES*
(Millions of Barrels)

Year	First of Year Reserves	Annual Production	Indicated Additional Reserves
1-1-76 Secondary Reserves†	10,617	1,263	663
1977	10,017	1,192	663
1978	9,488	1,129	663
1979	9,022	1,074	663
1980	8,611	1,025	663
1981	8,249	982	
1982	7,267	865	
1983	6,402	762	
1984	5,640	671	
1985	4,969	591	
1986	4,378	521	
1987	3,857	459	
1988	3,398	404	
1989	2,980	355	
1990	2,625	312	
1991	2,313	275	
1992	2,038	243	
1993	1,796	214	
1994	1,582	188	
1995	1,394	166	
1996	1,228	146	
1997	1,082	129	
1998	953	113	
1999	840	100	
2000	740	88	

* Excluding North Slope.

† Secondary Reserves: P/R = 0.119.

Note: Assumed approx. 66% of indicated additional reserves of 5 billion barrels is to be added from secondary recovery (over a five-year period).

TABLE 49

PROJECTION OF PRODUCING RATES*
(Thousand Barrels per Day)

Year	Primary	Secondary	Total
1976	3,654	3,451	7,105
1977	3,239	3,266	6,505
1978	2,863	3,093	5,956
1979	2,530	2,942	5,472
1980	2,231	2,800	5,031
1981	1,978	2,690	4,668
1982	1,748	2,370	4,118
1983	1,546	2,088	3,634
1984	1,363	1,833	3,196
1985	1,208	1,619	2,827
1986	1,068	1,427	2,495
1987	944	1,258	2,202
1988	832	1,104	1,936
1989	738	972	1,710
1990	652	855	1,507
1991	576	753	1,329
1992	508	664	1,172
1993	450	586	1,036
1994	398	515	913
1995	352	455	807
1996	310	400	710
1997	275	353	628
1998	243	310	553
1999	215	274	489
2000	189	240	429

* Excluding North Slope.

oil prices (see Table 50).*

Lease condensate and plant liquids were not included in this analysis. They are extracted from natural gas "nonassociated" with crude oil, and "associated-dissolved," as produced with crude oil. During the past decade these natural gas liquids have contributed from 17 percent (1965) to 19.5 percent (1975) of the U.S. total liquid hydrocarbon production. In 1975, natural gas liquids added about 1.9 million barrels to the 7.9 million barrel crude oil daily stream. About one-third of the current natural gas liquid reserves are associated with crude oil reserves. The small increment of liquid production that will be associated with enhanced oil recovery is not included in projections made in this study.

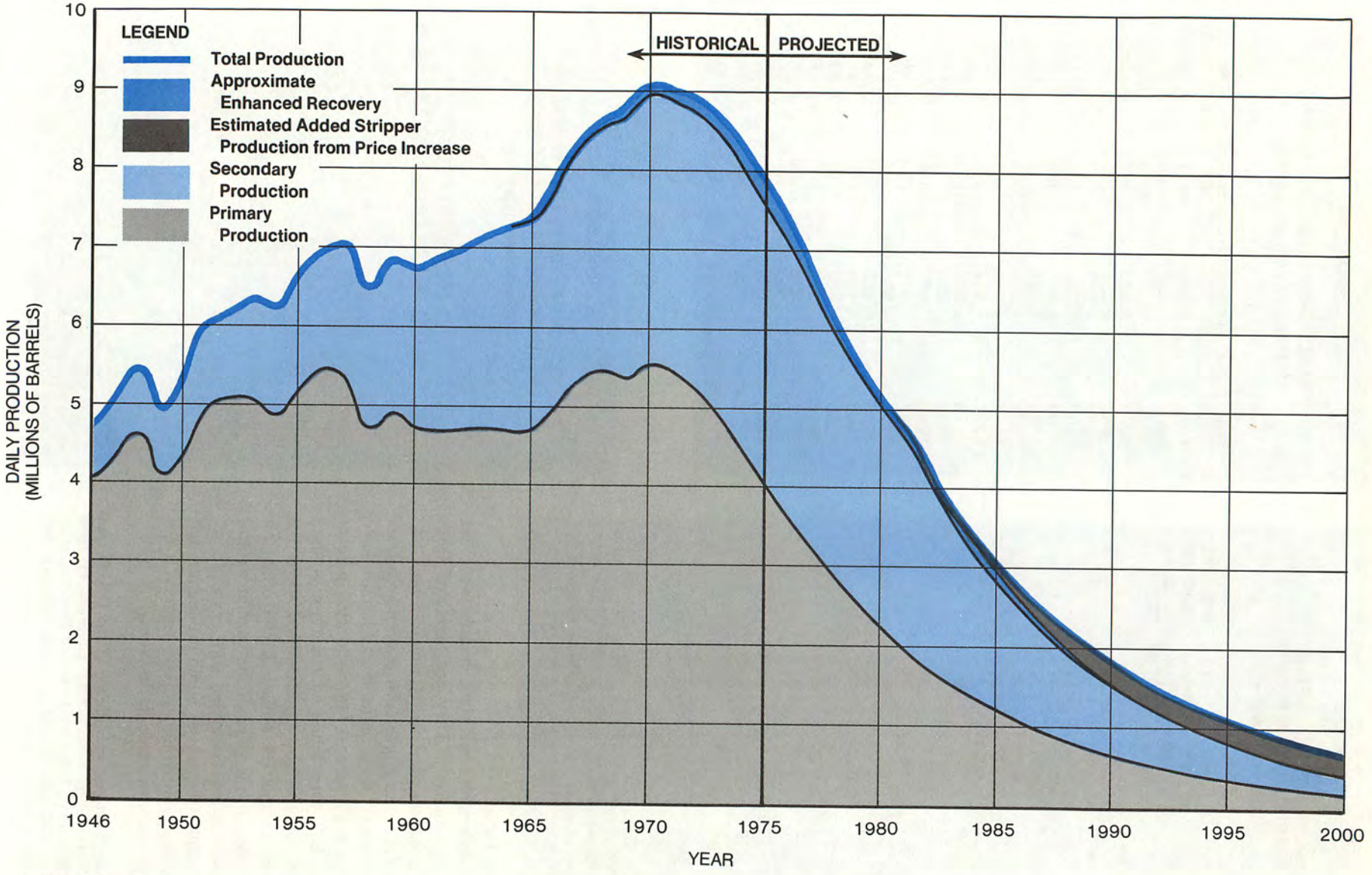
*Data were developed with the aid of the U.S. Bureau of Mines (USBM) using methodology published by John A. Pederson, "Economic Index for Increased Recovery from Stripper Wells," *Colorado School of Mines Industry Bulletin*, Vol. 17, No. 2, March 1974.

TABLE 50

PROJECTION OF STRIPPER TYPE ADDED OIL PRODUCTION FROM PRICE INCREASE
(Thousand Barrels per Day)

Year	Added Daily Production Rate	
	$10-$25 per Barrel	$10-$15 per Barrel
1980	0	0
1981	0	0
1982	46	46
1983	88	88
1984	126	126
1985	159	159
1986	181	159
1987	214	159
1988	238	159
1989	260	159
1990	260	159
2000	260	159

Source: Data developed with the aid of U.S. Bureau of Mines, using methodology published by John A. Pederson, "Economic Index for Increased Recovery from Stripper Wells," Colorado School of Mines Mineral Industry Bulletin, V. 17, No. 2, March 1974.



Historical Data: A.P.I.

Note: Projected total daily production(to which future EOR will be added) excludes the following: extensions; new field discoveries; and new reservoir discoveries in old fields. It does include the secondary portion of API indicated additional reserves from known reservoirs. These will show up in future revisions. Extensions, which are not proved, can be significant and are referred to as "inferred" by some analysts.

Figure 146. U.S. Oil Production (Excluding North Slope).

Glossary

NOTE: *Definitions in the Glossary are intended to be helpful to the reader who is generally unfamiliar with petroleum production technology. Many of the definitions have somewhat specialized meanings as used in this report and are not rigorous or general.*

alkaline—refers to a material that causes a high pH in water when dissolved in water; sodium hydroxide and sodium carbonate are typical alkaline materials used in EOR.

alkaline flooding—EOR with an alkaline solution.

API—American Petroleum Institute.

°API—degrees API; API gravity: an index of specific gravity.

aquifer—a subsurface rock interval that will produce water. Many oil reservoirs are underlaid or surrounded by an aquifer.

bank—a concentration of oil (oil bank) or other fluid or fluids in a reservoir that moves through the reservoir with integrity during EOR.

barrel—a unit of volume used to measure petroleum equal to 42 U.S. gallons.

booked rate of return—the ratio of annual net earnings to owners' investment, expressed as percent.

BTU—British Thermal Unit; a unit of energy approximately equal to the energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

BTU/MMCF—heat energy obtainable by burning one million cubic feet of gas.

cash flow—net profit after taxes plus charges to depreciation, amortization, and like accounts.

cash outlay—total cash expenditures.

chemical flooding—see enhanced recovery process.

CO_2 miscible flooding—see enhanced recovery process.

combustion—burning of petroleum in-situ for the purpose of EOR.

combustion thermal process—see enhanced recovery process.

combustion zone—the volume of reservoir rock wherein petroleum is undergoing combustion during EOR.

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.

conventional recovery—primary or secondary recovery.

conversion cost—the cost of changing a producing well to an injection well, or some other change in the function of an oilfield installation.

cost—the money required to implement an EOR process, carry out an oilfield step, or obtain materials; such as conduct a chemical flood, build a pipeline, drill a well, install environmental safeguards or buy chemicals.

crude oil—petroleum.

data base—a collection of information about oil fields in Louisiana, Texas, and California, which is useful in making analysis of EOR; also other collections.

DCFROR—discounted cash flow rate of return.

DCFROR, minimum requirement of 10%—DCFROR is equal to or greater than 10 percent for each project in an aggregate of projects for which EOR is being related to price or other parameter.

density—weight or mass per unit volume, such as pounds per cubic feet.

discounted cash flow rate of return (DCFROR)—a particular measurement of investment profitability that accounts for costs, revenues and the time value of money.

displacement efficiency—ratio of enhanced recovery to target oil.

dominance rules—rules that permit choice of an EOR process for a reservoir among two or more processes that meet qualifying screens for application.

emulsion—a dispersion of very small drops of one liquid in another liquid, such as oil in water.

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 processes are discussed in this report:

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 study, carbon dioxide (CO_2) is the only such material considered.

chemical flooding process: injection of water with added chemicals into a petroleum reservoir. In this study, three chemical types are considered:

a. surfactants
b. polymers
c. alkaline chemicals.

EOR—enhanced oil recovery.

evolution of technology—presumed future improvements in EOR techniques as a result of research and experience.

extrapolation—means of estimating EOR from oil fields not included in the data base.

field—an area from which petroleum has been produced.

field trial—a pilot test.

flood, flooding—the process of displacing petroleum from a reservoir with water; it may be by natural means (a form of primary recovery) or by induced means (secondary recovery by water injection). If water and chemicals are injected following secondary recovery, the chemical flooding is an enhanced recovery process.

flood pattern—the areal pattern of injection and producing wells selected for a secondary or enhanced recovery project. (See Figure 147.)

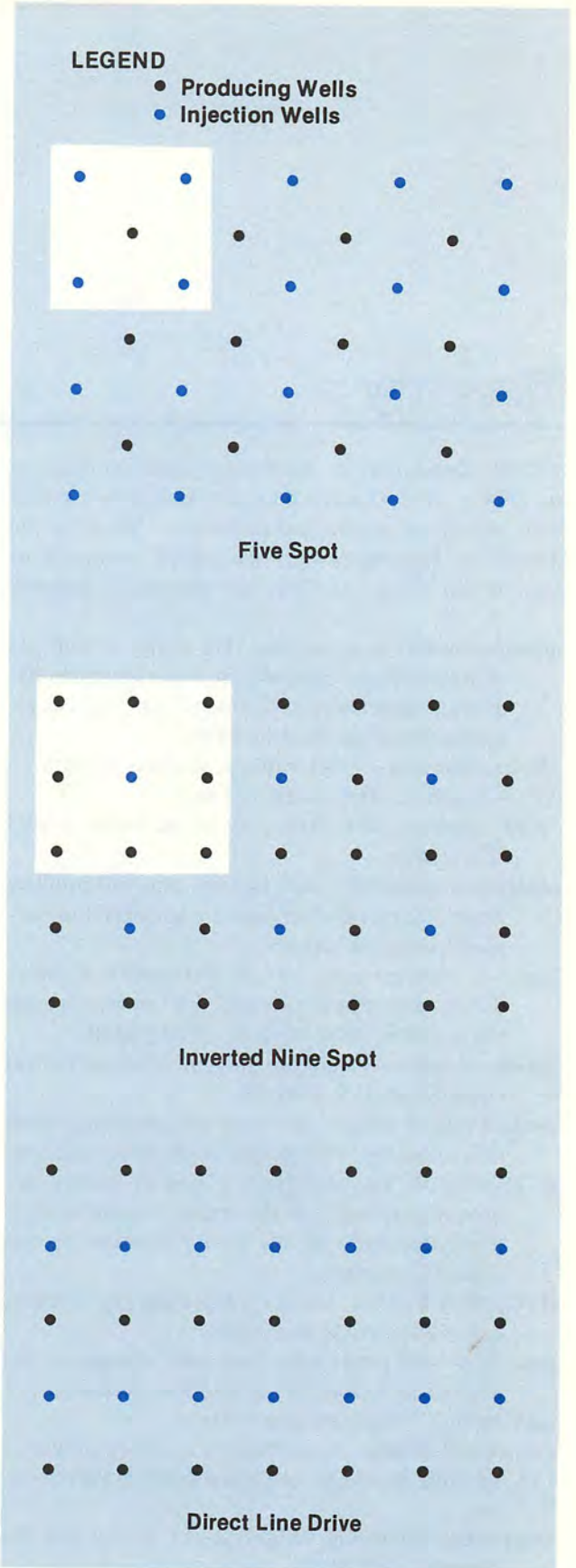


Figure 147. Flood Patterns.

fluid—a gas or a liquid.

formation—a reservoir.

fracture—a crack in reservoir rock, especially as distinguished from a pore space.

fracturing—hydraulic fracturing.

front end—at the beginning of an EOR project.

gas cap—a part of an oil reservoir at the top that will produce only gas.

gas-oil ratio—ratio of cubic feet of gas at atmospheric (standard) conditions to barrels of produced petroleum.

gas pressure maintenance—gas injection into one or more wells to augment reservoir pressure and energy.

good-fair-poor—classifications of reservoirs for EOR applications based on judgment and technical evaluation.

gravity—specific gravity or API gravity.

gravity segregation—partial separation of fluids in a reservoir caused by differences in density. (See "override.")

h—symbol for reservoir thickness.

heterogeneity—lack of uniformity in reservoir properties such as permeability.

hydraulic fracturing—splitting of reservoirs by high-pressure/high-volume injection of liquids through an injection well.

hydrocarbons—chemical compounds containing predominantly hydrogen and carbon.

incremental ultimate recovery—calculated recoverable oil for an EOR process under specified economic and process conditions.

injection well—a well in an oil field used for putting fluids into a reservoir.

in-situ—in the reservoir.

in-situ combustion—an EOR process consisting of injection of air into a reservoir under conditions favorable to in-situ burning of part of the in-situ petroleum; convection of this burning zone; and recovery of oil from a nearby producing well.

infill drilling—drilling additional wells in an established pattern.

interface—the area separating two non-miscible fluids that are in close contact with each other.

integrity—maintenance of a slug or bank more or less in its identified form without too much dispersion or mixing.

interfacial—refers to the interface between two fluids that are not miscible, such as oil and water.

IOCC—Interstate Oil Compact Commission.

IPAA—Independent Petroleum Association of America.

K—symbol for permeability.

known oil fields—oil fields in the United States that have produced petroleum before 1976.

lead time—the period of time between the start of an EOR project (including the planning phase) and the start of significant oil production.

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.

Lewin Report—report on enhanced recovery prepared by Lewin & Associates and issued by the FEA in April 1976.

lithology—the overall and specific characteristics of the reservoir rock.

M—thousand

MM—million

md—abbreviation for millidarcy, a unit of permeability.

methane—CH_4, the simplest in the straight-chain hydrocarbon molecules; normally the predominant chemical in natural gas.

micellar—refers to a special kind of emulsion.

millidarcy—a unit of permeability.

minimum DCFROR requirements—See DCFROR, minimum requirement of 10%.

miscible—refers to mixing between two fluids with a resulting lack of interfaces.

miscible flooding—see enhanced recovery process.

mobility—a measure of the ease with which a fluid moves through reservoir rock; the ratio of rock permeability to fluid viscosity.

mobility ratio—ratio of mobility of an injection fluid to mobility of a fluid being recovered.

Mscf—unit of gas volume equal to 1,000 standard cubic feet.

μ(mu)—symbol for viscosity.

natural gas—in-situ hydrocarbons and other chemicals produced as a gas, usually predominantly methane.

nominal rate of return—rate of return from an investment in current dollars, instead of constant dollars.

North Slope—the Prudhoe Bay field and adjoining area on the north coast of Alaska.

oil—petroleum.

oil field—see field.

oil price—value of produced oil at the oilfield location.

oil recovery—a procedure whereby petroleum is removed from a petroleum reservoir through wells. Three kinds of oil recovery are referred

to in this report:

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 well—a well for producing oil.

OPEC—Organization of Petroleum Exporting Countries.

override—flow of a lighter fluid in a reservoir above another heavier fluid in the reservoir caused by gravity forces.

OSHA—Occupational Safety and Health Administration.

original oil-in-place (OOIP)—petroleum existing in-situ before oil recovery.

parameter—a property (e.g., reservoir permeability) or other characteristic that helps determine the behavior of a system.

pattern—the configuration of two or more wells in an oil field.

pattern life—the length of time a pattern participates in oil recovery.

PDS—Petroleum Data System.

permeability—an index of the ability of reservoir rock to transmit fluids under the influence of a pressure gradient.

petroleum—a liquid mixture of hydrocarbons and small amounts of other materials naturally occurring in reservoirs.

pH—a measure of hydrogen ion concentration which in turn is a measure of acidity and alkalinity.

pilot—a pilot test.

pilot costs—costs of carrying out a pilot test.

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.

pool—a reservoir.

pore space—a small hole in reservoir rock which contains fluid or fluids; a fist-sized volume of reservoir rock may contain up to millions of interconnected pore spaces.

pore volume—total volume of all pores and fractures in a reservoir or part of a reservoir.

porosity—ratio of pore volume and fracture volume to total volume in reservoir rock, usually expressed as a percent.

potential producing rate—a producing rate by EOR that might be realized under assumed economic and EOR process conditions.

preflush—a slug injected into a reservoir before starting an EOR process, or injected as the first step, to condition or prepare the reservoir for the EOR process.

present worth—today's value of a future revenue or cash outlay.

pressure gradient—rate of change of pressure with distance.

pressure maintenance—augmenting the pressure (and energy) in a reservoir by injecting gas or water through one or more wells.

price—the market value of crude oil at the oilfield where it is produced or, on occasion, at other locations.

primary recovery—see oil recovery.

process—an operational procedure for EOR.

producibility—the rate at which oil or gas can be produced from a reservoir through a well bore.

producing well—a well in an oil field used for removing fluids from a reservoir.

production—fluid obtained from a producing well, commonly petroleum or natural gas.

psi—pounds per square inch.

public policy—laws, regulations and goals accepted and promulgated by government and society.

R&D—research and development.

recoverable oil—total oil that can be produced by oil recovery.

remaining oil—petroleum in-situ at any time during oil recovery.

reserves—recoverable oil; unless qualified, means economically recoverable oil with proved technology.

reservoir—a part of the earth rock below the surface, normally sedimentary, that contains petroleum or natural gas which has been or can be subjected to oil or gas recovery.

reservoir description—a qualitative and quantitative evaluation of the properties of a reservoir.

reservoir performance—behavior of a reservoir undergoing oil recovery.

reservoir simulation—analysis of reservoir performance with a computer model.

residual oil—petroleum remaining in-situ after oil recovery.

resource base—total petroleum in-situ which may be subjected to attempted oil recovery.

revenue—cash received for the sale of crude oil.

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.

sedimentary—formed by or from deposits of sediments, especially from sand grains or silts transported from their source and deposited in water, as sandstone and shale; or from calcareous remains of organisms, as limestone.

sensitivity study—evaluation of how much a factor such as oil production changes with respect to a change in a variable or a parameter.

SL—Straight Line; a technique for establishing capital depreciation rate. (See discussion in Appendix C, "Income Tax Cases.")

slug—a quantity of fluid injected into a well during EOR.

specific gravity—the ratio of the density of oil (or other substances) to the density of water.

start-up time—the time at which a process is started.

state-of-the-art—the overall stage of development of an EOR process and its background R&D.

steam flooding—injection of steam into an injection well and the production of oil as a consequence from a nearby well.

steam stimulation—injection of steam into a well and the subsequent production of oil from the same well.

steam thermal process—steam stimulation and/or steam flooding.

surfactant—a type of chemical, characterized as one that reduces interfacial resistance to mixing between oil and water or changes the degree that water wets reservoir rock.

sweep efficiency—the ratio of the volume of reservoir rock contacted by enhanced recovery injected fluids to the total volume of reservoir rock in the project area.

SYD—Sum-of-the-Year's Digits; a technique for establishing capital depreciation rate. (See discussion in Appendix C, "Income Tax Cases.")

target oil—petroleum in-situ at the start of an EOR process in the part of the reservoir expected to be within the sweep efficiency volume and subjected to EOR.

target return—objective discounted cash flow rate of return for an EOR project.

technical feasibility—denotes what may be accomplished with proved technology.

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.

tight gas sands—reservoir rock containing natural gas that cannot be recovered under current economic and technologic conditions because of low permeability.

transmissibility (transmissivity)— $\frac{kh}{\mu}$, an index of producibility of a reservoir (or part of a reservoir) of thickness h.

turbidite—a type of reservoir rock, normally heterogeneous, containing high concentrations of silts and clays.

viscosity (μ)—a fluid property that determines its ease of movement through reservoir rock.

waterflooding—a secondary recovery process.

well—a hole drilled into the earth for the purpose of removing fluid from a reservoir or putting fluid into a reservoir.

well bore—the hole in the earth comprising a well; a well.

well conversion cost—the cost of changing a producing well to an injection well.

workover—a maintenance job on a well to improve its performance.

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