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ECONOMICS OF ENHANCED OIL RECOVERY

Final Report

Work Performed for the Department of Energy
Under Contract No. DE-AC01-78ET12072

Date Published—May 1981

Lewin and Associates, Inc.
Washington, D.C.

U. S. DEPARTMENT OF ENERGY

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ECONOMICS OF ENHANCED OIL RECOVERY

Final Report

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ECONOMICS OF ENHANCED OIL RECOVERY

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EXECUTIVE SUMMARY

During the last several years, costs and revenues associated with enhanced oil recovery have changed significantly. The market price for tertiary oil has more than doubled, but inflation has also increased investment and operating costs. In addition, there have been changes in taxation, such as the (addition of the) Windfall Profit Tax. These events have markedly changed the economics of enhanced oil recovery.

The costs of various EOR techniques were last estimated on a consistent basis in 1978. The purpose of this report is to analyze the economics of five different EOR techniques in mid-1980 dollars under a consistent basis, incorporating experimental results, field tests as well as an improved understanding of EOR process that has been obtained since 1978. Three separate tasks were undertaken:

- Task 1. Collect and update cost data to mid-1980,
- Task 2. Update the recovery models for each EOR technology, and
- Task 3. Evaluate the economics of each EOR technique.

For Task 1, published data sources were updated using various inflation indices and verified with vendor quotes. Costs were derived by geographical region for the following techniques:

-- Steam Drive
-- In Situ Combustion
-- Carbon Dioxide Flooding
-- Surfactant/Polymer Flooding
-- Polymer Waterflooding

Enhanced oil recovery costs vary significantly with geography. Previously, the analysis was conducted for over 100 different geographical areas; however, these areas were now reduced to 11 regions to correspond to the petroleum provinces of the National Petroleum Council. This allows more consistent comparison with other production forecasts for EOR and for conventional oil.

The three types of costs that were updated are general production costs, economic costs, and technique specific costs.

- General production costs, for normal field development and operation, are a function of depth and geographic location. Equations were developed through regression analysis by region for each of the general cost components, expressing the cost as a function of depth.

- The economic models were updated to incorporate recent changes in financial costs. Examples of these are the Windfall Profit Tax, which is a 30% excise tax (Tier 3 oil) on revenues in excess of a variable adjusted base price and a reduction in the federal tax rate from 48% to 46% of revenues.

- Costs specific to each enhanced oil recovery technique have also been updated. These costs include fuel for steam drive, carbon dioxide supplies for CO_2 flooding, and chemicals for enhanced waterfloods.

Much of the uncertainty involved in the production response of an EOR technique can only be resolved empirically, although a better understanding of the various recovery mechanisms has been gained over the past several years. Task 2 consisted of revising the recovery models based on the most recent insights. The major activities under this task consisted of the following:

- The steam drive oil recovery model was altered to explicitly model heat balances and steam zone development in the reservoir. This allows the oil-steam ratio to be calculated based on the time and volumes of steam injected, the latent heat in the steam, and key reservoir parameters.

- The recovery model for in situ combustion is based on correlations derived from 14 field projects and expresses oil recovery as a function of initial oil saturation, thickness of the reservoir, and the viscosity of the oil, as well as the effective amount of air injected.

- The CO_2 model is based on the results of field and laboratory tests conducted during the past three years. Annual and cumulative production is a function of reservoir and crude oil characteristics, such as saturation at project initiation and swelling characteristics, and prior performance under waterflooding.

- The surfactant/polymer and the polymer waterflooding recovery models were updated based on recent field experiences and an improved understanding of the relationships between fluid viscosities and oil recovery.

In Task 3, EOR recovery and economics were analyzed by technique. The models were used to determine a representative range of costs for reservoirs that vary from the most favorable, to ones that are technically feasible, but not economic under current conditions. The economic analysis was conducted as of mid-1980 using an oil price of $30 per barrel for three reservoirs under each technique. This oil price was also used to determine those cost components that are dependent upon the selling price of crude, such as the Windfall Profit Tax, royalties, and severance taxes. The range of costs and the recovery efficiencies for the five EOR techniques are discussed below:

A. Steam Drive Economics

The range of costs for steam drive in California heavy oil reservoirs is shown in the table below:

Cost Components	$/Produced Barrel	
	Burning Purchased Crude	Burning Lease Crude
Investment Costs	1 - 3	2 - 5
Operating Costs	4 - 6	6 - 9
Steam Costs	12 - 16	2 - 3
Subtotal	17 - 25	10 - 17
Financial Costs		
- Royalty & Severance	4	4
- State & Federal	2	2
- Windfall Profit	3	3
Subtotal	9	9
Capital Cost (ROR 15%)	1	2
Total	27 - 35	21 - 28

As shown above, the cost of producing a barrel of oil by steam drive ranges from $27 to $35 per barrel, assuming the price of oil burned for generating steam is $30 per barrel. Since a major cost component is steam, the economics were also analyzed assuming lease crude is used as fuel. If lease crude is burned, no taxes are paid on this fuel and the cost of generating steam decreases substantially. However, the investment and operating costs per barrel of marketable oil increases somewhat since less oil is now available for sale. The resulting cost per produced barrel would range from $21 to $28 per barrel.

The oil-steam ratio for the reservoirs analyzed ranges from 0.15 to 0.19, measured in terms of barrels of oil produced per barrel of steam injected, with recovery efficiencies ranging from 36% to 64% of the oil in place after primary and secondary.

B. In Situ Combustion Economics

The range of costs for in situ combustion in technically feasible, heavy oil reservoirs is shown in the table below:

Cost Components	$ / Produced Barrel
Investment Costs	2 - 5
Operating Costs	6 - 9
Injected Air Costs	6 - 11
Subtotal	14 - 25
Financial Costs	
- Royalty & Severance	4
- State & Federal	2
- Windfall Profit	3
Subtotal	9
Capital Cost (ROR 15%)	2
Total	25 - 36

The cost of in situ projects ranges from $25 to $36 per incremental barrel of oil. This indicates that in situ combustion projects could be economic if the technical challenges of controlling the burn front and the other operating problems can be solved.

Other results of the recovery model are that the air/oil ratio for the three reservoirs analyzed ranges from 14 Mcf to 30 Mcf of air per barrel of oil produced. Recovery efficiency, as a fraction of the remaining oil in place, varies from 28% to 38%.

C. Carbon Dioxide Flooding Economics

The range of costs for CO_2 floods in West Texas carbonate reservoirs is shown in the table below:

Cost Components	$ / Produced Barrel
Investment Costs	1 - 4
Operating Costs	3 - 7
CO_2 Costs	12 - 16
Subtotal	16 - 27
Financial Costs	
- Royalty & Severance	4
- State & Federal	2 - 3
- Windfall Profit	3
Subtotal	9 - 10
Capital Cost (ROR 15%)	1 - 2
Total	26 - 39

The injection materials (carbon dioxide) are the most significant cost item, and accounts for nearly half of the $26 to $39 per barrel recovery costs. For the reservoirs analyzed, the volume of CO_2 injected per barrel of oil produced ranges from 10 to 13 Mcf per barrel, resulting in a recovery efficiency of between 15 and 19% of the remaining oil in place.

D. Surfactant/Polymer Flooding Economics

The range of costs for surfactant/polymer flooding of sandstone reservoirs in the Illinois Basin are shown in the table below:

Cost Components	$ / Produced Barrel
Investment Costs	3 - 6
Operating Costs	5 - 9
Surfactant/Polymer Costs	12 - 15
Subtotal	20 - 30
Financial Costs	
- Royalty & Severance	4
- State & Federal	4
- Windfall Profit	3
Subtotal	11
Capital Cost (ROR 15%)	4 - 5
Total	35 - 46

As with other EOR techniques, the cost of the injection materials (sulfonates, polymers, etc.), which escalate with energy costs, comprise the most significant portion of total costs. About 0.5 barrels of surfactant (8.75 pounds of sulfonates, 1.75 pounds of alcohol, and 35 pounds of crude oil) and 1.5 pounds of polymer are injected per barrel of incremental oil produced. Recovery efficiency ranges from 30 to 43% of the remaining oil in place.

Because surfactant/polymer flooding is uneconomic at the assumed crude oil price of $30 per barrel, the effect of improved surfactant sweep and the use of the process in reservoirs with a higher residual oil saturation were also analyzed. Improving the sweep efficiency by 10% reduces costs by $2 to $3 per barrel. Conducting the surfactant flood in reservoirs having a residual oil saturation five points higher than average decreases the cost by $3 to $5 per barrel. This shows that the surfactant/polymer oil recovery process can be economic in the more favorable high residual oil reservoirs should improvements in the technology be attained.

E. Polymer Flooding Economics.

The range of costs for polymer flooding in Mid-Continent sandstone reservoirs is shown in the table below:

Cost Components	$/Produced Barrel	
	Tertiary Mode	Secondary Mode
Investment Costs	3 - 7	0
Operating Costs	10 - 14	2 - 3
Polymer Costs	9 - 13	9 - 13
Subtotal	22 - 34	11 - 16
Financial Costs		
- Royalty & Severance	4	4
- State & Federal	3	3
- Windfall Profit	3	3
Subtotal	10	10
Capital Cost (ROR 15%)	1 - 2	1 - 2
Total	30 - 46	22 - 28

The cost of oil from polymer floods ranges from $30 to $46 per barrel, with operating and chemical costs being the major cost items. Approximately 3 to 5 pounds of polymer are injected per barrel of incremental oil. Recovery efficiency is low, about 4% of the remaining oil in place; a third of which is due to the better displacement in the zone previously swept by the waterflood, and two thirds of which is due to the additional volumetric sweep of the polymer flood.

Polymer flooding can also be viewed as a supplement to a waterflood, where only the cost of the chemicals and any incremental operating and investment costs associated with using polymers should be assigned to the polymer flood. In this case, the costs of polymer flooding drop to $22 to $28 per barrel of incrementally recovered oil.

* * * * *

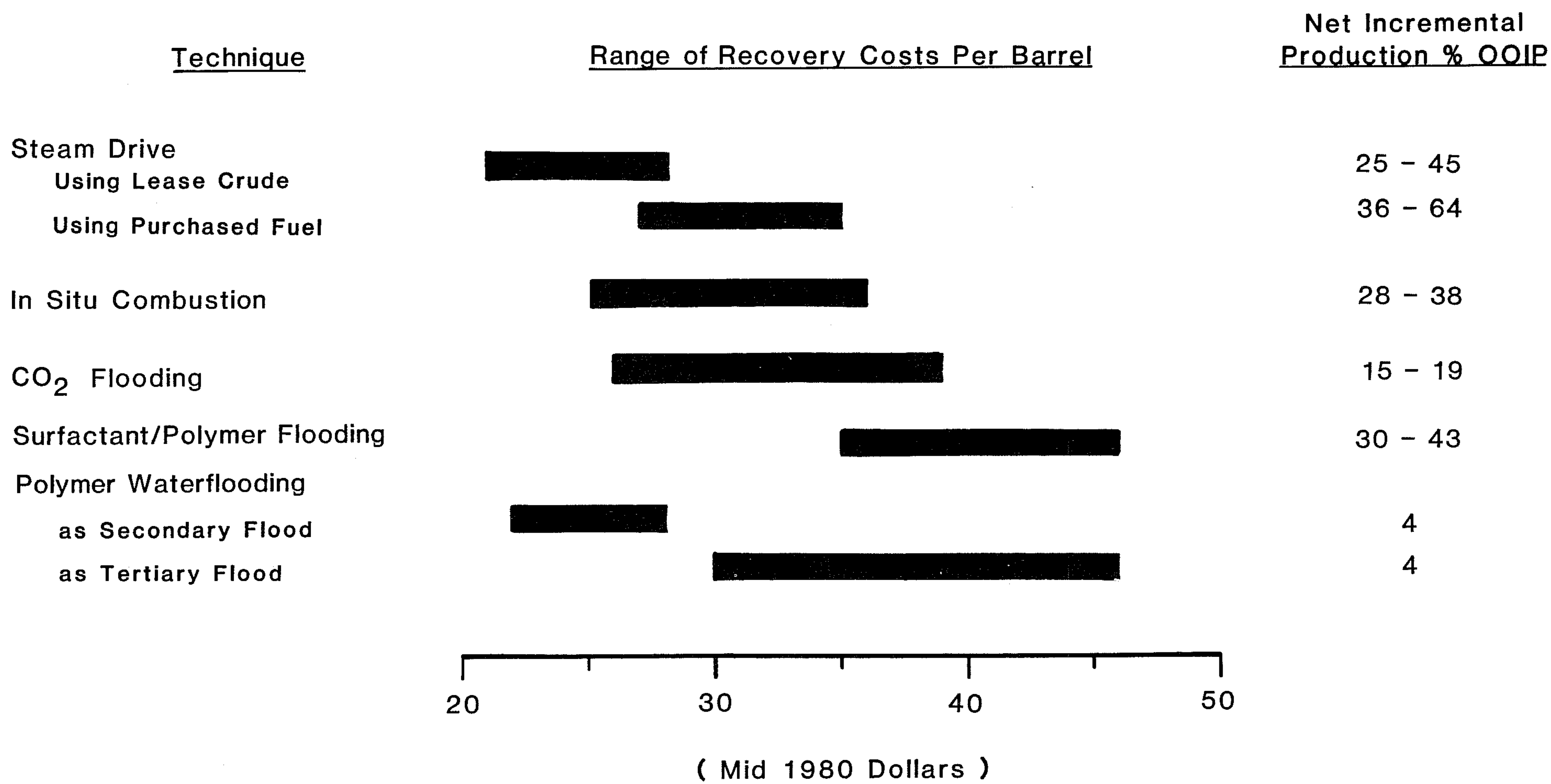
The preceeding analysis of EOR economics shows, under conventional financial standards (15% return on investment), field scale, and successful operations, that the extraction and production costs in a representative sample of domestic reservoirs range from $21 to $46 per barrel of incrementally recovered oil. Steam drive, when using lease crude, and polymer flooding, conducted as part of an ongoing waterflood, are financially the most attractive, with costs ranging from $21 to $28 per barrel of oil. Carbon dioxide and chemical floods, particularly when conducted in less ideal reservoir settings, have upper-bound costs of $39 to $46 per barrel of recovered oil.

Because of the low primary/secondary recoveries in heavy oils, the thermal techniques, steam drive and in situ combustion, have the highest recovery efficiencies, up to 64% of the remaining oil in place. Polymer flooding is at the other extreme with recovery efficiencies of only 4% of the oil in place after primary and secondary. Currently, the carbon dioxide and surfactant/polymer technologies are in the lower part of this range, with recovery efficiencies of 15% to 43% of the remaining oil in place. However, advances in mobility control and an improved scientific understanding of the interaction between the reservoir and crude oil and the injected materials can appreciably increase the efficiencies of these two promising enhanced oil recovery technologies.

The range of EOR costs and recovery efficiencies for the technically most feasible reservoirs are shown on the next page and tabulated below:

EOR TECHNIQUE	COSTS, \$/BARREL	NET INCREMENTAL PRODUCTION, % OF REMAINING OIL IN PLACE
Steam Drive		
- Lease crude	\$21 - \$28	25% - 45%
- Purchased fuel	\$27 - \$35	36% - 64%
In Situ Combustion	\$25 - \$36	28% - 39%
CO_2 Flooding	\$26 - \$39	15% - 19%
Surfactant/Polymer Flooding	\$35 - \$46	30% - 43%
Polymer Waterflooding		
- Secondary mode	\$22 - \$28	4%
- Tertiary mode	\$30 - \$46	4%

EOR COST RANGE & RECOVERY EFFICIENCY, BY TECHNIQUE



ECONOMICS OF ENHANCED OIL RECOVERY

INTRODUCTION

The economics of enhanced oil recovery were last estimated on a consistent basis in 1978 by C. Perry, R. Hertzberg, and G. Stosur in their paper, "The Status of Enhanced Oil Recovery in the United States with an Overview of the U.S. Department of Energy Program," presented at the World Oil Petroleum Conference, and by Lewin and Associates in the same year, as part of an internal report to the Department of Energy. Both analyses were conducted in 1976 dollars, updated with inflation indices to 1977.

Since then, as shown below, the price a U.S. producer could realize from enhanced oil recovery (EOR) has increased substantially in both current and constant dollars.

Range of Prices for EOR ($/Bbl)*

	Actual $	Constant 1976 $
1976	5.13 - 12.16	5.13 - 12.16
1977	5.19 - 13.59	4.85 - 12.71
1978	5.46 - 13.95	4.72 - 12.06
1979	16.75	13.02
1980	32.45	22.89

Although the price of tertiary oil has increased significantly, inflation has also increased investment and operating costs. In addition, the Windfall Profit Tax has added a significant financial

* Price range for 1976-1978 reflects lower tier to stripper oil price; prices in 1979 and 1980 reflect allowed price for incremental tertiary oil.

burden to the economics of EOR projects. Because the enhanced oil recovery projects, themselves, consume considerable energy (e.g., as fuel for steam generation, petroleum for chemicals, etc.) and a substantial portion of the financial costs (e.g., royalties, state severance taxes, etc.) rise directly with the market price of oil, only a small portion of the increased prices translate into an improved economic profit margin.

This report examines these revised economics based on mid-1980 costs and recovery models that reflect developments in process design since 1976.

STUDY PURPOSE

The purpose of this report is to estimate, on a consistent basis, the economics of five major EOR techniques as of mid-1980. Three separate tasks were undertaken:

- Task 1: Collect and update cost data to mid-1980,
- Task 2: Update the EOR models, including the development of new recovery models, and
- Task 3: Analyze EOR economics by technique.

In the first task, mid-1980 cost data were determined for the following five EOR techniques: steam drive, in situ combustion, CO_2 flooding, surfactant/polymer flooding, and polymer waterflooding. This update of costs included a review of changes in equipment, operating procedures and injection material costs. For example, the costs of obtaining carbon dioxide for gas flooding were based on recent price quotes of CO_2 and engineering studies of transporting and reinjecting the CO_2. The basic cost updating task is discussed in the main body of the report under Task 1 and documented in greater detail in Attachment I. The economics portion of the EOR models also incorporate changes in taxation, such as the Windfall Profit Tax and a lowering of the corporate tax rate from 48% to 46%.

Under the second task, the recovery portions of Lewin and Associates' EOR models were updated for steam drive, in situ combustion, CO_2 flooding, surfactant/polymer flooding, and polymer waterflooding. These revised recovery models are based on results of field tests, technological developments, and a better understanding of EOR recovery mechanisms which have emerged during recent years. These models are presented in this report under Task 2 and discussed in detail in Attachment II.

In the third task, the economics of the various EOR techniques were analyzed. These analyses were conducted in two forms. First, a range of costs for each technique was derived by individual cost components for reservoirs in which the technique was considered technically sound and showed promise of being economically feasible (otherwise, the upside range of costs per barrel would always be infinitely high). These costs were developed using a discounted cash flow model and a 15% rate of return. Second, a sensitivity analysis was conducted on selected reservoirs in the middle of each cost range to evaluate the economics of changing key reservoir and economic parameters.

This report transmits and documents the three tasks conducted for this 1980 study on the economics of enhanced oil recovery.

TASK 1: COST UPDATING

PURPOSE

The purpose of Task 1 is to review, modify and update the costs associated with EOR to mid-1980 levels using the most recent published data sources, inflation indices, and vendor quotes. Costs were updated by geographical region for the following techniques:

- Steam drive
- In Situ Combustion
- Carbon Dioxide Flooding
- Surfactant/Polymer Flooding
- Polymer Waterflooding

ESTABLISHING COST CATEGORIES

Costs associated with EOR production were divided into three categories:

1. General Production Costs

This category consists of costs that do not vary by EOR recovery technique, such as:

- Drilling and Completion Costs
- Producing Equipment
- Other Leased Equipment
- Injection Equipment
- Well Workover
- Basic Operating and Maintenance Costs

2. Financial Costs

Four types of financial costs are associated with all enhanced oil recovery projects. These are:

- Royalties, Severance, and Ad Valorem Taxes
- State and Federal Income Taxes
- Windfall Profit Tax
- Return on Capital

3. Technique Specific Costs

Beyond the general field development, operating and financial costs, each enhanced oil recovery technique has costs that are specific to that technique. These costs include fuel costs for steam drive, carbon dioxide supplies for CO_2 flooding and chemicals for surfactant and polymer flooding. Capital costs for injection equipment such as generators, scrubbers, and compressors are also included in this category.

The general production costs and the financial costs are discussed under this task, while the technique specific costs will be discussed under Task 3.

ESTABLISHING GEOGRAPHIC REGIONS

Enhanced oil recovery costs vary significantly with geography. In the past, the EOR models developed by Lewin and Associates for the Department of Energy (DOE) included data from approximately 100 different geographic areas. Although several of these areas had identical or similar costs, the multitude of areas to be processed added considerable computer time to the analysis. The geographical areas were therefore reduced to eleven regions that correspond to the Petroleum Provinces of the National Petroleum Council, Exhibit 1. This reduction in geographical regions allows improved comparison with production forecasts for conventional oil, and, because of the high (0.95+) correlation of costs within each region, appears to have little effect on individual reservoir economics.

DATA SOURCES

The engineering costs of enhanced oil recovery were updated using various data sources. Equipment, workover, and operating costs were obtained from the "Cost and Indexes for Domestic Oilfield Equipment and Production Operations, 1979."[1] Drilling costs were obtained from the "1978 Joint Association Survey on Drilling Costs,"[2] and workover costs were computed based on weighted percentages of drilled and completed wells as set forth in the "Report of the Cost Study Committee."[3]

Technique specific cost items were collected for individual items (such as generators, compressors, piping, and chemical costs) from various vendors throughout the U.S. Quotes for several of these items were also available from articles in the Oil and Gas Journal, The Energy Daily, and Enhanced Recovery Weekly.

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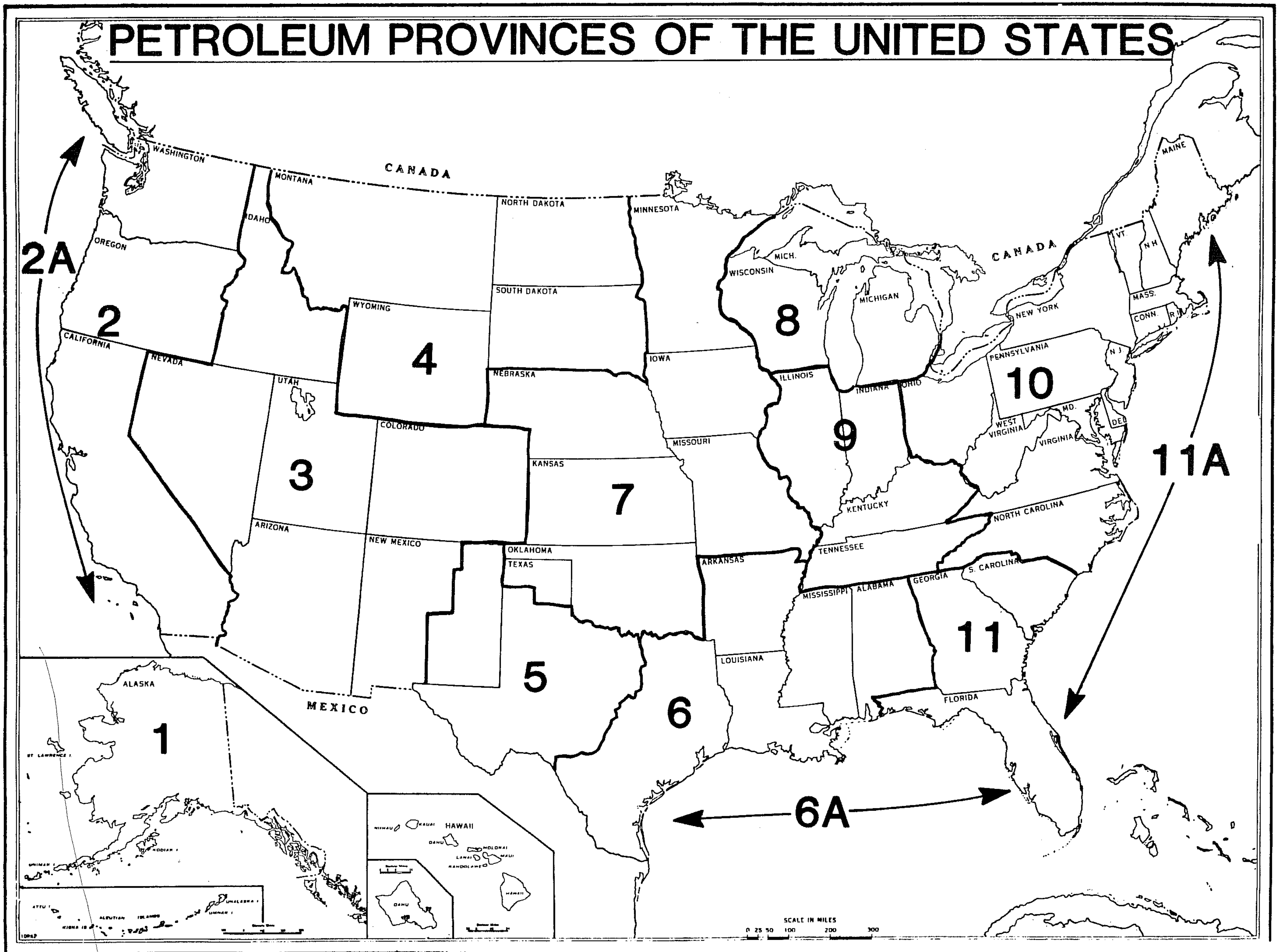
1 U.S. Department of Energy, T. Anderson and V. Funk, Feb. 6, 1980
2 American Petroleum Institute, Feb. 1980
3 Independent Petroleum Association of America, Oct. 1980

Exhibit 1


PETROLEUM PROVINCES OF THE UNITED STATES
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11A

State taxes and severance taxes were determined from "State and Local Oil and Gas Severance and Production Taxes."[4] Information for calculating the Windfall Profit Tax was obtained from "Crude Oil Pricing/Windfall Profit Tax Information Service."[5]

UPDATING PROCEDURE

Several of the engineering cost sources, because of data collection time lags, report costs only through 1978 or 1979. Thus, updating was required to index these costs to mid-1980. For this, inflation indices for various categories of costs were constructed as summarized below:

- Labor costs index -- based on the Bureau of Labor Statistics (BLS) indices of average weekly earnings for "Crude Petroleum and Natural Gas Field Operations" (BLS Item No. 131.2), and "Oil and Gas Field Services" (BLS Item No. 138).

- Well equipment costs index -- based on Bureau of Labor Statistics "Wholesale Price Index for Steel Pipe and Tube" (BLS Item No. 33176).

- Construction costs index -- based on the "Engineering News Record Construction Cost Index."

The development and use of these indices is further described in Attachment I.

4 American Petroleum Institute, July 25, 1980
5 Federal Programs Advisory Service, July 1, 1980

COST COMPUTATIONS

1. General Costs. Enhanced oil recovery projects incur a series of traditional oil field development costs for drilling and completing wells, installing surface equipment, and operating the wells. These costs are generally a function of well depth and location.

Cost equations were developed through regression analysis for each of the major components by region as a function of depth. The cost equations by component, technique, and area are detailed in Attachment I. Examples of such costs for two important oil producing areas, California and Texas, at typical depths are shown on Exhibit 2.

2. Financial Costs. Financial costs associated with enhanced oil recovery projects which are paid from production revenues are:

- Royalties, Severance and Other Taxes -- royalties generally are 12.5% of revenues (although 20% royalty rates are becoming more frequent); state severance and ad valorem taxes range from negligible to 12.5%; commonly, these cost categories are equal to about 20% of gross revenues.

- Windfall Profit Tax -- recent tax legislation has established a statutory decline curve for existing oil production when EOR projects are initiated and a 30% excise tax on revenues from EOR projects in excess of a variable adjusted base price.

- State and Federal Income Taxes -- a series of tax laws, depreciation rates, investment tax credits, depletion, etc., ultimately determine the state and federal income taxes due on a project; Federal taxes are 46% and in general, state taxes average 5% of net revenues.

- Return on Capital -- a 15% after-tax return was assumed in the analysis using constant mid-1980 dollars.

EXHIBIT 2

GENERAL COSTS - CALIFORNIA

Cost Category	Equation	Example; 1,000 ft. Well
• Drilling & Completion	Cost = $48,451e^{.000324(Depth)}$	\$ 67,000
• Producing Equipment	Cost = $33,292e^{.000114(Depth)}$	\$ 37,000
• Remaining Lease Equipment	Cost = $34,797e^{.000027(Depth)}$	\$ 36,000
• New Injection Equipment	Cost = $22,892e^{.000088(Depth)}$	\$ 25,000
• Well Workover	Cost = 48% D&C + 50% Prod Equip	\$ 51,000
• Operating & Maintenance Costs	Cost = $13,298e^{.000132(Depth)}$	\$ 15,000/year

GENERAL COSTS - TEXAS

Cost Category	Equation	Example; 5,000 ft. Well
• Drilling & Completion	Cost = $30,430e^{.000345(Depth)}$	\$171,000
• Producing Equipment	Cost = $24,910e^{.000141(Depth)}$	\$ 50,000
• Remaining Lease Equipment	Cost = $20,183e^{.000039(Depth)}$	\$ 25,000
• New Injection Equipment	Cost = $22,892e^{.000088(Depth)}$	\$ 36,000
• Well Workover	Cost = 48% D&C + 50% Prod Equip	\$107,000
• Operating & Maintenance Costs	Cost = $13,308e^{.000114(Depth)}$	\$ 24,000/year

An enhanced oil recovery project might incur from $10 to $16 per barrel of these financial "costs", assuming a $30.00 per barrel wellhead price:

• Royalties, Severance and Other Taxes --	$4
• Windfall Profit Tax --	$3
• State and Federal Income Taxes --	$2 - $4
• Return on Capital (15% ROI) --	$1 - $5
Total Financial Costs --	$10 - $16

USE OF ENGINEERING COSTS IN ASSESSING ECONOMIC FEASIBILITY

The results of Task 1 provide an engineering basis for establishing a consistent set of costs for each enhanced oil recovery process. The subsequent tasks demonstrate how these engineering costs are used in assessing the economic feasibility of enhanced oil recovery.

TASK 2. ENHANCED RECOVERY MODELS

INTRODUCTION

The greatest uncertainties in achieving an economically successful enhanced recovery project exist in two areas:

- Estimating the incremental oil recovered and its production rate, and
- Establishing the relationship between the injection of fluids (steam, air, CO_2, chemicals) and the additional production of oil.

Much of this uncertainty can only be resolved empirically by conducting a field pilot or by extrapolating performance from an EOR project in an analogous reservoir, taking into account differences in oil and reservoir properties (e.g., oil saturation, reservoir thickness, and past reservoir production) at the selected project site. However, a first-order assessment of economic feasibility can be obtained by combining development and operating costs with results from field tests and the scientific work and theoretical modeling that has been conducted over the past few years. The oil recovery and injection fluid rates used in this study reflect this combination of empirical field data and new scientific understanding.

A. STEAM DRIVE RECOVERY MODEL

The steam drive recovery model used in the analysis determines oil recovery as a function of steam injection, steam zone growth, heat balance equations and key reservoir characteristics. The major parameters that effect the viability of steam drive are related to the oil-steam ratio through the dimensionless time of steam injection, t_d, and the ratio of latent heat to sensible heat in the injected steam, h_d:

$$t_d = \frac{4k_{h2}M_2t}{Z_t^2M_1^2} \tag{1}$$

and

$$h_d = \frac{f_{sd}\,L_v}{C_w\,\Delta T} \tag{2}$$

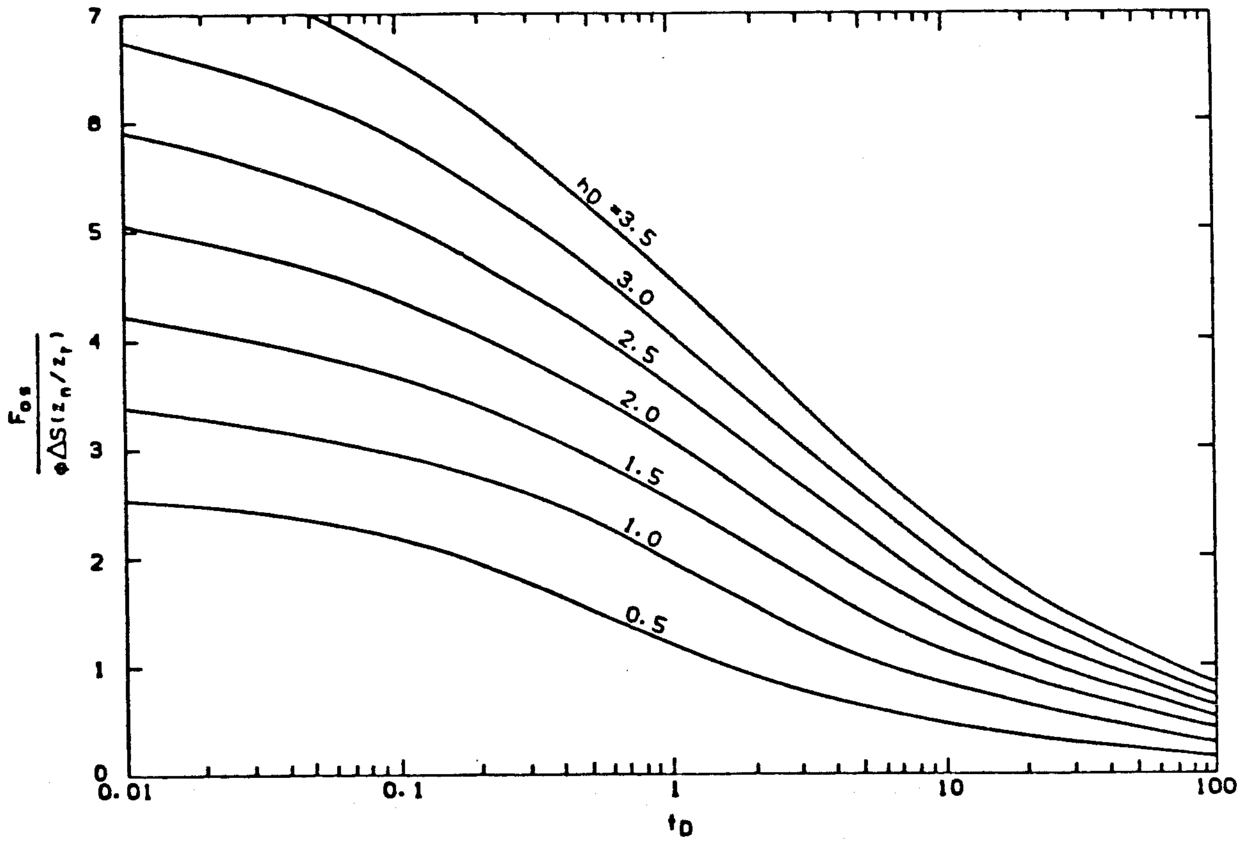
where:

- t = Time of steam injection, hours
- Z_t = Gross thickness of reservoir, feet
- M_1 = Average heat capacity of steam zone, BTU/cu ft-^{O}F
- M_2 = Average heat capacity of cap and base rock, BTU/cu ft-^{O}F
- k_{h2} = Thermal conductivity of cap and base rock, BTU/ft hr-^{O}F
- L_v = Heat of vaporization of steam, BTU/lb
- f_{sd} = Steam quality in reservoir, dimensionless
- ΔT = steam zone temperature minus original formation temperature, ^{O}F
- C_w = specific heat of water, BTU/lb/^{O}F

The relationship of the normalized oil-steam ratio to t_d and h_d is derived from simplified heat and flow equations and is shown graphically on Exhibit 3.

Exhibit 3

OIL/STEAM RATIO AS A FUNCTION OF DIMENSIONLESS PARAMETERS



Source: Myhill and Stegemeier, "Steam Drive Correlation and Prediction", Journal of Petroleum Technology, February 1978.

After the normalized oil-steam ratio is found from Exhibit 3, the actual oil-steam ratio can be calculated from:

$$F_{os} = N_{os} * (\phi * \Delta S * \frac{Z_n}{Z_t}) * C \qquad (3)$$

where:

F_{os} = actual oil-steam ratio
N_{os} = normalized oil-steam ratio
ϕ = porosity
ΔS = average initial saturation less average ending saturation
Z_n = net thickness of reservoir
Z_t = gross thickness of reservoir
C = empirical corrective factor of 0.75

Given a steam injection rate and the injection time, the cumulative incremental oil production can be calculated from the oil-steam ratio, as follows:

$$\text{Incr. Rec. (bbl)} = F_{os} * \text{(Steam Inj. Rate)} * \text{(Time of Steam Inj.)}$$

Steam was injected at a rate of 1.5 barrels per acre-foot per day. This injection rate has been determined to be the optimum from field tests and laboratory scaled physical models.

To determine incremental oil recovery, steam is injected until the marginal oil-steam ratio is 0.12 or until 2.0 pore volumes of steam have been injected. Oil production begins during the first year of steam injection, and terminates shortly after injection is discontinued.

B. IN SITU COMBUSTION RECOVERY MODEL

The recovery model for in situ combustion is based on correlations derived from 14 field projects (Brigham, et al., 1980).

The recovery equation used for the in situ combustion model is as follows:

$$\text{Cumulative Rec. (Bbl)} = \text{Incr. Rec. (\%)} * N \qquad (4)$$

where:

$$\text{Incr. Rec.} = 47\,(1-e^{-1.2C}) = \frac{N_p + N_b}{N} * 100 \qquad (5)$$

$$C = (0.427S_{orw} - 0.00135h + 2.196\left(\frac{1}{\mu_o}\right)^{0.25})X \qquad (6)$$

$$X = \frac{A_i * E_{02}}{(N/\phi\, S_{orw})(1-\phi)} \qquad (7)$$

and

A_i = Cumulative air injection, Mscf
E_{02} = Oxygen Utilization, fraction
h = Net pay, feet
N = Original oil in place, barrels
ϕ = Porosity, fraction
S_{orw} = Oil saturation at start of test, fraction
μ_o = Viscosity, centipoise
N_p = Oil produced, barrels
N_b = Oil burned, barrels

This recovery equation is valid until the fireflood must be abandoned for technical reasons, such as the arrival of the burning front at the production wells or the severe breakthrough of air. The equation signifies that recovery increases as air injection continues, but that the efficiency (barrels of oil per Mcf of air) decreases exponentially. Maximum ultimate recovery ($N_p + N_b$) using this equation is 47%. Oil recovery increases with higher values of S_o, the oil saturation at initiation of the burn, and decreases for thicker reservoirs and for more viscous oils.

The injection rate of air was determined as the rate at which the economics were optimized and were found to equal 1,000 to 1,500 Mscf per acre-foot per year. Injection is assumed to continue for 6 years or until the air-oil ratio reaches 30 MMcf of air injected per barrel of oil recovered. Oil production begins during the first year of air injection and terminates upon completion of injection.

C. CARBON DIOXIDE FLOODING RECOVERY MODEL

The oil recovery equation used for carbon dioxide flooding is shown below:

$$\text{Incr. Rec.} = 0.75 * E_v * PV * \left(\frac{S_{orw}}{B_o} - \frac{S_{CO2}}{B_{CO2}}\right) * \left(1 - e^{-5.4(V_{CO2} - 0.2)}\right) \quad (8)$$

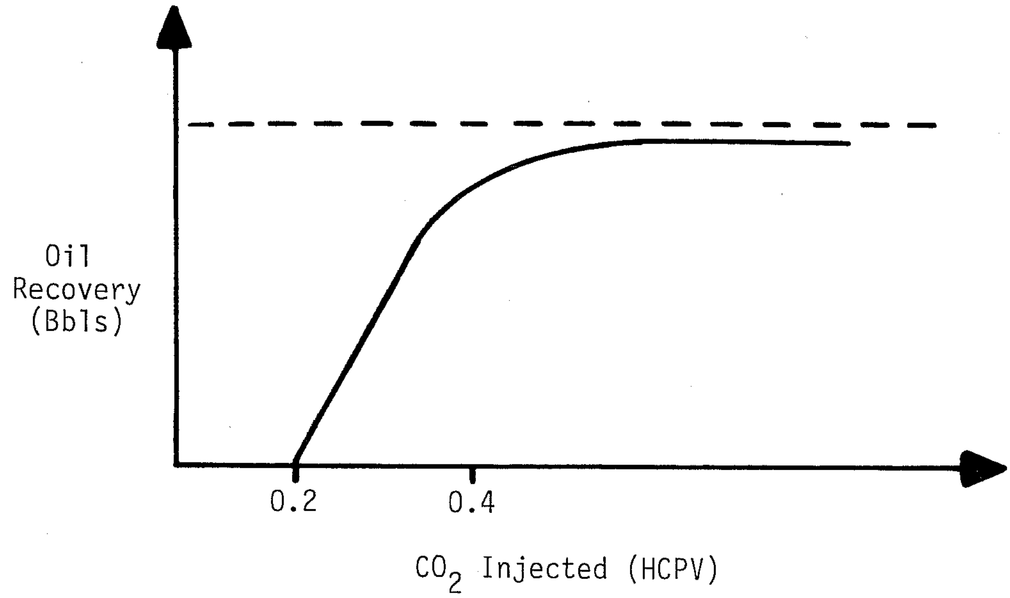
where:

E_v = Volumetric waterflood sweep efficiency
PV = Pore volume of pattern
S_{orw} = Waterflood residual oil saturation in swept zone
S_{CO2} = Oil saturation after CO_2 flood
B_o = Formation volume factor after waterflood
B_{CO2} = Formation volume factor after CO_2 flood
V_{CO2} = Injected volume of CO_2, in hydrocarbon pore volumes

This recovery equation signifies that initially 0.2 hydrocarbon pore volumes of CO_2 must be injected before oil recovery starts. Cumulative oil recovery then increases linearly until it rapidly breaks over and goes asymtotically toward a maximum value, as shown on Exhibit 4.

EXHIBIT 4

GENERALIZED CO_2 RECOVERY CURVE



This equation is used to calculate incremental cumulative oil production assuming 0.1 HCPV of carbon dioxide is injected annually. Annual production is found as the difference between the cumulative recovery for successive years. Produced CO_2 is reinjected until 0.7 HCPV of purchased and recycled CO_2 are injected cr the incremental CO_2-oil ratio exceeds 30 Mcf of CO_2 per barrel of recovered oil.

D. SURFACTANT/POLYMER FLOODING RECOVERY MODEL

Recovery projections for surfactant/polymer flooding are based on existing high concentration surfactant/polymer projects. This analysis incorporates the following assumptions:

1. The effective sweep efficiency for surfactant/polymer is 65% of the waterflood sweep, but not less than 40%.

2. Residual oil saturation in the swept zone after the surfactant/polymer flood is 10%.

3. Residual oil saturation in the unswept zone stays the same as at initiation of the project.

Thus, incremental recovery is calculated by the following equation:

$$\text{Incr. Rec.} = (S_{sweep}) * N * \frac{B_{oi}}{B_o} * \frac{(S_{orw} - 0.10)}{S_{oi}} \tag{9}$$

where:

- N = Original oil in place
- S_{sweep} = Surfactant sweep ($0.65\ E_v$; $\geq 40\%$)
- E_v = Waterflood sweep efficiency
- S_{orw} = Oil saturation after primary and secondary recovery, in swept zone
- S_{oi} = Initial oil saturation
- B_{oi} = Initial formation volume factor
- B_o = Formation volume factor after primary and secondary recovery

Fluid is injected in three stages. First, a surfactant slug of 0.10 to 0.14 reservoir pore volume is injected; this is followed by a tapered polymer slug equal to 1 pore volume over three years, and, finally, water is used to drive the chemicals through the reservoir.

The production schedule assumes a response during the third year followed by increasing production for 2 years and then 2 years of declining production.

E. POLYMER WATERFLOODING RECOVERY MODEL

A review of polymer waterflood projects shows that on average the use of polymers improves the waterflood sweep by one percent for every 10% that the sweep efficiency is less than 100%. Thus, recovery is inversely related to the effectiveness of earlier primary and/or secondary recovery -- the less efficient previous recovery, the better a subsequent polymer flood will work. In addition, because of the higher viscosity of the polymer flood, there will be a slight decrease of the residual oil saturation relative to that of a waterflood. The recovery formula is:

$$\text{Incr. Rec.} = \left[(0.1 - \frac{E_v}{10}) * \frac{(S_{oi} - S_{orp})}{S_{oi}} + E_v \frac{(S_{orw} - S_{orp})}{S_{oi}} \right] * \frac{B_{oi}}{B_o} * N \qquad (10)$$

where

- E_v = Waterflood sweep
- N = Original oil in place
- B_{oi} = Initial formation volume factor
- B_o = Formation volume factor after primary and secondary recovery
- S_{oi} = Initial oil saturaton
- S_{orw} = Residual oil saturation after primary and secondary recovery, in swept zone
- S_{orp} = Residual oil saturation to polymer flood = 0.98 S_{orw}

The amount of polymer injected is assumed to be 0.5 swept pore volume of 400 ppm concentration (increased proportionately for crudes less than 32^{o}API) injected evenly over 5 years. Production is assumed to last for 9 years following an initial response in the second year.

TASK 3. EOR ECONOMICS

INTRODUCTION

Task 3 examines the economic feasibility of the five major enhanced oil recovery techniques -- steam drive, in situ combustion, carbon dioxide flooding, surfactant/polymer flooding, and polymer waterflooding.

The approach followed is to combine the general economic costs and oil recovery models described under Tasks 1 and 2 with the process specific costs unique to each EOR process. All costs and revenues are computed on a production unit basis, for example, 2.5 acre spacing for steam drive or 40 acres for CO_2 flooding. After establishing the specific costs for each process, these costs are combined with a financial rate of return model to establish the economic results.

The results of the economic models are demonstrated on sample reservoirs, representing favorable, average and below average properties. A series of sensitivity runs are conducted for each technique to establish the importance of key reservoir and process parameters on economic viability.

A. STEAM DRIVE

The analysis of steam drive economics is based on three sample California heavy oil reservoirs; Kern River, Cymric, and South Belridge. These reservoirs encompass depths ranging from 1,000 feet to 1,700 feet, oil saturations after primary recovery ranging from 52% to 64%, and net pays ranging from 34 to 77 feet, as shown on Exhibit 5. This variatior in reservoir parameters is characteristic of California heavy oil reservoirs where steam drive is an appropriate EOR technique.

1. Sample Calculation for Steam Drive

The example below demonstrates how the recovery model calculates the recovery from the Cymric heavy oil field. The model continues injecting steam at a rate of 1.5 barrels per acre-foot until a marginal oil-steam ratio of 0.12 is reached.

Assuming an injection pressure of 350 psia and a rate of 200 barrels of steam (water equivalent) per day, the calculations for t_d and h_d from equations 1 and 2 are:

$$t_d = \frac{4 * 1.3 * 35 * 70{,}000}{35^2 * 56^2} = 3.32$$

$$h_d = \frac{0.70 * 795}{1 * (431-100)} = 1.68$$

EXHIBIT 5

SELECTED RESERVOIR PARAMETERS FOR STEAM DRIVE RESERVOIRS

	Kern River, CA	Cymric, CA	South Belridge, CA
Depth, feet	1,000	1,225	1,700
Reservoir Temperature, ^{o}F	95	100	109
Net pay, feet	77	53	34
Gross pay, feet	81	56	36
Oil Saturation After Primary Recovery	0.605	0.517	0.638
Oil Saturation After Steam Drive	0.24	0.20	0.18
Oil Gravity, ^{o}API	14	13	13
Oil Viscosity, cp	400	3,000	1,600
Porosity	0.32	0.37	0.35
Pore Volume, MBbls	478	380	231
Original Oil in Place, MBbls*	315	244	157
Remaining Oil in Place, MBbls	289	197	147
Spacing, Acres	2.5	2.5	2.5

* All barrels of oil are stock tank barrels unless otherwise noted.

when the following terms are inserted in the steam drive recovery equations developed in Task 2:

- t = Time of steam injection = 8 years = 70,000 hours
- Z_t = Gross thickness of reservoir = 56 feet
- M_1 = Average heat capacity of steam zone = 35 BTU/cu.ft.-^oF
- M_2 = Average heat capacity of cap and base rock = 35 BTU/cu.ft.-^oF
- k_{h2} = Thermal conductivity of cap and base rock = 1.3 BTU/ft.hr.-^oF
- L_v = Heat of vaporization of steam = 795 BTU/lb
- f_{sd} = Injector bottom-hole steam quality = 0.70
- ΔT = Steam zone temperature (431^oF) minus original formation temperature (100^oF)
- C_w = Specific heat of water = 1 BTU/lb/^oF

Using Exhibit 3, the normalized oil-steam ratio is found to be 1.86 and the actual oil-steam ratio is derived from equation 3:

$$F_{os} = N_{os} * (\phi * \Delta S * Z_n/Z_t) * C$$

$$F_{os} = 1.86 * 0.37 * (0.317 * (53/56)) * 0.75 = 0.1549$$

where

- F_{os} = actual oil-steam ratio,
- N_{os} = normalized oil-steam ratio = 1.86,
- C = correction factor = 0.75,
- Z_n = net thickness of reservoir = 56 feet,
- ϕ = porosity = 0.37,
- ΔS = average initial saturation less average ending saturation = 0.317.

Since the injected steam is 200 barrels per day for 8 years, and the average oil-steam ratio is 0.155, approximately 87,200 barrels of oil would be recovered per zone from an average 2.5 acre unit in the Cymric Field.

2. Production Response

The production response of the three reservoirs was analyzed using the oil recovery and steam injection model described under Task 2. The summary results of the recovery models for a representative 2.5 acre pattern are shown in the table below.

Summary Results of Steam Drive Model

	Kern River	Cymric	South Belridge
Avg. Oil-Steam Ratio, Vol/Vol	0.19	0.15	0.16
Oil Recovery, MBbls	203	87	57
Recovery Efficiency, %	64	36	36
Time of Inj., Years	10	8	7
Steam Inj. Rate, BPD	300	200	135
Steam Inj., Pore Volume	2.0	1.75	1.5

The average oil-steam ratio ranges from 0.15 to 0.19 barrels of oil produced per barrel of steam injected. Oil production is 57,000 barrels for South Belridge (36% recovery efficiency); 87,200 barrels at Cymric (36% recovery efficiency) and 203,000 barrels at Kern River for a 64% recovery efficiency.

The annual production of oil and injection of steam is shown below:

	Thousands of Barrels per Year					
	Kern River		Cymric		South Belridge	
Years	Oil Production	Steam Injection	Oil Production	Steam Injection	Oil Production	Steam Injection
1	--	--	--	--	--	--
2	11.4	135.9	7.5	106.1	4.9	63.1
3	17.2	110.8	11.2	86.1	7.3	50.6
4	22.9	110.8	14.9	86.1	9.8	50.6
5	22.9	110.8	14.9	86.1	9.8	50.6
6	22.9	110.8	14.9	86.1	9.8	50.6
7	22.9	110.8	13.4	86.1	8.8	50.6
8	22.9	110.8	10.4	86.1	6.8	50.6
9	22.9	110.8	--	--	--	--
10	20.6	110.8	--	--	--	--
11	16.0	110.8	--	--	--	--
Total	202.6	1,133.1	87.2	622.7	57.2	366.7

3. Technique Specific Costs.

To determine whether the project will be economic, the costs specific to a steam drive operation need to be analyzed in detail. They include:

- Steam generator and its operation and maintenance
- Pollution control equipment and its operation
- Fuel costs
- Water supply and treatment costs
- Steam piping and valves, including insulation
- Thermal insulation for injection wells

The following equations and vendor quotes were used to establish these costs:

Cost Category	Vendor Quote	Cost Equation
Steam Generator	$320,000 for a 50MM BTU/Hr Unit	--
Generator O&M	$50,000 per year	$0.10 per barrel of produced steam
Fuel Costs (assuming $30/barrel fuel)	$2.26 per barrel of steam	$0.072 * price of fuel
Water Supply and Treatment Costs	--	$0.10 per barrel of produced steam
Steam Piping, Valves and Insulation	$300,000 for an 8 pattern configuration	--
Scrubbers (SOx, NOx)	$300,000 for a 50MM BTU/Hr Unit	--
Scrubber O&M	$100,000 per year	$0.20 per barrel of produced steam

Combining the above process specific costs with the general costs developed previously under Task 1, a typical steam drive in a shallow, 1,225 foot California reservoir might cost the following for one 2.5 acre 5 spot (as part of a larger field development plan):

Cost Category	No. of Items	Total Costs, $
a. General Costs		
• D&C of Production Wells	0.3	21,600
• New Production Equipment	0.3	22,200
• D&C of New Injection Wells	1	--
• New Injection Equipment	1	25,500
• Workover of Production Wells	0.1	5,400
Total Investment		74,700
• Normal Operating Expenses	2 Wells	16,600/yr

b. Process Specific Costs

	Total Costs, Dollars Investment	Annual Operating
• Steam Generator	21,500	--
• Generator O&M	--	7,700
• Fuel Costs	--	167,500
• Water Supply & Treatment Costs	--	7,700
• Steam Piping, Valves and Insulation	37,500	--
• Scrubbers	20,200	--
• Scrubbers O&M	--	14,400
Total	79,200	197,300

4. Economic Analysis.

The economic analysis was conducted at an oil price of $30.00 per barrel. This price was selected for those cost components that depend upon the selling price of crude, such as the Windfall Profit Tax, royalties and severence taxes. The range of costs for steam drive in the three sample reservoirs selected for analysis is shown in the table below:

	Dollars Per Produced Barrel Burning Purchased Crude	Burning Lease Crude
Investment Costs	1 - 3	2 - 5
Operating Costs	4 - 6	6 - 9
Steam Costs	12 - 16	2 - 3
Subtotal	17 - 25	10 - 17
Financial Costs		
- Royalty & Severance	4	4
- State & Federal	2	2
- Windfall Profit	3	3
Subtotal	9	9
Capital Cost (ROR 15%)	1	2
Total	27 - 35	21 - 28

As shown above, the cost of producing a barrel of oil with steam drive ranges from \$27 to \$35 per barrel assuming the oil used to generate steam is purchased at \$30 per barrel. The two major cost components are steam generation and taxes. As steam costs are about half of the total costs, steam drive is very dependent upon energy costs. If lease crude were used as fuel, no taxes would be paid on the crude burned, although the other cost components would increase because less oil is sold. In this case, the cost per produced barrel would range from \$21 to \$28.

The per barrel investment costs, and consequently the capital costs, are relatively small because most of the fields already have wells and the production rate per well is high.

The sensitivity of steam drive economics to changes in key reservoir and economic parameters were derived for an analytic unit in the Cymric Field, a reservoir whose costs were in the middle of the range shown above. The sensitivities computed for this reservoir are shown on Exhibit 6.

Also shown on Exhibit 6 are the oil-steam ratios and the barrels produced. The model assumes the continued injection of steam until the marginal oil-steam ratio falls below 0.12 (cutting off the year before that point is reached), so the oil-steam ratio and the incremental recovery show no change for the sensitivities, except when the initial oil saturation is changed. However, the cost per produced barrel does change.

In the Base Case, the cost of conducting a steam drive is calculated to be \$28 per produced barrel. Three changes in reservoir or oil parameters were analyzed that could lower those costs; the investment was lowered by 25%, the discount rate was decreased to 10% (from 15%), and the initial oil saturation was increased five percent. The effect of each of these sensitivities was to reduce the

EXHIBIT 6

STEAM DRIVE SENSITIVITIES

	$/Produced Barrel	Average Oil-Steam Ratio (Vol/Vol)	Barrels Produced
Base Case	28	0.15	87,200
Investment Costs, + 25%	29	0.15	87,200
Investment Costs, - 25%	28	0.15	87,200
Discount Rate @ 10%	27	0.15	87,200
Discount Rate @ 20%	30	0.15	87,200
WPT at 70%	33	0.15	87,200
WPT at 0%	26	0.15	87,200
Initial Oil Saturation, + 5%	25	0.15	134,500
Initial Oil Saturation, - 5%	30	0.17	73,400

costs by about one dollar per barrel, except for the last sensitivity where the cost was lowered by $3 per barrel.

While the great bulk of changes in economic conditions had only a small effect on the cost per barrel, certain actions could have a pronounced effect. For example, if the Windfall Profit Tax is increased to 70% from the statutory 30% for enhanced oil production, the cost per barrel increases by $5 per barrel.

Other sensitivities that increase the cost per produced barrel are increasing the investment costs by 25%, increasing the discount rate to 20% (which would be the case if the producer considers steam drive an unconventional technology with greater risk associated with it), and lowering the initial oil saturation. In these sensitivities, the cost increases by $1 to $2 per produced barrel.

B. IN SITU COMBUSTION

The economics of in situ projects were analyzed using three representative reservoirs (Brea Olinda, Caddo Pine, and Dominguez) that reflect a geographical dispersion and differences in depth, initial oil saturation and viscosity, Exhibit 7. As discussed under Tasks 1 and 2, these are the major reservoir-specific variables that influence oil production in the recovery model and the cost per barrel in the economic model.

1. Sample Calculation for In Situ Combustion

The sample calculation below demonstrates how the recovery model was used to calculate the cumulative production from the Caddo Pine Field. The model assumes that 190 MMcf of air is injected annually for six years.

The fuel content of the reservoir, F, is:

$$F = -0.12 + 0.00262h + 0.000114k + 2.23S_o + 0.000242kh/\mu_o - 0.000189D - 0.0000652\mu_o$$

or

$$F = 1.406$$

where:

F = Fuel content, lb/ft^3 burned volume

h = Net pay = 19 feet

k = Permeability = 500 md

S_o = Original oil saturation = 0.718

μ_o = Viscosity = 110 cp

D = Depth = 1,035 feet

EXHIBIT 7

SELECTED RESERVOIR PARAMETERS FOR IN SITU COMBUSTION RESERVOIRS

	Brea Olinda, CA	Caddo Pine, LA	Dominguez, CA
Depth, feet	4,112	1,035	5,805
Net Pay, feet	28	19	16
Initial Oil Saturation	0.791	0.718	0.790
Oil Saturation at Start of Project	0.385	0.693	0.385
Oil Gravity, ^{o}API	18	21	26
Oil Viscosity, cp	40	110	4
Porosity	0.38	0.34	0.26
Permeability, md	842	500	1,250
Pore Volume, MBbls	826	501	645
Original Oil in Place, MBbls*	653	360	500
Remaining Oil In Place, MBbls	318	295	248
Spacing, acres	10	10	20

* Stocktank barrels

The amount of oil burned per acre-foot can then be calculated from the volumetric equation:

$$N_b = \frac{43,560 * F}{330} = 185.6 \text{ (Bbl/acre-foot)}$$

The basic recovery equation (4) then gives the recovery after 6 years:

$$y = 47 \left(1 - e^{-1.2C}\right)$$

where

$$C = \left[0.427 S_{orw} - 0.00135h + 2.196 \left(\frac{1}{\mu_o}\right)^{0.25}\right] X = 0.96 * X$$

and

$$y = \left(\frac{N_p + N_b}{N}\right) * 100 = \left(\frac{185.6 * 196 + N_p}{360,000}\right) * 100 = 33.2$$

$$X = \frac{A_i * E_{02}}{(N/\phi\ S_{orw})(1-\phi)} = \frac{1,140,000 * 0.95 * (0.34 * 0.693)}{360,000\ (1 - 0.34)} = 1.07$$

and

A_i	= Cumulative air injection = 1,140 MMcf
E_{02}	= Oxygen utilization = 0.95
h	= Net pay = 19 feet
k	= Permeability = 500 md
N_b	= Fuel burned = 185.6 bbls/acre-foot = 36,400 barrels
N_p	= Cumulative incremental oil production
S_{orw}	= Oil saturation at start of test = 0.693
μ_o	= Oil viscosity = 110 cp
ϕ	= Porosity = 0.34
N	= Original oil in place = 360,000 barrels

This recovery equation gives

N_p = 429.1 barrels per acre foot, or 84,100 barrels.

2. Production Response

The results of the recovery model are summarized on the table below for the representative patterns from the three fields:

Summary Results of In Situ Combustion Model

	Brea Olinda	Caddo Pine	Dominguez
Air-Oil Ratio, Mcf/Bbl	15.3	13.6	30
Oil Recovery, MBbls	110	84	94
Recovery Efficiency, %	35%	28%	38%
Time of Inj., Years	6	6	6
Air Inj. Rate, Mcf/Year	280,000	190,000	480,000
Air Inj., MMMcf	1,680	1,140	2,880

The air/oil ratio ranges from 13.6 Mcf/Bbl for Caddo Pine to 30 Mcf/Bbl for Dominguez while the recovery efficiency varies from 28% to 38% of the remaining oil in place.

The annual and cumulative production of oil and injection of air as calculated by the model is shown below:

	Thousands of Barrels or Mcf per Year					
	Brea Olinda		Caddo Pine		Dominguez	
Years	Oil	Air	Oil	Air	Oil	Air
1	--	--	--	--	--	--
2	11.0	280	8.4	190	4.7	240
3	17.6	280	13.5	190	7.5	240
4	24.2	280	18.5	190	10.3	240
5	22.0	280	16.8	190	9.4	240
6	19.8	280	15.1	190	8.5	240
7	15.4	280	11.8	190	6.5	240
Total	110.0	1,680	84.1	1,140	46.9	1,440

3. Technique Specific Costs.

To determine whether a project will be economic, the technique specific costs must be developed. Costs specific to in situ combustion include:

- The air compressor and its operation and maintenance
- Fuel costs
- Treatment costs
- Field development

The following equations and vendor quotes were used to establish these costs:

Cost Category	Vendor Quote	Cost Equation
Air Compressor	$425,000 for a six-stage 800 hp bank of compressors	$530 per installed horsepower
Compressor O&M	$60,000 per year	$0.10 per Mcf
Compression Energy Costs (assuming $30 barrel fuel)	$0.50 per Mcf Air	$0.0162 * price of fuel
Oil Treatment Costs (Emulsion Breakers)	--	$0.25 per barrel recovered oil
Field Development	High pressure injection lines	$37,500 per pattern

A typical in situ combustion project in a shallow (1,000 ft.) Louisiana reservoir (Caddo Pine) might cost the following for a 10-acre five spot, that is part of a larger field development project:

Cost Category	No. of Items	Total Costs ($)
a. General Costs		
• D&C of Production Wells	1	67,800
• New Production and Lease Equipment	1	73,200
• D&C of New Injection Wells	0.8	54,200
• New Injection Equipment	0.8	20,000
• Workover of Production Wells	0	0
Total Investment		215,200
• Normal Operating Expenses	2 Wells	16,200/year

b. Process Specific Costs	Total Costs, $	
	Investment	Annual Operating
• Air Compressor @ 260 HP	138,000	--
• Compressor O&M	--	19,000
• Fuel Costs	--	53,700
• Treatment Costs	--	3,500
• Field O & M	--	14,000
• Field Development	18,800	--
Total	156,800	90,200

4. Economic Analysis

The range of costs for in situ combustion in the three sample reservoirs selected for analysis is shown in the table on the following page:

	$ / Produced Barrel
Investment Costs	2 - 5
Operating Costs	6 - 9
Injected Air Costs	6 - 11
Subtotal	14 - 25
Financial Costs	
- Royalty & Severance	4
- State & Federal	2
- Windfall Profit	3
Subtotal	9
Capital Cost (ROR 15%)	2
Total	25 - 36

At the lower end of the range, $25 per barrel, in situ combustion would be an economic technique if the burn front and other operating problems could be controlled.

The upper range reflects the unfavorable reservoir characteristics of Dominguez,such as greater depth, smaller net pay, and lower porosity, resulting in lower oil content and higher operating costs per pattern.

Sensitivities for the in situ combustion economics are shown on Exhibit 8 for the Caddo Pine Field along with the cumulative oil production and the air-oil ratios.

Production ranges from 42,100 barrels when the air injection rate is halved to 107,000 barrels when the injection rate is doubled. Even though oil recovery is considerably higher in the "double air injection" case than in the Base Case, the economics are worse, $26 versus $25 per barrel, because of higher air costs.

Most of the sensitivities examined resulted in an economic project. The worst economics were obtained when the net pay was decreased by 50% ($30 per produced barrel) and the oil saturation was lowered by 5% ($31 per produced barrel).

EXHIBIT 8

IN SITU COMBUSTION SENSITIVITIES

	\$/Produced Barrel	Air-Oil Ratio (Mcf/Bbl)	Barrels Produced
Base Case	25	13.6	84,100
WPT at 70%	29	13.6	84,100
WPT at 0%	22	13.6	84,100
Discount Rate @ 10%	24	13.6	84,100
Discount Rate @ 20%	26	13.6	84,100
Investment Costs + 25%	26	13.6	84,100
Investment Costs - 25%	22	13.6	84,100
Air Inj. Rate + 50%	26	16.0	107,000
Air Inj. Rate - 50%	27	13.5	42,100
Net Pay - Double	27	15.9	71,700
Net Pay - Half	30	18.9	60,300
Oil Saturation + 5%	24	12.9	90,000
Oil Saturation - 5%	31	14.6	78,000

C. CARBON DIOXIDE FLOODING

The three reservoirs used in the analysis of carbon dioxide flooding are Crossett, North Cowden, and Keystone, all of which are west Texas carbonates, the primary target for current CO_2 technology. These three reservoirs were chosen because of their variations in depth, size, net pay, and formation volume factors, Exhibit 9, the key variables in the recovery and economic models, .

1. Sample Calculation for CO_2 Flood

The sample calculation below demonstrates how the recovery model was used to calculate the cumulative production from North Cowden, assuming that 0.7 HCPV of CO_2 is injected. Note that because the waterflood sweep is less than 0.6, no corrective factor (0.75) is used.

The equation for cumulative recovery is:

$$\text{Inc. Rec.} = E_v * PV * \left(\frac{S_{orw}}{B_o} - \frac{S_{CO2}}{B_{CO2}} \right) * \left(1 - e^{-5.4\,(V_{CO2} - 0.2)} \right)$$

where:

E_v = Waterflood sweep = 0.540
PV = Pore volume = 1,490,000
S_{orw} = Waterflood residual saturation = 0.350
S_{CO2} = CO_2 flood residual saturation = 0.315
B_o = Formation volume factor after waterflood = 1.08
B_{CO2} = Formation volume factor after CO_2 flood = 1.62
V_{CO2} = Injected volume of CO_2 = 0.7 HCPV

EXHIBIT 9

SELECTED RESERVOIR PARAMETERS FOR CO_2 FLOODING

	Crossett, TX	North Cowden, TX	Keystone, TX
Depth, feet	5,382	5,170	1,939
Net pay, feet	67	60	30
Oil Saturation After Secondary	0.485	0.350	0.325
Oil Gravity, ^{o}API	43	33	37
Oil Viscosity, cp	2.5	1.4	6.0
Porosity, %	22	8	12
Oil Formation Volume Factor after primary	1.31	1.08	1.05
B_{CO2}	1.97	1.62	1.58
Pore Volume, MBbls	4,574	1,490	1,117
Original Oil in Place, MBbls*	2,973	1,192	726
Remaining Oil in Place, MBbls	1,761	521	363
Waterflood Sweep	0.508	0.540	0.400
Spacing, Acres	40	40	40

*Stocktank barrels

Inserting the reservoir parameters into the recovery equation and allowing for four years of recovery after CO_2 injection stops gives:

Recovery = 0.540 * 1,490,000 * 0.130 * 0.992 = 103,800 barrels

2. Recovery Response

The response of these three reservoirs to CO_2 flooding was calculated using the recovery model described in Task 2. The results are summarized below for representative 40 acre patterns. The recovery efficiency ranges from 15% to 20% of the remaining oil in-place while the average CO_2/oil ratio varies from 10.1 to 12.3.

Summary Results of CO_2 Model

	Crossett	North Cowden	Keystone
Oil Prod., MBbls	271	104	55
Recovery Efficiency, %	15	20	15
Time of Inj., Years	7	7	6
Avg. CO_2/Oil Ratio	11.8	10.1	12.3

Except for Keystone, CO_2 is injected for 7 years before the marginal cost of re-injecting CO_2 is higher than the added revenues from incremental production.

The annual and cumulative production of oil and injection of CO_2 as calculated by the model is shown below:

	Thousands of Barrels					
	Crossett		Cowden		Keystone	
Years	Oil Production	CO_2 Injection	Oil Production	CO_2 Injection	Oil Production	CO_2 Injection
1	--	--	--	--	--	--
2	--	457.4	--	149.0	--	111.8
3	--	457.4	--	149.0	--	111.8
4	114.0	457.4	43.5	149.0	23.0	111.8
5	66.4	457.4	25.4	149.0	13.5	111.8
6	38.7	457.4	14.8	149.0	7.8	111.8
7	22.6	457.4	8.6	149.0	4.6	111.8
8	13.1	457.4	5.0	149.0	2.7	--
9	7.7	--	2.9	--	1.6	--
10	4.5	--	1.8	--	0.9	--
11	2.5	--	1.2	--	0.5	--
12	1.5	--	0.6	--	--	--
Total	271.0	3,201.8	103.8	1,043.0	54.6	670.8

Production is assumed to start two years after the initial injection of CO_2 and to continue for four years after injection of carbon dioxide stops, since CO_2 is still in the reservoir and energy is still available because the water injection is continued.

3. <u>Technique Specific Costs</u>.

To determine whether a project will be economic, even if it is technically feasible, the costs specific to CO_2 injection must be determined. They include:

- Cost of CO_2 (natural, manufactured, recycled)
- CO_2 transport & compression
- CO_2 reinjection equipment
- CO_2 separation
- CO_2 reinjection
- Field development

The following equations and vendor quotes were used to establish these costs:

Cost Category	Vendor Quote	Cost Equation
CO_2 (Natural)	$1.00 per Mcf	$1.00 per Mcf
CO_2 (Manufactured)	$1.70 per Mcf	$1.70 per Mcf
CO_2 (Recycled)	$0.14 per Mcf for hydrocarbon separation $0.14 per Mcf H_2S separation $0.26 per Mcf for repressuring	$0.54 per Mcf
Transport & Compression	0.25 per 100 miles	0.25 * distance (100 mile units)
Field Development	Convert new or existing injection wells to CO_2 injection	$85,000 + (1.85 * Depth)

Combining the above process specific costs with the general costs developed under Task 1, a 40 acre unit in the North Cowden field as part of a larger field development project, might cost as follows:

Cost Category	No. of Items	Total Costs ($)
a. General Costs		
• D&C of Production Wells	0.4	72,400
• New Production Equipment	0.4	30,500
• D&C of New Injection Wells	0.8	144,900
• New Injection Equipment	0.8	28,900
• Workover of Production Wells	0.6	67,600
Total Investment		344,300
• Normal Operating Expenses	2 Wells	24,000/yr

b. Process Specific Costs	Total Costs ($) Investment	Operating
• Cost of Natural CO_2	--	446,900
• CO_2 Transportation	--	558,600
• CO_2 Reinjection Equipment	10,000	--
• CO_2 Separation	--	160,800
• CO_2 Reinjection	--	154,200
• Field Development	95,000	--
Total Costs	105,000	1,320,500

4. Economic Analysis

The economic analysis was conducted at a fuel price of $30 per barrel to fix those cost components that are a function of the selling price of crude. The range of costs for CO_2 flooding for the three sample reservoirs is shown in the table below:

CO_2 Flooding Cost Components

	$ / Barrel Produced Oil
Investment Costs	1 - 3
Operating Costs	3 - 7
CO_2 Costs	12 - 16
Subtotal	16 - 27
Financial Costs	
- Royalty & Severance	4
- State & Federal	2 - 3
- Windfall Profit	3
Subtotal	9 - 10
Capital Cost (ROR 15%)	1 - 2
Total	26 - 39

The cost of the injection materials constitutes a significant portion of the total cost which varies from $26 to $39 per barrel.

The sensitivity of CO_2 flooding to variations in reservoir and economic parameters was analyzed using an analytic unit from North Cowdon, a reservoir whose costs are in the middle of the range. These sensitivities are shown on Exhibit 10, together with the total production and the average CO_2/oil ratio.

In the Base Case, 104,000 barrels are produced at a cost of $32 per barrel. The greatest variation in production and economics arises when the oil saturation at the start of the CO_2 flood is varied; an oil saturation 5% higher lowers the cost to $29 per barrel and increases production to 118,200 barrels, while an oil saturation 5% lower increases the cost to $36 per barrel and lowers production to 88,200 barrels.

EXHIBIT 10

CO_2 FLOODING SENSITIVITIES

	$/Produced Barrel	CO_2/Oil Ratio	Production, MBbls
Base Case	32	10.1	104,000
Investment Costs, + 25%	33	10.1	104,000
Investment Costs, - 25%	31	10.1	104,000
Discount Rate @ 10%	31	10.1	104,000
Discount Rate @ 20%	34	10.1	104,000
Windfall Profit Tax @ 70%	36	8.7	102,900
Windfall Profit Tax @ 0%	29	10.1	104,000
Oil Saturation +5%	29	8.8	118,200
Oil Saturation -5%	36	10.2	88,200
Purchase Cost of CO_2 @ $1.50/Mcf	36	10.1	104,000
Purchase Cost of CO_2 @ $0.75/Mcf	31	10.1	104,000

Changing the investment costs by 25% had little effect on the economics because the field is already developed, and investment costs are small. Increasing the discount rate to 20% from 15% (which would signify that the investor viewed the technique as more risky than conventional projects) would raise the cost per barrel to $34.

The major cost item in carbon dioxide flooding is purchasing and transporting CO_2, thus the economics are very sensitive to the purchase price of carbon dioxide. Increasing the initial purchase cost of CO_2 to $1.50 per Mcf from $1.00 raises the price to $36 per barrel; lowering the initial purchase cost of CO_2 to $0.75 per Mcf lowers the cost to $31 per barrel.

D. SURFACTANT/POLYMER FLOODING

The three reservoirs chosen to analyze the costs of surfactant/polymer flooding are Salem Consolidated, Robinson Main, and Dale Consolidated. These reservoirs reflect variations in key parameters, such as depth and waterflood sweep, that determine incremental tertiary recovery and economics, Exhibit 11.

1. Sample Calculation for Surfactant/Polymer

The following sample calculation demonstrates how the recovery model discussed in Task 2 was used to calculate the cumulative production from Dale Consolidated for a 5 acre unit.

Incremental tertiary recovery is calculated by the following equation:

$$\text{Incremental Rec. (Bbls)} = (S_{sweep}) * N * \frac{B_{oi}}{B_o} * \frac{(S_{orw} - 0.10)}{S_{oi}}$$

where:

- N = Original oil in place = 85,000 barrels
- S_{sweep} = Surfactant sweep = 0.61
- S_{orw} = Oil saturation after primary and secondary recovery = 0.385
- S_{oi} = Initial oil saturation = 0.625
- B_{oi} = Initial formation volume factor = 1.18
- B_o = Formation volume factor after secondary = 1.18

and:

$$\text{Recovery} = 0.61 * 85{,}000 * \frac{1.18}{1.18} * \frac{(0.385 - 0.10)}{0.625} = 23{,}600 \text{ barrels}$$

EXHIBIT 11

SELECTED RESERVOIR PARAMETERS FOR SURFACTANT/POLYMER FLOODING

	Salem Consol., IL	Dale Consol., IL	Robinson Main Consol., IL
Depth, feet	1,780	3,150	950
Net Pay, feet	73	23	24
Initial Oil Saturation	0.696	0.625	0.761
Oil Saturation After Waterflood	0.367	0.385	0.385
Waterflood Sweep	0.95	0.933	0.767
Surfactant Sweep	0.62	0.61	0.50
Gravity, ^{o}API	38	37	36
B_{oi}	1.1	1.18	1.05
B_{o}	1.05	1.18	1.05
Pore Volume, MBbls	510	160	177
Original Oil in Place, MBbls*	344	85	133
Remaining Oil in Place, MBbls	190	55	83
Spacing, Acres	5	5	5

*Stocktank barrels

2. Production Response

The three reservoirs were analyzed using the recovery model presented in Task 2. The summary results for a representative 5 acre pattern are shown below for each of the reservoirs. The recovery efficiency ranges from 30% to 43% of the remaining oil in place, while the amount of injection material is about 0.5 barrels of surfactant and from 1.4 to 1.7 pounds of polymer per barrel of oil produced. Each barrel of surfactant is composed of 17.5 pounds of petroleum sulfonate (100-percent active), 3.5 pounds of alcohol, and 70 pounds of crude oil; therefore, about 8.75 pounds of sulfonates, 1.75 pounds of alcohol, and 35 pounds of crude oil are injected per barrel of incremental oil recovered.

Summary Results of Surfactant/Polymer Model

	Salem Consol.	Dale Consol.	Robinson Main
Oil Rec., Bbls	82,000	23,600	25,000
Recovery Efficiency, %	43	43	30
Surfactant Inj., Bbls	35,675	11,200	12,400
- Sulfonate, lbs	625,000	217,000	196,000
- Alcohol, lbs	125,000	43,400	39,200
- Crude Oil, lbs	2,500,000	868,000	784,000
Polymer Inj., @ 700 ppm			
- Barrels	509,700	160,600	176,900
- Pounds	123,800	39,000	43,000

The annual and cumulative injection of surfactant and polymer and recovery of oil is:

	Thousands of Barrels								
	Salem			Dale			Robinson		
Years	Oil	Surf	Polym	Oil	Surf	Polym	Oil	Surf	Polym
1	--	--	--	--	--	--	--	--	--
2	--	35.7	--	--	11.2	--	--	12.4	--
3	--	--	259.9	--	--	81.9	--	--	90.2
4	7.6	--	168.2	2.4	--	53.0	2.4	--	58.4
5	19.9	--	81.6	6.2	--	25.7	6.2	--	28.3
6	24.4	--	--	7.5	--	--	7.7	--	--
7	15.3	--	--	4.7	--	--	4.8	--	--
8	9.2	--	--	2.8	--	--	2.9	--	--
Total	76.4	35.7	509.7	23.6	11.2	160.6	24.0	12.4	176.9

No injection is assumed during the first year where the capital investment is made. During the second year, surfactant is injected followed by polymer the next three years. Oil production starts in the fourth year and continues for five years.

3. Technique Specific Costs. To analyze the project economics, the costs of conducting a surfactant/polymer flood must be evaluated. Costs specific to this EOR process include the:

- Surfactant slug
- Polymer slug

The surfactant slug is composed of 5-wt percent petroleum sulfonate (100-percent active), 1-wt percent alcohol, and 20-volume percent crude oil. The concentration of the polymer begins at 1200 ppm and decreases to 200 ppm at the end of injection for an average of 700 ppm average. The following equations and vendor quotes were used to establish these costs:

Cost Category	Vendor Quote	Cost Equation
Surfactant Slug	$30 Crude Price	$16.25 per bbl injected
- Alcohol	$0.31 per lb	
- Sulfonates	$0.67 per lb	
- Crude Oil	$0.09 per lb	
Polymer	$2.83 per lb	$0.69 per bbl @ 700 ppm injected

Combining the above costs with the general costs developed under Task 1, the Dale Consolidated Reservoir might cost the following for a 5 acre unit that is part of a larger field development unit.

Cost Category	No. of Items	Total Costs ($)
a. General Costs		
• D&C of Production Wells	--	--
• New Production Equipment	--	--
• D&C of New Injection Wells	1	81,700
• New Injection Equipment	1	30,100
• Workover of Production Wells	1	58,600
Total Investment		170,400
• Normal Operating Expenses	2 Wells	19,000/yr
b. Process Specific Costs		Operating Costs ($)
• Surfactant Slug		182,000
• Polymer Slug		110,300
Total Chemical Costs		292,300

4. Economic Analysis

The range of costs for surfactant/polymer flooding is shown below, assuming that the price of crude oil is $30 per barrel.

Surfactant/Polymer Flooding Cost Components

	$ / Barrel Produced Oil
Investment Costs	3 - 6
Operating Costs	5 - 9
Surfactant/Polymer Costs	12 - 15
Subtotal	20 - 30
Financial Costs	
- Royalty & Severance	4
- State & Federal	4
- Windfall Profit	3
Subtotal	11
Capital Cost (ROR 15%)	4 - 5
Total	35 - 46

Sensitivities to surfactant/polymer flood economics are shown on Exhibit 12. The Base Case economics for Dale Consolidated give a cost of $45 per barrel. Lowering the discount rate to 10% or removing the Windfall Profit Tax reduces the cost to $40 and $42 per barrel, respectively, while increasing the discount rate to 20% increases the cost to $50 per barrel.

Changing the sweep efficiency of the surfactant/polymer flood by 10% results in a change in costs of $3 to $4 per barrel. However, the economics are even more sensitive to a change in the residual oil saturation where a 5 point change varies the cost of the produced oil by $5 to $8 per barrel.

EXHIBIT 12

SURFACTANT/POLYMER FLOODING SENSITIVITIES

	$/Produced Barrel	Surf./Oil (*Bbl/Bbl)	Poly/Oil (Lbs/Bbl)	Barrels Produced
Base Case	45	0.48	1.6	23,500
Windfall Profit Tax at 70%	50	0.48	1.6	23,500
Windfall Profit Tax at 0%	42	0.48	1.6	23,500
Discount Rate @ 10%	40	0.48	1.6	23,500
Discount Rate @ 20%	50	0.48	1.6	23,500
Waterflood Sweep + 10%	42	0.43	1.3	25,000
Waterflood Sweep - 10%	50	0.53	1.8	21,200
Oil Saturation + 5%	40	0.41	1.4	27,600
Oil Saturation - 5%	53	0.58	2.0	19,400

* See "2. Production Response" for surfactant composition in pounds.

E. POLYMER WATERFLOODING

Reservoir characteristics of the three reservoirs (Gilbertown, Delaware Childers and Main Consolidated) chosen for analyzing polymer waterflooding are shown on Exhibit 13. They reflect a range of depth, geographical location, waterflood sweep and pore volumes; the variables that are most important in determining the economics of polymer waterflooding.

1. Sample Calculation for Polymer Flooding

The example below demonstrates how the recovery model presented in Task 2 was used to calculate the recovery from Gilbertown.

The recovery formula is:

Incremental Recovery (Bbl) Due to Polymer Addition =

$$\left[(0.1 - \frac{E_v}{10}) * \frac{(S_{oi} - S_{orp})}{S_{oi}} + E_v \frac{(S_{orw} - S_{orp})}{S_{oi}}\right] * \frac{B_{oi}}{B_o} * N$$

where:

Ev	= Previous, or anticipated waterflood sweep in a particular reservoir = 0.40
N	= Original oil in place = 1,453,000
B_{oi}	= Oil formation volume factor at initial conditions = 1.05
B_o	= Oil formation factor at ultimate primary and secondary recovery = 1.05
S_{orw}	= Residual oil saturation in water-swept region = 0.397
S_{oi}	= Initial oil saturation = 0.628
S_{orp}	= Residual oil saturation in polymer swept region = (0.397 * 0.98) = 0.389

EXHIBIT 13

SELECTED RESERVOIR CHARACTERISTICS FOR POLYMER WATERFLOODING

	Delaware-Childers OK	Gilbertown AL	Main Consol. Fed IL
Depth, feet	620	3,380	880
Thickness, feet	38	27	14
Initial Oil Saturation	0.639	0.628	0.693
Residual Oil Saturation After Waterflood	0.330	0.397	0.385
Waterflood sweep	0.763	0.400	0.645
Gravity, ^{o}API	37	17	34
Porosity	0.21	0.29	0.19
B_{oi}	1.16	1.05	1.10
B_{o}	1.10	1.05	1.05
Pore Volume, MBbls	2,476	2,430	825
Original Oil in Place, MBbls*	1,370	1,453	545
Remaining Oil In Place, MBbls	708	919	303
Spacing, Acres	40	40	40

*Stocktank barrels

$$\text{Incr. Recovery} = [(0.1 - 0.40/10) * (0.628 - 0.389)/0.628) + 0.40$$

$$* ((0.397 - 0.389)/0.628)] * 1.05/10.5 * 1{,}453{,}000$$

$$= [\ 0.06 * 0.38 + 0.40 * 0.013] * 1 * 1{,}453{,}000$$

$$= [\ 0.023 + 0.005] * 1 * 1{,}453{,}000$$

$$= 40{,}500 \text{ barrels}$$

The volume of polymer injected is 50% of the swept pore volume at a rate of 0.10 PV for each of the first five years.

Thus, the volumes of polymer required in barrels are:

$$0.5\ PV\ (E_V + (0.1 - E_V/10))$$

where there are 2.88 barrels per pound of polymer at a concentration of 1000 ppm.

The primary economic variable, pounds of polymer per barrel of incremental oil, can be derived from the following equation:

$$[0.5\ PV * (E_V + (0.1 - E_V/10)) * 1000 * 10^{-6}] / \text{Incremental Oil Recovery}$$

For our sample reservoir, with properties as defined on Exhibit 13, the polymer/incremental oil ratio is:

$$[0.5\ (2.43 \times 10^6)(0.40 + 0.06)(1000 * 10^{-6})(350)]/40{,}500$$

$$= 195{,}600 \text{ lbs}/40{,}500 \text{ bbls} = 4.8 \text{ lbs/Bbl}$$

2. Production Response

The three reservoirs were analyzed using the oil recovery and polymer injection model of Task 2. The summary results of these models on one representative 40 acre pattern for each reservoir are shown below.

Summary Results of Polymer Waterflooding

	Delaware-Childers	Gilbertown	Main Consol.
Oil Rec., Barrels	28,200	40,500	12,100
Rec. Efficiency, %	4	4	4
Polymer Inj.			
- Barrels	974,000	558,800	280,900
- Pounds	135,200	193,900	39,000
Conc., ppm	400	1,000	400

Recovery efficiency is low, only 4% of the oil in place after primary and secondary production. A third of the tertiary recovery is due to the better sweep of the previously waterswept zone, and two thirds is due to the additional sweep of the polymer flood. Polymer injection ranges from 13 to 34 barrels of polymer solution per barrel of incremental oil, equivalent to 3.2 to 4.8 pounds of polymer per barrel of incremental oil.

Based on the model, the incremental oil recovery and polymer injection requirements are as follows:

	Thousands of Barrels					
	Delaware-Childers		Gilbertown		Main Consol.	
Years	Oil	Polym	Oil	Polym	Oil	Polym
1	--	--	--	--	--	--
2	--	194.8	--	111.8	--	56.2
3	1.4	194.8	2.0	111.8	0.6	56.2
4	2.8	194.8	4.1	111.8	1.2	56.2
5	5.7	194.8	8.1	111.8	2.4	56.2
6	5.7	194.8	8.1	111.8	2.4	56.2
7	4.2	--	6.0	--	1.8	--
8	2.8	--	4.1	--	1.2	--
9	2.8	--	4.1	--	1.2	--
10	1.4	--	2.0	--	0.6	--
11	1.4	--	2.0	--	0.6	--
Total	28.2	974.0	40.5	559.0	12.1	281.0

Polymer injection is assumed to start in the second year and continue for five years. Oil production starts in the third year and continues for nine years.

3. Technique Specific Costs

The primary additional cost specific to polymer waterflooding is the cost of the polymer solution.

The following equations and vendor quotes were used to establish these costs:

Cost Category	Vendor Quote	Cost Equation	
		1000 ppm	400 ppm
Polymer	$2.83 per lb.	(0.02 * Oil Price + 2.20)/2.88 per bbl	(0.02 * Oil Price + 2.20)/7.21 per bbl

Combining the above process specific costs with the general costs developed under Task 1, the Gilbertown reservoir might cost the following for a 40 acre unit:

Cost Category	No. of Items	Total Costs, $
a. General Costs		
• D&C of Production Wells	0.2	18,000
• New Production Equipment	0.2	12,600
• D&C of New Injection Wells	0.8	72,100
• New Injection Equipment	0.8	24,700
• Workover of Production Wells	0.8	50,700
Total Investment		178,100
• Normal Operating Expenses	2 Wells	19,600/yr

b. Process Specific Costs	Total Costs, $ Investment	Total Costs, $ Operating
• Cost of Polymer @ 1,000 ppm	--	542,800

4. Economic Analysis

A range of costs for technically feasible polymer floods is shown in the table on the next page. These costs were calculated using the same economic assumptions as in the previous cases; namely, that the cost of oil is $30 per barrel and that those components that depend upon the crude price are calculated using this price.

Polymer Flooding Cost Components

	$ / Produced Barrel	
	Tertiary Mode	Secondary Mode
Investment Costs	3 - 7	0
Operating Costs	10 - 14	2-3
Polymer Costs	9 - 13	9-13
Subtotal	22 - 34	11-16
Financial Costs		
- Royalty & Severance	4	4
- State & Federal	3	3
- Windfall Profit	3	3
Subtotal	10	10
Capital Cost (ROR 15%)	1 - 2	1-2
Total	30 - 46	22-28

The cost of oil from polymer floods, when used in a tertiary mode, ranges from $30 to $46 per barrel; a range which would signify that this EOR technique is marginally economical. The major reason for the high per barrel costs is that the incremental oil recovery is low, about 4% of the remaining oil in place.

Since polymer flooding can be viewed as an addition to waterflooding, so that it could be undertaken when the field is to be waterflooded, the cost of polymer flooding in this secondary mode was also calculated, assuming the EOR project is only burdened with the cost of chemicals. This decreases the cost to $22 to $28 per barrel, which would make the Gilbertown polymer flooding an economic project.

Sensitivities to the polymer flood economics for Gilbertown are shown on Exhibit 14. The Base Case economics show that the cost is $40 per barrel.

EXHIBIT 14

POLYMER WATERFLOODING SENSITIVITIES

	$/Produced Barrel	Poly/Oil (Lbs/Bbl)	Barrels Produced
Base Case	40	4.8	40,500
Investment Costs + 25%	41	4.8	40,500
Investment Costs - 25%	39	4.8	40,500
Discount Rate, 20%	43	4.8	40,500
Discount Rate, 10%	36	4.8	40,500
Windfall Profit @ 70%	44	4.8	40,500
Windfall Profit @ 0%	36	4.8	40,500
Initial Oil Saturation - 5%	46	5.8	33,600
Oil Sat. After Sec. - 5%	45	4.0	46,400
Oil Sat. After Sec. + 5%	36	5.5	34,600
Polymer conc. + 100 ppm	42	4.8	40,500
Polymer conc. - 100 ppm	38	4.8	40,500
Waterflood Sweep + 10%	42	6.1	39,000
Waterflood Sweep - 10%	37	3.6	42,000
W/o Waterflood Investment	26	4.8	40,500

The sensitivities that have the most effect on the economics of polymer flooding are changing the oil saturations or the waterflood sweep; varying the oil saturation after secondary by 5% (up or down) changes the cost by about $5 per produced barrel while varying the waterflood sweep by 10% results in about a $3 per barrel change in the economics. The most favorable economics (although the project is still uneconomic) arise when the discount rate is lowered to 10%, the Windfall Profit Tax rate is 0%, or when the oil saturation after waterflood is increased 5% ($36 per barrel).

ATTACHMENT I

GENERAL PRODUCTION COSTS

This Attachment contains the details of how the field development and operating costs were derived and updated from published sources and presents equations for estimating equipment costs by geographical area. It also updates the costs of transporting CO_2 in pipelines and summarizes the effect of the Windfall Profit Tax on the economics of EOR projects.

A. FIELD DEVELOPMENT, EQUIPMENT AND OPERATING COSTS

1. Updating Procedure

To develop EOR costs by technique on a consistent basis in mid-1980 dollars, the most recent published information on the various cost components had to be updated to mid-1980. Thus, drilling and completion costs were updated to mid-1980 from 1978 and equipment and operating costs from 1979.

The first step in constructing the inflation indices was to disaggregate the broad cost categories of drilling, completion and production equipment into smaller cost items, Exhibits I-1 and I-2. Individual cost items for drilling and completion, such as casing or rig costs, were identified as escalating with either the Bureau of Labor Statistics (BLS) Labor Cost Index (No. 131.2), the Oil and Gas Service Index (No. 138), or the BLS Wholesale Price Index for steel pipe and tube (No. 33176). The relative percentage that each cost item contributed to the total cost of drilling and completion was used to determine the overall relative weight of each BLS index in the composite escalation index.

The relative weights for escalating drilling and completion costs were:

- 60% BLS Labor Costs (No. 131.2)
- 40% BLS Wholesale Price (No. 33176)

EXHIBIT I-1

DERIVATION OF DRILLING AND COMPLETION COSTS FOR PRODUCTION AND INJECTION WELLS

Cost Item	Allocation for Assigning Index Weighting: BLS Oil & Gas Field Service No. 138	Allocation for Assigning Index Weighting: BLS Wholesale Price Index No. 33176
Site Preparation:		
Clearing Wellsite	X	
Surveying and Plat	X	
Damages	X	
Pit and Clean-up	X	
Road Surveying	X	
Cattle Guards	X	
Roads	X	
Drilling and Completion		
Wellhead	X	X
Rig Non-drilling	X	
Rig Drilling	X	
Transportation of Rig	X	
Drill Bits		X
Water	X	
Drilling Mud	X	
Cementing	X	
Evaluation & Completion Services	X	
Special Tool Rental		X
Engineering & Geological	X	
Surface Casing		X
Intermediate Casing		X
Production Casing		X
Total Site Preparation, Drilling and Completion	60%	40%

EXHIBIT I-2

DERIVATION OF WELL, LEASE, AND FIELD PRODUCTION EQUIPMENT COSTS

Cost Item	Allocation for Assigning Index Weighting: BLS Labor Costs No. 131.2	BLS Wholesale Price Index No. 33176	Eng. News-Recd. Const. Cost Index
Production Equipment:			
Tubing	X	X	
Rods	X	X	
Pumps		X	X
Pumping Equipment	X	X	X
Miscellaneous Fittings	X	X	
Gathering System:			
Flowlines	X	X	X
Manifold		X	
Lease Equipment:			
Producing separator	X	X	X
Test Separator	X	X	X
Heater-Treater	X	X	X
Tanks	X	X	X
Water Disposal System	X	X	X
Fence	X	X	X
Total Well, Lease and Field Equipment Costs	20%	60%	20%

Well, lease, and field equipment were escalated similarly with the addition of a third index, the Marshal and Swift Industrial Construction Cost Index which is found in the Engineering News Record. The relative weighting for this category was:

- 20% BLS Labor Costs (No. 131.2)
- 60% BLS Wholesale Price (No. 33176)
- 20% Construction Cost Index

A multiplier to escalate prior year costs to mid-1980 costs was computed for each index by dividing the mid-1980 number by the earlier years number. These multipliers were then weighted by the above percentages and summed to form a composite index for each cost category. Exhibits I-3 and I-4 contain the index values and multipliers used for each cost category.

Prior year cost quotes were updated by applying the appropriate multiplier for each category. The updated costs were used in determining cost equations as described in the next section.

2. Cost Computations

Each enhanced oil recovery project will incur a series of traditional oil field development costs for drilling and completing pattern wells, installing surface equipment, and operating the wells. These costs are generally a function of well depth and location. Equations for computing these costs were determined using exponential regression and a large, statistically significant data base. Exhibit I-5 can be used to determine completion, workover, conversion, equipment, and operating costs in any region at any depth.

EXHIBIT I-3

UPDATE FOR
DRILLING AND COMPLETION COSTS
AND
WORKOVER AND CONVERSION COSTS

BLS Item Number	Title	1980	1979	1978
138	Crude Petroleum and Natural Gas Yearly Average of Weekly Earnings (Production Worker)	382.45	328.55	303.45
33176	Steel Pipe and Tube Producer Price Index	293.9	272.9	256.9

		Multiplier Required to Equate Prior Years Costs to 1980 Costs	
Item	Relative Weighting	1979	1978
138	60%	1.164	1.260
33176	40%	1.077	1.144
Composite Index	100%	1.129	1.214

EXHIBIT I-4

UPDATE FOR
WELL LEASE AND FIELD EQUIPMENT COSTS
AND
DIRECT OPERATING AND MAINTENANCE COSTS

BLS Item Number	Title	1980	1979	1978
131.2	Crude Petroleum and Natural Gas Yearly Average of Weekly Earnings (Production Worker)	400.73	363.49	334.08
33176	Steel Pipe and Tube Producer Price Index	293.9	272.9	256.9
Eng. Record	Construction Cost Index Marshall & Swift Industrial	280.0	260.0	231.0

		Multiplier Required to Equate Prior Years Costs to 1980 Costs	
Item	Relative Weighting	1979	1978
131.2	20%	1.102	1.200
33176	60%	1.077	1.144
Eng. Rec.	20%	1.077	1.212
Composite Index	100%	1.082	1.169

EXHIBIT I-5

COST EQUATIONS BY COMPONENT AND AREA

A. Drilling & Completion Costs

Area	Equation
2	Cost = 48,451 $e^{(.00032D^{1})}$
2A	Cost = 128,390 $e^{(.00032D)}$
3	Cost = 55,335 $e^{(.00027D)}$
4	Cost = 51,688 $e^{(.00028D)}$
5	Cost = 30,392 $e^{(.00034D)}$
6	Cost = 30,430 $e^{(.00035D)}$
6A	Cost = 688,514 $e^{(.00011D)}$
7	Cost = 29,360 $e^{(.00035D)}$
8	Cost = 45,167 $e^{(.00038D)}$
9	Cost = 23,742 $e^{(.00039D)}$
10	Cost = 16,257 $e^{(.00051D)}$
11A	Cost = 149,329 $e^{(.00030D)}$

B. Production Equipment Costs

1,2,2A	Cost = 33,292 $e^{(.00011D)}$
3,4	Cost = 21,509 $e^{(.00015D)}$
5-11A	Cost = 24,908 $e^{(.00014D)}$

---

[1] D = Depth (ft)

EXHIBIT I-5 (Continued)

C. Remaining Lease Equipment Costs

1,2,2A Cost = $34,797\ e^{(.00003D)}$

3,4 Cost = $24,027\ e^{(.00003D)}$

5-11A Cost = $20,183\ e^{(.00004D)}$

D. Injection Equipment Costs

1-11A Cost = $22,892\ e^{(.00009D)}$

E. Annual Operating Costs

1. Primary Recovery

1,2,2A Cost = $7,567\ e^{(.00009D)}$

3,4 Cost = $7,290\ e^{(.00006D)}$

5-11A Cost = $7,292\ e^{(.00006D)}$

2. Enhanced Recovery

1,2,2A Cost = $14,139\ e^{(.00013D)}$

3,4 Cost = $13,283\ e^{(.00011D)}$

5-11A Cost = $13,298\ e^{(.00011D)}$

F. Workover Costs

1-11A Cost = .48 D&C + .50 Prod. Equip.

B. Transportation Costs for Carbon Dioxide

The costs of transporting CO_2 in pipelines and the associated economies of scale are derived in the following. The analysis follows a five step sequence:

1. Calculate the relationship between pipeline capacity and costs.

2. Calculate the pipeline investment costs per Mcf for various pipeline capacities.

3. Calculate the fixed and variable carbon dioxide delivery costs per Mcf.

4. Calculate full costs per Mcf for natural and manufactured carbon dioxide.

5. Translate pipeline capacity to minimum required field size.

1. Relationship between Capacity and Costs:

The relationship between pipeline capacity and cost is based on published engineering and cost analyses for CO_2 pipelines.

a. Assume the following for calculating pipeline and compression investment costs:

- Operating pressure at 2000 psi
- Initial and intermediate booster compressors are required
- Costs in mid-1980 dollars
- Pipeline life of 20 years
- Costs to be modified based on terrain

b. As a base case for 125 MMcf/day pipeline capacity at a transmission length of 100 miles over flat terrain, the following was assumed:

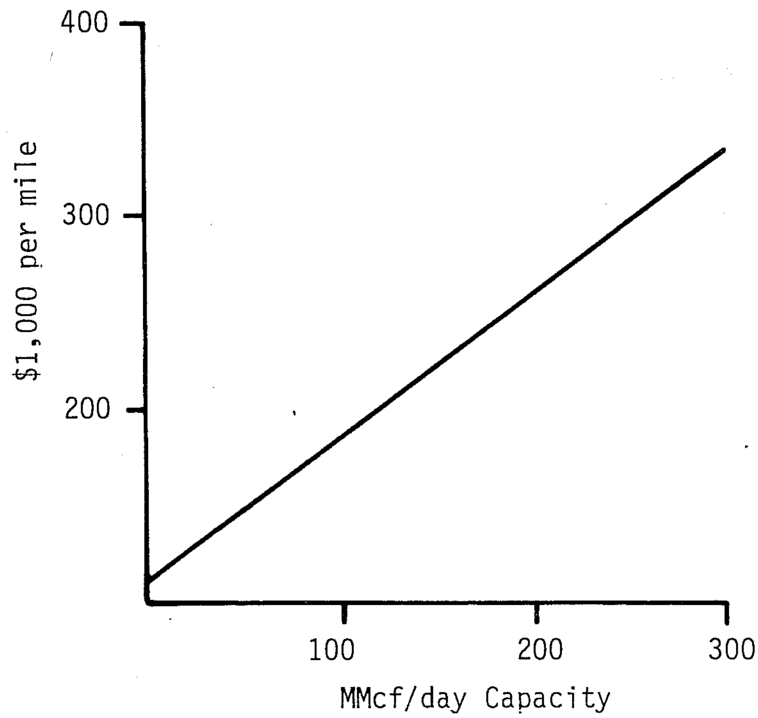
- Booster compressors required - 19
- Total compressor investment costs - \$3,300,000
- Pipe plus installation - \$18,700,000
- Total costs - \$22,000,000

c. On a per mile basis, the cost is \$220,000. To compute per mile costs at any capacity, the following equation may be used:

$$\text{Unit Cost} = 100{,}000 + 2{,}008[(\text{MMcf/d})^{.834}]$$

The relationship of capacity to costs is shown on the following graph:

PIPELINE CAPACITY VERSUS COST



d. Pipeline costs will be affected by the terrain through which the pipeline passes. The effects of terrain on per mile costs is summarized below*:

- Rugged terrain -- add $290,000/mile
- Rolling hill terrain -- add $16,500/mile
- River crossings -- add $330,000/mile
- Elevation differential -- add $2,100/foot

---

*Sources and Delivery of Carbon Dioxide for Enhanced Oil Recovery, Dec. 1978, Pullman Kellog under DOE/FE. Updated to 1980 using Bureau of Labor Statistics inflation indices.

2. <u>Pipeline Investment Costs per Mcf</u>:

The cost/capacity graph is translated into a cost per Mcf (per 100 miles) by dividing costs by capacity, as follows:

a. For 200 MMcf/day capacity at $267,000 per mile, the cost per Mcf per 100 miles is:

- (267,000 * 100)/(200,000 * 365 * 20) = $0.018 per Mcf

b. Applying a 20 percent before tax rate of return requirement would raise the costs to:

- $0.018 * 4 = 0.07 per Mcf per 100 miles

c. Similarly, the following table of pipeline investment cost per Mcf can be generated:

Pipeline Capacity (MMcf/day)	Pipeline Investment Costs per MCF (per 100 miles)
300	$0.06
200	$0.07
100	$0.11
50	$0.17
25	$0.28
10	$0.56
5	$1.12

3. <u>Fixed and Variable Carbon Dioxide Costs per Mcf</u>:

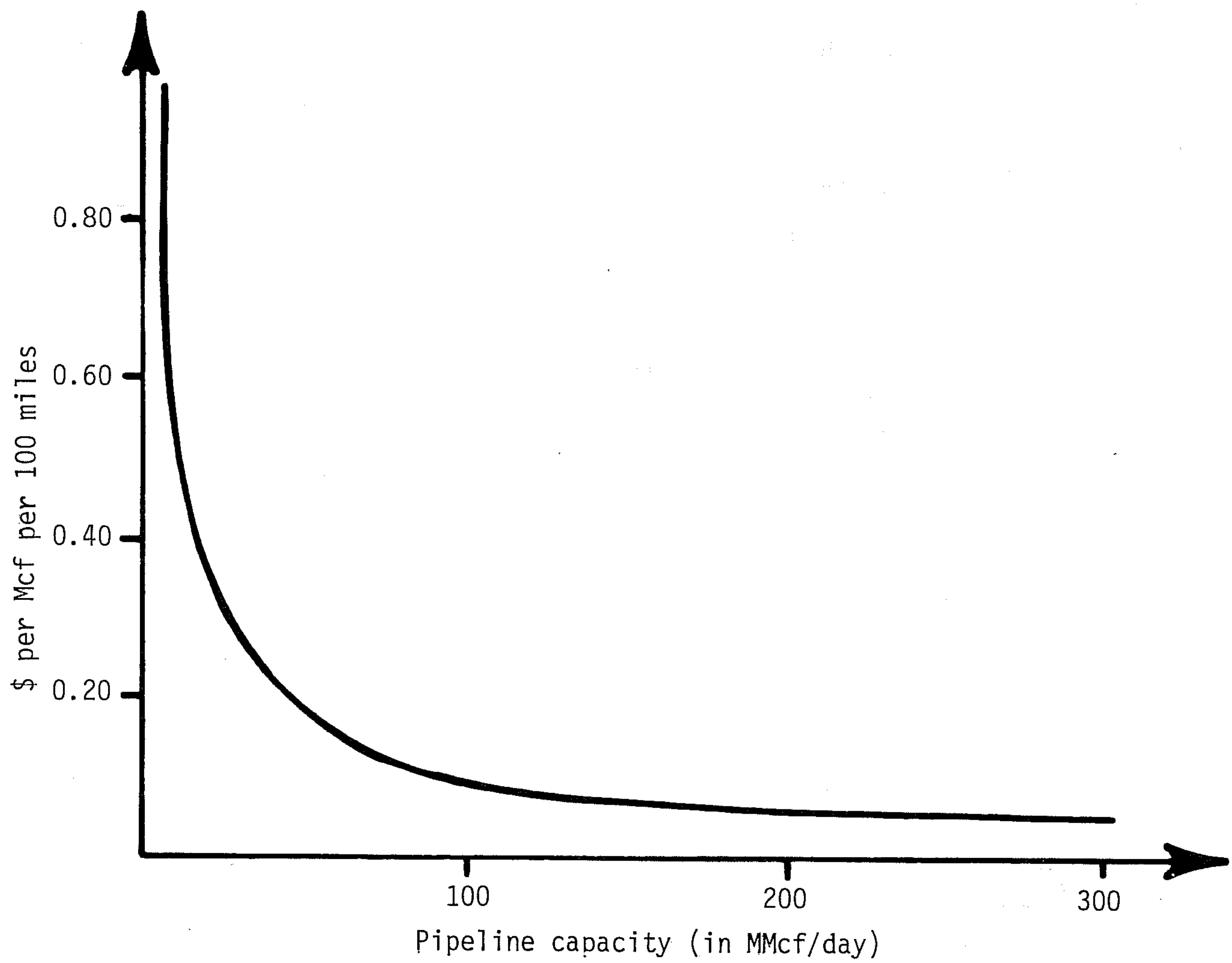
The pipeline investment cost is added to pipeline operating costs to develop pipeline costs per Mcf that vary by distance.

a. Assume that:

- Pipeline operating costs are $0.03 per Mcf per 100 miles,

- Use the pipeline capital costs from the preceding table,

b. Then the following variable cost per Mcf per 100 miles can be drawn:



4. Full Costs per Mcf:

The investment and operating costs are then added to the purchase price for natural CO_2 and acquisition and gathering costs for manufactured CO_2 to derive the full costs per Mcf as shown on the following table.

Assume that for fixed carbon dioxide costs:

- The purchase cost of naturally occurring carbon dioxide is $1.00 per Mcf*
- The acquisition cost for manufactured carbon dioxide is $1.70 per Mcf**
- Additional lateral lines will be required to gather and transport manufactured carbon dioxide as follows:

Pipeline Capacity (MMcf/day)	Amount and Size of Lateral Lines	Gathering Costs $/Mcf
300	4 - 50 mile @ 50 MMcf/day	0.05
200	3 - 50 mile @ 50 MMcf/day	0.06
100	3 - 50 mile @ 25 MMcf/day	0.11
50	2 - 50 mile @ 10 MMcf/day	0.11
25	1 - 50 mile @ 10 MMcf/day	0.11
10	1 - 50 mile @ 5 MMcf/day	0.28
5	None	

*Enhanced Recovery Weekly, Oct. 27, 1980 and other sources.

**Sources and Delivery of Carbon Dioxide for Enhanced Oil Recovery, Dec. 1978, Pullman Kellog under DOE/FE. Updated to 1980 using Bureau of Labor Statistics inflation indices.

Cost Components of Delivered Carbon Dioxide, $/Mcf

Pipeline Capacity (MMcf/day)	Distance	Transp. Costs	Natural CO_2 Purchase Costs	Manuf. CO_2 Acqui. Costs	Manuf. CO_2 Gather. Costs	Full Cost Natural CO_2	Full Cost Manuf. CO_2
300	100	0.09	1.00	1.70	0.05	1.09	1.84
	200	0.18	1.00	1.70	0.05	1.18	1.93
	300	0.27	1.00	1.70	0.05	1.27	2.02
	400	0.36	1.00	1.70	0.05	1.36	2.11
200	100	0.10	1.00	1.70	0.06	1.10	1.86
	200	0.20	1.00	1.70	0.06	1.20	1.96
	300	0.30	1.00	1.70	0.06	1.30	2.06
	400	0.40	1.00	1.70	0.06	1.40	2.16
100	100	0.14	1.00	1.70	0.11	1.14	1.95
	200	0.28	1.00	1.70	0.11	1.28	2.09
	300	0.42	1.00	1.70	0.11	1.42	2.23
	400	0.56	1.00	1.70	0.11	1.56	2.57
50	50	0.10	1.00	1.70	0.11	1.10	1.91
	100	0.20	1.00	1.70	0.11	1.20	2.01
	200	0.40	1.00	1.70	0.11	1.40	2.21
	300	0.60	1.00	1.70	0.11	1.60	2.41
	400	0.80	1.00	1.70	0.11	1.80	2.71
25	50	0.16	1.00	1.70	0.11	1.16	1.97
	100	0.31	1.00	1.70	0.11	1.21	2.12
	200	0.62	1.00	1.70	0.11	1.62	2.43
	300	0.93	1.00	1.70	0.11	1.93	2.74
10	50	0.28	1.00	1.70	0.28	1.28	2.26
	100	0.56	1.00	1.70	0.28	1.56	2.54
	200	1.12	1.00	1.70	0.28	2.12	3.10
5	50	0.56	1.00	1.70	--	1.56	2.26
	100	1.12	1.00	1.70	--	2.12	2.82
	200	2.24	1.00	1.70	--	3.24	3.94

5. Relationship of Pipeline Capacity to Field Size:

The pipeline capcity is converted to field size, as follows:

a. Assume that:

- 5 Mcf of purchased CO_2 are required per barrel of recovered oil,
- CO_2 is injected over 10 years,
- CO_2 recovers 20% of the oil left after primary/secondary recovery.

b. Then the following conversions of pipeline capacity to field size would hold:

Pipeline Capacity (MMcf/day)	Minimum Required Field Size: Incremental Oil Recovery by CO_2 (in million barrels)	Minimum Required Field Size: Residual Oil in Place (in million barrels)
300	146	730
200	98	490
100	48	240
50	24	120
25	12	60
10	6	30
5	4	17

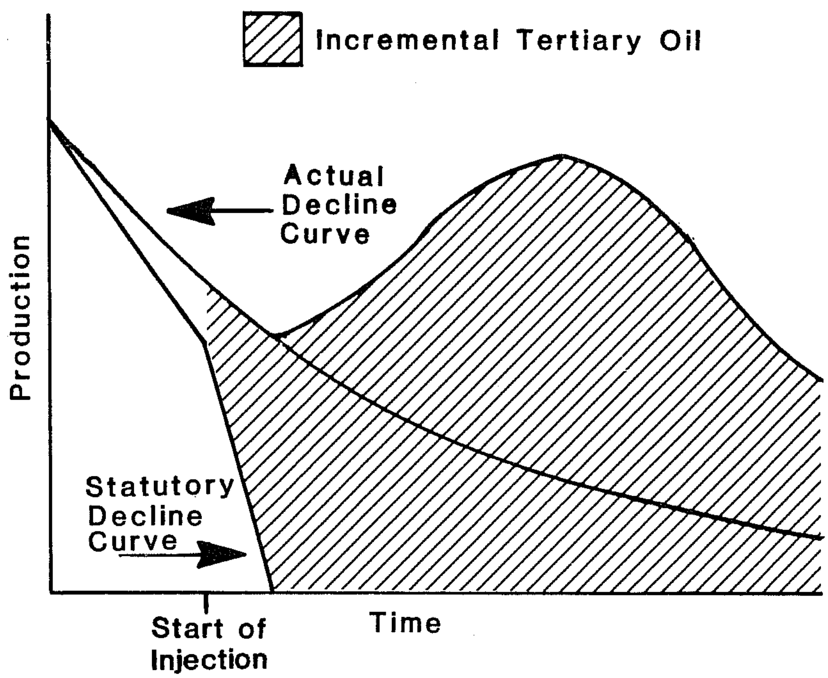
C. <u>THE WINDFALL PROFIT TAX</u>

The Crude Oil Windfall Profit Tax Act of 1980 (WPT) effects the economics of enhanced oil recovery projects in two ways:

- It establishes a 30% excise tax on revenues from tertiary recovery in excess of a variable adjusted base price

- It can reclassify a portion of old production as incremental tertiary oil (Tier 3), thereby potentially reducing the tax rate on old production to 30% from 70%

The graph below illustrates the oil production that is covered by each of these two effects. The production above the "statutory decline curve", the hatched area, is the tertiary recovery that is taxed at a rate of 30%. The area above the "actual decline curve" is the production due to the enhanced oil recovery project while the area between the "actual decline curve" and the "statutory decline curve" is production that is reclassified as EOR production. The area below the statutory decline curve is considered old production and is taxed at the full WPT rate.



The statutory decline curve is specified in the Act and is based on the average monthly production during the six month period ending March 31, 1979. It decreases at 1% per month of this base amount, starting January 1979.

Once the project has both begun injection and has been certified, the statutory decline rate accelerates to 3 1/2% of the base amount per month until the decline curve reaches zero, whereupon all production is defined by the WPT as "incremental tertiary oil". Thus, the WPT can act as a bonus or incentive for EOR projects by providing a reduction in tax if the statutory decline is more rapid than the actual decline.

Just how much of an incentive the WPT provides is dependent upon the classification of the old oil and whether the production is by a major or an independent, as the table below indicates:

Type of Production	Producer	WPT Percentage
Tier 1 (primary, secondary production)	Major	70
	Independent	50
Tier 2 (includes stripper production)	Major	60
	Independent	30
Tier 3 (EOR and heavy oil production)	All	30

The greatest EOR incentive would be for a major producer under Tier 1, while there would be no incentive for Independents with stripper wells. Also, there would be no incentive for anyone producing heavy oil less than 20°API.

Seven of the 15 projects analyzed in this study are not currently producing any "old oil." One field that has old production is producing heavy oil (Brea Olinda, 18°API), while 6 more have only stripper status production. The remaining field in this study is Crosset which does have significant "old production." Making the most favorable assumptions (Tier 1 oil being produced by a major), the Windfall Profit Tax EOR incentive due to the reclassification of old oil was calculated for this field.

The difference (incentive) between the WPT on the old production and the WPT on the old production plus "Incremental Tertiary Oil" over the life of the EOR project at an oil selling price of $30 per barrel was calculated to be $233,800. The yearly differences and the incremental oil due to CO_2 injection were discounted at 15 percent and divided to yield a per barrel incentive of $0.44 after state and federal taxes. This is relatively insignificant compared with the other costs for EOR, including the WPT of over $3 per barrel. There would be less, if any, incentive for stripper projects because the initial tax rate is lower (60% instead of 70%) and the tax savings would be lower because of less old production.

ATTACHMENT II

ENHANCED OIL RECOVERY MODELS

INTRODUCTION

The purpose of this Attachment is to document the Enhanced Oil Recovery models used in the 1980 cost update study. These models incorporate the empirical results of recent laboratory and field tests and reflect a current understanding of recovery mechanisms for each of the five EOR techniques analyzed by the study.

The five recovery models discussed are:

1. Steam Drive
2. In Situ Combustion
3. Carbon Dioxide Flooding
4. Sufactant/Polymer Flooding
5. Polymer Waterflooding

A. STEAM DRIVE

Steam drive consists of introducing steam into a reservoir through injection wells to mobilize oil which is subsequently produced from production wells. Steam is very efficient at mobilizing oil when injected, but becomes progressively less efficient as it moves away from the injection area, condenses, and rises to the top of the reservoir because of gravity segregation. In addition, heat losses to the cap and base rock and to the produced fluids lower the efficiency of steam drive.

1. Basic Steam Drive Model

A technically and economically successful steam drive involves selecting a reservoir with amenable characteristics and tailoring the steam drive process to fit the reservoir. The major reservoir and steam parameters that have an effect on the viability of the operation can be related to the oil-steam ratio through the dimensionless time of steam injection, t_d, and the ratio of latent heat to sensible heat in the injected steam, h_d;

$$t_d = \frac{4k_{h2}M_2t}{Z_t^2M_1^2} \tag{1}$$

and

$$h_d = \frac{f_{sd}L_v}{C_w \Delta T} \tag{2}$$

where:

t = Time of steam injection; hours

Z_t = Gross thickness of reservoir; ft.

M_1 = Average heat capacity of steam zone; Btu/cu.ft.-^oF

M_2 = Average heat capacity of cap and base rock; Btu/cu.ft.-^oF

k_{h2} = Thermal conductivity of cap and base rock; Btu/ft.hr.-^oF

L_v = Heat of vaporization of steam; Btu/lb

f_{sd} = Steam quality in reservoir; dimensionless

ΔT = Steam zone temperature minus original formation temperature; ^oF

C_w = Specific heat of water; Btu/lb/^oF

The relationship of the normalized oil-steam ratio to t_d and h_d is derived from simplified heat and flow equations and is shown graphically on Exhibits II-1 and II-2.

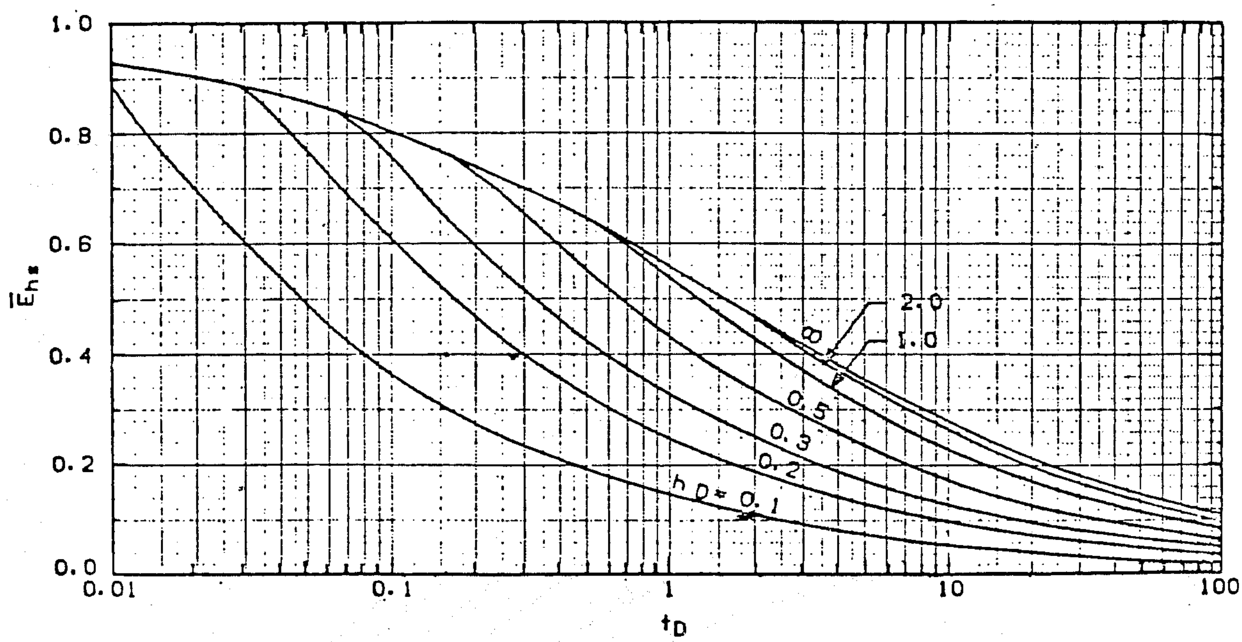
Once the reservoir parameters and the injection time for steam are given, these variables can be inserted into equations (1) and (2) and the normalized oil-steam ratio determined.

The actual steam-oil ratio, F_{os}, can be calculated from the normalized ratio as follows:

$$F_{os} = N_{os} * (\phi * \Delta S * \frac{Z_n}{Z_t}) C \qquad (3)$$

Exhibit II-1

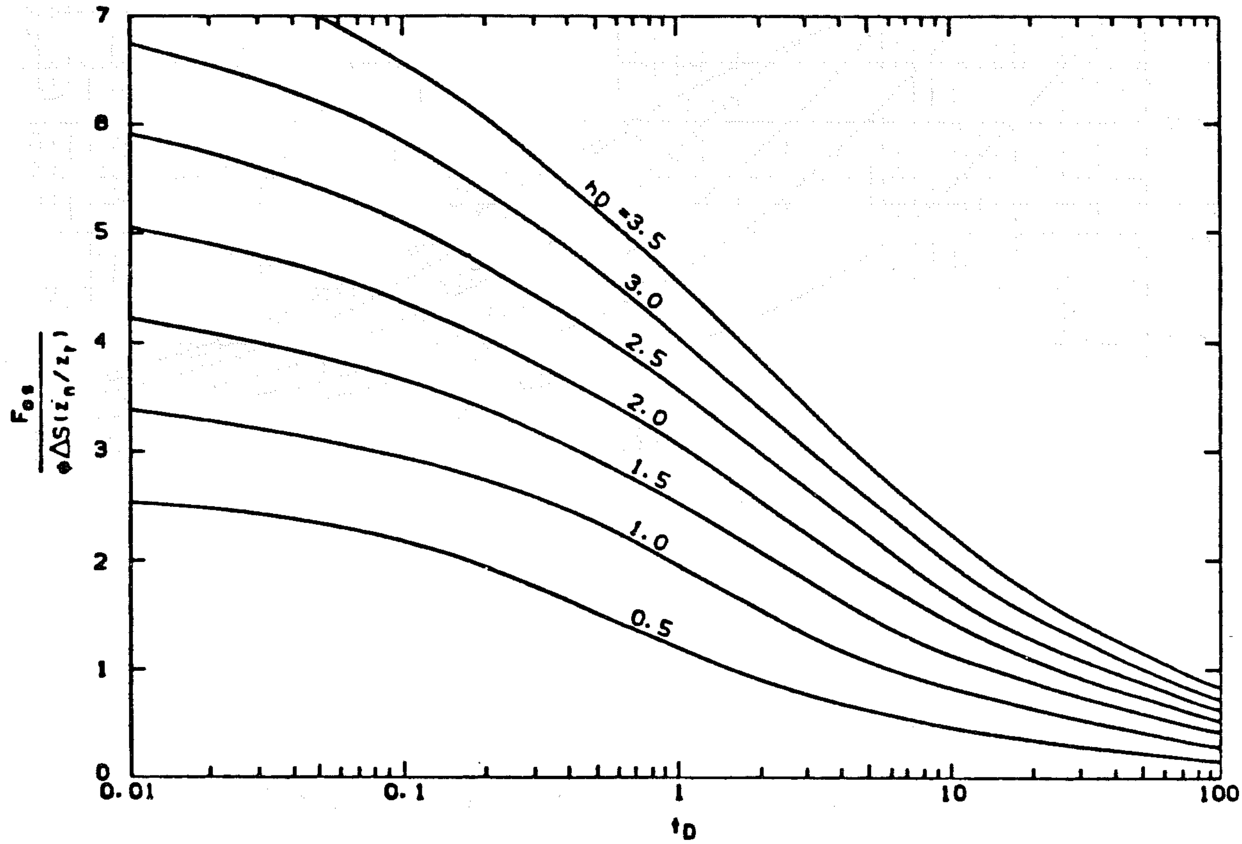
STEAM-ZONE THERMAL EFFICIENCY AS A FUNCTION OF DIMENSIONLESS PARAMETERS



SOURCES: Myhill & Stegemeier, "Steam Drive Correlation and Prediction", Journal of Petroleum Technology, February 1978.

Exhibit II-2

OIL/STEAM RATIO AS A FUNCTION OF DIMENSIONLESS PARAMETERS



Source: Myhill and Stegemeier, "Steam Drive Correlation and Prediction", Journal of Petroleum Technology, February 1978.

where:

F_{os} = Actual steam-oil ratio
N_{os} = Normalized steam-oil ratio
ϕ = Porosity
ΔS = Average initial saturation less average ending saturation
Z_n = Net thickness of reservoir
Z_t = Gross thickness of reservoir
C = Empirical corrective factor

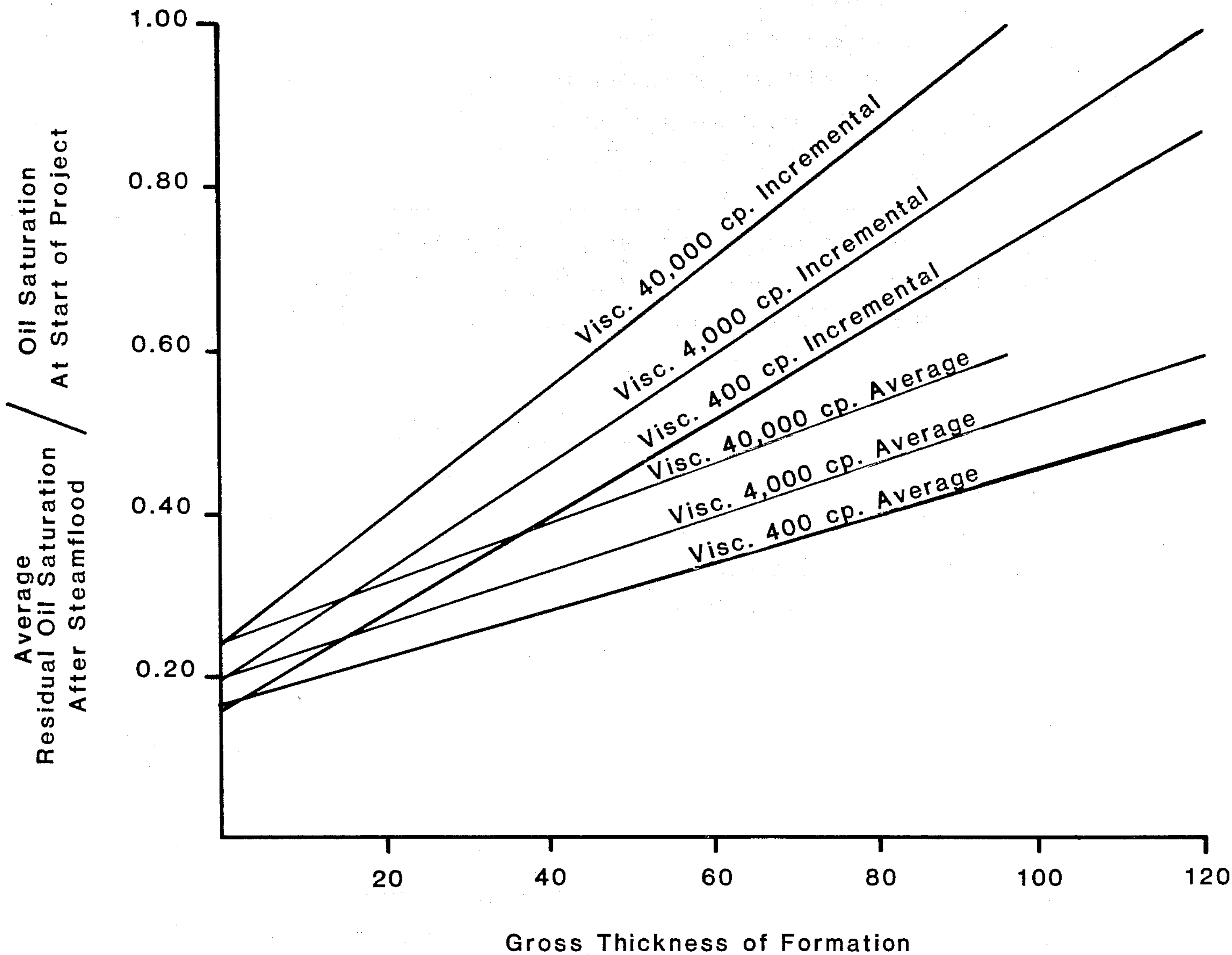
To use the model effectively, it must be calibrated with actual results. A review of the accuracy of this model with field results by Myhill and Stegemeier led the authors to recommend a value of 75% as the correction factor, C.

The ending saturation after steam drive will be dependent on the initial saturation, the thickness of the reservoir and the viscosity of the oil. The ending saturation was found using the correlation shown in Exhibit II-3. In this exhibit, the "incremental" lines denote the change in saturation as a function of distance from the top of the reservoir, while the "average" lines are used to find the average residual saturation for the reservoir.

This model has limitations in that it cannot predict an optimal injection rate nor does it include the effects of steam override or reservoir heterogeneities. The model assumes constant injection rates, frontal advance of the steam, and a steam injection rate above the critical rate that allows an oil bank to form. The model is therefore not applicable at very low injection rates, nor, since the model assumes no channeling of steam, applicable to the engineering of specific field operations where override usually occurs.

Exhibit II-3

DETERMINATION OF RESIDUAL OIL SATURATION AFTER STEAM DRIVE



However, as an approximation of the steam drive process the simple model is sound and by the inclusion of an empirical correction factor, it agrees quite well with field operations which are operated near optimal injection rates. Detailed analysis of reservoir specific operations will require reservoir simulation or a scaled physical model.

Equations (1) and (2) and Exhibits II-1 and II-2 illustrate major aspects of this steam drive analysis, such as:

- The oil-steam ratio is increased by minimizing t_d and maximizing h_d, i.e., injecting high quality steam at a high rate (the frontal displacement mechanism does not predict an optimum rate),
- The value of t_d can be minimized by selecting thick reservoirs,
- The value of h_d can be maximized by increasing the quality of the steam while maintaining as low a temperature differential between the steam and the formation as possible,
- For a given reservoir and steam quality, the oil-steam ratio decreases with time. The optimal economic recovery thus depends on an interdependent selection of injection rate, steam temperature, and injection time.

2. Injection Schedule

The injection schedule consists of an injection rate of 1.5 barrels of steam per day per acre-foot of pattern plus a first-year 0.05 pore volume injection of steam for an initial cyclic steam simulation. This injection rate reflects an optimum rate derived from field tests and scaled physical models. In total, steam is injected until the incremental oil-steam ratio falls below 0.12 or until 2.0 pore volumes of steam have been injected. The required injection time is derived from the pore volume of the analytic unit and the injection schedule above.

3. Unit Costs for Steam

The formula used to calculate unit costs for steam is:

- Cost of Steam, \$/Bbl = 0.40 + 0.072 * Fuel price (4)

The co-efficient, 0.072, is derived from the BTU requirements to generate 1 barrel of steam. The constant term, 0.40, represents the operating and maintenance costs for the steam generator, the costs of water supply and treatment, and the operating costs of pollution control. Other maintenance costs are included in the basic operating and maintenance costs.

4. Generator Costs

The units and costs of installed generating equipment have been scaled from a 50 MM BTU/hour steam generator costing \$320,000. In addition, the scrubbers needed to reduce SO_x and NO_x emissions of the generator cost \$300,000. A 50 MM BTU/hour unit is assumed to be able to generate 3,288 barrels of 80% quality, 1,000 Psig steam (water equivalent) per day, operating at 95% yearly efficiency. The number of generators required for the project is derived from the pore volume of the analytic unit and the injection schedule described above.

5. Production Schedule

The recovery of tertiary oil is derived by multiplying the oil-steam ratio from the recovery model by the volume of injected steam.

A standard production profile has been assumed for all steam drive projects. Recovery during the first and second years of a steam drive is assumed to be 50% and 75%, respectively, of the maximum production. Thereafter, the production schedule shows a constant production rate for the next several years followed by a decline to 90% of the constant rate during the next to last year, and to 70% during the last year. For a 6 year project the production schedule used in the steam drive model would be:

Year	% of Incremental Recovery
1	10
2	15
3	21
4	21
5	19
6	14
Total	100

6. Timing of Costs

All field development, workover, and equipment outlays for the analytic unit are assumed to be made one year prior to the initial injection of steam. Each zone is assumed to be steamed separately and the necessary well workover costs for each zone as assumed to require that steaming be discontinued for a year.

7. Detailed Cost Data

Detailed data on development, production, and operating costs are estimated based on the specific characteristics and geographical location of each project as discussed in the main body of the report and summarized in Attachment I.

B. IN SITU COMBUSTION

Basic In Situ Recovery Model

An analysis of 14 combustion field tests and pilots by W.E. Brigham, et al., in "Recovery Correlations for In Situ Combustion Field Projects and Application to Combustion Pilots" shows that recovery is a function of injected air, oil content, reservoir net pay, and crude oil characteristics. The basic recovery equation was derived from this work and is:

$$y \text{ (Oil Recovery, Bbls)} = 47\,(1 - e^{-1.2C}) \tag{5}$$

where:

$$C = [0.427\, S_{orw} - 0.00135h + 2.196\, (\frac{1}{\mu o})^{0.25}] * X \tag{6}$$

and:

$$y = \frac{N_p + N_b}{N} * 100 \tag{7}$$

$$X = \frac{A_i \quad * \quad E_{02}}{(N/\phi\ S_{orw})\ (1-\phi)} \tag{8}$$

and

A_i = Cumulative air injection, MMcf
E_{02} = Oxygen utilization, fraction
h = Net pay, ft
k = Permeability, md
N_b = Fuel burned, barrels
N_p = Cumulative incremental oil production, barrels
S_{orw} = Oil saturation at start of test, fraction
μ_o = Oil viscosity, cp
ϕ = Porosity, fraction
N = Original oil in place

This model is only valid until the burn front reaches a producing well or until an air channel has been created in the reservoir. Subsequent injection of air will then result in a marked deterioration in the performance of the combustion drive.

This recovery equation expresses oil recovery as a function of the injected volume of air. The recovery efficiency decreases exponentially with increasing volumes of air and asymptotes at a maximum value of $(N_p + N_b)$ equal to 47% of the oil in place. The rate of oil production is determined by A_i (the air injected) and (C/X). This latter factor depends in turn on the oil saturation, the net pay of the reservoir and the oil viscosity; the greater the oil saturation, the faster the recovery rate; the thicker the reservoir and the more viscous the oil, the slower the recovery rate.

By using an air injection rate and an injection time based on economic considerations, the cumulative oil recovery can be calculated.

The amount of oil burned per acre-foot is a function of the fuel content of the reservoir oil and the quantities of air efficiently utilized.

The fuel content of the reservoir oil, F, is a complex function of various reservoir crude oil properties that govern the coking tendencies of the crude. Chu (1977) developed the following correlation between fuel content and selected reservoir properties (having a correlation coefficient of 0.816):

$$\begin{aligned} F = & - 0.12 + 0.00262h + 0.000114k + 2.23S_{orw} + 0.000242kh/\mu_o \\ & - 0.000189D - 0.0000652\,\mu_o \end{aligned} \tag{9}$$

where:

F = fuel content, lb/ft^3 burned volume

h = reservoir thickness, ft

k = permeability, md

S_{orw} = oil saturation, fraction

μ_o = viscosity, cp

D = depth, ft

When other data is not available, assume fuel content is 1.5 lbs/cu ft.

The amount of oil burned per acre-foot can then be calculated from the volumetric equation:

$$N_b = \frac{43,560 * F}{330} \tag{10}$$

Oxygen utilization, E_{02}, is a decreasing function of cumulative oil recovery, as shown from the South Belridge Thermal Recovery experiment, Exhibit II-4.

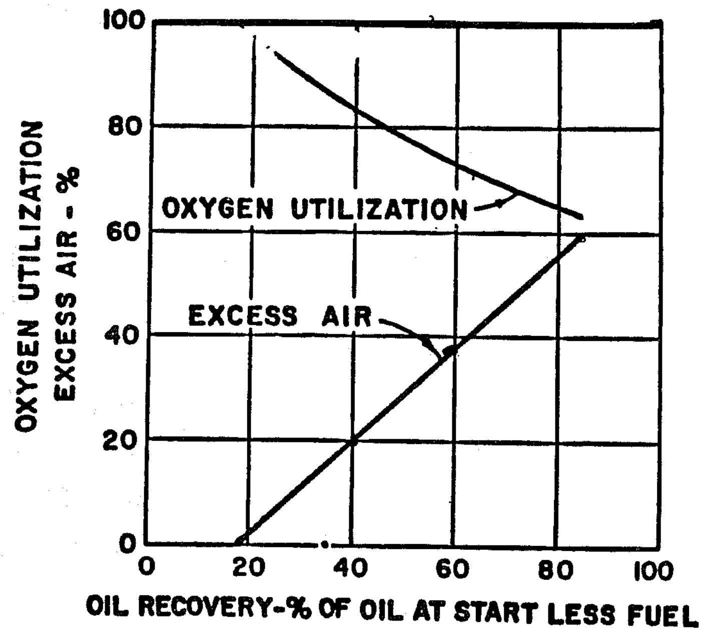
For simplicity, assume the following:

$\frac{N_b}{N}$, %	Oxygen Utilization %
0-5	100
5-10	90
10-15	80
15-20	70
20-25	60

Exhibit II-4

EXCESS AIR VERSUS OIL RECOVERY

(South Belridge Thermal Recovery Experiment)



$$\text{EXCESS AIR} = \frac{\text{UNUSED AIR}}{\text{AIR USED TO BURN FUEL}} \times 100\% \qquad \text{(INSTANTANEOUS)}$$

Injection Schedule

Based on an analysis of the air injected per acre-foot for actual combustion field tests, an annual injection rate of 1,000 to 1,500 Mscf per acre-foot per year was assumed. Injection continues at this rate for six years or until the incremental air-oil ratio reaches 30 Mcf per barrel.

3. Operating Costs for Air Compression

The formula used to estimate unit costs for air is:

- Cost of compressed air, \$/MSCF,

$$= 0.10 + 0.0162 * \text{Fuel Price} \quad (11)$$

The co-efficient, 0.0162, is derived from the BTU requirements to generate 1 Mcf of compressed air. The co-efficient varies by depth, and is 0.01863 for depths greater than 10,000 feet, and 0.01299 for depths less than 5,000 feet. The constant term, 0.10, represents the incremental operating and maintenance costs for six stages of air compression, estimated at \$0.017 per Mcf per stage. Other maintenance costs are covered in the basic operating and maintenance costs.

4. Compressor Capital Costs

Compressed air is provided by a six stage bank of compressors with one horsepower of compression providing 2.0 Mcf per day or 730 Mcf per year. Using a base cost of \$530 per installed horsepower, the compressor capital costs are based on the number of horsepower required by the analytic unit as a function of its pore volume and air injection schedule.

5. Other Costs

Additional chemical costs for emulsion breakers of $0.25 per barrel of recovered oil have been included for treating the emulsified oil.

6. Production Schedule

The recovery of tertiary oil is determined by calculating the oil recovery assuming a constant injection of air at 1,000 to 1,500 Mcf per acre-foot per year.

Production is assumed to occur over 6 years as follows:

Year	% of Incremental Recovery
1	10
2	16
3	22
4	20
5	18
6	14
Total	100

This production schedule shows an increasing recovery for the first three years and thereafter, a decline through year 6 when the economic limit is reached.

7. Timing of Costs

All field development and equipment outlays are assumed to be made one year prior to the initial injection of air into the first zone. Each zone is assumed to be burned separately and the associated workover costs for each well is assumed to require that air injection be discontinued for a year.

is assumed to equal the waterflood sweep and no corrective factor is used.

2. Injection Schedule

The number of years that CO_2 is injected is determined by assuming that 0.1 HCPV of CO_2 is injected per year until the annual revenues are less than the annual operating and other costs, until 0.7 HCPV of CO_2 have been injected or until the incremental CO_2/oil ratio is 30 Mcf/barrel. An alternating slug of 0.1 HCPV of water is injected into the reservoir per year along with CO_2. Water injection continues after CO_2 injection terminates.

In the CO_2 flooding model, it is assumed that the CO_2 produced from the reservoir is compressed and reinjected. The following schedule is used in the model (and extended or truncated if the injection period is shorter or longer):

Years	Purchased, HCPV	Recycled CO_2, HCPV
1	0.1	--
2	0.1	--
3	0.05	0.05
4	--	0.10
5 - on	--	0.10

This injection schedule assumes 0.25 HCPVs of CO_2 are purchased and that the injection of recycled CO_2 starts in the third year and builds up while injection of purchased CO_2 tapers off.

3. Unit Costs for CO_2

The model assumes a unit cost for purchased, natural CO_2 of:

- Cost of natural CO_2, \$/Mcf = 1.00 + 0.25 * (pipeline distance from CO_2 source to the field, in 100 mile units) (13)

This unit cost for CO_2 is calculated by assuming a \$1.00 per Mcf purchase price and transportation and delivery costs of \$0.25 per Mcf per 100 miles. The \$0.25 per Mcf is derived by assuming a 500 mile, 200 MMcf/day pipeline to the Permian Basin from the Four Corners area and allowing for the differences in terrain.

The cost of recycled CO_2 is assumed to be \$0.54 per Mcf, derived as follows:

- \$0.26 per Mcf for CO_2/hydrocarbon separation and CO_2/H_2S separation, and

- \$0.28 per Mcf for repressurizing.

Additional field equipment, however, is required for recovering and recycling the CO_2, as discussed under 4. Field Equipment Costs.

Where natural CO_2 is unavailable, the model assumes a unit cost of manufactured CO_2 of 1.70 + 0.34 * (pipeline distance from the CO_2 source to the field, in 100 mile units). The manufactured CO_2 unit cost is calculated by assuming \$1.70 per Mcf for by-product or waste gas extraction and transportation costs (requiring extensive gathering lines and generally smaller pipelines) of \$0.34 per Mcf per 100 miles, with a minimum transportation/pressurizing charge of \$0.68.

4. Field Equipment Costs

The cost of field separation and compression equipment for recycled CO_2 is set at $100,000 for a three stage unit. Such a unit is assumed to be able to separate and recompress 1 Bcf of CO_2 per year.

5. Production Schedule

The production schedule for a CO_2 flood is determined from the cumulative recovery equation by calculating the cumulative amount of oil produced at the end of each year, assuming an annual injection of 0.1 HCPV of CO_2 and 0.1 HCPV of water. The annual recovery can then be found as the difference between the cumulative recovery of the current and the preceding year. Production is assumed to continue for four years after CO_2 injection stops or until the recovery is uneconomic (annual revenue less than marginal operating costs). The calculation of this recovery follows the recovery equation for the CO_2 flood since energy, in the form of water injection, and CO_2 is available in the reservoir to continue recovery.

6. Timing of Costs

All field development and equipment outlays are assumed to be made one year prior to injection of CO_2. Field separation and compression equipment outlays for recycling the produced CO_2 are made during the third year of the project.

7. Detailed Cost Data

Detailed data on development, production, and operating costs are estimated based on the specific characteristics and geographical location of each project.

D. SURFACTANT/POLYMER FLOODING

1. Basic Surfactant/Polymer Model

Recovery projections for surfactant/polymer flooding are derived from existing high concentration chemical slug projects.

This analysis is based on the following assumptions:

1. The target oil at project initiation is the residual oil in the waterflood swept zone.
2. The effective sweep efficiency for surfactant/ polymer is 65% of a waterflood sweep, but the areal sweep is not less than 40%.
3. Residual oil saturation in the swept zone after the surfactant/polymer flood is 0.10.
4. Residual oil saturation in the unswept zone stays the same as at the project initiation.

Thus, incremental recovery is calculated by the following equation:

$$\text{Incr. Cumulative Recovery} = (S_{sweep})^{*} N * \frac{B_{oi}}{B_{o}} \left(\frac{S_{orw} - 0.10}{S_{oi}}\right) \tag{14}$$

where:

N	= Original oil in place
S_{sweep}	= Surfactant sweep (0.65 Ev; $\geq$ 40%)
Ev	= Waterflood sweep efficiency
S_{orw}	= Oil saturation after primary and secondary recovery, in the swept zone
S_{oi}	= Initial oil saturation
Boi	= Initial formation volume factor
Bo	= Formation volume factor after primary and secondary recovery

2. Injection Schedule

Fluid is injected in three stages. First, a surfactant slug of 0.10 to 0.14 reservoir pore volume is injected; this is followed by the injection of polymer equal to 1 reservoir pore volume using a decreasing concentration of polymer solution over three years; and third, 1 pore volume water is injected over the next three years. Exhibit II-5 indicates the assumed polymer concentration decline curve, showing the tapered polymer slug has an average concentration of 700 ppm.

3. Unit Costs of Injected Fluids

Each barrel of surfactant is composed of 17.5 pounds of petroleum sulfonate (100 percent active), 3.5 pounds of alcohol, and 70 pounds of crude oil. Each barrel of polymer injected contains 0.243 pounds of polymer at 700 ppm.

Unit costs of surfactant/polymer flooding are:

- Surfactant Costs, \$/Bbl = 3.87 + 0.417 * (Oil Price) (15)

Unit costs of polymer solution (at 700 ppm) are:

- Polymer Costs, \$/Bbl = 2.20 + 0.2 * (Oil Price)/4.12 (16)

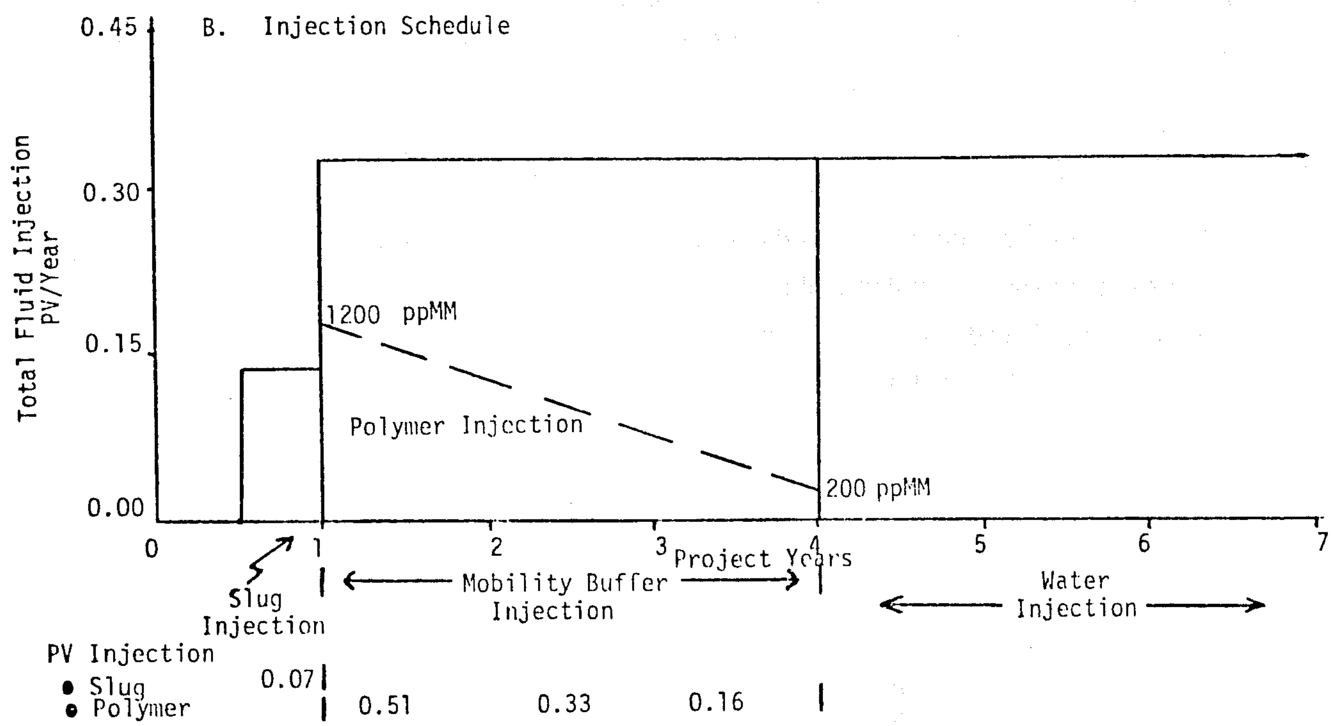
Equations 15 and 16 were derived based on the following table* using regression analysis:

Oil Price (\$/Bbl)	Total Surfactant and Slug Cost (\$/Bbl)	Polymer Cost (\$/lb)
5	6.26	2.30
10	7.96	2.40
15	10.07	2.49
20	12.13	2.58
25	14.24	2.70

* Source: "Enhanced Oil Recovery," National Petroleum Council, December 1976, Tables 19 and 20.

Exhibit II-5

SURFACTANT/POLYMER FLOODING



The surfactant and polymer costs in this study are based on a \$30 per barrel oil price, and that one pound of polymer is dissolved in 4.12 barrels of water for an average concentration of 700 ppm.

4. Other Costs

Additional field and well equipment is needed to handle, store and inject surfactant and polymer. For example, because of the corrosive effects of the surfactant, the storage tanks and injection wells will need to be lined. Thus, each five acre analytic unit is assessed \$50,000 for these additional field and well equipment outlays.

5. Production Schedule

The production schedule used for a surfactant/polymer flood assumes a response during the third year (assuming the injection of polymer) followed by increasing production for the next two years and a decline to the economic limit the last two years. Thus, the production schedule for oil from a surfactant/polymer flooding project is:

Year	% of Incremental Recovery
1	0
2	0
3	10
4	26
5	32
6	20
7	12
Total	100

6. Timing of Costs

All field development and equipment outlays are assumed to be made one year prior to slug injection. The analytic unit operates for seven years until the increasing water/oil ratio makes further operation uneconomic.

7. Detailed Cost Data

Detailed data on development, production, and operating costs are estimated based on the specific characteristics and geographical location of each project.

E. POLYMER WATERFLOODING

1. Background

The purpose of polymer flooding is to increase the viscosity of the drive water and by selective polymer deposition to reduce water channeling in heterogeneous reservoirs.

The increase in water viscosity results in an improved areal sweep by improving the mobility ratio ($\lambda_{pw}/\lambda_o > \lambda_w/\lambda_o$) where λ is the mobility and the subscripts pw, w and o stand for polymer water, water and oil.

Work to date suggests that the use of high molecular weight polymers are capable of increasing the apparent viscosity of water by factors of 10 to 100, depending on the rate of flow. Exhibit II-6 shows the relationship of areal sweep, at water breakthrough, for a five-spot pattern, for different mobility ratios. Improved oil recovery due to the increase in viscosity results from two factors:

- more of the reservoir is swept before economically limiting water-oil ratios is reached, (generally ranging from 10 - 50 to 1, depending on costs of water disposal and the absolute volume of oil produced)
- the residual oil saturation to water has been found (by Abrams) to be a function of:

$$\frac{V * \mu_w}{\sigma_{ow}} \left(\frac{\mu_w}{\mu_o}\right)^{0.4} \tag{17}$$

where:

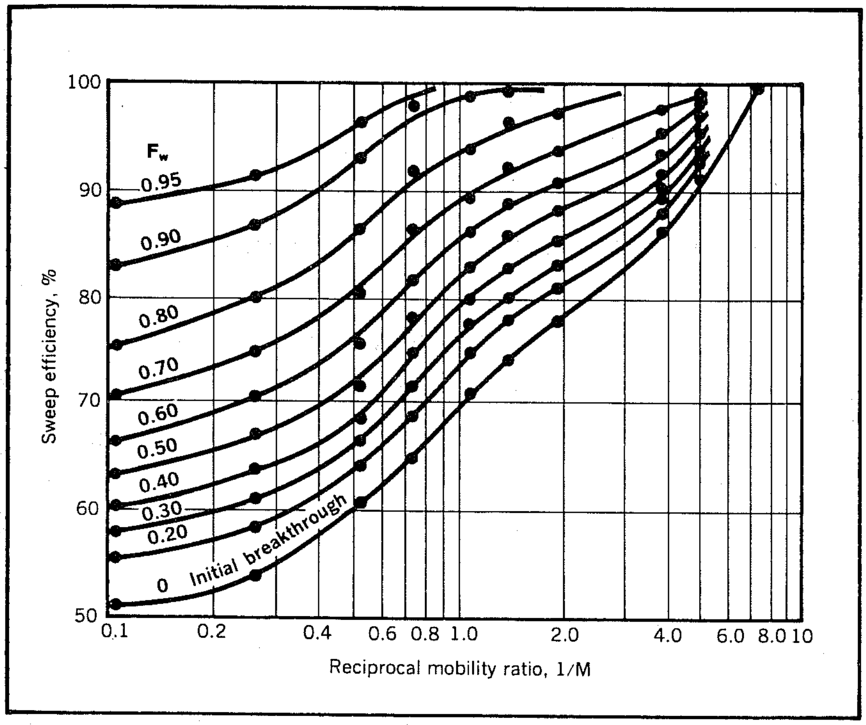
V = flow velocity, cm/sec

σ_{ow} = interfacial tension, dyne/cm

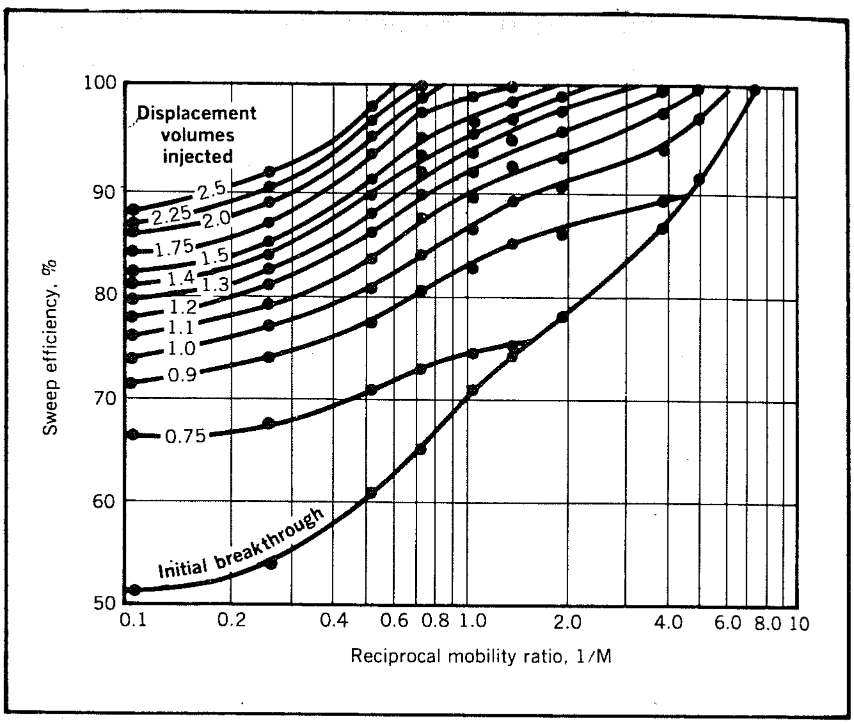
μ_w = water viscosity, poise

μ_o = oil viscosity, poise

Exhibit II-6



Effect of mobility ratio on sweep efficiencies for the five-spot pattern; f_w is the reservoir cut and $M = \lambda_w/\lambda_o$. (After Dyes, Caudle, and Erickson, *Trans. AIME.*)



Effect of mobility ratio on the displaceable volumes injected for the five-spot pattern. $M = \lambda_w/\lambda_o$. (After Dyes, Caudle, and Erickson, *Trans. AIME.*)

Thus, an improved viscosity ratio will lead to lower residual oil, although because of the small absolute difference between μ_w and μ_o and the fractional power, this effect is generally small.

A second, very promising use of polymers is to correct reservoir heterogenieties and thus improve vertical conformance. Here, polymer deposition in the higher permeability strata and into the higher water saturation pores and channels serves to "block" water channels, improve the permeability profile of the reservoirs and thereby improve the water-oil ratios. Increased recovery would be due to increased volumetric sweep before reaching economically limiting water-oil ratios.

Although the theoretical basis for increased oil recovery is sound, field performance has been mixed and even when successful generally lower than predicted from laboratory and analytic work. Thus, an empirically derived incremental oil recovery model is used which views recovery from polymer flooding as having two components. The first is a "sick patient" process that can improve the performance of poor waterfloods but that has decreasing incremental effect when waterflood performance is already good. The second component is due to a slightly increased recovery from the zone swept by the waterflood due to the better mobility ratio between polymer augmented water and oil.

A review of polymer waterflood projects, shows that the addition of polymer improves the sweep by 1% for every 10% that the primary/secondary sweep efficiency is less than 100%. Thus, recovery projections are inversely dependent on the effectiveness of the waterflood sweep. The formula for incremental recovery due to polymer flooding is:

$$\text{Cum. Rec.} = \left[(0.1 - \frac{E_v}{10}) * \frac{(S_{oi} - S_{orp})}{S_{oi}} + E_v \frac{(S_{orw} - S_{orp})}{S_{oi}} \right] * \frac{B_{oi}}{B_o} * N \qquad (18)$$

where: E_v = Previous, or anticipated, waterflood sweep in a particular reservoir

N = Original oil in place

B_{oi} = Initial formation volume factor

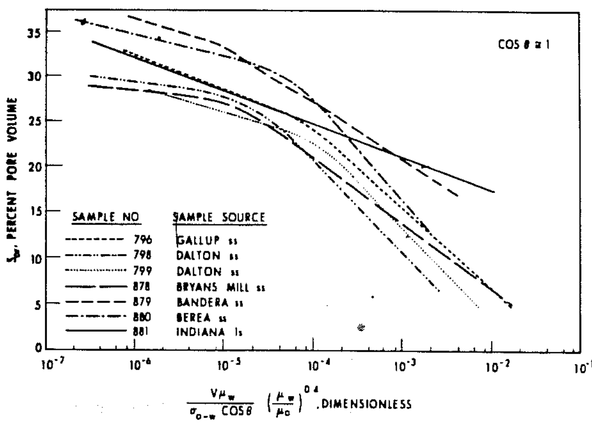
B_o = Oil formation volume factor after primary and secondary recovery

S_{oi} = Initial oil saturation

S_{orw} = Residual oil saturation, in water-swept region

S_{orp} = Residual oil saturation to polymer flooding

As discussed above, Abrams has found that the residual oil saturation is a function of water viscosity multiplied by the water viscosity divided by the oil viscosity raised to the 0.4 power. This relationship is shown below.



Assuming that the addition of 400 ppm polymer increases the viscosity of the water 10 times, the dimensionless function would increase 25 times. For a typical waterflood, the value of this function would be less that 10^{-6}. For Berea sandstone, the residual oil saturation would therefore be reduced by 1 to 2%. Since this redution must be a function of S_{orw}, we will assume that

$$S_{orp} = 0.98 * S_{orw}$$

2. Injection Schedule

The basic polymer concentration is 400 ppm for reservoir oils with viscosities less than or equal to 10 centipoise or gravity greater than or equal to 32°API. Beyond this, the concentration of polymer is increased with viscosity according to the following formula (where API gravity serves as a proxy for viscosity):

$$\text{Polymer Concentration} = \frac{10 + 32 - {}^{o}\text{API}}{10} * 400 \text{ ppm} \tag{19}$$

The equation is valid for API gravity greater than 10 and less than 32.

The volume of polymer injected is 50% of the swept pore volume at a rate of 0.10 pore volume for each of the first five years.

Thus, the volumes of polymer required in barrels are:

$$0.5 \text{ pore volume } (E_v + (0.1 - E_v/10))$$

3. Unit Costs for Polymer Solution

The cost of polymer solution (at a concentration of 400 ppm) is:

- Polymer Cost, \$/Bbl = 2.20 + 0.02 * (Oil Price)/7.21 (20)

Equation 20 is derived from the following table* using regression analysis:

Oil Price ($/Bbl)	Polymer Price ($/Bbl)
5	2.30
10	2.40
15	2.49
20	2.70

The polymer cost in this analysis is based on a $30 per barrel oil price and one pound of polymer is injected in 7.21 barrels of water at a concentration of 400 ppm. The polymer is assumed capable of withstanding the salinity encountered in polymer augmented waterflood without deterioration.

4. Production Schedule

The production schedule used for polymer shows a response during the second year, an increasing production rate for two years, and then a gradual decline to the economic limit after nine years. Thus, the production schedule for the oil recoverable from polymer augmented waterflooding is:

Year	% of Incremental Recovery
1	0
2	5
3	10
4	20
5	20
6	15
7	10
8	10
9	5
10	5
Total	100

*Source: "Enhanced Oil Recovery," National Petroleum Council, December 1976, Table 19.

5. Timing of Costs

All field development and equipment outlays are assumed to be made in the first year. The analytic unit operates for ten years until increasing water/oil ratios make further operations uneconomic.

6. Detailed Cost Data

Detailed data on development, production, and operating costs are estimated based on the specific characteristics and geographical location of each project.

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