# Appendix B

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

# LIST OF TABLES

## LIST OF FIGURES



96-594 O - 78 - 11

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

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

# Technological Projections

## Surfactant/Polymer Flooding

### State of the Art—Technological Assessment

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

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

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

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

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

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

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

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

| Field | Location |
|---|---|
| El Dorado | Kansas |
| North Burbank | Oklahoma |
| Bradford | Pennsylvania |
| Bell Creek | Montana |
| Robinson | Illinois |
| Wilmington | California |

**Screening** Criteria. —The screening criteria in table 7 of the main text reflect estimates of technological advances in the next 20 years as well as current technology inferred from past and ongoing field tests. For example, technological advances in temperature tolerance are projected so that reservoirs which have a temperature of 200° F can have a technical field test in 1985.

The OTA screening criteria coincide with those used by the National Petroleum Council (NPC)[16] with one exception. The OTA data base did not contain adequate water-quality data for all reservoirs. Consequently, reservoirs were not screened with respect to water quality.

The screening criteria were reviewed prior to acceptance. The review process included informal contacts with personnel who did not participate in the NPC study and an examination of the technical literature. The principal variables are discussed in the following sections.

The screening criteria are judged to be representative of the present and future technological limits. As discussed later, it is recognized that permeability and viscosity criteria have economic counterparts. However, the number of reservoirs eliminated as candidates for the surfactant/polymer process by either of these screening criteria was insignificant.

*Current Technology* (1976).--Current limits of technology are reflected by field tests which have been conducted or are in an advanced stage of testing. These are summarized in table B-2.[17] Field tests are generally conducted in reservoirs where variation in rock properties is not large enough to obscure the results of the displacement test due to reservoir heterogeneities. These reservoirs tend to be relatively clean sandstone with moderate clay content. A crude oil viscosity less than 10 centipoise is characteristic of most surfactant/polymer field tests. Reservoir temperatures range from 55° F to 169° F.

*Reservoir* Temperature.—Surfactants and polymers are available which tolerate temperatures up to about 170° F. Research on systems which will be stable at 200° F is underway in several laboratories. The rate of technological advance in this area will probably be related to the success of field tests of the surfactant/polymer process in lower-temperature reservoirs. Successful field tests will stimulate development of fluids for higher-temperature deeper reservoirs as potential applications in those reservoirs become a reality. The assumed timing of technological advances in temperature limitations appears attainable.

*Permeability and Crude Oil Viscosity. -*Permeability of the reservoir rock is both a technological and an economic factor. The surfactant/polymer process will displace oil from low permeability reservoir rock.[18] A minimum permeability based on technical performance of the process has not been established. Low permeability may correlate with high-clay content of the reservoir rock and corresponding high-surfactant losses through adsorption. The surfactant slug must be designed so that its integrity can be maintained in the presence of large adsorption

## Table B-2
## Summary of Surfactant Field Tests Being Conducted by Industry Without ERDA Assistance

| Field | State | County | Operator | Process Type* | Area (Acres) | Start | Pay | Porosity (%) | Perm. (Md) | Depth (ft) | Reservoir °API | Oil (Cp) | Temp. (°F) | Salinity (ppm) | Comment |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Robinson | Ill. | Crawford | Marathon | MSF | 0.75-40 | 11 /62 | Robinson | 20 | 200 | 1,000 | 35-36 | 7 | 72 | HPW 18,150 ppm TDS (1 19-R) | 6 tests |
| | Ill. | | Marathon | MSF | 4.3 | 5/70 | Aux Vases | | | 3,000 | | | | | |
| Bingham | Pa. | McKean | Pennzoii | MSF | 0.75-45 | 12/68 | Bradford | 18 | 82 | 1,860 | | 5 | 68 | 2,800 $Cl^-$ | 2 tests |
| Goodwill Hill | Pa. | Waxyen | Quaker St. | MSF | 10 | 5/71 | First Venongo | | | 600 | 40 | 4.5 | 55 | | |
| Benton | Ill. | Franklin | Shell | Aqueous | 1-160 | 11/67 | Tar Springs | 19 | 69 | 2,100 | | 4 | 86 | 77,000 ppm TDS | 2 tests |
| Loudon | Ill. | | Exxon | Aqueous solution | 0.65 | 9/70 | Chester Cypress | 21 | 103 | 1,460 | | 4 | Est. 95 | 64,000 $Cl^-$ 104,000 TDS | |
| Higgs Unit | Tex. | Jones | Union | SOF | 8.23 | 8/69 | Bluff Creek | 22.9 | 500 | 1,870 | 37 | 4.3 | 95 | 54,000 cl– | |
| Big Muddy | Wyo. | Converse | Conoco | SF | 1 | 8/73 | Second Wall Creek | 19.2 | 52 | 3,100 | 34 | 5.6 | 114 | 7,700 TDS, 20 ppm CA+ Mg | fractured, |
| Griffin Consol. | Ind. | Gibson | Conoco | SF | 0.8 | 11 /73 | Upper Cypress | 20 | 75 | 2,400 | 37 | | | | |
| Wichita Co. Regular | Tex. | Wichita | Mobil | LTWF | 209 | 7/73 | Gunsight | 22 | 53 | 1,750 | 42 | 2.2 | 89 | 160,000 TDS | |
| Borregos | Tex. | Kleberg | Exxon | Aqueous solution | 1.25 | mid 60's | Frio | 21 | *400 | 5,000 | 42 | 0.4 | 165 | 33,000 TDS | |
| Guerra | Tex. | Star | Sun | SF | 2.0 | | Jackson | 33 | 2,500 | 2,270 | 36 | 1.6 | 122 | 20,000 TDS | |
| Bridgeport | Ill. | Lawrence | Marathon | MSF | 2.5 | 9/69 | Kirkwood | 18 | 90 | 1,500 | 38-39 | 5.5 | 72 | | |
| Sayles | Tex. | Jones | Conoco | SF | 2.5 | /63 | Flappen | 21.7 | 457 | 1,900 | 38 | | | | |
| Montague | Tex. | Montague | Conoco | SF | 2.5 | /63 | Cisco | 24.2 | 394 | 1,200 | 27 | | | 150,000 TDS | |
| Loma Novia | Tex. | Duval | Mobil | SF | S.o | mid 60's | | | | | | | | | 4% kaolinitc 5.5% montmorillonite |
| Salem | Ill. | Marion | Texaco | LTWF | 5.8 | 4/74 | U. Benoist | 14.8 | 87 | 1,750 | 38 | 3.6 | 0.85 | 40,000cl– | |
| Sloss | Nebr. | Kimball | Amoco | SF | 10.0 | 1 /75 | Muddy J. | 17.1 | 93 | 6,250 | 34 | 0.8 | 165 | 2,457 TDS | |
| West Ranch | Tex. | Jackson | Mobil | LTWF | 2.5 | 6J74 | 41A | 31 | 950 | 5,700 | 32 | 0.7 | 169 | 60,000$Cl^-$ | |
| La Barge | Wyo. | Sublette | Texaco | SF | 1.7 | 1/75 | Almy | 26 | 450 | 700 | 26 | 17 | 60 | 1,017 $Ca^{++}$ and $Mg^{++}$ | |

* Process Type normally refers to specific surfactant floods used, but is not intended to characterize actual differences: Aqueous-dispersion of sulfonate in water with very little oil in slug; MSF—micellar surfactant flood; SOF—normally considered "oil external" chemical slug; SF and LTWF—surfactant flood and low-tension waterflood *normally* similar to aqueous *systems.*

Source: *Enhanced 0// Recovery,* National Petroleum Council, December 1976, p. 97.

losses. As a result, larger slugs or higher concentrations may be needed with corresponding increases in costs.

Permeability, fluid viscosities, well spacing, and maximum injection pressure affect the rate at which a chemical slug can displace oil from a reservoir. Low permeability translates to low displacement rates or increased well density to maintain a specific rate. Both lead to higher process costs.

The same reasoning applies to crude oil viscosity. As viscosity increases, displacement rates decrease or well density increases. Mobility control in the surfactant/polymer process is attained by increasing the viscosities of the chemical slug and the drive water. Both of these changes require addition of expensive constituents to these fluids. Therefore both permeability and viscosity are constrained by economics.

It is known from laboratory tests that oil recovery by the surfactant/polymer process is a function of displacement rate. For example, more oil is recovered at an average displacement rate of 5 ft per day than at the rate of 1 ft per day[19] which exists in a typical reservoir. Rate effects in field size patterns may be revealed in the Marathon-ERDA commercial demonstration test.[20]

*Water* Quality .-Composition of the formation water is a critical variable in the surfactant/polymer process. Fluids under field tests can tolerate salinities of 10,000 to 20,000 ppm with moderate concentrations of calcium and magnesium, although reservoirs containing low-salinity flu ids are preferred. Some field tests are in progress in which preflushes are used to reduce salinity to levels which can be tolerated by the injected chemicals.[21,22] However, in one large field test[23] the inability to attain a satisfactory preflush was considered to be a major contributor to poor flood performance. Potential shortages of fresh water for preflushing and uncertainty in effectiveness of preflushes have stimulated research to improve salinity tolerance.

Technological advances were projected in the NPC study which would increase the salinity tolerance from 20,000 ppm in 1976 to 150,000 ppm in 1980 and 200,000 ppm in 1995. The OTA technical screen does not contain a similar scenario because salinity data were not available for all the reservoirs in the OTA data base. It does not appear that results would have been affected appreciably if the data were available in the data base to schedule technological advances in salinity tolerance.

*Rock Type.*—The surfactant/polymer process is considered to be applicable to sandstone reservoirs. Carbonate reservoirs are less attractive candidates because 1 ) the formulation of compatible fluids is more difficult due to interaction with calcium and magnesium in the rocks; 2) carbonate reservoirs frequently produce through small- and large-fracture systems in which maintenance of an effective surfactant slug would be difficult; and 3) there is a consensus among technical personnel that the $C0_2$ miscible displacement process is a superior process for carbonate reservoirs.

*Reservoir Constraints.*—Reservoirs with large gas caps which could not be waterflooded either by natural water drive or water injection are likely to be unacceptable. Also, reservoirs which produce primarily through a fracture system fall in the same category. However, there is the possibility of technological developments[24] which would restrict flow in the fracture system and perm t displacement of the surfactant slug through the porous matrix.

## Oil Recovery Projections

The surfactant/polymer process is applied in a reservoir which has been previously waterflooded, There are different opinions among technical personnel concerning the volume of the reservoir which may be swept by the process. Some consider that the swept volume will be less than the volume swept by the waterflood, while others envision **more** volume swept by the surfactant/polymer process. The reasoning behind these viewpoints is summarized in the following subsections.

*Swept Volume Less Than Water flood Sweep.*—Residual oil saturations and volumetric sweep efficiencies attributed to waterflooding are frequently the result of displacing many pore volumes of water through the pore space. In contrast, the surfactant/polymer process can be approximated as a 1- to 2-pore volume process which may lead to a smaller fraction of the reservoir being contacted by the surfactant/polymer process.

Many reservoirs are heterogeneous. It can be demonstrated that heterogeneities in the vertical direction of a reservoir which have relatively small effect on the sweep efficiency of a waterflood may have large effects on the sweep efficiency of the surfactant/polymer process.[25] For instance, in a layered reservoir it may not be possible to inject enough surfactant into all layers to effectively contact the regions which were previously waterflooded.

Surfactant/Polynmer Swept *Volume Outside of Waterflood Region.*—The region outside of the volume swept by the waterflood contains a high oil saturation. in many surfactant processes, the viscosity of the injected fluids is much higher than water used in the previous waterflood. This could lead to increased volumetric sweep efficiency for the surfactant/polymer process. Davis[26] has presented data from a Maraflood™ oil recovery process test in the Bradford Third Sand of Pennsylvania. An increase of 7 to 10 percent in the volumetric sweep efficiency for the surfactant process over the previous waterflood was indicated in his interpretation of the data.

*OTA* Model.-The OTA model is based on the assumption that the region contacted by the surfactant/polymer process in most reservoirs is the region swept by the previous waterflood. The surfactant/polymer process displaces oil from the previously water-swept region by reducing the oil saturation following the waterflood ($S_{orw}$) to a lower saturation, termed $S_{or}$, which represents the residual oil saturation after a region is swept by the surfactant/polymter process. The oil recovery using this representation of the process was computed using equation 1 B for each pattern area,

$$N_{pc} = \frac{A_p h \phi E_{vm}}{B_o} (S_{orw} - S_{of}) \qquad \text{1B}$$

where

$N_{pc}$ = oil displaced by the chemical flood, stock-tank barrels
$A_p$ = area of the pattern
h = net thickness of pay
9 = porosity, the fraction of the rock volume which is pore space
$E_{vm}$ = fraction of the reservoir volume which was contacted by water and surfactant/polymer process determined by material balance calculations
$B_o$ = ratio of the volume of oil at reservoir temperature and pressure to the volume of the oil recovered at stock-tank conditions (60° F, atmospheric pressure)

Residual oil saturations left by the chemical flood ($S_{or}$ ranging from 0.05 to 0.15 have been reported in laboratory[27,28] and field tests.[29] A value of 0.08 was selected for the OTA computations.

The residual oil saturation following waterflood ($S_{orw}$ for the high-process performance case was the oil saturation corresponding to the particular geographic region in table A-1 modified by the material balance calculation as described in appendix A, in the section on *Distribution of (the Remaining Oil Resource* on page 139. In the low-process performance model, the residual oil saturations following waterflood ($S_{ORW}$) were reduced by 5 saturation percent from the values in table A-1. This caused a decrease in recoverable oil which averaged 28.6 percent for all surfactant/polymer reservoirs. Due to the method of analysis, the process performance of a small number of reservoirs was not affected by this saturation change. Some reservoirs which had 90-percent volumetric sweep imposed by the material balance discussed on page 139 for the high-process performance case also had 90-percent volumetric sweep efficiency under low-process performance.

*Pattern Area and Injection* Rate.—Each reservoir was developed by subdividing the reservoir area into five-spot patterns with equal areas. The size of a pattern was determined using the procedure developed in the NPC study.[30] A pattern life of 7 years was selected. Then, the pattern area and injection rates were chosen so that 1.S swept-pore volumes of fluids could be injected into the pattern over the period of 7 years. The relationship between pattern area and the injection rate is defined by equation 2B.

where

- $i$ = injection rate, barrels per day
- $\phi$ = porosity
- $h$ = thickness, feet
- $A_p$ = pattern area, acres

Maximum pattern area was limited to 40 acres.

Injection rates were constrained by two conditions. In Texas, California, and Louisiana, it was assumed that maximum rates were limited by well-bore hydraulics to 1,000 barrels per day, 1,500 barrels per day, and 2,000 barrels per day, respectively. Rate constraints in the reservoir were also computed from the steady-state equation for single-phase flow in a five-spot pattern given in equation 3B. The viscosity of the surfactant/polymer slug was assumed to be 20 times the viscosity of water at formation temperature. The lowest injection rate was selected. other parameters are identified after the definition of the equation.

$$i = \frac{3.541 \times 10^{-3} kh \Delta P}{\mu_{eff}\left\{\ln\left(\frac{d}{R_w}\right) - 0.619\right\}} \qquad 3B$$

where

- $i$ = injection rate, barrels per day
- $k$ = average permeability, millidarcies
- $h$ = average thickness, feet
- $\Delta P$ = pressure drop from injection to producing well, taken to equal depth/2
- $\mu_{eff}$ = effective viscosity of surfactant/polymer slug, or 20 times viscosity of water at reservoir temperature
- ln = natural logarithm
- $d$ = distance between the injection and production well, feet, or $147.58 \sqrt{A_p}$
- $A_p$ = pattern area, acres
- $R_w$ = radius of the well **bore**

*Development of Pattern.*-Development of each five-spot pattern took place according to the schedule shown in table B-3. Drilling and completion of wells and installation of surface facilities were done in the first 2 years. The surfactant slug was injected during the third year with the polymer injected as a tapered slug from years 4 through 6. The oil displaced by the surfactant/polymer process as computed from equation IB was produced in years 5 through 9 according to the schedule in table B-3.

**Table B-3**
**Development of a Five-Spot Pattern Surfactant/Polymer Process**

| Year of pattern development | Activity | Annual oil production % of incremental recovery |
|---|---|---|
| 1 | Drill and complete injection wells. Rework production well. | 0 |
| 2 | Install surface equipment. | 0 |
| 3 | Inject surfactant slug. | 0 |
| 4 | Inject polymer slug with average concentration of 600 ppm. Polymer concentration tapered. | 0 |
| 5 | | 10 |
| 6 | | 26 |
| 7 | Injection of brine. | 32 |
| 8 | | 20 |
| 9 | | 12 |
| | Total . . . . . . . | 100 |

*Volumes of Injected Materials.—*

*Current technology*

Surfactant Slug, . . 0.1 swept pore volume*
Polymer Bank. . . . 1.0 swept pore volume

*Advancing technology case*

Surfactant Slug. . . 0.1 swept pore volume
Polymer Bank, . . . 0.5 swept pore volume

● The swept pore volume of a pattern is defined by equation 4B.

$$V_p = E_v \sim A_p h\, o\, (7{,}758) \quad 4B$$

= volume of pattern swept by the surfactant/polymer process, barrels

The volumes of surfactant and polymer approximate quantities which are being used in field tests. Volume of the surfactant slug needed to sweep the pattern is affected by adsorption of surfactant on the reservoir rock. The slug of 0.1 swept-pore volume contains about 36 percent more sulfonate than needed to compensate for loss of surfactant that would occur in a reservoir rock with porosity of 25 percent and a surfactant retention of 0.4 mg per gm rock. The OTA data base contained insufficient information to consider differences in adsorption in individual reservoirs. The effect of higher retention (and thus higher chemical costs) than assumed in the advanced technology cases is examined in the high-chemical cost sensitivity runs.

## Composition and Costs of Injected Materials

The surfactant slug for all cases except the current technology case contained 5-wt percent petroleum sulfonate (100-percent active), 1-wt percent alcohol, and 10-volume percent lease crude oil. In the current technology case, the surfactant slug contained 20 percent lease crude oil. The concentration of the polymer solution was 600 ppm for reservoir oils with viscosities less than or equal to 10 centipoise. Concentration of polymer was increased with viscosity for oils above 10 centipoise according to the multiplier given in equation 5B.

$$\text{Concentration Multiplier} = (1 + \frac{32- \text{API}}{10}) \quad 5B$$

Equation 5B is valid for API gravities greater than 10. A polysaccharide polymer was used.

Table B-4 summarizes surfactant slug and polymer costs as a function of oil price. Costs of surfactant and alcohol based on data from the NPC study are presented in table B-5.

Net Oil, -Projected oil recovery from the surfactant/polymer process was reported as net barrels. The oil used in the surfactant slug and an estimate of the oil equivalent to the surfactant was deducted from the gross oil to determine net production.

**Table B-4**
**Chemical Coats**

| Oil price $/bbl | Surfactant slug cost - 10-percent lease crude $/bbl | Surfactant slug cost - 20-percent lease crude $/bbl | ‘Polymer cost* polysaccharide $/lb |
|---|---|---|---|
| 10 . . . . . . . . | 7.69 | 8.69 | 2.30 |
| 15 . . . . . . . . | 9.73 | 11.23 | 2.40 |
| 20 . . . . . . . . | 11.74 | 13.74 | 2.49 |
| 25 . . . . . . . . | 13.78 | 16.28 | 2.58 |

● Source: Enhanced Oil *Recovery,* National Petroleum Council, December 1976, p. 100.

**Table B-5**
**Component Costs***

| Oil price $/bbl | Surfactant cost 100-percent active $/lb | Alcohol cost $/lb |
|---|---|---|
| 5 . . . . . . . . | 0.29 | 0.13 |
| 10 ....., . . | 0.35 | 0.16 |
| 15 . . . . . . . . | 0.43 | 0.20 |
| 20 . . . . . . . . | 0.51 | 0.23 |
| 25 . . . . . . . . | 0.59 | 0.27 |

*Includlng tax and transportation.
Source: *Enhanced 011 Recovery,* National Petroleum Council, December 1976, p. 99.

## Sensitivity Analyses

Additional computations were made using the low- and high-process performance models to determine sensitivity to changes in chemical costs. Cost sensitivity analysis was accomplished by altering the volumes of surfactant and polymer used in the displacement process. The low-chemical cost case assumes a 40 percent reduction in the volume of the surfactant slug while the high-chemical cost case assumes that 40 percent more surfactant and 50 percent more polymer would be required than used in the base-chemical cost case.

Ultimate recoveries of oil using the surfactant/polymer process with high- and low-chemical cost assumptions are summarized in table B-6 for the advancing technology cases. With high chemical costs, there would be a negligible volume of oil produced at world oil price. The combination of both high-process performance and oil prices approaching the alternate fuels price would be needed to offset high chemical costs if the surfactant/polymer process is to contribute substantial volumes of oil to the Nation's reserves.

Low chemical costs have the largest impact on the low-process performance case where substantial increases in ultimate recovery could occur at both upper tier and world oil price. The effect of lower chemical costs on the high-process performance case is to reduce the oil price required to call forth a fairly constant level of production. For example, if chemical costs are low, the ultimate recovery projected at alternate fuels price is about the same as ultimate recovery at upper tier price. However, low chemical costs have a low probability of occurring unless a major technological breakthrough occurs.

The sensitivity analyses in this study were designed to bracket the extremes which might be expected assuming technology develops as postulated in the advancing technology cases. There are other process and economic variables which would be considered in the analysis of an individual field project which could not be analyzed in a study of this magnitude.

## Polymer Flooding

### State of the Art—Technological Assessment

The concept of mobility control and its relationship to the sweep efficiency of a waterflood evolved in the early to mid-1950's.[31,32] It was found that the sweep efficiency could be improved if the viscosity of the injected water could be increased. Thickening agents were actively sought. Numerous chemicals were evaluated but none which had economic potential were found until the early 1960's.

During this period, development in the field of polymer chemistry provided new molecules which had unique properties. High-molecular weight polymers were developed which increased the apparent viscosity of water by factors of 10 to 100 when as little as 0.1 percent (by weight) was dissolved in the water. The first polymers investigated were partially hydrolyzed polyacrylamides with average molecular weight ranging from 3 million to 10 million.

The discovery of a potential low-cost method to "slow down" the flow of water and improve sweep efficiency of the waterflood led to many field tests in the 1960's. Nearly all field tests used

**Tabie B-6**
**Surfactant/Polymer Process-Uitimate Recovery**
**Summary of Computed Results-Process and Economic Variations**
**(billions of barrels)**

| Case | Advancing technology cases Oil price $/bbl | | | | | |
|---|---|---|---|---|---|---|
| | Low-process performance | | | High-process performance | | |
| | 11.62 | 13.75 | 22.00 | 11.62 | 13.75 | 22.00 |
| High chemical costs . . . . . . . . . | 0.1 | 0.1 | 1.0 | 0.2 | 0.2 | 9,0 |
| Base chemical costs . . . . . . . . . | 1.0 | 2.3 | 7.1 | 7.2 | 10.0 | 12.2 |
| Low chemical costs . . . . . . . . . | 5,8 | 7.5 | 8.8 | 12.0 | 12.4 | 14.5 |

partially hydrolyzed polyacrylamides. By 1970 at least 61 field tests had been initiated[33] and by 1975 the number of polymer field tests exceeded 100. Although most field tests were relatively small, two were substantial. These were the Pembina test in the Pembina Field in Alberta and the Wilmington test in the Ranger V interval of the Wilmington Field in California.

Results of field tests have been mixed. Successful use of polymers has been reported in several projects 3536 where incremental oil above that expected from waterflooding has been produced. At least 2 million barrels of oil have been attributed to polymer flooding from successful projects. [37] Continuation of some projects and expansion of others indicate commercial operation is possible. However, polymer flooding has not been widely adopted. Many field tests yielded marginal volumes of oil. Response to polymer flooding was not significant in either the Pembina Flood or the Wilmington Flood.

Reasons for mixed field performance are not completely understood. polymer floods initiated early in the life of a waterflood are more likely to be successful than those initiated toward the end of a project. Reservoirs which have been waterflooded to their economic limit have not responded to polymer flooding as a tertiary process. Recent research [38] has demonstrated that partially hydrolyzed polyacrylamides degrade when sheared under conditions which may be present in injection well bores. Thus, it is not certain in previous field tests that a reservoir flooded with polymer solution was contacted with the same fluid used in laboratory tests.

Further research and development produced a polysaccharide biopolymer[39] which has improved properties. Polysaccharides are relatively insensitive to mechanical shear and have high tolerance to salt, calcium, and magnesium ions. Solutions containing polysaccharides must be filtered prior to injection to remove bacterial debris which may plug the injection wells. Since the polysaccharide is a product of a biological process, it is susceptible to further biological attack in the reservoir unless adequate biocide is included in the injected solution. Few field tests have been conducted using polysaccharide polymers.

polymer flooding has economic potential because it uses materials which are relatively low cost. Field application is similar to waterflooding with minor changes to permit mixing and proper handling of the polymer solutions. Widespread use by most operators would be possible without extensive technical support. Performance of polymer floods cannot be predicted accurately, and well-documented demonstration projects such as those being conducted in the N. Burbank Stanley Stringer[40] and the Coalinga[41] fields are essential to the widespread use of polymer flooding.

*Screening* Criteria. --Polymer flooding is not a potential process for all reservoirs which can be waterflooded. Geologic constraints, properties of the reservoir rock and oil, and stage of the waterflood are all critical parameters. Reservoirs which produce primarily through large fracture systems and reservoirs with large gas caps which could not be waterflooded were excluded. In these reservoirs, the polymer slug is likely to bypass much of the reservoir rock. A permeability constraint of 20 millidarcies was selected. While the lower limit of permeability is not known precisely, there is a range of permeabilities where the polymer molecules are filtered out of the injected solution and cannot be propagated through a reservoir. Selection of the correct molecular weight distribution of the polymer reduces the minimum permeability.

Field experience indicates that polymer floods have not been successful when applied after the waterflood has been completed. Reservoirs under waterflood which have volumetric sweep efficiency greater than 80 percent and low residual oil saturations are not good polymer candidates. Consequently, reservoirs with no ongoing waterflood and reservoirs with high volumetric sweep efficiency and low oil saturation were screened from the polymer flooding candidates.

Water quality was not used to screen reservoirs because salinity and divalent ion content do not determine whether a reservoir can be flooded with polymer solutions. These parameters do indicate the type of polymer which may be used. For example, partially hydrolyzed polyacrylamides are frequently preferred in low-salinity systems. Polysaccharides are relatively insensitive to salinity and may be required in order to flood successfully a reservoir which contains high-salinity fluids.

The use of polymers is limited by temperature stability. Proven temperature stability is about 200° F. This limit is expected to be 250° F by 1995. The same temperature limits used in the surfactant/polymer process screen apply to polymer flooding.

Crude oil viscosity was the final screening parameter. Field tests suggest an upper limit of about 200 centipoise. However, there is little published literature which shows that polymer solutions will not displace oil at higher viscosities. Other factors enter in the determination of the upper viscosity limit. Steam displacement and in situ combustion are considered superior processes because both can potentially recover more oil. As crude oil viscosity increases, higher polymer concentrations are required to maintain mobility control. Oil-displacement rates decline for a fixed pattern size. Both of these factors operate in the direction of reducing the rate of return at fixed oil price or requiring a higher oil price to produce a fixed rate of return. Then the crude oil viscosity becomes an economic factor rather than a technical factor.

Most reservoirs which were polymer candidates yielded more oil when developed as $CO_2$, surfactant/polymer, steam, or in situ combustion candidates. Thus, the OTA method of process selection, i.e., maximum oil if profitable at 10 percent rate of return and world oil price, led to assignment of the poorest reservoirs to polymer flooding.

## Oil Recovery Projections

Estimates of oil recovery from the application of polymer-augmented waterflooding to reservoirs which satisfied the technical screen were made using an empirical model. Incremental recovery for the low-process performance case was assumed to be 2.5 percent of the original oil in place. The incremental recovery for the high-process performance case was assumed to be 3 percent of the original oil in place. These estimates closely approximate recent projections for the N. Burbank Stanley Stringer and Coalinga field demonstration tests. They also approximate the average performance of published field tests.[42]

Each reservoir was developed on 40-acre spacing with a ratio of 0.5 injection well per production well. Injection of polymer was continued over the first 4 years of the project at a rate of 0.05 pore volumes per year. Average polymer concentration was 250 ppm. The polymer used was polysaccharide. Costs of polymer at various oil prices were identical to those used for the surfactant/polymer process (table B-4).

The recoverable oil was produced over an 11-year period according to the schedule in table B-7.

**Table B-7**
**Production Schedule**
**for Polymer-Augmented Waterflood**

| Year | Incremental oil percent of total |
|---|---|
| 1-2 | 0 |
| 3 | 5 |
| 4 | 10 |
| 5 | 20 |
| 6 | 20 |
| 7 | 15 |
| 8 | 10 |
| 9 | 10 |
| 10 | 5 |
| 11 | 5 |
| Total | 100 |

## Sensitivity Analyses

The effects of changes in polymer costs and/or volumes were examined for low- and high-polymer costs for both low- and high-process performance cases. Bases for cost variation were +/- 25 percent change in polymer cost. Results of the economic evaluations are presented in table B-8.

There is essentially no effect of chemical costs on oil production from polymer flooding at the upper tier, world oil, and alternate fuels prices. The sensitivity analyses show that uncertainty in process performance is larger than uncertainties introduced by chemical costs.

**Table B-8**
**Polymer-Augmented Waterflooding**
**Ultimate Recovery**
(billions of barrels)

| Case | Advancing technology cases oil price $/bbl | | | | | |
|---|---|---|---|---|---|---|
| | Low-process performance | | | High-process performance | | |
| | 11.62 | 13.75 | 22.00 | 11.62 | 13.75 | 22.00 |
| High polymer cost (+25°/0 over base) . . . . . . . . . . . . . | 0.2 | 0.2 | 0.3 | 0.4 | 0.4 | 0.4 |
| Base polymer cost. . . . . . . . . . . . . | 0.2 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 |
| Low chemical cost (-25°/0 from base). . . . . . . . . . . . . | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 |

### Effect of Polymer Flooding on Subsequent Application of Surfactant/Polymer or Carbon Dioxide Miscible Processes

The OTA analysis assumes a single process would be applied to a reservoir. The possibility of sequential application of two processes was not analyzed. Some reservoirs assigned to the surfactant/polymer process or the $C0_2$ miscible process would also be economic (rate of return greater than 10 percent at world oil price) as polymer floods. However, the decision rules for process assignment placed these reservoirs in the process which yielded the largest ultimate recovery.

One concern caused by this assignment procedure was whether or not the low costs and low financial risk from the polymer projections would cause operators to use polymerflooding as the final recovery process for a reservoir, precluding use of methods which potentially recover more oil.

The principal displacement mechanism in polymer flooding is an increase in the volume of the reservoir which is swept by the injected fluid. No reduction in residual oil saturation over that expected from waterflooding is anticipated because the viscosities of the oils in these reservoirs are low enough to make the residual oil saturations relatively insensitive to the viscosity of the displacing fluid.

A successful polymer flood in the OTA high-process performance would recover 3 percent of the original oil in place. This corresponds roughly to improved volumetric sweep efficiencies of 2 to 7 percent. Both OTA models for surfactant/polymer and $CO_2$ miscible processes are based on recovery of the residual oil from some percentage of the volume displaced by the preceding waterflood. Polymer flooding increases this contacted volume. Slightly more oil would be recovered from reservoirs which had been polymer flooded prior to surfactant flooding or $C0_2$ flooding if the OTA models of these displacement processes are substantially correct. Therefore, the application of polymer flooding will not prevent subsequent surfactant/polymer or $C0_2$ floods under the conditions postulated in the OTA study.

Finally, polymer flooding prior to surfactant/polymer flooding has been proposed as a method to improve volumetric sweep efficiency by increasing the flow resistance in more permeable paths in the reservoir.[43]

## Steam Displacement

### State of the Art—Technological Assessment

Steam displacement is a process which has primarily evolved in the last 10 to 15 years.

Development of the process was motivated by poor recovery efficiency of waterfloods in reservoirs containing viscous oil and by low producing rates in fields which were producing by primary energy sources. Most of the development occurred in California and Venezuela, where large volumes of heavy oil are located. Steam displacement has potential application in heavy oil reservoirs in other oil-producing States.

Large-scale field tests of steam injection began in the late 1950's [44,45] with field testing of hot water injection underway at the same time[46,47,48] in an attempt to improve the recovery efficiency of the conventional waterflood. Early steam and hot water injection tests were not successful. injected fluids quickly broke through into the producing wells, resulting in low producing rates and circulation of large volumes of heated fluids.

The process of cyclic steam injection was discovered accidentally in Venezuela in 19s9 and was developed in California. [49] Cyclic injection of small volumes of steam into producing wells resulted in dramatic increases in oil production, particularly in California where incremental oil due to cyclic steam injection was about 130,000 barrels per day in 1968.50 By *1971* about 53 percent of all wells in California had been steamed at least once.

Cyclic steam injection demonstrated that significant increases in production rate could be obtained by heating the reservoirs in the vicinity of a producing well. However, the process is primarily a stimulation process because natural reservoir energy sources like solution-gas drive or gravity drainage cause the oil to move from the reservoir to the producing well, Depletion of this natural reservoir energy with repeated application of cyclic steam injection will diminish the number of cyclic steam projects. Many of these projects will be converted to steam displacement.

The success of the steam displacement process is due to the high displacement efficiency of steam and the evolution of methods to heat a reservoir using steam. Development of the steam displacement process in the United States can be traced to large-scale projects which began in the Yorba Linda Field in 1960[51] and the Kern River Field in 1964.52 Estimates of ultimate recoveries (primary, secondary, cyclic steam, and steam displacement) from 30 to 55 percent of the original oil in place have been reported for several fields.

A comparison[53] of trends in incremental oil production from cyclic steam and steam injection for California is shown in figure B-1. Cyclic steam injection is expected to decline in importance as natural reservoir energy is depleted. Production from steam displacement could increase as cyclic projects are converted to continuous steam injection. The rate of conversion will be controlled by environmental constraints imposed on exhaust emissions from steam generators. Incremental oil from steam displacement will be limited to 110,000 barrels per day in California, the level which currently exists, unless technological advances occur to reduce emissions.

Commercial steam-displacement projects are also in operation in Wyoming,[54] Arkansas,[55] and Texas.[56] A large portion of the incremental oil now produced by application of EOR processes is produced by the steam displacement process.

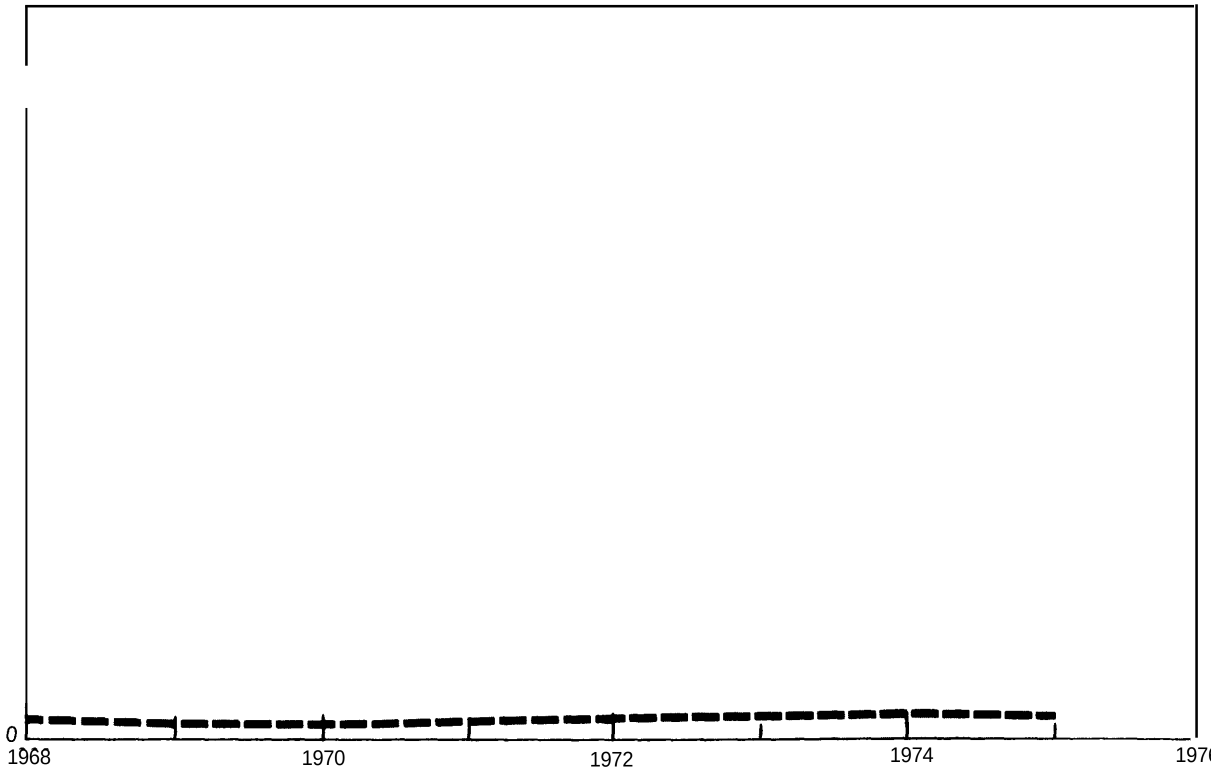
Screen/rig Criteria.—Steam displacement was considered applicable in reservoirs which were located at depths between 500 and 5,000 feet. The upper depth limitation was imposed in order to maintain sufficient steam injection pressure. The lower depth of 5,000 feet is determined by well-bore heat losses in the injection wells. At depths approaching 5,000 feet, heat losses can become excessive even with insulated injection strings. In addition, as depth increases the injection pressure increases, but the fraction of the injected fluid which is condensable decreases. Reduction in displacement efficiencies is expected to occur under these conditions.

The second screening criterion was transmissibility. The transmissibility (permeability x thickness/oil viscosity) is a measure of the rate that the oil moves through a reservoir rock. A transmissibility of about 100 millidarcy feet/centipoise is required for steam and hot-water injection processes in order to keep heat losses from the reservoir to overlying and underlying formations from becoming excessive. ST

## Oil Recovery Projections

*Recovery Models.*—Although steam displacement is the most advanced EOR process, it was

**Figure B-1. Historical Incremental Production Thermal Recovery-California**




difficult to develop recovery models which applied to an entire reservoir. The OTA data base as well as the Lewin data bases used in the NPC and ERDA reports contained little information on reservoir variability. Review of the technical literature and personal contacts with companies operating in fields with major steam displacement projects revealed considerable variability in thickness and oil saturation. It became apparent that most steam displacement projects were being conducted in the best zones of a reservoir, where oil saturations were higher than the average values in the data base. Thus, OTA concluded that empirical recovery models based on the results of these displacement tests could not be extrapolated to poorer sections of larger reservoirs with the available information. Subdivision of several large reservoirs into smaller segments of different properties as done in the NPC study was considered, but could not be done with the available computer program.

Recovery models were developed by OTA to estimate the recovery based on development of the entire reservoir. In taking this approach, it is

Acknowledged that recovery from the better sections of a reservoir will be understated and the recovery from poorer sections will be overstated. However, this approach was preferable to overstatement of recovery caused by applying empirical recovery models from the better zones[58] to other intervals and areas of a reservoir, or application of recovery adjustment factors to extrapolate single-pattern performance to total-project performance.[59]

Each reservoir with multiple zones was developed zone by zone. The technology necessary to complete each zone selectively was assumed to evolve through research and development. The average thickness per zone was determined by dividing the net thickness by the number of zones. Two displacement models were used based on the thickness of the zone. Single zone reservoirs were handled in the same way-according to thickness of the zone.

*High-Process Performance Case.—Zone Thickness Less Than or Equal to 75* Feet. -Gross oil recoverable by primary and secondary production followed by steam was considered to be 50 percent of the original oil in place. Thus in each zone,

$$\text{Steam Displacement Oil} = \frac{\text{Original Oil}}{2} - (\text{Primary} + \text{Secondary})$$

Zone Thickness **Greater Than** 75 Feet. –Oil displacement in thick reservoirs is based on the following model of the displacement process.

Steam displacement patterns were developed on 2.5-acre spacing with one injection well per producing well.

| Region | Areal sweep efficiency | Maximum vertical thickness of swept zone, feet | Residual oil saturation |
|---|---|---|---|
| Steam Zone . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | 0.75 | 25 | 0.10 |
| Hot Water Zone . . . . . . . . . . . . . . . . . . . . . . . . . . . | 0.90 | 35 | 0.25 |

Low-Process *Performance Case.*—Well spacing was increased to 5 acres. Gross oil displaced by steam was 80 percent of the amount estimated for the high-process performance case.

*Timing of Production.*—The incremental oil from the steam-displacement process was produced according to the production schedule in table B-9.

**Table B-9**
**Production Schedule for Steam Displacement Process**

| Year | Annual incremental oil percentage total |
|---|---|
| 1-2 . . . . . . . . . . . . . . . . . ~ ~ ~ ~€ . | 0 |
| 3 . . . . . . . . . . . . . . . . . . . . . . . . | 12 |
| 4 . . . . . . . . . . . . . . . . | 22 |
| 5 : : : : : : : : . . . . . . . . . . . . . . . . | 22 |
| 6 . . . . . . . . . . . . . . . . . . . . . . . . | 20 |
| 7 . . . . . . . . . . . . . . . . . . . . . . . . | 14 |
| 8 . . . . . . . . . . . . . . . . . . . . . . . . | 10 |
| Total . . . . . . . . . . . . . . . . . . | 100 |

The same schedule was used for low- and high-process performance models.

## Steam Requirements and Costs

Steam requirement was 1 pore volume based on net heated thickness. That is the volume occupied by the combined steam and hot water zones considering the areal sweep efficiency to be 100 percent. Zones with thicknesses less than or equal to 75 feet were assumed to be heated in the entire vertical cross section. Steam was injected over a 5-year period beginning in the third year of field development at the rate of 0.2 pore volume per year.

Lease crude was used as fuel for the steam generators. Twelve barrels of steam were produced per barrel of lease crude consumed. The full cost of the lease crude was charged as an operating cost to the project. Oil consumed as fuel was deducted from the gross production to obtain the net production. Cost of steam generation in addition to the fuel charge was $0.08 per barrel of steam generated to cover incremental operating and maintenance costs for the generator and water treatment.

*Other Costs.*—The costs of installed steam generation equipment were scaled from a 50 million Btu per hour steam generator costing $300,000.[60] A 1 million Btu per hour unit was assumed to generate 20,000 barrels of steam (water equivalent) per year. The number (possibly fractional) of generators required per pattern was determined from the pore volume of the pattern. Since the steam generator life was longer than pattern life, it was possible to use the same generator on two patterns in the field. The cost of moving a generator was assumed to be 30 percent of the initial cost. Thus the effective cost for the steam generator per pattern was 65 percent of the initial generator cost.

Reservoirs with multiple zones required workovers in production and, injection wells to close the zone just steamed and open the next zone. These costs are discussed in the section on Economic Data—General on page 178 of this appendix.

**Table B-10**
**Recovery Uncertainties Effecting Steam Displacement Results**

| Case | Production well spacing, acres | Recovery Model[a]: Zone thickness <75 ft.: Gross recovery (primary, secondary and steam displacement) as fraction of original oil in place | Zone thickness > 75 ft.: Maximum steam zone thickness | Zone thickness > 75 ft.: Maximum hot water zone thickness |
|---|---|---|---|---|
| Low recovery . . . . . . . . . ... . . . | 2.5 | 0.45 | 25 | 30 |
| High-process performance ... | 2.5 | 0.50 | 25 | 35 |
| High recovery. . . . . . . . . . . . . . . . | 2.5 | 0.55 | 30 | 35 |

[a]All other model parameters were the same as in the high-process Performance case.

## Sensitivity Analyses

Projections of oil recovery by steam displacement contain uncertainties which are primarily related to the recovery efficiency of the process. Additional analyses were made to determine the range of variation in oil recovery due to uncertainties in process performance (table B-10).

One set of projections was based on variations of recovery for a well spacing of 2.5 acres per production well. Projections for low recovery (45 percent) and high recovery (55 percent) are compared with the high-process performance case (50 percent recovery) in table B-11. Results from the low recovery case are essentially the same as the low-process performance case. The projections from the high recovery case are appreciably higher than the high-process performance case.

**Table B-n**
**Effect of Uncertainties in Overall Recovery on Ultimate Production**

**Steam Displacement Process**
**(billions of barrels)**

| Case | Upper tier price ($1 1.62/ bbl) | World oil price ($1 3.75/ bbl) | Alternate fuels price ($22.00/ bbl) |
|---|---|---|---|
| Low recovery . . . . . . . | 2.1 | 2.5 | 3.4 |
| High-process performance | 2.8 | 3.3 | 6.0 |
| High recovery. . . . . . . | 3.9 | 5.9 | 8.8 |

These extremes in recovery performance are also measures of energy efficiency. Crude oil is burned to produce steam. The amount of crude consumed is proportional to the volume of steam required to heat the reservoir. Nearly the same volume of steam and consequently the same amount of lease crude is consumed for each of the three cases. Slight variations occur for zones with thicknesses greater than 75 feet, Most of the additional oil projected in the high recovery case is produced with little additional lease crude required for steam generation. In contrast, a larger fraction of the produced oil is consumed in the low recovery case because about the same amount of crude is consumed to produce steam while a smaller amount of oil is produced by the displacement process.

Pattern size is the second variable which was investigated in sensitivity calculations. Oil recovery was estimated for two additional well spacings using the high-process performance model. Results are summarized in table B-12. If recovery is unaffected by well spacing, there is an economic incentive to increase well spacing over the 2.5-acre spacing used in the OTA study. Results are sensitive to spacing primarily because the costs to work over both injection and production wells in order to move from zone to zone are significant.

Increasing well spacing reduces these costs in producing wells by a margin which permits several large reservoirs to meet the 10-percent

**Table B-12**
**Effect of Well Spacing on Ultimate Recovery of Oil Using the Steam Displacement Process**

| Case | Production well spacing acres | Incremental 011 (billions of barrels) Upper tier price ($11.62/bbl) | World oil price **($1 3.75/bbl)** | Alternate fuels price **($22.00/bbl)** |
|---|---|---|---|---|
| **High-process performance . . . . . . . . . . . .** | **2.5** | **2.8** | **3.3** | **6.0** |
| **High-process performance ., . . . . . . . .,** | **3.3** | **3.5** | **5.3** | **6.8** |
| **High-process performance . .... .** | **5.0** | **5.6** | **6.4** | **7.0** |

rate-of-return criteria at lower prices. This is a potential area for technological advances beyond those which were assumed in this study.

## In Situ Combustion

### State of the Art—Technological Assessment

In situ combustion has been investigated in the united States since 1948.[61] By the mid-1950's, two pilot tests had been conducted. One test was done in a reservoir containing a light oil (35° API) with a low viscosity (6 cp).[62] The second reservoir tested contained 18.4° API oil which had a viscosity of 5,000 cp.[63] These initial pilot tests demonstrated that a combustion front could be initiated and propagated in oil reservoirs over a wide range of crude oil properties.

The initial demonstrations of the technical feasibility of in situ combustion stimulated research and development of the process both in the laboratory and in the field. Over 100 field tests of in situ combustion have been conducted in the United States.[64]

Field testing developed considerable technology. Methods were developed to initiate combustion, control production from hot wells, and treat the emulsions produced in the process. Improved process efficiency evolved with research and field testing of methods to inject air and water simultaneously.[65,66] The wet combustion process was found to have the potential of reducing the air requirements by as much as 30 to so percent over dry combustion.

Many field tests have been conducted but few have resulted in projects which are commercially successful. Economic information was not available on current in situ combustion projects. Continued operation over a several-year period with fieldwide expansion implies satisfactory economics. California fields include the Moco Unit in the Midway Sunset.[67] West Newport,[68] San Ardo, South Belridge, Lost Hills, and Brea-Olinda.[69] Successful operations have also been reported in the Glen Hummel, Gloriana, and Trix Liz Fields in Texas,[70] and the Bellevue Field in Louisiana.[71] The number of commercial operations in the United States is estimated to be 10.[72]

In situ combustion has not been applied widely because of marginal economics at existing oil prices, poor volumetric sweep efficiency in some reservoirs, and competition with steam displacement processes. Some field tests showed a net operating gain but could not generate enough income to return the large investment required for an air compressor. The phrase "a technical success but an economic failure" best describes many projects.

The movement of the in situ combustion zone through a reservoir is controlled in part by variations in reservoir properties. Directional movement has been observed in most in situ combustion projects. There has been limited success in controlling the volume of the reservoir which is swept by the process. This is a major area for research and development.

Reservoirs which are candidates for steam displacement are also candidates for in situ combustion. Experience indicates that steam displacement is generally a superior process from the viewpoint of oil recovery, simplicity of operation, and economics. Thus, applications of in situ combustion have been limited by the development of the steam displacement process.

In situ combustion has one unique characteristic. It is the only process which may be applicable over a wide range of crude gravities and viscosities.

Screening Criteria.--In situ combustion is applicable to a wide range of oil gravities and viscosities. No constraints were placed on oil viscosity. The maximum permissible API gravity is determined by the capability of a particular reservoir rock/crude oil combination to deposit enough coke to sustain combustion. Low-gravity oils which are composed of relatively large fractions of asphaltic-type components meet this requirement. It is also known that some minerals catalyze in situ combustion, allowing high gravity oils to become candidates for in situ combustion.[73] The maximum oil gravity which might be a candidate with catalytic effects was estimated to be 45° API.

Minimum reservoir depth was set at 500 feet.[74] Adequate reservoir transmissibility, i.e.,

$$\frac{\text{Permeabilitv x thickness}}{\text{oil viscosity}}$$

is necessary to prevent excessive heat losses to overlying and underlying formations. The minimum acceptable transmissibility for in situ combustion is about 20 millidarcy feet/centipoise.[75] Carbonate reservoirs were not considered to be candidates for in situ combustion.

## Oil Recovery Projections

The wet combustion process was used for the OTA study. All projects were developed as 20-acre patterns. In the wet combustion process, three distinct displacement zones are formed: a burned zone, a steam zone, and a hot water zone. Gross oil recovered from each pattern was computed from the sum of the volumes displaced from each zone. Areal sweep efficiency, maximum zone thickness, and residual oil saturation for each zone are included in table B-13 for the advancing technology cases.

Fuel consumption was 200 barrels per acre foot.[76] The equivalent oil saturation consumed in the burned zone is $S_{ob}$, where $S_{ob}$ = 200/7,758 X 0); @ is the porosity of the rock, and 7,758 is barrels per acre foot.

The initial oil saturation was S,,,, the material balance average oil saturation computed from equation 1. The volume of oil displaced was determined in the following manner. The actual thickness of each zone was determined by allocating the net pay between the three zones in the order shown in table B-13. A reservoir 20 feet thick would have a burned zone and a steam zone while a reservoir 100 feet thick would experience the effects of three zones in a 50-foot interval. The volume of oil displaced from each zone was computed from the product of the pattern area, areal sweep efficiency, zone thickness, porosity, and displaceable oil in the swept interval. All oil displaced from the swept zones was considered captured by the producing well.

Timing of *Production.—The* life of each pattern was 8 years. Drilling, completion, and other development was completed in the first 2 years. Air and water injection began in year 3 and continued through year 8 for a total productive life of 6 years. The displaced oil was produced according to the schedule in table B-14.

**Table B-13**
**Advancing Technology Cases**
**Oil Displacement Model**
**Wet Combustion**

| Region | Areal sweep efficiency | Max. vertical thickness, ft. | Residual oil saturation: Low-process performance | Residual oil saturation: High-process performance |
|---|---|---|---|---|
| Burned zone ... . . | 0.55 | 10 | 0 | 0 |
| Steam zone. ., | 0.60 | 10 | (),20 | 0.15 |
| Hot water zone | 080 | 30 | 0.30 | 0.25 |

**Table B-14**
**Production Schedule**
**Wet Combustion**

| Year | Annual production of incremental oil Percentage of total |
|---|---|
| 1 - 2, . . . . . . . . . . . . . . . . . . . . | 0 |
| 3 . . . . . . . . . . . . . . . . . | 10 |
| 4: : :::. . . . . . . . . . . . . . . . . | 16 |
| 5 . . . . . . . . , . . . . . . . . . . . . , | 22 |
| 6... . . . . . . . . . . . . . . . . . . . . | 20 |
| 7 | 18 |
| 8 : : : : : : : : : : : : : : : : : : : : : : | 14 |
| **Total . . . . . . . . . . . . . . . .** | **100** |

## Operating Costs

Air required was computed on the basis of 110-acre feet burned per 20-acre pattern (if the reservoir is at least 10 feet thick) and a fuel consumption of 200 barrels per acre foot. If the air/oil ratio was less than 7,500 standard cubic feet (Scf) per stock-tank barrel (STB), air requirements were increased to yield 7,500. Air requirements were then used to size compressors and to determine the equivalent amount of oil which would be consumed as compressor fuel.

The amount of oil used to fuel the compressors was computed as a Btu equivalent based on 10,000 Btu per horsepower hour. Energy content of the oil was 6,3 million Btu per barrel. This oil was deducted from the gross production.

The corresponding equations for the price of air as the price per thousand standard cubic feet ($/MScf) were derived from data used in the NPC study.[77]

| Depth feet | Cost Equation $/MScf |
|---|---|
| O - 2,500 | 0.08 + 0.01108 P |
| 2,500- 5,000 | 0.08 + 0.01299 P |
| 5,000-10,000 | 0.08 + 0.01863 P |
| 10,000-15,000 | 0.08 + 0.02051 P |

where

P = oil price in $/bbl and the multiplier of P is the barrels of oil consumed to compress 1 MScf of air to the pressure needed to inject into a reservoir at the specified depth.

Compressed air was supplied by a six-stage bank of compressors with 1 horsepower providing 2.0 MScf per day.[78] Compressor costs were computed on the basis of $40()/installed horsepower.

### Sensitivity Analyses

The effect of uncertainties in operating costs was examined using the high-process performance model. A low-cost case was analyzed by reducing the compressor maintenance cost from $0.08/MScf to $0.07/MScf. A high-cost case increased the compressor maintenance to $0.10/MScf. Results of these cases are compared in table B-1 5. Cost reduction had little effect on the projected results while the 25-percent increase in maintenance cost reduced the ultimate recovery by 19 percent at upper tier price and 8 percent at world oil price for the high-process performance case,

A case was also simulated in which the displacement efficiency in the steam and hot water zones was increased by changing the residual oil saturation in the steam zone to 0.10 and in the hot water zone to 0.20, Results of this case are indicated as high-displacement efficiency in table B-1 s. The effect of assumed improvement in displacement efficiency resulted in a 17- to 20-percent increase in ultimate recovery but little change in price elasticity.

**Table B-15**
**Effect of Changes in Compressor Operating Costs and Displacement Efficiency in Ultimate Oil Recovery Using the In Situ Combustion Process**

| Case | Incremental oil (billions of barrels) | | |
|---|---|---|---|
| | Upper tier price ($1 1.62/ bbl) | World oil price ($1 3.75/ bbl) | Alternate fuels price ($22.00/ bbl) |
| High cost. . . . . . . . . . . | 1.4 | 1.7 | 1.9 |
| High-process performance . . . . . . . . | 1.7 | 1.9 | 1.9 |
| Low cost . . . . . . . . . . . | 1.7 | 1.9 | 1.9 |
| High-displacement efficiency . . . . . . . . | 2.1 | 2.2 | 2.3 |

## Carbon Dioxide Miscible

### State of the Art—Technological Assessment

It has been known for many years that oil can be displaced from a reservoir by injection of a solvent that is miscible with the oil. Because such solvents are generally expensive, it is necessary to use a "slug" of the solvent to displace the oil and then to drive the slug through the reservoir with a cheaper fluid, This process was shown to be feasible at least 20 years ago.[79] An overview of the various kinds of miscible displacements is given by Clark, et al.[80]

Hydrocarbon miscible processes have been developed and studied fairly extensively. A number of field tests have been conducted.[81] While it has been established that hydrocarbon miscible processes are technically feasible, the high cost of hydrocarbons used in a slug often makes the economics unattractive. Recently, attention has focused on carbon dioxide ($C0_2$) as the miscibility agent.[82]

In the OTA study it was assumed that, in general, economics and solvent availability would favor the use of $C0_2$. The $C0_2$ process was therefore used exclusively as the miscible displacement process in the study.

Carbon dioxide has several properties which can be used to promote the recovery of crude oil when it is brought into contact with the oil. These properties include: 1 ) volubility in oil with resultant swelling of oil volume; 2) reduction of oil viscosity; 3) acidic effect on rock; and 4) ability to vaporize and extract portions of the crude oil under certain conditions of composition, pressure, and temperature.

Because of these properties, $C0_2$ can be used in different ways to increase oil recovery, i.e., different displacement mechanisms can be exploited. The three primary mechanisms are solution gas drive, immiscible displacement, and dynamic miscible displacement.

Solution-gas-drive recovery results from the fact that $Co_2$ is highly soluble in oil. When $C0_2$ is brought into contact with oil under pressure, the $Co_2$ goes into solution. When the pressure is lowered, part of the $C0_2$ will evolve and serve as an energy source to drive oil to producing wells. The mechanism is similar to the solution-gas-drive primary recovery mechanism and can be operative in either immiscible or miscible displacement processes.

Helm and Josendalal[83] have shown that $C0_2$ can be used to displace oil immiscible. In experiments conducted with liquid $C0_2$ below the critical temperature, residual oil saturations were significantly lower after flooding with $C0_2$ than after a waterflood. The improved recovery was attributed primarily to viscosity reduction and oil swelling with resultant improvement in the relative permeability. It was noted that the $C0_2$ displacement was not as efficient when a waterflood preceded the $C0_2$.

Carbon dioxide, at reservoir conditions, is not directly miscible with crude oil. However, because $C0_2$ dissolves in the oil phase and also extracts hydrocarbons from the crude, it is possible to create a displacing phase composition in the reservoir that is miscible with the crude oil.

Menzie and Nielson, in an early paper,[84] presented data indicating that when $C0_2$ is brought into contact with crude oil, part of the oil vaporizes into the gaseous phase. Under certain conditions of pressure and temperature, the extraction of the hydrocarbons is significant, especially extraction of the intermediate molecular weight hydrocarbons ($C_5$ to $C_{30}$). Helm and Josendahl[85] also showed that $C0_2$ injected into an oil-saturated core extracts intermediate hydrocarbons from the oil phase and establishes a slug mixture which is miscible with the original crude oil. Thus, while direct contact miscibility between crude oil and $C0_2$ does not occur, a miscible displacement can be created in situ. The displacement process, termed dynamic miscibility, results in recoveries from linear laboratory cores which are comparable to direct contact miscible displacement.

Holm[86] has pointed out that the $C0_2$ miscible displacement process is similar to a dynamic miscible displacement using high-pressure dry gas. However, important differences are that $C0_2$ extracts heavier hydrocarbons from the crude oil and does not depend upon the existence of light hydrocarbons, such as propane and butanes, in the oil. Miscible displacements can thus be achieved with $CO_2$ at much lower pressures than with a dry gas. Methods of estimating miscibility pressure have been presented.[87,88]

The $CO_2$ miscible process is being examined in a number of field pilot tests.[89,90] The largest of these is the SACROC unit in the Kelly-Snyder Field.[91] Different variations of the process are being tested. In one, a slug of $CO_2$ is injected followed by water injection. In another, $CO_2$ and water are injected alternatively in an attempt to improve mobility control. [92]

The preliminary indication from laboratory experiments and these field tests is that the $CO_2$ process has significant potential. However, the field experience is quite limited to date and some difficulties have arisen. Early $CO_2$ breakthrough has occurred in some cases and the amount of CO, required to be circulated through the reservoir has been greater than previously thought .93 Operating problems such as corrosion and scaling can be more severe than with normal waterflooding. Greater attention must be given to reservoir flow problems such as the effects of reservoir heterogeneities and the potential for gravity override.

in general, the operating efficiency of the process or the economics have not been firmly established. In the OTA study, the reported laboratory investigations and preliminary field results were used as the basis for the recovery models and the economic calculations.

*Screening Criteria.*—Technical screening criteria were set in accordance with the following:

Oil viscosity
<12 Cp

Attainable pressure assumed to be = .6 **x** depth -300 psi

Miscibility pressure

| | |
|---|---|
| < 27° API | 4,000 psi |
| 27° - 30" API | 3,000 psi |
| ≥ 30° API | 1,200 psi |

Temperature correction to miscibility pressure

| | |
|---|---|
| O psi if T < 120° F. | |
| 200 psi if T = 120- 150° F. | |
| 350 psi if T = 150- 200° F. | |
| 500 psi if T > 200° F. | |

This leads to depth criteria as follows (not temperature corrected):

| | |
|---|---|
| < 27° API | 7,200 ft |
| 27° - 30° API | 5,500 ft |
| ≥ 30° API | 2,500 ft |

This was the same correlation as used in the NPC study.[94] It is noted that the general validity of this correlation has not been established. Crude oils in particular reservoirs may or may not establish miscibility with $CO_2$ at the pressures and temperatures indicated. Other correlations have been presented in the literature, but they are based on a knowledge of the crude oil composition. Data on composition were not available in the data base used in the OTA study, and a generalized correlation of the type indicated above was therefore required.

## Oil Recovery Projections

*Onshore Reservoirs*.—The recovery model used was as follows:

$$R = \frac{NB_c}{S_{oi}B_o}(S_{orw} - S_{orm})E_{vm}\left(\frac{E_m}{(E_{vm})}\right) \qquad \textbf{6B}$$

where

| | | |
|---|---|---|
| R | = | recovery by $CO_2$ process, stock-tank barrels |
| $S_{orm}$ | = | residual oil saturation in zone swept by $CO_2$. Set at 0.08, No distinction was made between sandstone and carbonate reservoirs. |
| $E_m$ | = | sweep efficiency of $CO_2$ miscible displacement. $(E_m/E_{vm})$ was set at 0.70. |
| $E_{vm}$ | = | volumetric sweep efficiency of the waterflood computed from procedure described in appendix A. |

The sweep efficiency for $CO_2$ miscible ($E_m$ was determined by making example calculations on $CO_2$ field tests. Field tests used were the following:

Slaughter
Wasson
Level land
Kelly-Snyder (SACROC)

Cowden-North
Crosset

All projects except the Wasson test were reported in the SPE Field Reports.[95] Data on Wasson were obtained from a private communication from Lewin and Associates, Inc. Based upon reported data and reported estimates of the tertiary recovery for each field test, sweep efficiency values were calculated. The ratio $E_m/E_{vm}$ averaged 0.87. Discarding the high and low, the average was 0.80. It was judged that the national average recovery would be less, therefore a value of $E_mE_{vm}$ of 0.70 was used for all reservoirs in the **OTA** calculations.

The high-process performance model assumes the waterflood residual ($S_{Orw}$ for each reservoir is determined from table A-1 according to geographic region. This value was used unless the volumetric sweep efficiency for the waterflood ($E_v$J fell outside the limits described in appendix A. The low-process performance was simulated by reducing the $S_{Orw}$ values in table A-1 by 5 saturation percent. The same limits on the calculated values of $E_{vm}$ were used in the low-process performance model. The recovery model (equation 6B) was unchanged except for $E_{vm}$ and $S_{O:w}$.

The low-process performance model reduced the EOR for those reservoirs in which the calculated $E_{vm}$ fell within the prescribed limits. Where $E_{vm}$ was outside the limits, $S_{o,w}$ was recalculated using the limiting $E_{vm}$ value. Therefore, for these latter reservoirs the recovery results were the same in both the high- and low-process performance models. For $C0_2$ miscible, this was the case for about one-third of the total reservoirs. The average recovery for all reservoirs was 20 percent less in the low-process performance case than in the high-process performance case.

*Volurnes* of Injected Materials.—The $CO_2$ requirement was established as follows:

Sandstone Reservoirs—26 percent of pore volume
Carbonate Reservoirs—22 percent of pore volume

Conversion of $CO_2$ from surface conditions to reservoir conditions was assumed to be:

2 **Mcf $C0_2$ (std. cond.) per 1.0 reservoir bbl**
**(A constant value was used.)**

Twenty-five percent of the total $CO_2$ requirement was assumed to be from recovered, compressed, and reinfected gas. Seventy-five percent was purchased.

The $C0_2$ injection schedule was as shown in table B-1 6. The water alternating gas process was used. The ratios were:

Sandstones l:2 **$CO_2$:$H_2O$**
**Carbonates 1:1 $CO_2$:$H_2O$**

**Table B-16**
**Carbon Dioxide Injection** Schedule

| Year | Purchased $CO_2$ percent of total* | Recycled $C0_2$ percent of total* |
|---|---|---|
| 1-2 . . . . . . . . . . . | 0 | 0 |
| 3 . . . . . . . . . . . . . | 20 | 0 |
| 4 . . . . . . . . . . . . . | 20 | 0 |
| 5 | 16 | 4 |
| 6 : : : : : : : : : : : : | 13 | 7 |
| 7 . . . . . . . . . . . . . | 6 | 14 |

● **Total refers** to **total volume** of $CO_2$ injected over life of **pattern,**

Fluid injection occurred over a 5-year period; reinfected $C0_2$ was used beginning in the third year of the period, along with purchased $CO_2$.

*Timing of Production.*—The production profile was set at a fixed percentage of the total recovery (as computed by the recovery model above). The schedule is shown in table B-17. All reservoirs were developed on 40-acre spacing.

*Offshore* Reservoirs.--Offshore $CO_2$ miscible displacement was calculated using a different model than the onshore model. The reservoirs of the gulf offshore are steeply dipping because they are nearly universally associated with salt dome formations. This has limited effect on the other processes but great impact on $CO_2$ miscible. Due to the dip, the CO), with small quantities of $CH_4$ can be injected at the top of the dip and gravity stabilized. No production is noted until the oil bank ahead of the miscible slug reaches the first producers down dip. The bank is produced until the slug breaks through, at which time the producer is shut in and the slug proceeds further down dip, creating a new bank which is produced in like manner at the next producer further down. **The** process continues until

**Table B-17**
**Production Rate Schedule for Carbon Dioxide Miscible**

| Year | Percent of EOR |
|---|---|
| Carbonates | |
| 1-3 | 0 |
| 4 | 5 |
| 5 | 9 |
| 6 | 13 |
| 7 | 17 |
| 8 | 19 |
| 9 | 14 |
| lo | 10 |
| 11 | 6 |
| 12 | 4 |
| 13 | 2 |
| 14 | 1 |
| Total | 100 |
| Sandstones | |
| 1-3 | 0 |
| 4 | 6 |
| 5 | 19 |
| 6 | 26 |
| 7 | 21 |
| 8 | 13 |
| 9 | 9 |
| 10 | 6 |
| Total | 100 |

the final bank has been produced at the bottom of the formation. Because the integrity of the miscible slug must be maintained, no water injection is contemplated. However, air is compressed and used to push the $CO_2$-$CH_4$ mixture after a relatively large volume of the mixture has been injected. Residual oil saturation after miscible displacement, $S_{Orm}$, was set at 0.08. Sweep efficiency, Em, was set at O.80 (i.e (Em/Evm) x $E_{vm}$ = 0.80). This is a significantly higher sweep efficiency than used, on the average, for onshore reservoirs.

The fluid injection schedule for offshore reservoirs is shown in table B-18 and the oil production schedule is given in table B-19.

## Carbon Dioxide Costs

*Well Drilling and Completion Costs.*-Because of special requirements created by $CO_2$ flooding, the base drilling and completion cost was increased by a factor of 1.25 for injection wells.

*Compression Costs.*—Twenty-five percent of the $CO_2$ requirement was met from recycled $CO_2$. Compression equipment was purchased and fuel costs were charged to this recompression.

*Carbon Dioxide Pricing* Method.—The cost of $CO_2$ is a variable of major importance. Costs of $CO_2$ can vary widely depending on whether the source is natural or manufactured gas and depending on the transportation method and distance. In fact, this EOR technique probably has the greatest potential for economies of scale because of the variability of these costs.

The cost algorithm used in the OTA study was developed by Lewin and Associates, Inc., and a summary of this analysis follows. Reservoirs were placed into one of four categories. These categories are:

- Concentrations of large reservoirs adequate to support the construction of a major $CO_2$ pipeline.
- Concentrations of smaller reservoirs where the bulk of $CO_2$ transportation would be by

**Table B-18**
**Gas Injection Schedule**
**Offshore Carbon Dioxide Miscible**

| Year | $CO_2$-$CH_4$ | Air |
|---|---|---|
| 1 | 0 | 0 |
| 2 | 0.25PV | o |
| 3 | 0.25PV | o |
| 4 | 0 | 0.15PV |
| 5 | 0 | 0.15PV |

**Table B-19**
**Oil Production Schedule**
**Offshore Carbon Dioxide Miscible**

| Year | Production percent of total |
|---|---|
| 1 | 0 |
| 2 | o |
| 3 | o |
| 4 | 50 |
| 5 | 50 |
| Total | 100 |

major pipeline but where lateral lines would be required to deliver $CO_2$ to the numerous smaller fields,

- Smaller concentrations of large (and small) reservoirs where a smaller pipeline or alternative means for transporting $CO_2$ could be used.
- Individual, small reservoirs to be served by lateral pipeline or tanker trucks, where the amounts of required $CO_2$ would not justify the building of a new pipeline.

Results of the analysis of each of these categories is provided in the section below. The following subsection contains the details of the calculations.

## Results of Carbon Dioxide Cost Calculations

Concentrations of *Large* Reservoirs. Given the indicated locations of natural $CO_2$ and the concentration of large candidate reservoirs such as in western Texas, eastern New Mexico, and southern Louisiana, it appears that the reservoirs in these areas could be served by major $CO_2$ pipelines.

The $CO_2$ cost model uses the following algorithms for assigning $CO_2$ costs to reservoirs:

- $0.22 per Mcf for producing $CO_2$,
- $0.24 per Mcf for compression and operation costs, and
- $0.08 per 100 miles of pipeline distance, including small amounts of lateral lines, assuming a 200 MMcf per day of pipeline capacity.

Under these assumptions, the base cost for $CO_2$ delivered to concentrations of large reservoir areas would be according to the following chart. All reservoirs, large and small, in these geographic areas would be able to take advantage of the economies of scale offered by the basic concentration of large reservoirs.

| Geographic area | Approximate truckline distance (miles) | Laterals (miles) | Carbon dioxide cost per Mcf (dollars) |
|---|---|---|---|
| Louisiana—South | 200 | 100 | 0.70 |
| offshore | 400 | 200 | 0.94 |
| Texas-District 76 | 300 | 100 | 0.78 |
| District 7C,8,8A,9 | 300 | 100 | 0.78 |
| District 10 | 300 | 100 | 0.78 |
| Offshore | 500 | 100 | 0.94 |
| New Mexico East and West | 200 | 100 | 0.70 |
| Wyoming | 300 | — | 0.70 |

*Adequate Concentration of Large and Small Reservoirs Served by Lateral* Lines.—The second class of reservoirs would be the large and small reservoirs in close proximity to the major trunklines. These reservoirs could be serviced by using short distance lateral lines. Carbon dioxide costs were assigned as follows:

- $0.46 per Mcf for producing and compressing the $CO_2$, and
- $0.20 per Mcf per 100 miles for transportation.

The $CO_2$ model assumes that reservoirs in the following geographic areas could be served by short distance trunklines or linking lateral lines to the main trunklines, using pipelines of 50 MMcf per day capacity.

| Geographic area | Approximate distance trunklines or laterals (miles) | Carbon dioxide cost per Mcf (dollars) |
|---|---|---|
| Colorado | 100 | 0.70 |
| Mississippi | 100 | 0.70 |
| Oklahoma | 150 | 0.78 |
| Utah | 100 | 0.70 |

*Low Concentration, Large and Small Reservoirs, Close to Natural Sources of Carbon Dioxide.*—The third class of reservoirs are those close to natural $CO_2$ sources where only minimum transportation charges would be required to deliver the $CO_2$ to the field.

The first question is what size of pipeline can be justified. This was examined for the two smaller potential States of Alabama and Florida. It was assumed that both of these States would justify a 100 MMcf pipeline under a 10-year development plan and a 50 MMcf pipeline under a 20-year development plan. For a 50 MMcf pipeline the costs were assumed to be as follows:

- $0.46 per Mcf for producing and compressing the $CO_2$, and
- $0.20 per Mcf per 100 miles for transportation, including laterals.

The $CO_2$ model assumes that the following geographic areas are close to natural $CO_2$ sources and could be served by small pipelines, having 50 MMcf/day capacity.

| Geographic area | Approximate pipeline distance (miles) | Carbon dioxide cost per Mcf (dollars) |
|---|---|---|
| Alabama | 200 | 0.86 |
| Arkansas | 200 | 0.86 |
| Florida | 300 | 1.02 |
| Kansas | 200 | 0.86 |
| Montana | 200 | 0.86 |
| West Virginia | 100 | 0.70 |

An alternative to this third class of reservoirs are those similar reservoirs that are not close to natural $CO_2$ sources. The reservoirs in these geographic locations would need to be served by $CO_2$ extracted from industrial waste products (e.g., from chemical complexes, ammonia plants, gasoline plants, combined powerplants, etc.).

An analysis of minimum required pipeline size indicated that each of these areas could support a 200+ MMcf per day pipeline under a 10-year development plan and a 100 MMcf per day pipeline under a 20-year development plan. The following costs were used for these reservoirs:

- $0.90 per Mcf for extracting the manufactured $CO_2$,
- $0.25 per Mcf for compression and operation,
- $0.08 per Mcf for 100 miles of trunk pipeline (200 MMcf per day capacity), plus
- $0.30 per Mcf for three 50-mile lateral lines (50 MMcf per day capacity) connecting the $CO_2$ source to the trunkline.

Under these assumptions, the base cost for $CO_2$ for the geographic areas in this category would be as follows:

| Geographic area | Approximate pipeline distance (miles) | Purchasing, operating, and gathering costs per Mcf (dollars) | $CO_2$ cost per Mcf (dollars) |
|---|---|---|---|
| California-Central Coastal, L.A. Basin, and offshore | 200 | 1.45 | 1.61 |
| Louisiana—North | 200 | 1.45 | 1,61 |
| Texas--District 1 | 200 | 1.45 | 1.61 |
| Districts 2,3,4 | 200 | 1.45 | 1.61 |
| Districts 5,6. | 200 | 1.45 | 1.61 |

Low *Concentration, Small* Reservoirs.—The final category of reservoirs considered in the analysis are the small reservoirs located in the moderate- and low-concentration geographic areas. The alternatives here are to construct a small pipeline to the trunkline or to deliver the $CO_2$ via truck. Large trunkline construction for low concentration reservoirs is infeasible.

For those geographic regions where the large reservoirs are already served by a pipeline, it appears likely that additional small lateral lines could be added to extend the $CO_2$ delivery to small fields. These fields would only need to pay the marginal costs of delivery. Because of this, rather small $CO_2$ lateral lines could be constructed (as small as 5 MMcf per day), which would serve an area with as little as 5 million barrels of recoverable oil. it was thus assumed that the average $CO_2$ costs for the small fields in a region already served by a pipeline would be the same as base costs for that region.

For concentrations lacking such existing trunklines, i.e., the remaining States, tanker-trucks would deliver $CO_2$. These would include:

| | |
|---|---|
| Illinois | North Dakota |
| Indiana | Ohio |
| Kentucky | Pennsylvania |
| Michigan | South Dakota |
| New York | Tennessee |
| | Virginia |

The cost in these States was set at $2.75 per Mcf.

## Calculation Method and Details—Carbon Dioxide Costs

The method used to derive the $CO_2$ costs is briefly outlined in this section. The analysis followed a seven-step sequence:

- calculate the relationship of pipeline capacity to unit costs,
- translate pipeline capacity–cost relationship to pipeline investment costs per Mcf, for various pipeline capacities,
- calculate the pipeline delivery costs per Mcf that vary by distance,
- calculate the $CO_2$ purchase and delivery costs per Mcf that do not vary by distance,
- calculate full costs per Mcf for natural and manufactured $CO_2$,
- translate pipeline capacity to minimum required field size, and
- complete the breakeven analysis of using pipeline versus truck for delivering $CO_2$ to the field.

*Relationship of Capacity to Costs.*—The following were assumed for calculating pipeline investment costs:

- $330,000 per mile for 200 MMcf per day capacity,
- investment is scaled for capacity by a 0.6 factor, and
- pipeline will last 20 years.

Fixed and variable costs were set as follows:

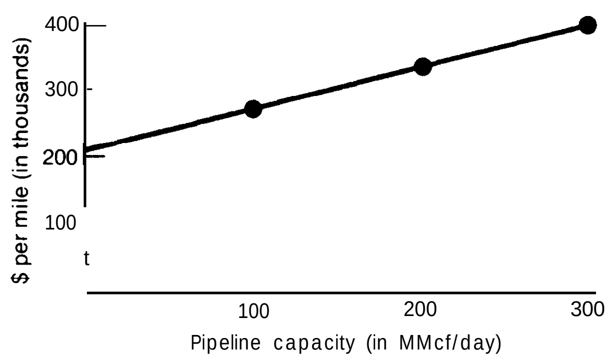
- fixed costs plus variable cost exponent (capacity) = total

Using the above data:

- fixed costs + 0.6 (200,000 Mcf/day) = $330,000 per mile,
- fixed costs = $210,000 per mile, and
- variable costs = $600 per MMcf/day per mile.

This relationship of costs to capacity has the general form shown in figure B-2.

Figure B-2. Pipeline Cost Versus Capacity




Pipeline Investment Costs *per* Mcf.—The cost–capacity graph was translated into a cost per Mcf (per 100 miles) graph by dividing costs by capacity, as follows:

For the 200 MMcf/day capacity at $330,000 per mile, the cost per Mcf per 100 miles with no discounting of capital is:

($330,000 X 100)/(200,000 X 365 X 20) = $0,023 per Mcl

**If** an 8-percent rate-of-return requirement is imposed, and it is assumed that no return results until the fourth year, the costs would be raised to:

$$C = \frac{330,000 \times 100}{200,000 \times 365}\left[\frac{\frac{(1.08)^4}{(1.08)^{16}-1}}{.08(1.08)^{16}}\right] \quad 7B$$

C = $0.07 per Mcf per 100 miles

Similarly, the pipeline investment cost per Mcf **can be** generated as shown in table B-20.

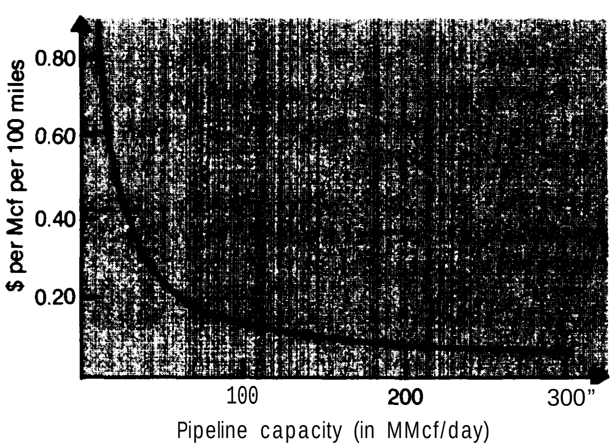
**labia 6-20**
**Pipeiine Capacity Versus investment**
(8-percent rate of return)

| Pipeline capacity (MMcf/day) | Pipeline investment cost per Mcf ($ per 100 miles) |
|---|---|
| 300 | 0.05 |
| 200 | 0.07 |
| 100 | 0.11 |
| 50 | 0.20 |
| 25 | 0.37 |
| lo | 0.89 |
| 5 | 1.79 |

*Pipeline Delivery Costs Variable by Distance.*— The pipeline investment cost was added to pipeline operating costs to develop pipeline costs per Mcf that are variable by distance. The following was assumed:

. pipeline operating costs are $O.01 per Mcf per 100 miles, and
- the pipeline capital costs from table 6-20 are applicable,
- with these assumptions, the variable cost per Mcf per lOO miles can redeveloped as shown in figure B-3.

**Figure B-3. Variable $CO_2$ Transportation Costs Versus Pipeline Capacity**




*Carbon Dioxide Costs Not Variable by* Distance.—The following was assumed:

. repressurizing operating costs are $0.16 per Mcf

- repressurizing capital costs are $0.08 per Mcfbased on the following:
  - $700 per hp
  - 280 hp required to pressurize 1,000 Mcf per day
  - Compressors will last 20 years
  - 8-percent discount rate,
- the purchase cost of naturally occurring $CO_2$ is $0.22 per Mcf,
- extraction costs for manufactured $CO_2$ are $0.90 per Mcf, and
- additional lateral lines will be required to gather and transport manufactured $CO_2$.

Based on the preceding, the fixed costs for manufactured $CO_2$ will be $1.14 per Mcf with lateral lines as shown in table B-21.

**Table B-21**
**Lateral Lines Associated With Pipeline Capacity**

| Pipeline capacity (MMcf/day) | Amount and size of lateral lines |
|---|---|
| 300 | 3 to 50 **mile** @ 50 MMcf/day |
| 200 | 3 to 50 **mile** @ 50 MMcf/day |
| 100 | 3 to 50 mile @ 25 MMcf/day |
| 50 | 2 to 50 mile @ 10 MMcf/day |
| 25 | 1 to 50 mile @ 10 MMcf/day |
| 10 | 1 to 50 **mile** @ 5 MMcf/day |
| 5 | None |

*Total Costs per Mcf.*—The investment and operating costs were then added to the purchase price for natural $CO_2$ and extraction and gathering costs for manufactured $CO_2$ to obtain the total cost per Mcf. These are shown for various conditions in table B-22.

*Relationship of Pipeline Capacity to Field* Size.—The pipeline capacity was related to field size using the following assumptions:

- 5 Mcf are required per barrel of recovered oil,
- $CO_2$ is injected over 10 years, and
- $CO_2$ recovers 30 percent of the oil left after primary/secondary recovery.

Then the conversions of pipeline capacity to field size shown in table B-23 were used.

*Break-Even* Analysis.-Using $2.75 per Mcf as the trucked-in cost for $CO_2$, two curves were

**Table B-22**
**Total Costs per Mcf of $CO_2$**
**(dollars)**

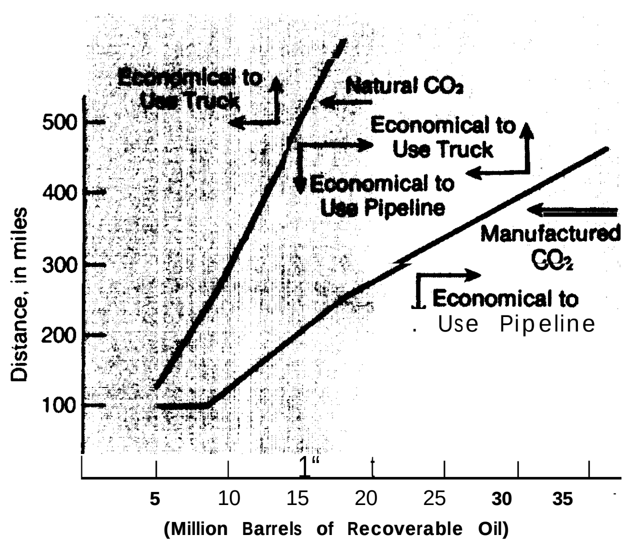
| Pipeline capacity (MMcf/day) | Distance (miles) | Transp. costs | Fixed operating | Purchase (natural) | Extract from manuf. | Gather from manuf. | Full cost for natural | Full cost for manufactured |
|---|---|---|---|---|---|---|---|---|
| 300 . . . | 100 | 0.06 | 0.24 | 0.22 | 0.90 | 0.30 | 0.52 | 1.50 |
| | 200 | 0.12 | 0.24 | 0.22 | 0.90 | 0.30 | 0.58 | 1.56 |
| | 300 | 0.18 | 0.24 | 0.22 | 0.90 | 0.30 | 0.64 | 1.62 |
| | 400 | 0.24 | 0.24 | 0.22 | 0.90 | 0.30 | 0.70 | 1.68 |
| 200 . . . | 100 | 0.08 | 0.24 | 0.22 | 0.90 | 0.30 | 0.54 | 1.52 |
| | 200 | 0.16 | 0.24 | 0.22 | 0.90 | 0.30 | 0.62 | 1.60 |
| | 300 | 0.24 | 0.24 | 0.22 | 0.90 | 0.30 | 0.70 | 1.68 |
| | 400 | 0.32 | 0.24 | 0.22 | 0.90 | 0.30 | 0.78 | 1.76 |
| 100 . . . | 100 | 0.12 | 0.24 | 0.22 | 0.90 | 0.57 | 0.58 | 1,83 |
| | 200 | 0.24 | 0.24 | 0.22 | 0.90 | 0.57 | 0.70 | 1.95 |
| | 300 | 0.36 | 0.24 | 0.22 | 0.90 | 0.57 | 0.82 | 2.07 |
| | 400 | 0,48 | 0.24 | 0.22 | 0.90 | 0.57 | 0.94 | 2.19 |
| 50 . . . | 50 | 0.10 | 0.24 | 0.22 | 0.90 | 0.90 | 0.56 | 2.14 |
| | 100 | 0,21 | 0.24 | 0.22 | 0.90 | 0.90 | 0.67 | 2.25 |
| | 200 | 0.42 | 024 | 0.22 | 0.90 | 0.90 | 1.88 | 2,46 |
| | 300 | 0.63 | 0.24 | 0.22 | 0.90 | 0.90 | 1.09 | 2.67 |
| | 400 | 0.84 | 0.24 | 0.22 | 0.90 | 0,90 | 1.30 | 2.88 |
| 25 | 50 | 0.19 | 024 | 0.22 | 0.90 | 0.90 | 0.65 | 2.23 |
| | 100 | 0.38 | 0.24 | 0.22 | 0.90 | 0.90 | 0.84 | 2.42 |
| | 200 | 0.76 | 0.24 | 0.22 | 0.90 | 0.90 | 1.22 | 2.80 |
| | 300 | 1.14 | 0.24 | 0.22 | 0.90 | 0.90 | 1.60 | 3.18 |
| 10 | 50 | 0.45 | 0.24 | 0.22 | 0.90 | 0.88 | 0.91 | 2.49 |
| | 100 | 0.90 | 0.24 | 0.22 | 0.90 | 0.88 | 1.36 | 2.94 |
| | 200 | 1.80 | 0.24 | 0.22 | 0.90 | 0.88 | 2.20 | 3.84 |
| 5 . . . | 50 | 0.88 | 0.24 | 0.22 | 0.90 | — | 1.34 | 2.02 |
| | 100 | 1.76 | 0.24 | 0.22 | 0.90 | — | 2.22 | 2.90 |
| | 200 | 3.52 | 0.24 | 0.22 | 0.90 | — | 3.98 | 4.66 |

**Table B-23**
**Pipeline Capacity as a Function of Field Size**

| Pipeline capacity (MMcf/day) | Minimum required concentration (or field size): Incremental oil recovered by C02 (million barrels) | Minimum required concentration (or field size): Residual oil in place (million barrels) |
|---|---|---|
| 300 . . . . . . . . . . . . | 219 | 730 |
| 200 . . . . . . . . . . . . | 146 | 490 |
| 100 . . . . . . . . . . . . | 73 | 240 |
| 50 . . . . . . . . . . . . | 36 | 120 |
| 25 . . . . . . . . . . . . | 18 | 60 |
| 10 . . . . . . . . . . . . | 9 | 30 |
| 5 . . . . . . . . . . . . | 5 | 17 |

determined: one for natural and one for manufactured $CO_2$. These curves, shown in figure B-4, indicate the field size (oil concentration) and distance combinations where either pipeline or trucked $CO_2$ would be more economic.

**Figure B-4. Transportation of $CO_2$— Break-Even Analysis**



## Sensitivity Analyses

Calculations were made with different sets of parameters than those presented in the main body of the report. In general, these additional calculations were done to determine the sensitivity of the results to certain of the important variables. For $CO_2$ miscible, two important considerations were the minimum acceptable rate of return and the price of the injected $CO_2$. Results of calculations in which these parameters were varied are given in this section.

*High-Process Performance—High-Risk Case.*— A calculation was made in which the minimum acceptable rate of return was set at 20 percent. The rate of implementation of projects was governed by the rate of return earned in a manner analogous to that given by table 8 in chapter Ill. The schedule of starting dates based on rate of return is given in the section on the economic model (p. 35).

Results of this calculation, considering the case in which the process is viewed as a high risk technology, are given in table B-24 for the world oil price. Ultimate recovery is dramatically reduced from the conventional risk case (lo-percent rate of return) presented in the body of the report. At lo-percent rate of return, the ultimate recovery is 13.8 billion barrels compared to 4.7 billion barrels with a 20-percent minimum rate of return. Production rates are correspondingly reduced.

This result strongly suggests that a great deal of research and development work must be done to establish the processes, and that economic incentives must be provided if the projections presented in the body of the report are to be reached,

Sensitivity *to Carbon Dioxide* Costs. -Calculitions were made in which the purchase cost of $CO_2$ was increased by factors of 1.5 and 2.5. A significant uncertainty exists relative to $CO_2$ costs and variations of these magnitudes are considered feasible.

Results for the high- and low-process performance cases are shown in table B-25 and B-26,

**Table B-24**
**Estimated Recoveries for Advancing Technology— High-Process Performance**

**High Risk (20-percent rate of return)**
**Carbon Dioxide Miscible**

| | World oil price ($13.75/bbl) Onshore | Offshore | Total |
|---|---|---|---|
| **Ultimate recovery: (billion barrels)** | 4.1 | 0.6 | 4.7 |
| **Production rate in: (million barrels/day)**** | | | |
| **1980** | 0.1 | * | 0.1 |
| **1985** | 0.1 | * | 0.1 |
| **1990** | 0.1 | • | 0.1 |
| **1995** | 0.6 | 0.1 | 0.7 |
| **2000** | 0.9 | 0.1 | 1.1 |
| **Cumulative production by: (million barrels)**** | | | |
| **1980** | 100 | • | 100 |
| **1985,** | 300 | * | 300 |
| **1990** | 400 | 100 | 600 |
| **1995** | 900 | 200 | 1,100 |
| **2000** | 2,700 | 500 | 3,200 |

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

**Tabie B-25**
**Sensitivity of Ultimate Recovery to Carbon Dioxide Cost**

**Advancing Technology-High-Process Performance Case**
**(billions of barrels)**

| Cost factor | Upper tier price ($11.62/bbl) | | | World 011 price [$1 3.75/bbl) | | | Alternate fuels price ($22 .00/bbl) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Onshore | Offshore | Total | Onshore | Offshore | Total | Onshore | Offshore | Total |
| 1.0” | 85 | 0,6 | 9.1 | 129 | 0.9 | 13.8 | 18.5 | 2.6 | 21 1 |
| 1.5 : | 3.9 | 01 | 4.0 | 6.7 | 0.3 | 7.0 | 15.9 | 19 | 178 |
| 2.5 . | 0.4 | 0.0 | 0.4 | 18 | 0.0 | 1.8 | 11.5 | 0 6 | 12 .1 |

“Case reported In body of report

**Table B-26**
**Sensitivity of Ultimate Recovery to Carbon Dioxide Cost**

**Advancing Technology—Low-Process Performance Case**
**(billions of barrels)**

| cost factor | Upper tier price ($11.62/bbl) | World oil price ($1 3.75/bbl) | Alternate fuels price ($22.00/bbl) |
|---|---|---|---|
| 1.0” | 3.5 | 4.6 | 12.3 |
| 1.5 | 0.8 | 1.8 | 8.9 |
| 2.5 | 0.3 | 0.3 | 4.2 |

“Case reported in body of report

respectively. As seen in table B-25, increasing the cost of $CO_2$ by a factor of 1.5 reduces ultimate recovery by a factor of about 2 at upper tier and world oil prices. The effect is not so pronounced at the alternate fuels price. Increase of the cost by a factor of 2.5 essentially eliminates production at the upper tier price and reduces recovery to less than 2 billion barrels at world oil price.

For the low-process performance case, an increase of $CO_2$ cost by a factor of 2.5 reduces ultimate recovery to about 0.3 billion barrels at world oil price, and to about 4 billion barrels at the alternate fuels price.

# Economic Model

The economic model was developed by Lewin and Associates, Inc.[96] In this section the structure of the basic model will be described, followed by tabulations of the economic parameters.

## Structure of the Model

The model uses a standard discounted cash-flow analysis. The unit of analysis is the reservoir with economic calculations being made for a single “average” five-spot pattern within the reservoir. Results of the single-pattern calculation are then aggregated according to a reservoir development plan (described below) to determine total reservoir economic and production performance.

Cash inflows are determined using the specific oil recovery models previously described for each process. Recovery models are applied using the reservoir parameters from the data base. An assumption was made that 95 percent of the oil remaining in a reservoir was contained within 80 percent of the area. This “best” 80 percent was then developed in the model. An adjustment of reservoir thickness was made to distribute the 95 percent of the remaining oil over an acreage equal to 80 percent of the total acreage. Timing and amounts of oil production are dependent on the particular EOR process applied as previously described.

Cash outflows are based on several different kinds of costs and investments. These are: 1) field development costs, 2) equipment investments, 3) operating and maintenance (O & M) costs, 4) injection chemical costs, and 5) miscellaneous costs, such as overhead. Listings and descriptions of the costs follow.

Using the cash inflows and outflows, an annual overall cash-flow calculation is made considering Federal and State taxes. Appropriate State tax rules are incorporated for each reservoir. Cash flows are then discounted at selected interest rates to determine present worth as a function of interest rate. Rate of return is also calculated.

The discounted cash-flow analysis was made at three different oil prices. These included upper tier price ($1 1.62 per barrel), world oil price ($1 3.75 per barrel), and an estimated price at which alternate fuels would become competitive ($22.00 per barrel). All costs were in 1976 real dollars with no adjustment for inflation.

Reservoirs were developed if they earned a rate of return of at least 10 percent by one of the EOR processes. In situations where more than one EOR process was applicable to a reservoir, the EOR process yielding the greatest ultimate recovery was selected as long as a rate of return of at least 10 percent was earned.

## Specific Economic Assumptions

*Date of Calculations.*—Ail calculations were made as of a date of July 1, 1976. Cost data were projected to that date. No attempt was made to build inflation factors into the calculations of future behavior.

*Sharing of Operating and Maintenance Costs.—Well* operating and maintenance costs were shared between primary and secondary production and enhanced oil production. A decline curve for primary and secondary production was generated for each reservoir. This was based on specific reservoir data, if available, or on regional decline curve data if reservoir data did not exist. Well operating costs were assigned annually to enhanced oil operations in direct proportion to the fraction of the oil production that was due to the EOR process.

*General and Administrative (Overhead)* Costs.—These costs were set at 20 percent of the operating and maintenance costs plus 4 percent of investments (excluding any capitalized chemical costs). Where O & M costs were shared between primary and secondary and enhanced recovery, only that fraction assigned to EOR was used as a basis for the overhead charge.

*Intangible and Tangible Drilling and Completion Costs.*—Intangible costs were expensed in the year incurred in all cases (no carryback or carry forward was used in the tax treatment). These costs were set at 70 percent of drilling and completion costs for new wells and 100 percent of workover costs.

Tangible costs were "recovered" by depreciation. Thirty percent of drilling and completion costs were capitalized plus any other lease or well investments. A unit of production depreciation method was applied.

*Royalty Rate.*—A rate of 12.5 percent of gross production was used in all cases.*

*Income Taxes.*—The Federal income tax rate was set at 48 percent. The income tax rate for each State was applied to reservoirs within the State. An investment tax credit of 10 percent of tangible investments was used to reduce the tax liability. If a negative tax were computed in any year, this was applied against other income in the company to reduce tax liabilities.

*Chemical Costs—Tax Treatment.*—For tax purposes, chemicals, such as $CO_2$, surfactant, polymer, and so on, were expensed in the year of injection. Tax treatment of the chemical cost is an important consideration. The effect of having

**"In most current leases, a royalty is charged on net production. However, there is a trend to charge a royalty on gross production in some Federal leases and because this trend could extend into the private sector in the future, OTA calculations assessed royalty charges against gross production.**

to capitalize chemicals (and recover the investment via depreciation) was treated as a part of the policy considerations. This is discussed in the main body of the report.

*Size of Production Units--For* purposes of the economic calculations, a production unit was assumed to consist of the acreage associated with one production well. This varied from process to process. The spacing used is shown in table B-27.

**Table B-27**
**Production Unit Size**

| Process | Acres | Production wells | Injection wells |
|---|---|---|---|
| $CO_2$ miscible . . . . . | 40 | 1.0 | 1.0 |
| Steam drive . . . . . . | 2.5-5.0 | 1.0 | 1.0 |
| In situ combustion . | 20 | 1.0 | 1.0 |
| Surfactant/polymer | Variable (Max= 40) | 1.0 | 1.0 |
| Polymer. . . . . . . . . . | 40 | 1.0 | 0.5 |

Information on number and age of production and injection wells was input as part of the data base. Existing wells were used and worked over as required according to their age and condition,

As previously indicated, an assumption was made that 95 percent of the remaining oil in place was located under 80 percent of the reservoir acreage. The oil in this "best" acreage was assumed to be uniformly distributed.

Timing of *Reservoir* Development.-Reservoirs were developed according to a plan designed to simulate industry implementation of EOR processes in a reservoir. The first part of the timing plan consists of a schedule of starting dates based on rate-of-return criteria. This was discussed in the main body of the report, and the schedule is given in table 8 in chapter III. This schedule is for the conventional risk situation with a 10-percent rate of return taken as the minimum acceptable rate,

A "high-risk" case was also considered in which the minimum acceptable rate of return was set at 20 percent. The schedule of starting dates was altered for this high-risk case as shown in table B-28.

The second part of the timing plan consists of the elements of the specific reservoir development scheme, once a starting date is assigned. The seven elements of the reservoir development plan are as follows:

**Table B-28**
**Schedule of Starting Dates**
**High-Risk Case**

| Date | Continuations of ongoing projects rate of return | New starts rate of return |
|---|---|---|
| 1977 . . . . . . . . . . . | ≥20% | %60% |
| 1978 . . . . . . . . . . . | ≥20% | >45% |
| 1979 . . . . . . . . . . . | ≥20% | >40% |
| 1980 . . . . . . . . . . . | >20% | >35% |
| 1981 . . . . . . . . . . . | >20% | >30% |
| 1982 . . . . . . . . . . . | >20% | >28% |
| 1983 . . . . . . . . . . . | >20% | >26% |
| 1984 . . . . . . . . . . . | >20% | >24% |
| 1985 . . . . . . . . . . . | >20% | >22% |
| 1986 . . . . . . . . . . . | >20% | >20% |
| 1987 -2000 . . . . . . | ≥20% | ≥20% |

*Reservoir study.* Preliminary engineering studies and laboratory tests are conducted. A decision is made whether or not to undertake a technical pilot.

Technical *pilot.* Pilot consists of one or two five-spot patterns on close spacing. Technical parameters are evaluated.

*Evaluate pilot, planning.* Pilot results are evaluated and plans are made for economic pilot. Budgeting occurs.

*Economic pi/et.* Pilot consists of four to eight five-spot patterns on normal spacing. Purpose is to evaluate economic and technical potential.

*Evaluation and planning,* Results of pilots are evaluated. Plans are made for full-scale development.

*Pipeline construction (CO,* miscible only). Pipeline necessary to carry $C0_2$ from source to reservoir is constructed.

*Development of complete reservoir.* The remaining part of the reservoir is developed according to a set time schedule.

The time devoted to each of the seven steps for each process is shown in table B-29.

*Extrapolation to Nation.—To* obtain the national potential for EOR, calculated reservoir

**Table B-29**
**Timing of Reservoir Development**

| Step | Years of Elapsed Time by EOR Technique | | | | |
|---|---|---|---|---|---|
| | Steam | In situ | $CO_2$ | Surfactant/ polymer | Polymer |
| Reservoir study . . . . . . . . . . | 1 | 1 | 1 | 1 | 1 |
| Technical pilot . . . . . . . . . . | 2 | 2 | 2 | 2 | 0 |
| Evaluate pilot, planning . . . | 1 | 1 | 1 | 1 | 0 |
| Economic pilot . . . . . . . . . . | 3 | 2 | 4 | 4 | 5 |
| Evaluation and planning. . . | 1 | 2 | 1 | 1 | 1 |
| Pipeline construction . . . . . | — | — | 2 | — | — |
| Development of reservoir. . . . . . . . . . . . . | 10 | 10* | 5 | 10 | 2 |
| . Total | 18 | 18 | 16 | 19 | 9 |

*In situ proceeds in four separate segments introduced 3 years apart.

recoveries were first extrapolated to the State or district level and then summed to yield the national total. The State or district extrapolation factor was the ratio of remaining oil in place (ROIP) (after secondary recovery) in the State or district divided by the ROIP in the data base reservoirs in the State or district.

An example calculation for the State of Wyoming follows (for world oil price).

Calculated EOR Recovery. . . . . . . . . . . . . . . 0.56 billion bbls
(from reservoirs in data base)
Percent of ROIP in data base. . . . . . . . . . . . . . . . . . . . . . 43.0
ROIP in data base . . . . . . . . . . . . . . . . . 10,628 million bbls
ROIP in State. . . . . . . . . . . . . . . . . . . . . . 24,700 million bbls
State EOR $= 0.56 \times 10^9 \times \frac{24.7 \times 10^9}{10.6 \times 10^9}$ ....1.3 billion bbls

The State and district subdivisions used for extrapolation are shown in the tables of economic parameters (Table B-30 for example).

## Economic Data— General

This subsection is taken directly from the report of Lewin and Associates, Inc., to the Energy Research and Development Administration.[97] Much of the material is quoted directly. Economic parameters are given which are used in the model previously described. In the analysis, specific values of the parameters are calculated based on geographic location, reservoir depth, condition of the wells, and the existence of waterflooding or other secondary recovery. A large number of geographic areas have been established. In many cases these correspond to a State, but in other cases (such as Texas) several districts are defined within a State. Four depth categories have been defined. Condition of the wells in a reservoir is judged by the year of most recent development. Existence of secondary recovery in a reservoir is noted from State reports.

The general economic parameters are presented through a series of tables as follows:

Table B-30 Drilling and Completion Costs for Production and Injection Wells
Table B-31 Well, Lease, and Field Production Equipment Costs—Production Wells
Table B-32 Costs of New Injection Equipment
Table B-33 Well Workover and Conversion Costs for Production and Injection Wells
Table B-34 Basic Operating and Maintenance Costs for Production and Injection Wells
Table B-35 Incremental Injection Operating and Maintenance Costs
Table B-36 State and Local Production Taxes
Table B-37 State Income Taxes.

Each exhibit presents the parameters actually used in the models. The first six tables are accompanied by attachments that explain or illustrate the derivation of the parameters. All the tables are stated in 1976 prices.

Parameters in the above tables are for onshore reservoirs. Additional economic parameters for offshore reservoirs follow.

## Table B-30
## Drilling and Completion Costs for Production and Injection Wells

**(dollars per foot of drilling and completion)**

| State/district | Geographic unit | Depth category 0-2,500' | 2500-5,000' | 5,000-10,000' | 10,000-15,000' |
|---|---|---|---|---|---|
| California | | | | | |
| East central | 1 | 31.60 | 28.03 | 50.02 | 93.62 |
| Central coast | 2 | 42.61 | 42.70 | 45.35 | 74.71 |
| South | 3 | 39.71 | 49.74 | 46.81 | 70.10 |
| Offshore | 4 | 75.88 | 59.99 | 56.38 | 64.59 |
| </ 200'wD | | N.A. | N.A. | N.A. | N.A. |
| 201 -400'WD | | N.A. | N.A. | N.A. | N.A. |
| 401 -800'WD | | N.A. | N.A. | N.A, | N.A, |
| >800'WD | | N.A. | N.A. | N.A. | N.A. |
| Louisiana | | | | | |
| North | 5 | 21.84 | 21.62 | 37.98 | 33.93 |
| South | 6 | 60.99 | 53.00 | 46.95 | 57.62 |
| Offshore | 7 | 112.32 | 110.32 | 109.42 | 103.20 |
| <=200'wD | | N.A. | N.A. | N.A. | N.A. |
| 201-400'WD | | N.A. | N.A. | N.A. | N.A. |
| 401-800'WD | | N.A. | N.A. | N.A. | N.A. |
| >=800'WD | | N.A. | N.A. | N.A. | N.A. |
| Texas | | | | | |
| l | 8 | 17.94 | 23.91 | 31.34 | 35.00 |
| 2 | 9 | 18.00 | 27.15 | 28.36 | 33.40 |
| 3 | 10 | 32.28 | 37.09 | 34.12 | 63.75 |
| 4 | 11 | 28.23 | 24.17 | 23.46 | 77.67 |
| 5 | 12 | 16,71 | 26.23 | 32.51 | 55.96 |
| 6 | 13 | 32.66 | 19.19 | 31.51 | 60.96 |
| 70 | 14 | 13.30 | 19.94 | 20.99 | N.A. |
| 7C | 15 | 30.91 | 20.60 | 26.50 | 43.42 |
| 8 | 16 | 30.86 | 23.15 | 31.66 | 43.85 |
| 8A | 17 | 17.49 | 18.00 | 24.87 | 41.58 |
| 9 | 18 | 14.72 | 23.38 | 28.32 | 33.00 |
| lo | 19 | 24.77 | 18.68 | 27.27 | 48.41 |
| Offshore | 20 | 112.32 | 110.32 | 109.42 | 103.20 |
| <=200'wD | | N.A. | N.A. | N.A. | N.A. |
| 201-400'WD | | N.A. | N.A. | N.A. | N.A. |
| 401-800'WD | | N.A. | N.A. | N.A. | N.A. |
| >=800'WD | | N.A. | N.A. | N.A. | N.A. |
| New Mexico | | | | | |
| East | 23 | 35.15 | 31.25 | 34.00 | 50.01 |
| West | 24 | 45.38 | 22.57 | 25.27 | 34.00 |
| Oklahoma | 25 | 20.37 | 25.10 | 30.59 | 49.61 |
| Kansas | | | | | |
| West | 30 | 15.72 | 20.07 | 23.03 | 34.00 |
| East | 31 | 15.72 | 20.07 | 23.03 | 34.00 |
| Arkansas | | | | | |
| North | 32 | 17.74 | 20.04 | 26.48 | 33.50 |
| South | 33 | 17.74 | 20.04 | 26.48 | 33,50 |
| Missouri | 34 | 20.57 | '25.10 | 30.59 | 49.61 |
| Nebraska | | | | | |
| Central | 35 | 20.37 | 25.10 | 30.59 | 49.61 |
| West | 36 | 45.38 | 22.57 | 25.27 | 34.00 |
| Mississippi | | | | | |
| Hi Sulphur | 40 | 23.32 | 23.32 | 23.69 | 56.25 |
| Lo Sulphur | 41 | 23.32 | 23.32 | 23.69 | 56.25 |

N.A. = not applicable.

**Table B-3 Cont.**

| State/district | Geographic unit | Depth category 0-2,500’ | 2,500-5,000’ | 5,000-10,000’ | 10,000-15,000’ |
|---|---|---|---|---|---|
| **Alabama** | | | | | |
| Hi sulphur. | 42 | 28.26 | 27.94 | 40.00 | 55.69 |
| Lo sulphur. | 43 | 28.26 | 27.94 | 40.00 | 55.69 |
| **Florida** | | | | | |
| Hi sulphur. | 44 | 28.26 | 27.94 | 40.00 | 55.69 |
| Lo sulphur. | 45 | 28.26 | 27.94 | 40.00 | 55.69 |
| Colorado | 50 | 45.38 | 22,57 | 25.27 | 34.00 |
| Utah | 53 | 39.18 | 42.00 | 45.13 | 93.48 |
| Wyoming | 55 | 42.24 | 47.07 | 34.81 | 104.69 |
| Montana | 57 | 15.98 | 30.05 | 36.80 | 48.98 |
| North Dakota | 58 | 26.00 | 31.05 | 37.87 | 45,10 |
| South Dakota | 59 | 26.00 | 31.05 | 37.87 | 45.10 |
| Illinois | 60 | 24.46 | 26.43 | 32.74 | 50.00 |
| Indiana. ........, | 61 | 24.46 | 26.43 | 32.74 | 50.00 |
| **Ohio** | | | | | |
| West | 62 | 24.46 | 26.43 | 32.74 | 50.00 |
| East | 63 | 15.38 | 19.09 | 18.14 | 30.00 |
| **Kentucky** | | | | | |
| West | 64 | 24.46 | 26.43 | 32.74 | 50.00 |
| East | 65 | 15.38 | 19.09 | 18.14 | 30.00 |
| **Tennessee** | | | | | |
| West | 66 | 24.46 | 26.43 | 32.74 | 50.00 |
| East | 67 | 15.38 | 19.09 | 18.14 | 30.00 |
| Pennsylvania. | 70 | 15.38 | 19.09 | 18.14 | 30.00 |
| New York | 71 | 15.38 | 19.09 | 18.14 | 30.00 |
| West Virginia | 72 | 15,38 | 19.09 | 18.14 | 30.00 |
| Virginia | 73 | 15.38 | 19.09 | 18.14 | 30.00 |
| **Alaska** | | | | | |
| North Slope | 80 | N.A. | N.A. | 370.00 | 340.00 |
| Cook Inlet | 31 | N.A. | N.A. | 190.00 | 180.00 |

N.A. = not applicable.

**Tabie B-31**
**Weii,Lease,and Fieid Production Equipment Costs-Production Wells**

**(dollars per production well)**

| State/district | Geographic unit | Depth category 0-2,500’ | 2,500-5,000’ | 5,000-10,000’ | 10,000-15,000’ |
|---|---|---|---|---|---|
| **California** | | | | | |
| East Central | 1 | 33,300 | 51,900 | 47,200 | 51,200 |
| Central Coast... | 2 | 33,300 | 51,900 | 47,200 | 51,200 |
| South | 3 | 33,300 | 51,900 | 47,200 | 51,200 |
| Offshore | 4 | 300,000 | 300,000 | 300,000 | 300,000 |
| <=200’wD. | 90 | 300,000 | 300,000 | 300,000 | 300,000 |
| 201-400’WD. | 91 | 300,000 | 300,000 | 300,000 | 300,000 |
| 401-800’WD | 92 | N.A. | N.A. | N.A. | N.A. |
| >800’WD | 93 | N.A. | N.A. | N.A. | N.A. |
| **Louisiana** | | | | | |
| North | 5 | 23,500 | 45,600 | 50,500 | 44,400 |
| South. | 6 | 24,700 | 47,300 | 52,900 | 48,800 |

**N.A. = nonapplicable.**

Table B-31—Cent.

| State/district | Geographic unit | Depth category 0-2,500' | 2,500-5,000' | 5,000-10,000' | 10,000-15,000' |
|---|---|---|---|---|---|
| Offshore | 7 | 300,000 | 300,000 | 300,000 | 300,000 |
| <=200'WD" | 95 | 300,000 | 300,000 | 300,000 | 300,000 |
| 201 -400'WD | 96 | 300,000 | 300,000 | 300,000 | 300,000 |
| 401-800'WD | 97 | N.A. | N.A. | N.A. | N.A. |
| >=800WD | 98 | N.A. | N.A. | N.A. | N.A. |
| Texas | | | | | |
| l | 8 | 23,500 | 45,600 | 50,500 | 44,400 |
| 2 | 9 | 23,500 | 45,600 | 50,500 | 44,400 |
| 3 | 10 | 23,500 | 45,600 | 50,500 | 44,400 |
| 4 | 11 | 23,500 | 45,600 | 50,500 | 44,400 |
| 5 | 12 | 23,500 | 45,600 | 50,500 | 44,400 |
| 6 | 13 | 23,500 | 45,600 | 50,500 | 44,400 |
| 7B" | 14 | 23,100 | 32,900 | 52,400 | 45,200 |
| 7C | 15 | 23,100 | 32,900 | 52,400 | 45,200 |
| 8 | 16 | 23,100 | 32,900 | 52,400 | 45,200 |
| 8 A | 17 | 23,100 | 32,900 | 52,400 | 45,200 |
| 9 | 18 | 23,100 | 32,900 | 52,400 | 45,200 |
| lo | 19 | 24,900 | 37,100 | 49,100 | 58,200 |
| Offshore | 20 | 300,000 | 300,000 | 300,000 | 300,000 |
| <=200'wD | 95 | 300,000 | 300,000 | 300,000 | 300,000 |
| 201-400'WD | 96 | 300,000 | 300,000 | 300,000 | 300,000 |
| 401-800'WD | 97 | N.A. | N.A. | N.A. | N.A. |
| >=800'WD | 98 | N.A. | N.A. | N.A. | N.A. |
| New Mexico | | | | | |
| East | 23 | 23,100 | 32,900 | 52,400 | 45,200 |
| West | 24 | 35,600 | 45,400 | 76,900 | 68,200 |
| Oklahoma | 25 | 24,900 | 37,100 | 49,100 | 58,200 |
| Kansas | | | | | |
| West | 30 | 24,900 | 37,100 | 49,100 | 58,200 |
| East | 31 | 24,900 | 37,100 | 49,100 | 58,200' |
| Arkansas | | | | | |
| North | 32 | 24,900 | 37,100 | 49,100 | 58,200 |
| South | 33 | 23,500 | 45,600 | 50,500 | 44,400 |
| Missouri | 34 | 24,900 | 37,700 | 49,100 | 58,200 |
| Nebraska | | | | | |
| Central | 35 | 24,900 | 37,100 | 49,100 | 58,200 |
| West | 36 | 35,600 | 45,400 | 75,900 | 68,200 |
| Mississippi | | | | | |
| Hi Sulphur | 40 | 23,500 | 45,600 | 50,500 | 44,400 |
| Lo Sulphur | 41 | 23,500 | 45,600 | 50,500 | 44,400 |
| Alabama | | | | | |
| Hi Sulphur | 42 | N.A. | N.A. | N.A. | N.A. |
| Lo Sulphur | 43 | 23,500 | 45,600 | 50,500 | 44,400 |
| Florida | | | | | |
| Hi Sulphur | 44 | N.A. | N.A. | N.A. | N.A. |
| Lo Sulphur | 45 | 23,500 | 45,600 | 50,500 | 44,400 |
| Colorado | 50 | 35,600 | 45,400 | 76,900 | 68,200 |
| Utah | 53 | 35,600 | 45,400 | 76,900 | 68,200 |
| Wyoming | 55 | 35,600 | 45,400 | 76,900 | 68,200 |
| Montana | 57 | 35,600 | 45,400 | 76,900 | 68,200 |
| North Dakota | 58 | 35,600 | 45,400 | 76,900 | 68,200 |
| South Dakota | 59 | 35,600 | 45,400 | 76,900 | 68,200 |
| Illinois | 60 | 24,900 | 37,100 | 49,100 | 58,200 |
| Indiana | 61 | 24,900 | 37,100 | 49,100 | 58,200 |

N.A. = not applicable.

**Table B-31-Cent.**

| State/district | Geographic unit | Depth category 0-2,500’ | 2,500-5,000’ | 5,000-10,000’ | 10,000-15,000’ |
|---|---|---|---|---|---|
| **Ohio** | | | | | |
| West | 62 | 24,900 | 37,100 | 49,100 | 58,200 |
| East | 63 | 8,400 | 17,000 | N.A. | N.A. |
| **Kentucky** | | | | | |
| West | 64 | 24,900 | 37,100 | N.A. | N.A. |
| East | 65 | 8,400 | 17,000 | N.A. | N.A. |
| **Tennessee** | | | | | |
| West | 66 | 24,900 | 37,100 | N.A. | N.A. |
| East | 67 | 8,400 | 17,000 | N.A. | N.A. |
| Pennsylvania | 70 | 8,400 | 17,000 | N.A. | N.A. |
| New York | 71 | 8,400 | 17,000 | N.A. | N.A. |
| West Virginia | 72 | 8,400 | 17,000 | N.A. | N.A. |
| Virginia | 73 | 8,400 | 17,000 | N.A. | N.A. |
| **Alaska** | | | | | |
| North Slope | 80 | N.A. | N.A. | N.A. | N.A. |
| Cook Inlet | 81 | N.A. | N.A. | N.A. | N.A. |

N.A. = not applicable.

NOTE:

Well, lease, and field production equipment designed for secondary but excluding Injection equipment Includes all items except tubing and wellheads (which are Included In JAS drilling costs) required to lift the fluid to the surface at the producing wellhead by artiflcial lift, Including rod pump, gas lift, or hydraulic lift, depending on geographic area and depth. These costs also Include all equipment to process the produced fluids prior to custody transfer. The major items included are: heater-treater, separator, well testing system, tanks, flow levers from producing wells, water disposal systems, and, when applicable, crude desulphurizatlon facilities. These are average costs per *production well.*

## Table B-32
## Costs of New Injection Equipment

**(dollars per injection well)**

| State/district | Geographic unit | Depth category 0-2,500’ | 2,500-5,000’ | 5,000-10,000’ | 10,000-15,000’ |
|---|---|---|---|---|---|
| **California** | | | | | |
| East Central | 1 | 30,500 | 30,500 | 48,500 | 48,500 |
| Central Coast | 2 | 30,500 | 30,500 | 48,500 | 48,500 |
| South | 3 | 30,500 | 30,500 | 48,500 | 48,500 |
| Offshore | 4 | 100,000 | 100,000 | 150,000 | 150,000 |
| <= 200’wD | 90 | N.A. | N.A. | N.A. | N.A. |
| 201 -400’WD | 91 | N.A. | N.A. | N.A. | N.A. |
| 401 -800’WD | 92 | N.A. | N.A. | N.A. | N.A. |
| >=800’WD | 93 | N.A. | N.A. | N.A. | N.A. |
| **Louisiana** | | | | | |
| North | 5 | 28,500 | 28,500 | 45,300 | 45,300 |
| South | 6 | 31,100 | 31,100 | 52,300 | 52,300 |
| Offshore | 7 | 100,000 | 100,000 | 150,000 | 150,000 |
| <= 200’wD | 95 | 100,000 | 100,000 | 150,000 | 150,000 |
| 201-400’WD | 96 | 100,000 | 100,000 | 150,000 | 150,000 |
| 401 -800’WD | 97 | N.A. | N.A. | N.A. | N.A. |
| >=800W D | 98 | N.A. | N.A. | N.A. | N.A. |

N.A. = not applicable.

**Table B-32-Cent.**

| State/district | Geographic unit | "Depth category 0-2,500' | 2,500-5,000' | 5,000-10,000' | 10,000-15,000' |
|---|---|---|---|---|---|
| Texas | | | | | |
| 1 | 8 | 28,500 | 28,500 | 45,300 | 45,300 |
| 2 | 9 | 28,500 | 28,500 | 45,300 | 45,300 |
| 3 | 10 | 28,500 | 28,500 | 45,300 | 45,300 |
| 4 | 11 | 28,500 | 28,500 | 45,300 | 45,300 |
| 5 | 12 | 28,500 | 28,500 | 45,300 | 45,300 |
| 6 | 13 | 28,500 | 28,500 | 45,300 | 45,300 |
| 70 | 14 | 27,700 | 27,700 | 44,100 | 44,100 |
| 7C | 15 | 27,700 | 27,700 | 44,100 | 44,100 |
| 8 | 16 | 27,70P | 27,700 | 44,100 | 44,100 |
| 8A | 17 | 27,700 | 27,700 | 44,100 | 44,100 |
| 9 | 18 | 27,700 | 27,700 | 44,100 | 44,100 |
| 10 | 19 | 30,000 | 30,000 | 64,100 | 64,100 |
| Offshore | 20 | 100,000 | 100,000 | 150,000 | 150,000 |
| <=200'WID | 95 | 100,000 | 100,000 | 150,000 | 150,000 |
| 201-400'WD | 96 | 100,000 | 100,000 | 150,000 | 150,000 |
| 401-800'WD | 97 | N.A. | N.A. | N.A. | N.A. |
| >=800WD | 98 | N.A. | N.A. | N.A. | N.A. |
| New Mexico | | | | | |
| East | 23 | 27,700 | 27,700 | 44,100 | 44,100 |
| West | 24 | 42,800 | 42,800 | 74,700 | 74,700 |
| Oklahoma | 25 | 30,000 | 30,000 | 64,100 | 64,100 |
| Kansas | | | | | |
| West | 30 | 30,000 | 30,000 | 64,100 | 64,100 |
| East | 31 | 30,000 | 30,000 | 64,100 | 64,100 |
| Arkansas | | | | | |
| North | 32 | 30,000 | 30,000 | 64,100 | 64,100 |
| South | 33 | 28,500 | 28,500 | 45,300 | 45,300 |
| Missouri | 34 | 30,000 | 30,000 | 64,100 | 64,100 |
| Nebraska | | | | | |
| Central | 35 | 30,000 | 30,000 | 64,100 | 64,100 |
| west | 36 | 42,800 | 42,800 | 74,700 | 74,700 |
| Mississippi | | | | | |
| Hi Sulphur | 40 | 28,500 | 28,500 | 45,300 | 45,300 |
| Lo Sulphur | 41 | 28,500 | 28,500 | 45,300 | 45,300 |
| Alabama | | | | | |
| HiSulphur | 42 | 28,500 | 28,500 | 45,300 | 45,300 |
| Lo Sulphur | 43 | 28,500 | 28,500 | 45,300 | 45,300 |
| Florida | | | | | |
| HiSulphur | 44 | 28,500 | 28,500 | 45,300 | 45,300 |
| Lo Sulphur | 45 | 28,500 | 28,500 | 45,300 | 45,300 |
| Colorado | 50 | 42,800 | 42,800 | 74,700 | 74,700 |
| Utah | 53 | 42,800 | 42,800 | 74,700 | 74,700 |
| Wyoming | 55 | 42,800 | 42,800 | 74,700 | 74,700 |
| Montana | 57 | 42,800 | 42,800 | 74,700 | 74,700 |
| North Dakota | 58 | 42,800 | 42,800 | 74,700 | 74,700 |
| South Dakota | 59 | 42,800 | 42,800 | 74,700 | 74,700 |
| Illinois | 60 | 30,000 | 30,000 | 64,100 | 64,100 |
| Indiana | 61 | 30,000 | 30,000 | 64,100 | 64,100 |
| Ohio | | | | | |
| West | 62 | 30,000 | 30,000 | 64,100 | 64,100 |
| East | 63 | 12,200 | 12,200 | N.A. | N.A. |

N,A. = not applicable

**Tabie B-32--Cent.**

| State/district | Geographic unit | "Depth category 0-2,500' | 2,500-5,000' | 5,000-10,000' | 1o,ooo-15,000' |
|---|---|---|---|---|---|
| **Kentucky** | | | | | |
| **West** | 64 | 30,000 | 30,000 | N.A. | N.A. |
| **East** | 65 | 12,200 | 12,200 | N.A. | N.A. |
| **Tennessee** | | | | | |
| **West** | **66** | 30,000 | 30,000 | N.A. | N.A. |
| **East** | **67** | 12,200 | 12,200 | N.A. | N.A. |
| **Pennsylvania.** | 70 | 12,200 | 12,000 | N.A. | N.A. |
| **New York** | 71 | 12,200 | 12,000 | N.A. | N.A. |
| **West Virginia** | 72 | 12,2(-)0 | 12,200 | N.A. | N.A. |
| **Virginia** | 73 | 12,200 | 12,000 | **N.A.** | N.A. |
| **Alaska** | | | | | |
| **North Slope** | 80 | N.A. | N.A. | **N.A.** | **N.A.** |
| **Cook Inlet** | 81 | N.A. | N.A. | **N.A.** | N.A, |

N.A **= not applicable.**

Note:

Cost of **water injection equipment** for waterflood projects in-eludes the **equipment necessary to** install a waterflood in a **depleted primary producing** field. The malor items included are: water supply wells, water tankage, injection plant and accessories, injection heads, water injection lines, and electrification.

## Table B-33: Part A
## Well Workover and Conversion Costs for Production and injection Wells

Workover and/or Conversion Costs for Enhanced Recovery

| Years field has been operated underexisting recovery **process** | Percent of wells worked **over** | Percent of wells over 25-years old— **(conversion costs)** | Composition conversion cost **percent** |
|---|---|---|---|
| **More than 25** | **100** | 100 | 100 |
| 16 **to 25.** | 50 | 80 | 40 |
| 6 **to 15. ....,** | **25** | **64** | 16 |
| 1 to 5. | 0 | 0 | 0 |

## Table B-33: Part B
## Well Workover and Conversion Costs for Production and injection Wells

**(dollars per well)**

| **State/district** | **Geographic unit** | **Depth category** **0-2,500'** | **2,500-** 5,000' | 5,000-1 0,000' | 10,000-1 5,000' |
|---|---|---|---|---|---|
| **California** | | | | | |
| **East Central** | 1 | **20,400** | **50,200** | 103,400 | 220,000 |
| **Central Coast.** | **2** | **20,400** | **50,200** | 103,400 | 220,000 |
| **South.** | **3** | **20,400** | **50,200** | 103,400 | 220,000 |
| **Offshore.** | **4** | **150,000** | 150,000 | 170,000 | 225,000 |
| **<=200'WD** | 90 | **N.A.** | N.A. | **N.A.** | N.A. |
| **201 -400'WD** | 91 | **N.A.** | N.A. | **N.A.** | N.A. |
| **401 -800'WD** | 92 | **N.A.** | N.A. | N.A. | **N.A.** |
| **>800'WD** | 93 | **N.A.** | N.A. | N.A. | **N.A.** |

**N.A. = not applicable.**

**Table B-33: Part B-Cent.**

| State/district | Geographic unit | Depth category 0-2,500' | 2,500-5,000' | 5,000-10,000' | 10,000-15,000' |
|---|---|---|---|---|---|
| Louisiana | | | | | |
| North. ... , . . . . . . . . . . . . . . . . . . | 5 | 21,700 | 38,200 | 64,100 | 135,000 |
| South . . . . . . . . . . . . . . . . . . . . . . . | 6 | 35,400 | 69,000 | 94,000 | 139,700 |
| Offshore . . . . . . . . . . . . . . . . . . . . | 7 | 150,000 | 150,000 | 170,000 | 225,000 |
| <=200'WD. . . . . . . . . . . . . . . . | 95 | 150,000 | 150,000 | 170,000 | 225,000 |
| 201-400'WD . . . . . . . . . . . . . . | 96 | 150,000 | 150,000 | 170,000 | 225,000 |
| 401-800'WD. . . . . . . . . . . . . . | 97 | N.A. | N.A. | N.A. | N.A. |
| >800'WD . . . . . . . . . . . . . . . | 98 | N.A. | N.A. | N.A. | N.A. |
| Texas | | | | | |
| l . . . . . . . . . . . . . . . . . . . . . . . . . | 8 | 21,700 | 38,200 | 64,100 | 135,000 |
| 2 . . . . . . . . . . . . . . . . . . . . . . . . . | 9 | 21,700 | 38,200 | 64,100 | 135,000 |
| 3 . . . . . . . . . . . . . . . . . . . . . . . . . | 10 | 21,700 | 38,200 | 64,100 | 135,000 |
| 4 . . . . . . . . . . . . . . . . . . . . . . . . . | 11 | 21,700 | 38,200 | 64,100 | 135,000 |
| 5 . . . . . . . . . . . . . . . . . . . . . . . . . | 12 | 21,700 | 38,200 | 64,100 | 135,000 |
| 6 . . . . . . . . . . . . . . . . . . . . . . . | 13 | 21,700 | 38,200 | 64,100 | 135,000 |
| 70" : . . . . . . . . . . . . . . . . . . . . . . | 14 | 16,900 | 27,400 | 57,500 | 133,400 |
| 7C . . . . . . . . . . . . . . . . . . . . . . . . | 15 | 16,900 | 27,400 | 57,500 | 133,400 |
| 8 | 16 | 16,900 | 27,400 | 57,500 | 133,400 |
| 8 A : : : : : : : : : : : : : : : : : : : : : : : : | 17 | 16,900 | 27,400 | 57,500 | 133,400 |
| 9 . . . . . . . . . . . . . . . . . . . . . . . . . | 18 | 16,900 | 27,400 | 57,500 | 133,400 |
| lo . . . . . . . . . . . . . . . . . . . . . . . . | 19 | 17,400 | 29,700 | 59,800 | 132,500 |
| Offshore . . . . . . . . . . . . . . . . . . . . | 20 | 150,000 | 150,000 | 170,000 | 225,000 |
| <=2()()'wD. . . . . . . . . . . . . . . , . | 95 | 150,000 | 150,000 | 170,000 | 225,000 |
| 201-400'WD . . . . . . . . . . . . . . | 96 | 150,000 | 150,000 | 170,000 | 225,000 |
| 401-800'WD. ..,, . . . . . . . . . . | 97 | N.A. | N.A. | N.A. | N.A. |
| >=800'WD. . . . . . . . . . . . . . . | 98 | N.A. | N.A. | N.A. | N.A. |
| New Mexico | | | | | |
| East . . . . . . . . . . . . . . . . . . . . . . . . | 23 | 16,900 | 27,400 | 57,500 | 133,400 |
| West . . . . . . . . . . . . . . . . . . . . . . . | 24 | 34,700 | 50,900 | 76,900 | 147,500 |
| Oklahoma . . . . . . . . . . . . . . . . . . . . . . . | 25 | 17,400 | 29,700 | 59,800 | 132,500 |
| Kansas | | | | | |
| West . . . . . . . . . . . . . . . . . . . . . . . | 30 | 17,400 | 29,700 | 59,800 | 132,500 |
| East . . . . . . . . . . . . . . . . . . . . . . . . | 31 | 17,400 | 29,700 | 59,800 | 132,500 |
| Arkansas | | | | | |
| North . . . . . . . . . . . . . . . . . . . . . . . | 32 | 17,400 | 29,700 | 59,800 | 132,500 |
| South . . . . . . . . . . . . . . . . . . . . . . . | 33 | 21,700 | 38,200 | 64,100 | 135,000 |
| Missouri. . . . . . . . . . . . . . . . . . . . . . . . . | 34 | 17,400 | 29,700 | 59,800 | 132,500 |
| Nebraska | | | | | |
| Central . . . . . . . . . . . . . . . . . . . . . | 35 | 17,400 | 29,700 | 59,800 | 132,500 |
| West . . . . . . . . . . . . . . . . . . . . . . . | 36 | 34,700 | 50,900 | 76,900 | 147,500 |
| Mississippi | | | | | |
| Hi Sulphur. . . . . . . . . . . . . . . . . . . | 40 | 30,000 | 50,000 | 100,000 | 200,000 |
| Lo Sulphur . . . . . . . . . . . . . . . . . . | 41 | 21,700 | 38,200 | 64,100 | 135,000 |
| Alabama | | | | | |
| Hi Sulphur. . . . . . . . . . . . . . . . . . . | 42 | 30,000 | 50,000 | 100,000 | 200,000 |
| Lo Sulphur . . . . . . . . . . . . . . . . . . | 43 | 21,700 | 38,200 | 64,100 | 135,000 |
| Florida | | | | | |
| Hi Sulphur. . . . . . . . . . . . . . . . . . . | 44 | 30,000 | 50,000 | 100,000 | 200,000 |
| Lo Sulphur . . . . . . . . . . . . . . . . . . | 45 | 21,700 | 38,200 | 64,100 | 135,000 |
| Colorado . . . . . . . . . . . . . . . . . . . . . . . . | 50 | 34,700 | 50,900 | 76,900 | 147,500 |
| Utah. . . . . . . . . . . . . . . . . . . . . . . . . . . . | 53 | 34,700 | 50,900 | 76,900 | 147,500 |
| Wyoming . . . . . . . . . . . . . . . . . . . . . . . . | 55 | 34,700 | 50,900 | 76,900 | 147,500 |
| Montana . . . . . . . . . . . . . . . . . . . . . . . . | 57 | 34,700 | 50,900 | 76,900 | 147,500 |
| North Dakota . . . . . . . . . . . . . . . . . . . . . | 58 | 34,700 | 50,900 | 76,900 | 147,500 |

N.A. = not applicable.

**Table B-33: Part B-Cent.**

| State/district | Geographic unit | Depth category 0-2,500' | 2,500-5,000' | 5,000-10,000' | 10,000-15,000' |
|---|---|---|---|---|---|
| South Dakota | 59 | 34,700 | 50,900 | 76,900 | 147,500 |
| Illinois | 60 | 17,400 | 29,700 | 59,800 | 132,500 |
| Indiana | 61 | 17,400 | 29,700 | 59,800 | 132,500 |
| Ohio | | | | | |
| West | 62 | 17,400 | 29,700 | 59,800 | 132,500 |
| East | 63 | 8,900 | 29,500 | N.A. | N.A. |
| Kentucky | | | | | |
| West | 64 | 17,400 | 29,700 | N.A. | N.A. |
| East | 65 | 8,900 | 29,500 | N.A. | N.A. |
| Tennessee | | | | | |
| West | 66 | 17,400 | 29,700 | N.A. | N.A. |
| East | 67 | 8,900 | 29,500 | N.A. | N.A. |
| Pennsylvania | 70 | 8,900 | 29,500 | N.A. | N.A. |
| New York | 71 | 8,900 | 29,500 | N.A. | N.A. |
| West Virginia | 72 | 8,900 | 29,500 | N.A. | N.A. |
| Virginia | 73 | 8,900 | 29,500 | N.A. | N.A. |
| Alaska | | | | | |
| North Slope | 80 | N.A. | N.A. | N.A. | N.A. |
| Cook Inlet | 81 | N.A. | N.A. | N.A. | N.A. |

N.A. = not applicable.

**Note:**

Costs of conversion of existing producing or injection well to "new" producing or injection well include those to workover old wells and equipment for production or injection service for EOR. Costs are averaEes ofcosts for woduction wells and infection wells and are calculated based on percentages of applicable items of new well drilling costs and equipment costs required for workover or conversion.

## Table B-34
## Bask Operating and Maintenance Coats for Production and Injection Wells

(dollars per well per year)

| State/district | Geographic unit | Depth category 0-2,500' | 2,500-5,000' | 5,000-1 0,000' | 10,000-1 5,000' |
|---|---|---|---|---|---|
| California | | | | | |
| East Central | 1 | 11,600 | 15,700 | 17,500 | 19,800 |
| Central Coast | 2 | 11,600 | 15,700 | 17,500 | 19,800 |
| South | 3 | 11,600 | 15,700 | 17,500 | 19,800 |
| Offshore | 4 | 60,000 | 60,000 | 75,000 | 75,000 |
| <=200'WD | 90 | 60,000 | 60,000 | 75,000 | 75,000 |
| 201-400'WD | 91 | 60,000 | 69,000 | 84,000 | 84,000 |
| 401-800'WD | 92 | 60,000 | 72,000 | 90,000 | 90,000 |
| >=800'WD | 93 | 60,000 | 84,000 | 105,000 | 105,000 |
| Louisiana | | | | | |
| North | 5 | 9,900 | 13,900 | 16,500 | 16,900 |
| South | 6 | 8,800 | 12,200 | 15,200 | 15,800 |
| Offshore | 7 | 60,000 | 60,000 | 75,000 | 75,000 |
| <= 200'wD | 95 | 60,000 | 60,000 | 75,000 | 75,000 |
| 201 -400'WD | 96 | 60,000 | 69,000 | 84,000 | 84,000 |
| 401 -800'WD | 97 | 60,000 | 72,000 | 90,000 | 90,000 |
| >=800'WD | 98 | 60,000 | 84,000 | 105,000 | 105,000 |
| Texas | | | | | |
| 1 | 8 | 9,900 | 13,900 | 16,500 | 16,900 |
| 2 | 9 | 9,900 | 13,900 | 16,500 | 16,900 |

N.A. = not applicable.

**Table B-34-Cent.**

| State/district | Geographic unit | Depth category 0-2,500’ | 2,500-5,000’ | 5,000-10,000’ | 10,000-15,000’ |
|---|---|---|---|---|---|
| 3 | 10 | 9,900 | 13,900 | 16,500 | 16,900 |
| 4 | 11 | 9,900 | 13,900 | 16,500 | 16,900 |
| 5 | 12 | 9,900 | 13,900 | 16,500 | 16,900 |
| 6 | 13 | 9,900 | 13,900 | 16,500 | 16,900 |
| 70 | 14 | 8,000 | 8,600 | 11,700 | 13,000 |
| 7C | 15 | 8,000 | 8,600 | 11,700 | 13,000 |
| 8 | 16 | 8,000 | 8,600 | 11,700 | 13,000 |
| 8A | 17 | 8,000 | 8,600 | 11,700 | 13,000 |
| 9 | 18 | 8,000 | 8,600 | 11,700 | 13,000 |
| lo | 19 | 10,000 | 11,100 | 15,500 | 18,000 |
| Offshore | 20 | 60,000 | 60,000 | 75,000 | 75,000 |
| <=200'WD | 95 | 60,000 | 60,000 | 75,000 | 75,000 |
| 201-400’WD | 96 | 70,000 | 70,000 | 84,000 | 84,000 |
| 401-800’WD | 97 | 72,000 | 72,000 | 90,000 | 90,000 |
| >=800'WD | 98 | 84,000 | 84,000 | 105,000 | 105,000 |
| New Mexico | | | | | |
| East | 23 | 8,000 | 8,600 | 11,700 | 13,000 |
| West | 24 | 8,700 | 14,400 | 25,500 | 41,800 |
| Oklahoma | 25 | 10,000 | 11,100 | 15,500 | 18,000 |
| Kansas | | | | | |
| West | 30 | 10,000 | 11,100 | 15,500 | 18,000 |
| East | 31 | 10,000 | 11,100 | 15,500 | 18,000 |
| Arkansas | | | | | |
| North | 32 | 10,000 | 11,100 | 15,500 | 18,000 |
| South | 33 | 9,900 | 13,900 | 16,500 | 16,900 |
| Missouri | 34 | 10,000 | 11,100 | 15,500 | 18,000 |
| Nebraska | | | | | |
| Central | 35 | 10,000 | 11,100 | 15,500 | 18,000 |
| West | 36 | 8,700 | 14,400 | 25,500 | 41,800 |
| Mississippi | | | | | |
| Hi Sulphur | 40 | 15,000 | 21,000 | 24,600 | 27,000 |
| Lo Sulphur | 41 | 9,900 | 13,900 | 16,500 | 16,900 |
| Alabama | | | | | |
| Hi Sulphur | 42” | 15,000 | 21,000 | 24,600 | 27,000 |
| Lo Sulphur | 43 | 9,900 | 13,900 | 16,500 | 16,900 |
| Florida | | | | | |
| Hi Sulphur | 44 | 15,000 | 21,000 | 24,600 | 27,000 |
| Lo Sulphur | 45 | 9,900 | 13,900 | 16,500 | 16,900 |
| Colorado | 50 | 8,700 | 14,400 | 25,500 | 41,800 |
| Utah | 53 | 8,700 | 14,400 | 25,500 | 41,800 |
| Wyoming | 55 | 8,700 | 14,400 | 25,500 | 41,800 |
| Montana | 57 | 8,700 | 14,400 | 25,500 | 41,800 |
| North Dakota | 58 | 8,700 | 14,400 | 25,500 | 41,800 |
| South Dakota | 59 | 8,700 | 14,400 | 25,000 | 41,800 |
| Illinois | 60 | 6,000 | .6,700 | 9,900 | 10,800 |
| Indiana | 61 | 6,000 | 6,700 | 9,900 | 10,800 |
| Ohio | | | | | |
| West | 62 | 6,000 | 6,700 | 9,900 | 10,800 |
| East | 63 | 2,300 | 2,600 | N.A. | N.A. |
| Kentucky | | | | | |
| West | 64 | 6,000 | 6,700 | N.A. | N.A. |
| East | 65 | 2,300 | 2,600 | N.A. | N.A. |
| Tennessee | | | | | |
| West | 66 | 6,000 | 6,700 | N.A. | N.A. |
| East | 67 | 2,300 | 2,600 | N.A. | N.A. |

N.A. = nonapplicable.

**Table B-*Cont.**

| State/district | Geographic unit | “Depth category 0-2,500’ | 2,500-5,000’ | 5,000-10,000’ | 1o,ooo-15,000’ |
|---|---|---|---|---|---|
| Pennsylvania . . . . . . . . . . . . . . . . . . . . . . | 70 | 2,300 | 2,600 | N.A. | N.A. |
| New York . . . . . . . . . . . . . . . . . . . . . . . . | 71 | 2,300 | 2,600 | N.A. | N.A. |
| West Virginia . . . . . . . . . . . . . . . . . . . . . | 72 | 2,300 | 2,600 | N.A. | N.A. |
| Virginia . . . . . . . . . . . . . . . . . . . . . . . . . . | 73 | 2,300 | 2,600 | N.A. | N.A. |
| Alaska | | | | | |
| North Slope . . . . . . . . . . . . . . . . . | 80 | N.A. | N.A. | N.A. | N.A. |
| Cook Inlet . . . . . . . . . . . . . . . . . . . | 81 | N.A. | N.A. | N.A. | N.A. |

N.A. = not applicable.
Note:
Direct annual operating expense, including waterflooding, in-eludes expenditures for operating producing wells and operating a water injection system. These operating expenditures include the normal daily operating expense, surface repair and maintenance ex-pense, and subsurface repair; maintenance and services. These are average expenditures per *producttin we//,* and include the expend-itures of operating an injection system,

## Table B-35
## Incremental Injection Operating and Maintenance Cost*

**(dollars for injection well per year)**

| State/district | Geographic unit | Depth category 0-2,500’ | 2,500-5,000’ | 5,000-10,000’ | 1o,ooo-15,000’ |
|---|---|---|---|---|---|
| California | | | | | |
| East Central . . . . . . . . . . . . . . . . . | 1 | 7,700 | 6,900 | 11,600 | 13,200 |
| Central Coast. . . . . . . . . . . . . . . . | 2 | 7,700 | 6,900 | 11,600 | 13,200 |
| South. . . . . . . . . . . . . . . . . . . . . . . . | 3 | 7,700 | 6,900 | 11,600 | 13,200 |
| Offshore . . . . . . . . . . . . . . . . . . . . | 4 | 40,000 | 40,000 | 50,000 | 50,000 |
| <=200’wD . . . . . . . . . . . . . . . . | 90 | 40,000 | 40,000 | 50,000 | 50,000 |
| 201-400’WD . . . . . . . . . . . . . . | 91 | 40,000 | 56,000 | 56,000 | 56,000 |
| 401 -800’WD . . . . . . . . . . . . . . | 92 | 40,000 | 48,000 | 60,000 | 60,000 |
| >800’WD . . . . . . . . . . . . . . . . | 93 | 40,000 | 56,000 | 70,000 | 70,000 |
| Louisiana | | | | | |
| North. . . . . . . . . . . . . . . . . . . . . . . | 5 | 6,600 | 9,300 | 11,000 | 11,300 |
| South. . . . . . . . . . . . . . . . . . . . . . . . | 6 | 6,000 | 8,100 | 10,100 | 10,600 |
| Offshore . . . . . . . . . . . . . . . . . . . . | 7 | 40,000 | 40,000 | 50,000 | 50,000 |
| <= 200’WD . . . . , . . . . , . . . . . . | 95 | 40,000 | 40,000 | 50,000 | 50,000 |
| 201 -400’WD . . . . . . . . . . . . . . | 96 | 40,000 | 56,000 | 56,000 | 56,000 |
| 401 -800’WD . . . . . . . . . . . . . . | 97 | 40,000 | 48,000 | 60,000 | 60,000 |
| >=800’WD . . . . . . . . . . . . . . . . | 98 | 40,000 | 56,000 | 70,000 | 70,000 |
| Texas | | | | | |
| 1 . . . . . . . . . . . . . . . . . . . . . . . . . . | 8 | 6,600 | 9,300 | 11,000 | 11,300 |
| 2 . . . . . . . . . . . . . . . . . . . . . . . . . . | 9 | 6,600 | 9,300 | 11,000 | 11,300 |
| 3 . . . . . . . . . . . . . . . . . . . . . . . . . . | 10 | 6,600 | 9,300 | 11,000 | 11,300 |
| 4 . . . . . . . . . . . . . . . . . . . . . . . . . . | 11 | 6,600 | 9,300 | 11,000 | 11,300 |
| 5 . . . . . . . . . . . . . . . . . . . . . . . . . . | 12 | 6,600 | 9,300 | 11,000 | 11,300 |
| 6 . . . . . . . . . . . . . . . . . . . . . . | 13 | 6,600 | 9,300 | 11,000 | 11,300 |
| 7B” : : : . . . . . . . . . . . . . . . . . . . . . | 14 | 5,400 | 5,800 | 7,800 | 8,600 |
| 7C . . . . . . . . . . . . . . . . . . . . . . . . . | 15 | 5,400 | 5,800 | 7,800 | 8,600 |
| 8 | 16 | 5,400 | 5,800 | 7,800 | 8,600 |
| 8 A : : : : : : : : : : : : : : : : : : : : : : : : : | 17 | 5,400 | 5,800 | 7,800 | 8,600 |
| 9 . . . . . . . . . . . . . . . . . . . . . . . . . . | 18 | 5,400 | 5,800 | 7,800 | 8,600 |
| lo . . . . . . . . . . . . . . . . . . . . . . . . . | 19 | 6,700 | 7,400 | 10,300 | 12,000 |
| Offshore . . . . . . . . . . . . . . . . . . . . | 20 | 40,000 | 40,000 | 50,000 | 50,000 |
| <=200’wD. . . . . . . . . . . . . . . . | 95 | 40,000 | 40,000 | 50,000 | 50,000 |
| 201-400’WD . . . . . . . . . . . . . . | 96 | 45,000 | 45,000 | 56,000 | 56,000 |
| 401-800’WD . . . . . . . . . . . . . . | 97 | 48,000 | 48,000 | 60,000 | 60,000 |
| >=800'WD . . . . . . . . . . . . . . . | 98 | 56,000 | 56,000 | 70,000 | 70,000 |

N.A. = not applicable.

Table B-35-Cent.

| State/district | Geographic unit | Depth category 0-2,500’ | 2,500-5,000’ | 5,000-10,000’ | 10,000-15,000’ |
|---|---|---|---|---|---|
| **New Mexico** | | | | | |
| East | 23 | 5,400 | 5,800 | 7,800 | 8,600 |
| West | 24 | 5,800 | 9,600 | 17,000 | 27,900 |
| **Oklahoma** | 25 | 6,700 | 7,400 | 10,300 | 12,000 |
| **Kansas** | | | | | |
| West | 30 | 6,700 | 7,400 | 10,300 | 12,000 |
| East | 31 | 6,700 | 7,400 | 10,300 | 12,000 |
| **Arkansas** | | | | | |
| North | 32 | 6,700 | 7,400 | 10,300 | 12,000 |
| South | 33 | 6,600 | 9,300 | 11,000 | 11,300 |
| **Missouri** | 34 | 6,700 | 7,400 | 10,300 | 12,000 |
| **Nebraska** | | | | | |
| Central | 35 | 6,700 | 7,400 | 10,300 | 12,000 |
| West | 36 | 5,800 | 9,600 | 17,000 | 27,900 |
| **Mississippi** | | | | | |
| Hi Sulphur | 40 | 10,000 | 14,000 | 16,400 | 18,000 |
| Lo Sulphur | 41 | 6,600 | 9,300 | 11,000 | 11,300 |
| **Alabama** | | | | | |
| Hi Sulphur | 42 | 10,000 | 14,000 | 16,400 | 18,000 |
| Lo Sulphur | 43 | 6,600 | 9,300 | 11,000 | 11,300 |
| **Florida** | | | | | |
| Hi Sulphur | 44 | 10,000 | 14,000 | 16,400 | 18,000 |
| Lo Sulphur | 45 | 6,600 | 9,300 | 11,000 | 11,300 |
| **Colorado** | 50 | 5,800 | 9,600 | 17,000 | 27,900 |
| **Utah** | 53 | 5,800 | 9,600 | 17,000 | 27,900 |
| **Wyoming** | 55 | 5,800 | 9,600 | 17,000 | 27,900 |
| **Montana** | 57 | 5,800 | 9,600 | 17,000 | 27,900 |
| **North Dakota** | 58 | 5,800 | 9,600 | 17,000 | 27,900 |
| **South Dakota** | 59 | 5,800 | 9,600 | 17,000 | 27,900 |
| **Illinois** | 60 | 4,000 | 4,400 | 6,200 | 7,200 |
| **Indiana** | 61 | 4,000 | 4,400 | 6,200 | 7,200 |
| **Ohio** | | | | | |
| West | 62 | 4,000 | 4,400 | 6,200 | 7,200 |
| East | 63 | 1,600 | 1,800 | N,A. | N.A. |
| **Kentucky** | | | | | |
| West | 64 | 4,000 | 4,400 | N.A. | N.A. |
| East | 65 | 1,600 | 1,800 | N.A. | N.A. |
| **Tennessee** | | | | | |
| West | 66 | 4,000 | 4,400 | N.A. | N.A. |
| East | 67 | 1,600 | 1,800 | N.A. | N.A. |
| **Pennsylvania** | 70 | 1,600 | 1,800 | N.A. | N.A. |
| **New York** | 71 | 1,600 | 1,800 | N.A. | N.A. |
| **West Virginia** | 72 | 1,600 | 1,800 | N.A. | N.A. |
| **Virginia** | 73 | 1,600 | 1,800 | N.A. | N.A. |
| **Alaska** | | | | | |
| North Slope | 80 | N.A. | N,A. | N.A. | N.A. |
| Cook inlet | 81 | N.A. | N.A. | N.A. | N.A. |

**N.A. = not applicable.**

**Note:**

Direct annual operating expense, including waterflooding, ineludes expenditures for operatlng producing 011 wells and operating a water injection system, These operating expenditures Include the normal daily operating expense, surface repair and malntenanceexpense, and subsurface repair; maintenance and services These are average expenditures *perproduc(iorrwel~* and include the expend-Itures of operating an injection system,

**Table B-36**
**State and Local Production Taxes**

**Includes Severance, Ad Valorem, and Other Local Taxes.**

| State/district | Geographic unit | Tax rate |
|---|---|---|
| California | 1-4 | 0.080 |
| Louisiana | 5-7 | 0.129 |
| Texas | 8-19 | 0.082 |
| New Mexico | 23-24 | 0.090 |
| Oklahoma | 25 | 0.071 |
| Kansas | 30-31 | 0.050 |
| Arkansas | 32-33 | 0.060 |
| Missouri | 34 | 0.050 |
| Nebraska | 35-36 | 0.046 |
| Mississippi | 40-41 | 0.060 |
| Alabama | 42-43 | 0.061 |
| Florida | 44-45 | 0.050 |
| Colorado | 50 | 0.100 |
| Utah | 53 | 0.050 |
| Wyoming | 55 | 0.100 |
| Montana | 57 | 0.050 |
| North Dakota | 58 | 0.050 |
| South Dakota | 59 | 0.000 |
| Illinois | 60 | 0.020 |
| Indiana | 61 | 0.050 |
| Ohio | 62-63 | 0.050 |
| Kentucky | 64-65 | 0.050 |
| Tennessee | 66-67 | 0.050 |
| Michigan | 69 | 0.050 |
| Pennsylvania | 70 | 0.050 |
| New York | 71 | 0.050 |
| West Virginia | 72 | 0.050 |
| Virginia | 73 | 0.050 |
| Alaska | 80-81 | 0.080 |

Source: State tax records.

**Table B-37**
**State Income Taxes**

**State Income Tax Rates for Corporations.**

| State/District | Geographic unit | Tax Rated |
|---|---|---|
| California | 1-4 | 0.09 |
| Louisiana | 5-7 | 0.04 |
| Texas | 8-19 | — |
| New Mexico | 23-24 | 0.03 |
| Oklahoma | 25 | 0.04 |
| Kansas | 30-31 | 0.04 |
| Arkansas | 32-33 | 0.05 |
| Missouri | 34 | 0.05 |
| Nebraska | 35-36 | 0.05 |
| Mississippi | 40-41 | 0.03 |
| Alabama | 42-43 | 0.05 |
| Florida | 44-45 | 0.05 |
| Colorado | 50 | 0.05 |
| ‘Utah | 53 | 0.04 |
| Wyoming | 55 | 0.05 |
| Montana | 57 | — |
| North Dakota | 58 | 0.06 |
| South Dakota | 59 | 0.04 |
| Illinois | 60 | — |
| Indiana | 61 | 0.05 |
| Ohio | 62-63 | 0.05 |
| Kentucky | 64-65 | 0.05 |
| Tennessee | 66-67 | 0.05 |
| Michigan | 69 | 0.05 |
| Pennsylvania | 70 | 0.05 |
| New York | 71 | 0.10 |
| West Virginia | 72 | 0.05 |
| Virginia | 73 | 0.05 |
| Alaska | 80-81 | 0.05 |

‘Percent of value of gross production, paid in year incurred.

Source: Local and State tax records verified by production company data,

## Offshore Costs

Basic offshore development and operating costs were placed in one of two categories, depending on whether the costs varied or not with water depth. They were derived from U.S. Bureau of Mines data and a Lewin and Associates, Inc., study for OTA. All costs were updated to mid-1976 using similar inflation indices as apiied for the onshore cost models.

### Costs That Do Not Vary With Water Depth

Three cost items within basic development and operating costs, while varying by reservoir depth, are not materially affected by water depth. These are:

- well, lease, and field equipment costs for producing wells;
- New injection equipment for injection wells;and
- Well workover and conversion costs.

These cost data are presented in table B-38.

Air costs (for injection) were set at the same value as in the in situ combustion cost model.

**Table B-38**
**Offshore Costs That Do Not Vary by Water Depth**

(costs in dollars)

| Activity | Reservoir depth categories 0-2,500’ | 2,400-5,000’ | 5,000-1 0,000’ | 10,000-1 5,000’ |
|---|---|---|---|---|
| Well, lease, and field equipment costs per production well | 300,000 | 300,000 | 300,000 | 300,000 |
| New injection equipment per injection well | 100,000 | 100,000 | 150,000 | 150,000 |
| Well workover and conversion costs per well | 150,000 | 150,000 | 170,000 | 225,000 |

## Costs That Vary With Water Depth

The remaining three offshore development and operating costs do vary by water depth. These are:

- Drilling and completion costs,
- Basic operating and maintenance costs,
- Incremental injection, operating, and maintenance costs.

These are presented on table B-39. The bases of the drilling and completion costs are shown in table B-40.-This table gives a breakdown of the drilling and completion costs by water depth.

**Table B-39**
**Offshore Costs That Vary by Water Depth**

(costs in dollars)

| Activity | Reservoir depth categories 0-2,500” | 2,500-5,000’ | 5,000-1 00,000’ | 100,000-1 50,000’ |
|---|---|---|---|---|
| Drilling and completion costs per foot per well, by water depth: | | | | |
| <200 ft. | 112.32 | 96.87 | 101.44 | 97.87 |
| 201-400 ft. | 112.32 | 130.64 | 121.49 | 111.24 |
| 401-800 ft. | 112.32 | 225.82 | 178.00 | 148.92 |
| >800 ft. | 112.32 | 522.30 | 354.04 | 266.27 |
| Basic operating and maintenance costs per well per year, by water depth: | | | | |
| <200 ft. | 60,000 | 60,000 | 75,000 | 75,000 |
| 201-400 ft. | 60,000 | 69,000 | 84,000 | 84,000 |
| 401-800 ft. | 60,000 | 72,000 | 90,000 | 90,000 |
| >800 ft. | 60,000 | 84,000 | 105,000 | 105,000 |
| Incremental injection operating and maintenance costs per injection well per year, by water depth: | | | | |
| <200 ft. | 40,000 | 40,000 | 50,000 | 50,000 |
| 201-400 ft. | 40,000 | 46,000 | 56,000 | 56,000 |
| 401-800 ft. | 40,000 | 48,000 | 60,000 | 60,000 |
| >800 ft. | 40,000 | 56,000 | 70,000 | 70,000 |

“No reservoirs in this depth category-average figure used in water depth categories.

## Tabie B-40
## Driiiing and Completion Cost Bases

(costs in dollars)

| | Depth category | | |
|---|---|---|---|
| | 2,500-5,000 | 5.000-10.000 | 10,000-15,000 |
| **A. 0-200' WATER DEPTH (Mean = 100' WD)** | | | |
| (1) Av. Cost/ft. (Incl. av. platform), JAS, updated . . . . . . . . . | 110.32 | 109.42 | 103.20 |
| (2) X wghtd. av. depth (JAS) . . . . . . . . . . . . . . . . . . . . . . . . . | 4,760 | 8,000 | 12,000 |
| (3) = Av. total cost/well. . . . . . . . . . . . . . . . . . . . . . . . . . . . | 524,020 | 875,360 | 1,238,400 |
| (4) Av. platform cost (assume 18-slot, 1/2 at 100', 1/2 at 300' WD) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | 7,000,000 | 7,000,000 | 7,000,000 |
| (5) / Av. No. wells (Assume 18) = Av. platform cost/well. . . | 388,900 | 388,900 | 388,900 |
| (6) Line (3) – Line (5) = Av. Drilling and completion (D&C) costs per well ... , . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | 135,120 | 486,460 | 849,500 |
| (7) Line (6) / (2) = Av. Drilling cost/ft. (ex. platform) . . . . | 28.45 | 60.81 | 70.79 |
| (8) Av. platform for depth (1 2-slot) @ $3.9 million / 12 slots = Platform cost/well. . . . . . . . . . . . . . . . . . . . . . . . . . . . | 325,000 | 325,000 | 325,000 |
| (9) Line (8) / Line (2) = Av. Platform cost/f t.. . . . . . . . . . . . . | 68.42 | 40.63 | 27.08 |
| (lo) Line (9) + Line (7) "= Av. D&C cost incl. platform . . . . . . . | 96.87 | 101.44 | 97.87 |
| **B. 201-400' WATER DEPTH (Mean = 300' WD)** | | | |
| Line (1) – (6) – See Section A | | | |
| Line (7) Average drilling cost/ft. (ex. platform) . . . . . . . . . | 28.45 | 60.81 | 70.79 |
| ,Line (8) Av. platform for depth (half 18, half 24, 1/2 @ $8.7 million / 18 dots 1/2@ $11./million / 24 slots . . . . . . . . . | 485,400 | 485,400 | 485,400 |
| (9) Line (8) / Line (2) (wght. av. depth) = Av. platform cost/ft. . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | 102.19 | 60.68 | 40.45 |
| (lo) Line (9) + Line (7) = Av. D&C cost incl. platform . . . . . . . | 130.64 | 121.49 | 111.24 |
| **C. 401-800' WATER DEPTH (Mean = 600' WD)** | | | |
| Lines (1) – (6) – See Section A | | | |
| Line (7) Av. drilling cost/ft. (ex. platform). . . . . . . . . . . . . | 28.45 | 60.81 | 70.79 |
| Line (8) Av. platform. @ $22.5 million / 24 slots . . . . . . | 937,500 | 937,500 | 937,500 |
| (9) Line (8) / (2) – Av. platform. cost/ft. , . . . . . . . . . . . . . . . . | 197.37 | 117.19 | 78.13 |
| (lo) Av. D&C costs incl. platform . . . . . . . . . . . . . . . . . . . . . . . | 225.82 | 178.00 | 148.92 |
| **D. Greater Than 800' WATER DEPTH (Mean = 1,000' WD)** | | | |
| Lines (1) – (6) – See Section A | | | |
| Line (7) Av. drilling cost/ft (ex. platform) . . . . . . . . . . . . . . | 28.45 | 60.81 | 70.79 |
| Line (8) Av. platform @ $56.3mm / 24 slots ... , . . . . . . . . | 2,345,800 | 2,345,800 | 2,345,800 |
| (9) Line (8) / Line (2) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | 493.85 | 293.23 | 195.48 |
| (lo) Av. D&C costs incl. platform. . . . . . . . . . . . . . . . . . . . . . . | 522.30 | 354.04 | 266.27 |

# Appendix B
# Footnotes

[1] *Enhanced Oil* Recovery, National Petroleum Council, December 1976, p. 114.

[2] W.B. Gogarty, H.P. Meabon, and H.W. Milton, Jr., "Mobility Control Design for Miscible-Type Waterfloods Using Micellar Solutions," *J. Pet. Tech.,* February 1970, Vol. 22, pp. 141-147.

[3] E. Ojeda, F. Preston, and J.C. Calhoun, "Correlation of Oil Residuals Following Surfactant Floods," *Producers Month/y,* December 1953, pp. 20-29.

[4] W.B. Gogarty and W.C. Tosch, "Miscible-Type Waterflooding: Oil Recovery with Micellar Solutions," *J. Pet. Tech.,* December 1968, Vol. 20, pp. 1407-1 414; *Trans. AIME,* Vol. *243.*

[5] L.L. Helm, "Use of Soluble Oils for Oil Recovery," *J. Pet. Tech.,* December 1971, Vol. 23, pp. 1475-2483; *Trans. AIME,* Vol. *251.*

[6] W. B. Gogarty, "Mobility Control with Polymer Solution," *Soc. Pet. Eng. J.,* June 1967, Vol. 7, pp. 161-173.

[7] *Enhanced Oil* Recovery, National Petroleum Council, December 1976, p. 98.

[8] J. A. Davis, jr., "Field Project Results with the Maraflood™ Process," *Proceedings,* Tertiary Oil Recovery Conference, Tertiary Oil Recovery Project, University of Kansas, Oct. 23-24, 1975.

[9] L.W. Helm and R.K. Knight, "Soluble Oil Flooding," *Petroleum Engineer,* November 1976, pp. 19-22.

[10] H.H. Danielson, W.T. Paynter, and H.W. Milton, Jr., "Tertiary Recovery by the Maraflood Process in the Bradford Field," *SPE* 4753, Improved Oil Recovery Symposium of SPE of AIME, Tulsa, Okla., Apr. 22-24, 1974.

[11] S.A. Pursley, R.N. Healy, and El. Sandvik, "A Field Test of Surfactant Flooding, Loudon, Ill.," *J. Pet.* Tech., July 1973, p. 793.

[12] M. s, French, G.W. Keys, G.L. Stegemeir, R.C. Ueber, A. Abrams, and H.J. Hill, "Field Test of an Aqueous Surfactant System for Oil Recovery, Benton Field, Ill." *I. Pet. Tech.,* February 1973, p. 195.

[13] R.H. Widmyer, A. Satter, G.D. Frazier, and R.H. Groves, "Low Tension Waterflood Pilot at the Salem Unit, Marion County, Ill. -Part 2: Performance Evaluation," *J. Pet. Tech.,* August 1977, pp. 933-938.

[14] Ibid.

[15] L.K. Strange and A.W. Talash, "Analysis of Salem Low Tension Waterflood Test," *SPE* 5885, Improved Oil Recovery Symposium of SPE of AIME, Tulsa, Okla., Mar. 22-24, 1976, Preprint.

[16] *Enhanced Oil* Recovery, National Petroleum Council, December 1976, p. 98.

[17] *Enhanced Oil Recovery,* National Petroleum Council, December 1976, p. 97.

[18] H.H. Danielson and W.T. Paynter, *Bradford Sand Micellar-Polymer Flood, Bradford, Pa.,* Third ERDA Symposium on Enhanced Oil, Gas Recovery, and Improved Drilling Methods, Aug. 30-Sept. 1, 1977, p. A-5.

[19] R.N. Healy, R.L. Reed, and C.W. Carpenter, "A Laboratory Study of Microemulsion Flooding," *Soc. Pet. Eng. J.,* February 1975, Vol. 15, pp. 87-103, *Trans. A/ME, 1975.*

[20] *Marathon Oil Company: Commercial Scale Demonstration,* Enhanced *Oil Recovery By Micellar-Polymer* Flooding, M-7 Project-Design Report, BERC/TPR-77/1, ERDA, April 1977.

[21] C. L. Coffman, "Chesney-Hegberg Micellar-Polymer Project, El Dorado, Kans.," *Paper A-4, Proceedings,* Second ERDA Symposium on Enhanced Oil and Gas Recovery, Tulsa, Okla., Sept. 9-10, 1976.

[22] *Sloss Field,* Amoco *Production Co.,* Improved Oil Recovery Field Reports, Society of Petroleum Engineers of AIME, Vol. 1, No. 4, March 1976.

[23] S. A. Pursley, R.N. Healy, and El. Sandvik, "A Field Test of Surfactant Flooding, Loudon, Ill." *J. Pet. Tech.,* July 1973, p. 793.

[24] Lloyd Elkins, HOW Might *the /dependent Move from Spectator to Participant in the Enhanced Oil Recovery Game?,* Second Tertiary Oil Recovery Conference, Tertiary Oil Recovery Project, University of Kansas, Apr. 20-21, 1977.

[25] C.A. Kossack, and H.L. Bilhartz, Jr., "The Sensitivity of Micellar Flooding to Reservoir Heterogeneities," *SPE* 5808, Improved Oil Recovery Symposium, SPE of AIME, Tulsa, Okla., Mar. 22-24, 1976.

[26] J.A. Davis, Jr., *Sweep Efficiency In Micellar Flooding Processes,* submitted to SPE of AIME, January 1977.

[27] W. B Gogarty, and W.C. Tosch, "Miscible-Type Waterflooding: Oil Recovery with Micellar Solutions," *J. Pet. Tech.,* December 1968, Vol. *20,* pp. 1407-1 414; *Trans. AIME,* Vol. *243.*

[28] *Marathon Oil Company: Commercial Scale Demonstration, Enhanced Oil Recovery By Micellar-Polymer Flooding, M-7 Project-Design Report,* BERC/TPR-77/1, ERDA, April 1977.

[29] *Enhanced Oil Recovery,* National Petroleum Council, December 1976, p. 98.

[30] *Enhanced Oil Recovery,* National Petroleum Council, December 1976, p. 114.

[31]A. B. Dyes, B.H. Caudle, and R.A. Erickson, "Oil Production After Breakthrough—As Influenced By Mobility Ratio," Trans. *AIME*, 207, 1954, pp. 81-86.

[32]F. F. Craig, Jr., T.M. Geffen, and R.A. Morse, "Oil Recovery Performance of Pattern Gas or Water Injection Operations From Model Tests," Trans. AIME 204, 1955, pp. 7-15.

[33]R. L. Jewett, and G.F. Schurz, "Polymer Flooding—A Current Appraisal," *J. Pet. Tech.*, 22, 675, 1970.

[34]E. K. Stevenson, "The Dow Flooding Process: An Economical Method For Increasing Oil Recovery From Waterflooding," *Proceedings*, Tertiary Oil Recovery Conference, Tertiary Oil Recovery Project, University of Kansas, Oct. 23-24, 1975, p. 79.

[35]H.J. Agnew, "Here's How 56 Polymer Oil Recovery Projects Shape Up," *Oil and Gas journal*, May 1, 1972, pp. 109-112.

[36]B. Sloat, "Oil Production Response From Polymer Treatment Under Varying Reservoir Conditions," Paper *45f*, 71st National Meeting, AIChE, February 1972.

[37]H. J. Agnew, "Here's How 56 Polymer Oil Recovery Projects Shape Up," *Oil and Gas Journal*, May 1, 1972, pp. 109-112.

[38]J.H. Maerker, "Shear Degradation of Partially Hydrolyzed Polyacrylamide Solutions," *Soc. Pet. Eng. J.*, *15*, No. 4, pp. 311-322.

[39]G. Kelco, "Kelzan MF for Viscous Waterflooding," *Technical Bulletin X2, 1973.*

[40]J. p. Johnson, J.W. Cunningham, and B.M. DuBois, "A Polymer Flood-Preparation and Initiation at North Stanley, Osage County, Okla.," *Paper B-2*, Second ERDA Symposium on Enhanced Oil and Gas Recovery, Tulsa, Okla, Sept. 9-10, 1976.

[41]G.E. Tinker, "Coalinga Demonstration Project, Oil Recovery by Polymer Flooding," *Paper B-3*, Second ERDA Symposium on Enhanced Oil and Gas Recovery, Tulsa, Okla., Sept. 9-10, 1976.

[42]H.J. Agnew, "Here's How 56 Polymer Oil Recovery Projects Shape Up," *Oil and Gas Journal*, May 1, 1972, pp. 109-112.

[43]M. K. Dabbous and L.E. Elkins, "Preinjection of polymers to Increase Reservoir Flooding Efficiency," *SPE* 5836, Improved Oil Recovery Symposium, SPE of AIME, Tulsa, Okla., Mar. 22-24, 1976.

[44]V.V. Valleroy, B.T. Willman, J.B. Cambell, and L.W. Powers, "Deerfield Pilot Test of Recovery by Steam Drive," *J. Pet. Tech.*, July 1967, p. 956.

[45]H.J. DeHaan and J. Van Lockeren, "Early Results of the First Large Scale Steam Soak Project in the Tia Juana Field, Western Venezuela," *J. Pet. Tech.*, 1969, 21 (1), pp. 101-10.

[46]D. N. Dietz, "Hot Water Drive," *Proceedings*, 7th World Petroleum Congress, 3, pp. 451-7, Barking, 1967, Elsevier, Publ. Co., Ltd.

[47]C.G. Bursell, H.J. Taggart, and H.A. De Mirjian, *Thermal Displacement Tests and Results, Kern River Field, Calif.*, Petroleum Industry Conference on Thermal Recovery, Los Angeles, Calif., June 6, 1966.

[48]W.L. Martin, J.N. Oew, M.L. Powers, and H.B. Steves, *Results of a Tertiary Hot Waterflood* in a *Thin Sand Reservoir.*

[49]D.D. Stokes and T.M. Doscher, "Shell Makes a Success of Steam Flood at Yorba Linda," *Oil and Gas Journal*, Sept. 2, 1974, pp. 71-76, 78.

[50]*Enhanced Oil* Recovery, National Petroleum Council, December 1976, p. 169.

[51]D. D. Stokes and T.M. Doscher, "Shell Makes a Success of Steam Flood at Yorba Linda," *Oil and Gas Journal*, Sept. 2, 1974, pp. 71-76,78.

[52]C.G. Bursell and G.M. Pittman, "Performance of Steam Displacement in the Kern River Field," *J. Pet. Tech.*, August 1975, p. 997.

[53]*Enhanced Oil* Recovery, National Petroleum Council, December 1976, p. 170.

[54]C.V. Pollack and T.X. Buxton, "Performance of a Forward Steam Drive Project—Nugget Reservoir, Winkleman Dome Field, Wyo.," *J. Pet. Tech.*, January 1969, p. 35.

[55]R.V. Smith, A.F. Bertuzzi, E.E. Templeton, and R.L. Clampitt, "Recovery of Oil by Steam Injection in the Smackover Field, Ark.," *SPE* 3779, IORS, Tulsa, Okla., Apr. 16-19, 1972.

[56]A.L. Hall and R.W. Bowman, "Operation and Performance of the Slocum Thermal Recovery Project," *J. Pet. Tech.*, April 1973, p. 402.

[57]*Enhanced Oil* Recovery, National Petroleum Council, December 1976, p. 175.

[58]Research and Development In Enhanced Oil Recovery Final Report, The Methodology, Energy Research and Development Administration, Part 3 of 3, ERDA 77-2013, December 1976, pp. V-1 9, 20.

[59]*Enhanced Oil* Recovery, National Petroleum Council, December 1976, p. 180.

[60]Research and Development In Enhanced Oil Recovery Final Report, The Methodology, Energy Research and Development Administration, Part 3 of 3, ERDA 77-2013, December 1976, pp. V-23.

[61]B.F. Grant and S.E. Szasz, "Development of an Underground Heat Wave for Oil Recovery," *Trans. AIME*, *207*, p. 108, 1954.

[62]Research and Development In Enhanced Oil Recovery Final Report, The Methodology, Energy Research and Development Administration, Part 3 of 3, ERDA 77-2013, December 1976, pp. V-23.

[63]C.S. Kuhn and R.L. Koch, "In-Situ Combustion—Newest Method of Increasing Oil Recovery," Oil *and Gas Journal*, Aug. 10, 1953, pp. 92-96, 113-114.

[64]*Enhanced Oil* Recovery, National petroleum Council, December 1976, p. 170.

[65]D.N. Dietz and J. Weijdemna, "Wet and Partially Quenched Combustion," *J. Pet. Tech.*, April 1968, p. 411.

[66]D.R. Parrish and F.F. Craig, jr., "Laboratory Study of a Combination of Forward Combustion and Waterflooding—The COFCAW Process," ). *Pet. Tech.*, June 1969, p. 753.

[67]C.F. Gates and 1. Sklar, "Combustion As A Primary Recovery Process—Midway Sunset Field, " ). Pet. *Tech.*, August 1971, pp. 981-986.

[68]H.J. Ramey, J., */r-r-Situ Combustion*, 8th World Petroleum Congress, 1971, p. 260.

[69]W. E. Showalter and M.A. Maclean, "Fireflood at Brea - Olinda Field, Orange County, Calif., " *SPE* 4763, Improved Oil Recovery Symposium, SPE of AIME, Tulsa, Okla. Apr. 22-24, 1974.

70R. W Buchwald, W.C, Hardy, and G.S. Neinast, "Case Histories of Three In-Situ Combustion Projects, " *J. Pet. Tech.*, July 1973, pp. 784-792.

[71]Bellevue Field, Getty Oil Co., Update Report, improved Oil Recovery Field Reports, SPE of AIME, Vol. 3, No. 1, June 1977.

[72]Research and Development In Enhanced Oil Recovery, Final Report, Overview, Part 1 of 3, Energy Research and Development Administration, ERDA 77-20/1, December 1976, p. III-2.

[73]W.C. Hardy, P.B. Fletcher, J.C. Shepard, E.W. Dittman, and D.W. Zadow, "In-Situ Combustion in a Thin Reservoir Containing High-Gravity Oil," *J. Pet. Tech.*, February 1972, pp. 199-208.

[74]*Enhanced Oil* Recovery, National Petroleum Council, December 1976, p. 175.

[75]*Enhanced Oil* Recovery, National petroleum Council, December 1976, p. 175.

76 *Enhanced Oil* Recovery, National petroleum Council, December 1976, p. 179.

[77]Working Pa pers, Technology Task Force, National Petroleum Council EOR Study, Apr. 21, 1976.

[78]Research and Development In Enhanced Oil Recovery Final Report, The Methodology, Energy Research and Development Administration, Part 3 of 3, ERDA 77-2013, December 1976, p. V-31.

[79]H A. Koch, Jr., and R.L. Slobad, "Miscible Slug Process,' " *J.* Pet. "Tech., February 1957, p. 40.

[80]N.J. Clark, H.M. Sheaun, W.P. Schultz, K. Gaines, and J.L. Moore, "Miscible Drive—Its Theory and Application, " *J. Pet. Tech.*, June 1958, p. 11.

[81]*Research and Development in Enhanced Oil Recovery*, ERDA 77/20, Lewin and Associates, Inc., December 1976, Part 1, pp. III-2.

[82]L.W. Helm, "Status of $CO_2$ and Hydrocarbon Miscible Oil Recovery Methods, " *SPE* 5560, presented at 50th Annual Meeting of Society of Petroleum Engineers, Dallas, Tex. Sep. 1 -Oct. 28, 1975.

[83]L. w. Helm and V.A. Josendal, "Mechanisms of Oil Displacement by Carbon Dioxide," *J. Pet. Tech.*, December 1974, p. 1147.

[84]D. F. Menzie and R.F. Nielson, "Study of Vaporization of Crude Oil by Carbon Dioxide Repressuring, " *J. Pet. Tech.*, November 1963, p. 1247.

[85]L.W. Helm and V.A. Josendal, "Mechanisms of Oil Displacement by Carbon Dioxide, " *J. Pet. Tech.*, December 1974, p. 1147,

[86]L W. Helm, "Status of $CO_2$ and Hydrocarbon Miscible Oil Recovery Methods, " *SPE* .5560, presented at 50th Annual Meeting of Society of Petroleum Engineers, Dallas, Tex. Sep. 1 -Oct. 28, 1975.

[87]L. W. Helm and V.A. Josendal, "Mechanisms of Oil Displacement by Carbon Dioxide," *J.* Pet. *Tech.*, December 1974, p. 1147.

[88]J.J. Rathmell, F.I. Stalkup, and R.C. Hassinger, "A Laboratory Investigation of Miscible Displacement by Carbon Dioxide, " *SPE* 3483, 46th National Meeting, Society of Petroleum Engineers, New Orleans, La., Oct. 3-6, 1971.

[89]*Research and* Development *in Enhanced Oil Recovery* ERDA 77/20, Lewin and Associates, Inc., December 1975, Part 1, pp. III-2.

[90]F.I. Stalkup, "An Introduction to Carbon Dioxide Flooding," *Proceedings*, Tertiary Oil Recovery Conference, Tertiary Oil Recovery Project, University of Kansas, April 1977.

[91]R.M. Dicharry, T.L. Perryman, and J.D. Ronquille, "Evaluation and Design of a $CO_2$ Miscible Flood Project O SACROC Unit, Kelly-Snyder Field," *J. Pet. Tech.*, November 1973, p. 1309.

[92]R.M. Dicharry, T.L. Perryman, and J.D. Ronquille, "Evaluation and Design of a $CO_2$ Miscible Flood Project O SACROC Unit, Kelly-Snyder Field, " ). *Pet. Tech.*, November 1973, p. 1309.

[93]EOR Workshop on Carbon Dioxide, Sponsored by ERDA, Houston, Tex., Apr. 12, 1977.

[94]*Enhanced Oil* Recovery, National Petroleum Council, December 1975, p. 144.

[95]Improved 0,1 Recovery Field Reports, Society of Petroleum Engineers of AIME.

[96]Research and Development In Enhanced Oil Recovery Final Report, The Methodology, Energy Research and Development Administration, Part 3 of 3, ERDA 77-2013, December 1976, pp. V-1 9, 20.

[97]Research and Development In Enhanced Oil Recovery Final Report: The Methodology, Energy Research and Development Administration, Part 3 of 3, ERDA 77-2013, December 1976, pp. V-1 9, 20.