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NATIONAL BENEFITS/COSTS OF ENHANCED OIL RECOVERY RESEARCH

Final Report

August 1976

Work Performed Under Contract No. E(49-18)-2021

Little (Arthur D.), Incorporated
Cambridge, Massachusetts

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

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ABSTRACT

THE NATIONAL BENEFITS/COSTS OF ENHANCED OIL RECOVERY RESEARCH
By Arthur D. Little, Inc., Cambridge, Massachusetts
For the U.S. Energy Research and Development Administration

This analysis is a more detailed updating of an earlier analysis performed in mid-1974 for the Bureau of Mines. It is an assessment based upon available information of the benefits/costs of planned Federal R&D programs in enhanced oil recovery technologies. The primary type of benefit quantified in this report is the national savings to be realized as a result of having cheaper supplementary oil available from enhanced recovery than would be otherwise available under uncertain alternative futures.

Alternative types of benefits are also reviewed, including those associated with avoiding more expensive re-entry of stripper wells at a later time, those associated with the balance of payments value of enhanced recovered oil, and those associated with enhanced recovered oil becoming part of a national emergency stockpile. Other benefits which remain unquantified are those associated with the insurance and portfolio values of a broad program of research in enhanced oil techniques.

Assuming the availability of "upper tier" prices ($11.28/Bbl) for enhanced oil, and a discount rate of 6% per year to represent a constant dollar opportunity cost of capital, the estimated benefit/cost ratios of Federal R&D related to enhanced oil research are:

a) between 3 and 7 assuming that enhanced recovered oil will delay the requirement for more expensive oil from offshore sources, and

b) or, alternatively, between 2 and 8 assuming that enhanced recovered oil will delay the requirements for more expensive imported oil.

The uncertainties associated with the analysis require that the benefit/cost ratios be viewed only as an indication of the level of benefit/cost advantages to be attributed to enhanced oil recovery research. The sensitivity of the benefit/cost ratios to alternative assumptions is illustrated through a number of sensitivity analyses. The consistent indications from these analyses are that the expected benefits from the development of enhanced oil recovery technology substantially exceed Federal program costs.

1.0 SUMMARY

1.1 GENERAL

The analysis reported here was performed in mid-1976 and updates an earlier report performed in mid-1974.* In addition to its being a quick response, best efforts assessment, the earlier analysis was hampered by a lack of good estimates of the economics of enhanced oil recovery (EOR) technologies. This updated assessment has benefited from a much larger universe of recent studies than was available earlier. Yet, depsite the more realistic perceptions of the role of EOR which have resulted from these studies, the amount of uncertainty which surrounds the future of EOR production in this country remains roughly the same as before.

Assessing the future returns of R&D related to a new technology is by nature a speculative task, but the great uncertainty surrounding the analysis reported here does not lessen the importance of the assessment to R&D planning. These uncertainties do require that this kind of analysis continue to be viewed partly in a "What if?" context. In that sense, it is important to emphasize the key assumptions, the framework of numerical estimates, and the sensitivity of results to certain parameters.

In the context of varying industry interest, continued technological uncertainties, and the increasing costs which are affecting all kinds of oil production, this kind of analysis continues to show positive benefit/cost ratios for Federal research on EOR techniques. The scenarios and associated benefits in this report are different than the ones of the earlier version, but the conclusions remain qualitatively the same, i.e., that EOR continues to promise sufficient rewards in domestic oil supply and energy cost savings to justify accelerated Federal research and demonstration.

1.2 TYPES OF BENEFITS

Federal expenditures on research, development, and demonstration of EOR technology constitute a set of public costs, for which there are expected returns in the form of public benefits. The costs and benefits of an EOR research program are not all readily quantified. Nevertheless, they may be defined, grouped, and evaluated in a rational manner to assist in public policy and decision-making.

---

* The Benefits/Costs of Tertiary Oil Recovery, Report to U.S. Department of Interior, Bureau of Mines, Under Contract #J0155010, December 1974.

We have identified six types of benefits to be associated with an EOR research program:

- Type A Benefits: National Savings from an EOR Option

  The savings realized by the Nation as a result of having cheaper supplementary oil available from enhanced recovery than would be otherwise available under uncertain alternative futures.

- Type B Benefits: Avoiding the Cost of Re-Entry of Capped Wells

  The savings resulting from applying enhanced recovery methods to stripper wells which would otherwise be closed and require more expensive re-entry costs at a later time.

- Type C Benefits: Balance of Payments Value

  An alternative view of the benefits of enhanced recovery being equal to the full balance of payments value/ barrel of recovered reserves, recovered at an earlier time; or, conservatively, the benefit in terms of the interest on the balance of payments savings over the period assumed.

- Type D Benefits: Value as Part of an Emergency Stockpile

  The possible benefits tied to the coincident needs of developing enhanced recovery technologies and creating an emergency stockpile of oil which might be tapped in a crisis.

- Type E Benefits: Insurance and Portfolio Values

  The thus far unquantifiable benefits associated with: 1) insurance against the risks of overall program failure; and 2) portfolio diversification to reduce the uncertainty of overall program outcomes.

- Type F Benefits: General Societal Benefits

  Benefits suggested by other studies including those of training and employment, information exchange, increased competition, and increased knowledge of reservoir structure and recovery potentials.

The first three of these benefit types are more readily quantified in dollar terms, assuming that certain forecasts and/or reasonable assumptions about the cost of producing oil, the price of imports, etc., are available. The estimated benefits in dollars associated with these concepts are not necessarily additive. In particular, we believe Type C Benefits should be considered separately as an alternative measure of overall benefits of the program. The other additive benefits quantified in this analysis cannot be considered complete until the others are also quantified. Further, the benefits listed above cannot yet be considered a complete list of potential benefits to be derived from Federal R&D in support of enhanced oil recovery.

1.3 PRIMARY METHODOLOGY

The greatest emphasis in this report is upon the quantification of Type A Benefits--the savings to be realized by the Nation as a result of the probability of having some cheaper supplementary oil available from accelerated EOR research than would be otherwise available under uncertain alternative futures. Savings are further defined as the "differential in the total cost" for a given supply of oil between a scenario that assumes no Federal support of EOR-related R&D and a scenario that assumes significant Federal R&D support. The process by which these primary benefits and resulting benefits/costs ratios were developed is shown in Figure 1-1.

This updated analysis relied heavily upon both the use of recent studies and contacts in the field with knowledgeable authorities in order to assemble the best possible forecasts of the future economics of enhanced oil recovery and the future production potentials, associated with those economics. Similarly, it draws upon available estimates of the cost of oil production from off continental-shelf (OCS) resources and the current price of imported oil. In the cases of EOR and OCS oil production, costs were translated into cumulative probability distributions. In the case of imported oil, a constant unitary distribution of cost (i.e., current price) over time was assumed. The analysis is reported in terms of constant 1976 dollars.

These cost estimates were associated with a range of estimates of the probable production of oil from enhanced oil reserves through the year 2000. The probable savings per barrel were then calculated by means of a computerized Monte Carlo analysis of the probabilistic cost distributions. These savings were then compared to the total anticipated cost of Federal R&D related to enhanced oil recovery, and benefit/cost ratios of the Federal program were derived on non-discounted and discounted bases. Finally, the sensitivity of these results to important assumptions such as the most competitive alternative (OCS or imported oil), the availability of low tier ($5/Bbl) or high tier ($11/Bbl) prices for EOR oil, the use of different discounting rates (6% or 12%), and different levels of Federal R&D funding.

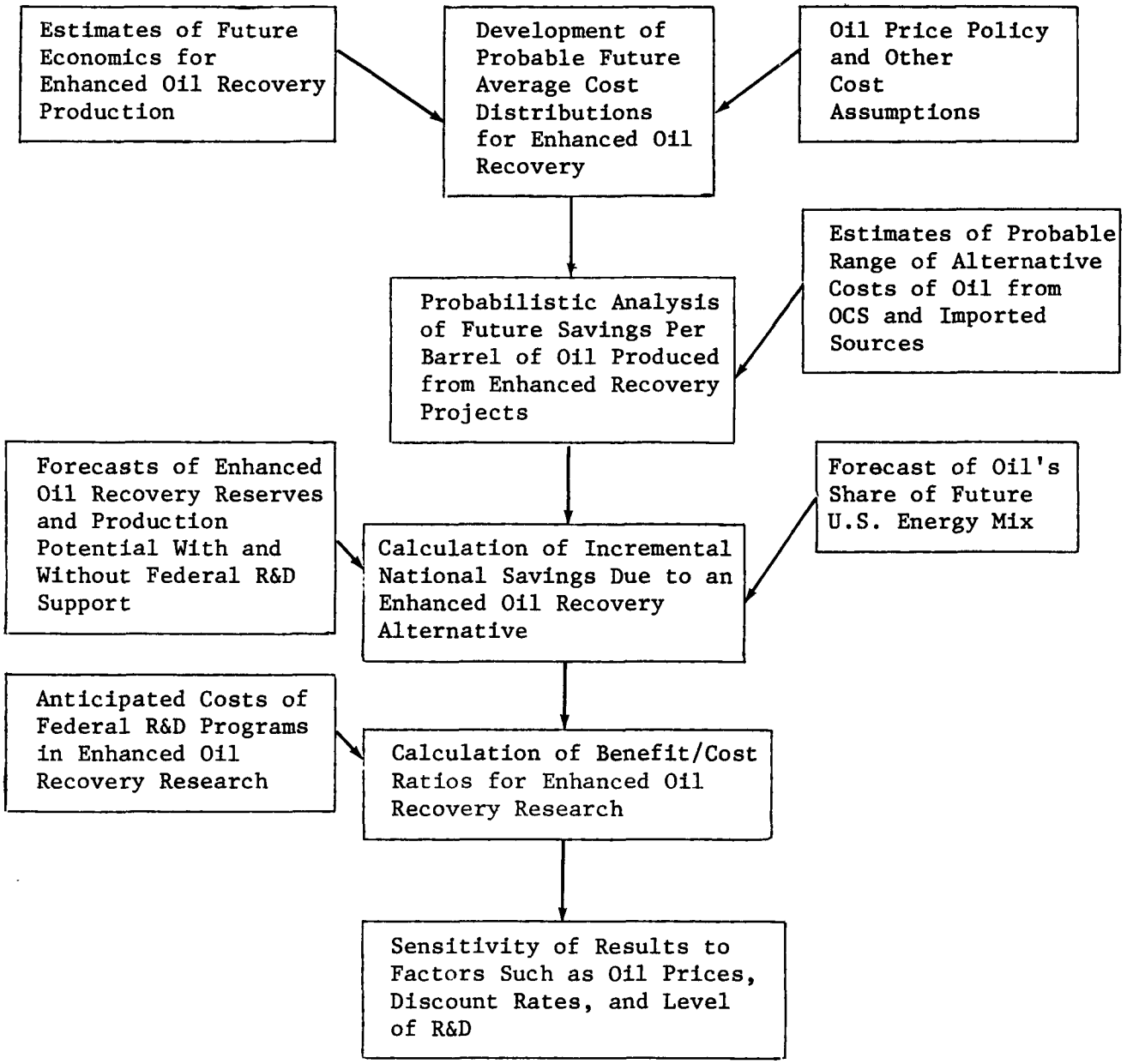


FIGURE 1-1

SUMMARY FLOW DIAGRAM OF STEPS OF ANALYSIS USED TO ESTIMATE PRIMARY BENEFIT/COST RATIOS FOR FEDERAL ENHANCED OIL RECOVERY RESEARCH

1.4 RESULTS

Representative benefit/cost (B/C) ratios developed in this analysis are listed in Table 1-1. The uncertainties of the analysis require that the B/C ratios be viewed only as an indication of the general levels of benefit/cost advantages of enhanced oil recovery research.

The sensitivity of the results of these analyses are illustrated by alternative scenarios or ranges of high or low estimates in Figure 1-2. All of these B/C ratios reflect benefits which are incremental to those that would occur as a result of industry R&D alone. Hence, the benefits represent incremental savings which may be attributed to an incremental Federal part of a combined private/public effort. The B/C ratios in the left hand column of Table 1-1 represent the non-discounted comparison of benefits over time versus cumulative future Federal R&D program costs. Traditionally, however, Federal agencies analyze the merits of R&D programs on a present value basis; hence, the B/C ratios have been calculated from a discounting of the stream of benefits and costs at two benchmark discounting rates--6% and 12%. These results are also presented in Table 1-1.

We explored several EOR production scenarios over the period 1976-2000 and calculated the benefits on a cost-per-barrel-produced basis. This was done in comparison either to OCS oil or to imported oil--in either case the concept being that there is a probability that some EOR oil will be cheaper than some OCS oil and imports. Two alternative definitions of these benefits were considered in the sense that EOR oil can be viewed as either replacing or displacing the need for an equal amount of OCS oil or imports. If there is a permanent replacement of a quantity of OCS or imported oil by cheaper EOR oil, the full benefit of savings discounted to present value is to be realized. If, however, EOR only displaces (in time) the need for OCS oil or imported oil, the benefit is different and is defined as the present value of the interest earned on the EOR savings, computed for the period of the displacement.

At a discount rate of 6%, the most likely estimates of the apparent B/C ratios range from 2 to 19 under an assumption of high tier prices for EOR oil and from 1 to 9 under assumptions of only low tier prices. Hence, it appears that the potential National benefits of a Federal R&D program will be roughly doubled as a high tier price for EOR oil is allowed under FEA guidelines. The relative B/C ratios are not too different in magnitude between the OCS and imported oil alternative scenarios. In general, these representative B/C ratios are less (e.g., 1-19 versus 10-44) but still as clearly attractive as those determined in the earlier study.

In conclusion, it is important to review the process by which this analysis was performed and the factors to which the results are sensitive:

- the analysis was performed in 1976, in 1976 dollars, at 1976 oil prices, and under 1976 oil price policies;

TABLE 1-1

BENEFIT/COST RATIOS OF
THE FEDERAL ENHANCED OIL RECOVERY RESEARCH PROGRAM

Scenarios (Most likely estimates only; assuming current estimates of EOR economics.)	B/C Ratio Ranges At Discount Rates of: 0%	6%	12%
A. High Tier Prices[1] for EOR Oil			
1. Replacing OCS Oil	12-34	6-17	3-9
2. Displacing OCS Oil	0[4]	3-7	2-6
3. Replacing Imports[3]	8-40	4-19	2-10
4. Displacing Imports	0	2-8	1-7
B. Low Tier Prices[2] for EOR Oil			
1. Replacing OCS Oil	5-14	4-9	3-7
2. Displacing OCS Oil	0	2-4	2-5
3. Replacing Imports[3]	3-14	2-9	1-7
4. Displacing Imports	0	1-4	1-5

1 $11.28/Bbl

2 $5.25/Bbl

3 $12/Bbl

4 No benefits under non-discounting basis if EOR only delays the use of an alternative resource.

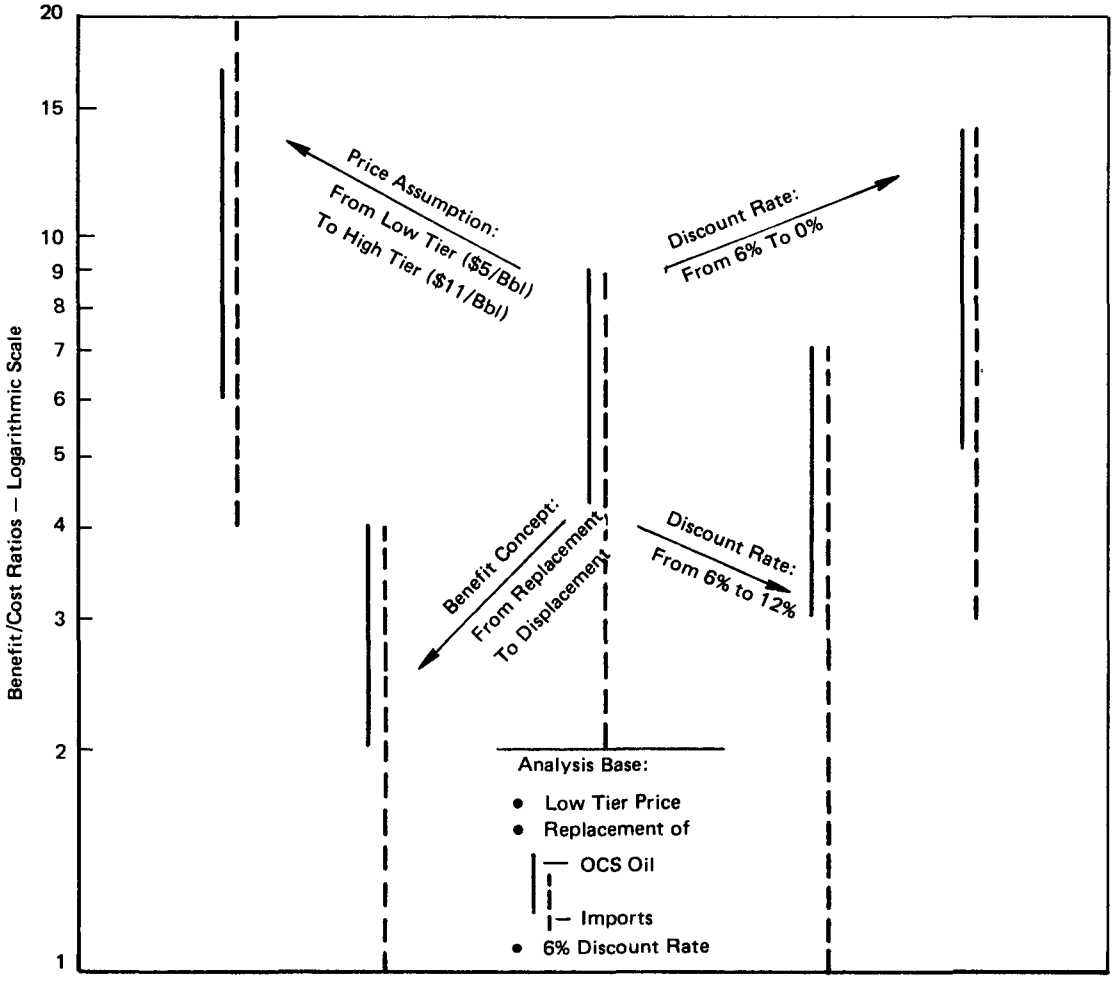


FIGURE 1-2

SENSITIVITY OF B/C RATIOS TO
DIFFERENT ANALYTICAL ASSUMPTIONS

- the primary benefits for enhanced oil recovery emphasized and quantitatively analyzed here are the savings attributable to the availability of an alternative technology in an uncertain future;

- alternative measures of benefits which were quantified, i.e., the Type B and Type C Benefits, indicate larger benefit/cost ratios (16-34 and 24-49 respectively) than the Type A Benefit. The Type B Benefit is thought to be additive--and the Type C alternative--to Type A Benefits. Thus, Type A Benefits alone probably understate the value of an EOR R&DD program;

- the results are sensitive to the projections of the economics of enhanced oil recovery, and the economics of alternative OCS and imported oil resources;

- the results are dependent upon the judgmental correlation between the level of Federal R&D effort and the technical results of that program in terms of enhanced oil production;

- finally, the interpretation of the results is sensitive to the selection of the discounting rate and the period of analysis.

2. STATUS OF ENHANCED OIL RECOVERY

2.1 DEFINITION

All studies have not adopted the same definition of enhanced oil recovery (EOR) oil production reserves. Given some consensus within ERDA and among other concerned government agencies and industrial contractors, the one we shall use is as follows:

> All recovery processes other than (a) gas injection for pressure maintenance, (b) waterflood without mobility control, and (c) cyclic steam processes,* directed to recovery of crude oil that cannot be recovered economically by conventional means.

Based on this kind of definition, for example, EOR presently accounts for production of about 250,000 Bbl/day.

2.2 REVIEW OF RECENT STUDIES OF EOR POTENTIAL AND COSTS

Several major studies of EOR have been reviewed in the course of this updated cost/benefit analysis, viz, those by the Gulf Universities Research Consortium (GURC), Lewin & Associates, and LaRue, Moore & Schafer (LMS), plus the many papers presented at the most recent (1976) SPE Symposium on Improved Oil Recovery. Other studies, notably assessments by the National Petroleum Council and EPA, were in progress and we were able to consider only some relevant information from these studies.

Our focus has been on the perceived costs of producing tertiary oil. Cost estimates, from whatever source, are viewed generally with great skepticism at this point in time, because of the lack of performance data in commercial operations, and because of large variations in reservoir characteristics from field to field. Generalized technical performance claims for various methods of EOR are also viewed skeptically. The apparent consensus among industry experts now is to expect the effective EOR cost-per-barrel-recovered to be significantly higher than estimates publicized 2 years ago (when our first analysis was performed).

GURC has reported, and we understand the NPC will soon report, a less sanguine view of the outlook for enhanced oil recovery than heretofore. GURC reflects the widely-held views that insufficient reservoir petrophysical data exist to prove that any chemically-based EOR process is broadly applicable and that reserves and economics associated with EOR

---

*Some fields under cyclic steam recovery may be included in certain analyses, under the presumption that they are in an EOR mode and/or are under steam drive, one of the five principal EOR techniques (and the leading one in terms of production) at the present time.

are still quite speculative. GURC suggests, however, that ERDA can enhance a productive, but realistic, national EOR program by: (1) serving as a funding catalyst to implement field test programs, and (2) disseminating information to hasten the industry's learning curve on EOR technology.

GURC's survey indicates that 296 billion barrels of oil remain that cannot be produced by conventional methods,* of which a portion is subject to EOR techniques. However, about 176 billion barrels, or 60% of this amount, is physically unrecoverable. That leaves 119 billion barrels as being theoretically recoverable by (present and future) EOR methods. GURC has also indicated that between 17 and 35 billion barrels of the latter could be recovered by present methods if:

- at least 90 field tests are implemented and conducted at a rate which compresses the national learning curve on the application of EOR technology to actual reservoir conditions.
- the findings of these field test programs are disseminated on a national basis; and
- individual companies have the technological basis and the economic basis to permit favorable investment decisions and to practice EOR methods.

GURC suggests that EOR of 33 to 40 billion barrels might be produced with current methods if current project economics were improved at least 50% (e.g., realized crude prices of $15/barrel). Looking ahead, the GURC studies suggest that as much as another 50 to 60 billion barrels could conceivably be recoverable if both project economics and EOR methods were dramatically improved.

The April 1976 Lewin & Associates study of the potential and economics of enhanced oil recovery looked in detail at a selection of reservoirs in California, Texas and Louisiana (representing an estimated 60% of all unrecovered oil potential), estimated recoverable tertiary oil reserves, and estimated the cost of EOR production by various techniques, under stated assumptions about price, rates of return, etc.

A comparison (Table 2-1) of the Lewin & Associates estimates of the EOR potential with that of GURC indicates significantly different views of the roles to be played by surfactant polymer processes vis-a-vis CO_2 processes.

*Report No. 148, "Preliminary Field Test Recommendations and Prospective Crude Oil Fields or Reservoirs for High Priority Field Testing," February 28, 1976, Gulf Universities Research Consortium (GURC).

TABLE 2-1

PROJECTED ROLES OF EOR TECHNOLOGIES

	GURC* Basis: U.S.A. Fraction	GURC* Basis: U.S.A. Bbls†	Lewin & Associates** Basis: Calif., Tex., La. (Major Target Reservoirs) Fraction	Lewin & Associates** Basis: Calif., Tex., La. (Major Target Reservoirs) Bbls (Net)
Surfactant/polymer processes††	58%	69.2	29%	11.7
Thermal processes	29	34.6	33	14.7
Carbon dioxide processes	8	9.6	38	16.9
Hydrocarbon miscible processes	5	6.0		--
TOTAL	100%	119.4	100%	43.3

*"The Potential of Enhanced Oil Recovery Processes," Paper by Dr. James M. Sharp, SPE 5557, Fall Meeting of the Society of Petroleum Engineers, AIMME, 1975.

**Report to Federal Energy Administration: "The Potential and Economics of Enhanced Oil Recovery," Executive Summary, Lewin & Associates, Inc., April 1976.

†Billions of barrels.

††See also "Chemicals for Microemulsion Flooding in E.O.R.," ACS Paper by Dr. Jerry Ham (ERDA) and Professor Joseph R. Crump (University of Houston), March 26, 1976.

Some idea of the cost uncertainty in EOR technologies is found in the recent study by LaRue, Moore & Schafer (LMS)*. Information in the following table (Table 2-2) was prepared by LMS by dividing total estimated project costs (using, respectively, Lewin and NPC methodology and cost estimates for the same hypothetical reservoir) by the total barrels of incremental oil recovered by each process.

TABLE 2-2

COMPARATIVE COST ESTIMATES FOR EOR TECHNOLOGIES

EOR Process	Total $ Project Cost/Incremental Bbl Oil Recovered*	
	Lewin	NPC
Steam Drive	6.23	6.01
In Situ Combustion	4.23	6.79
CO_2 Miscible	6.46	11.91
Surfactant/Polymer	9.52	11.38
Polymer Augmented Waterflood	5.72	5.49

LMS pointed out that "although costs are extremely important in determining the profitability (rate of return) for an EOR project, oil recovery is equally important. The most meaningful comparison of the effect of cost differences on EOR reserve additions (short of calculating rates of return) can be made by comparing the total cost/Bbl recovered."*

The foregoing cost numbers are not required price levels to produce the oil. Royalties, profits, and taxes must also be considered to estimate the required price. LMS used the NPC estimates (total cost/barrel) for each EOR process to provide insight into the relative economic status of each of the processes. They found that steam drive is the lowest cost and currently the most actively applied process. The polymer augmented waterflood process is proven but promises to be profitable only at upper tier oil prices. The latter is not, strictly speaking, a tertiary process, and its use is limited to reservoirs in the early stages of conventional

*LaRue, Moore, & Schafer, "Analysis and Assessment of Enhanced Oil Recovery Baseline Data, Volume I, Task 1, Detailed Characterization of Costs...and Assessments of Recent Studies...", October 1, 1976, Final Report to ERDA.

waterflooding (and then only if upper tier prices prevail). In situ combustion is normally applicable to reservoirs having low gravity crude oil and found predominantly in California and South Texas. Its higher cost in other regions has prevented widespread application. CO_2 miscible and surfactant/polymer are as yet technically unproven for widespread commercial applications. Widespread application will not occur until the risks are better defined by field testing, which has been inhibited by the high cost and limited sources of the injection materials.

FEA's 1976 National Energy Outlook estimated that EOR production of between 100,000 and 900,000 Bbl/day is possible by 1985, depending on the price to be received for recovered oil, as shown in Table 2-3 below:

TABLE 2-3

PROJECTED EOR RESERVES AND PRODUCTION AT DIFFERENT PRICE LEVELS

Marginal Oil Price ($/Bbl)	Incremental Reserves Added (billions of barrels)	Total Tertiary Production (millions of Bbl/day) 1980	1985	1989
8	0.6	0.1	0.1	0.1
10	3.4	0.4	0.6	0.5
12	3.9	0.4	0.9	1.3
14	3.1	0.4	0.9	1.9

Source: National Energy Outlook, FEA, February 1976.

Lewin & Associates has also examined a wide range of production possibilities from tertiary development (California, Texas and Louisiana), as indicated in Figure 2-1. The Lewin framework gives an indication of the reserves at stake (the areas under the curves) and of their sensitivity to price level and scenario.

Other estimates of tertiary oil production and additions to reserves were presented within the massive but "preembargo" analysis and projections of the Report of the Oil & Gas Subcommittee Supply Task Groups of the NPC Committee on the U.S. Energy Outlook. (This study was completed at the end of 1972 and issued in early 1973.) The worst case (Case IV supply) in that analysis indicated substantially more tertiary production than the above estimates for 1980, and nearly as much as the Lewin & Associates upper bound for 1985. There was apparently a more sanguine view of the prospects for EOR then. The NPC report assumed that tertiary production over the next 10-15 years would come primarily from "old" fields, (i.e.,

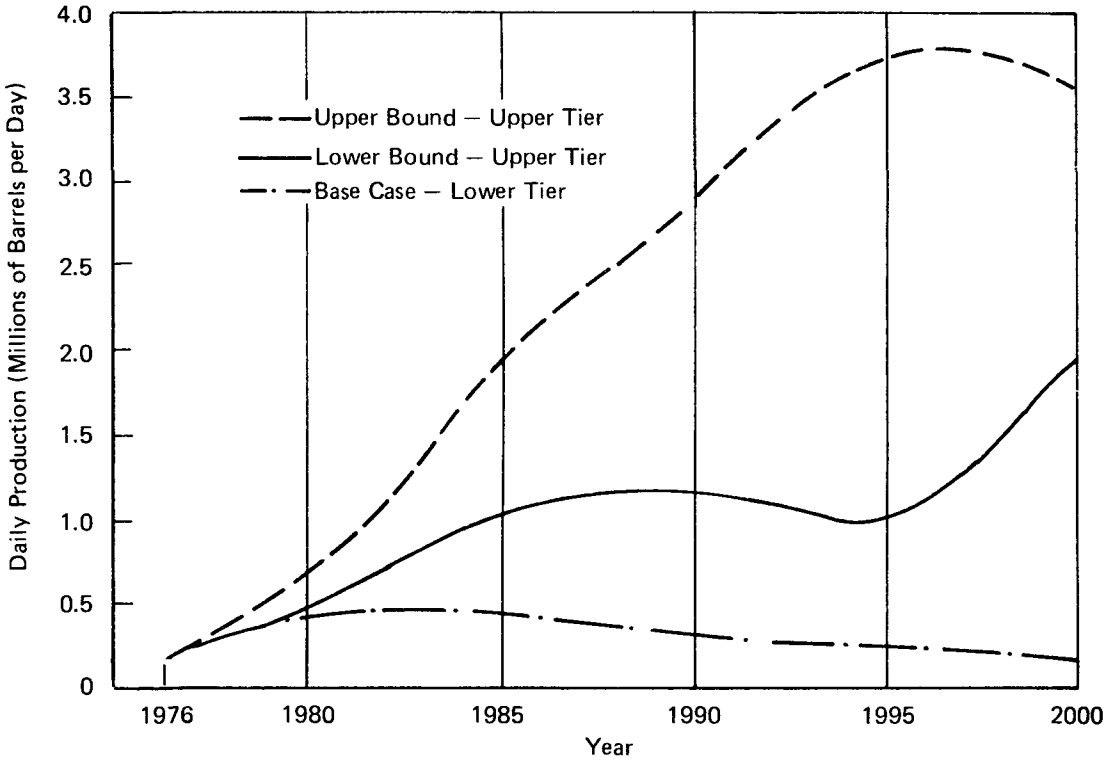


FIGURE 2-1

TERTIARY PRODUCTION FOR THREE CASES
(Total for Three States)

those discovered prior to 1/1/71). A comparison (Table 2-4) of the worst case in the NPC report with their intermediate Case III was as follows:

TABLE 2-4

THE NPC "PRE-EMBARGO" OUTLOOK FOR TERTIARY OIL PRODUCTION IN THE UNITED STATES (millions of Bbl/day)

Domestic Production (except North Slope)	1975		1980		1985	
	III	IV	III	IV	III	IV
All Tertiary	0.44	0.44	1.06	1.06	1.76*	1.74*
All Secondary	3.41	3.41	3.30	3.28	3.21	3.10
All Primary	4.29	4.19	3.80	3.24	3.58	2.54
Total (from old and new fields)	8.14	8.04	8.16	7.58	8.55	7.38

*1.68 from fields discovered prior to 1/1/71.

Source: NPC's "U.S. Energy Outlook," 1973.

It appears that Case III is remarkably close to the actual experience through 1975. It may thus be useful to put the overall picture in perspective, by "replaying" the pre-embargo Case III scenario. This is shown in Figure 2-2.

2.3 CONSTRAINTS

The major constraints on industry in respect to exploiting EOR were succinctly described by Lewin & Associates* in terms of the following factors:

a. Capital investment

b. Recovery chemicals and CO_2

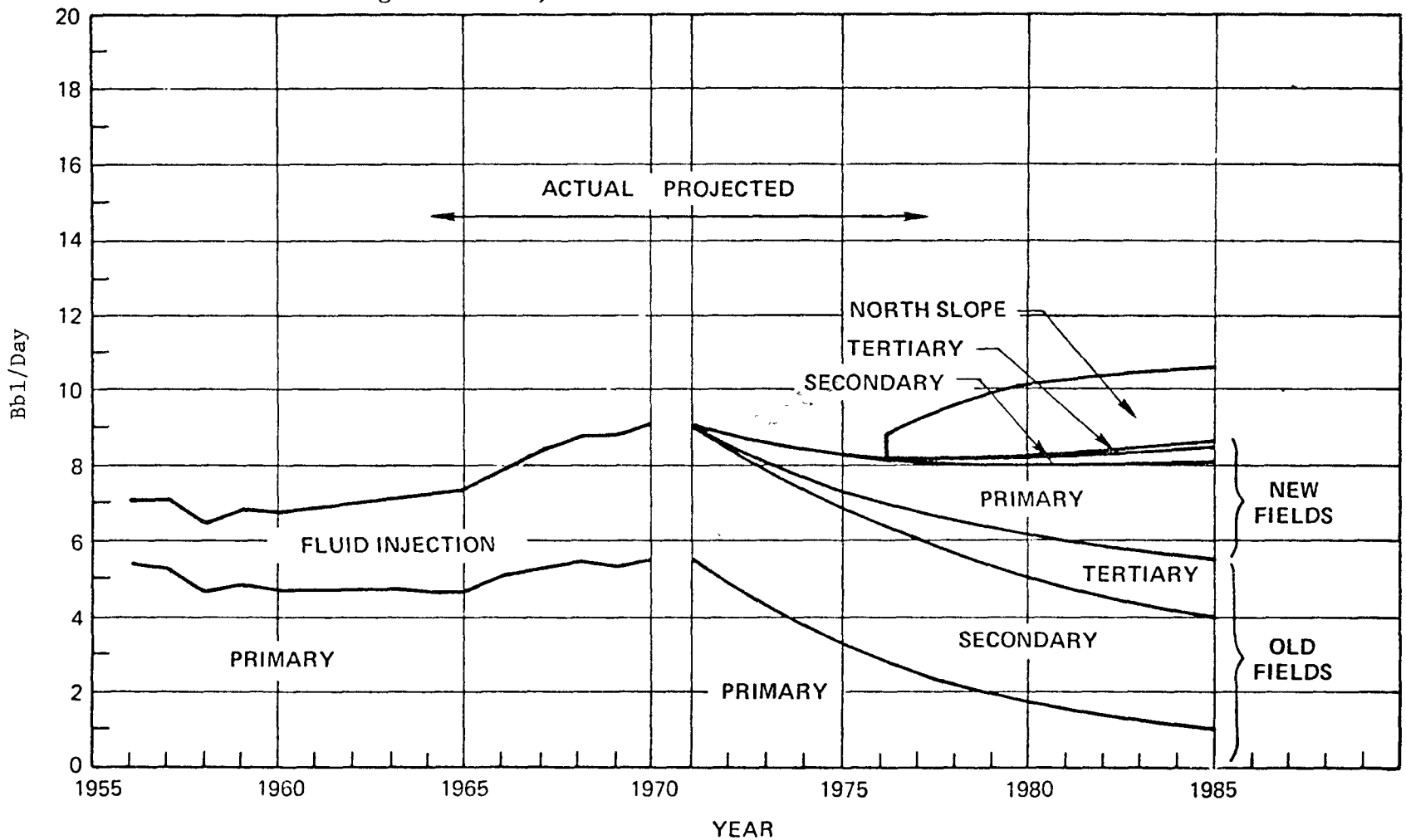
c. Technical uncertainties and risks

d. Price uncertainties

*"The Potential and Economics of Enhanced Oil Recovery," Final Report by Lewin & Associates, Inc., April 1976. Contract No. CO-03-50222-000, FEA Office of Regulatory Policy, Office of Policy.

THE INCREASING ROLE OF TERTIARY RECOVERY - A PRE-EMBARGO VIEW

(Basis: Case III (Intermediate) drilling and new field discovery rate with North Slope production assumed to begin in 1976.)*



*North Slope production will probably now be delayed to late 1977.

FIGURE 2-2

PRODUCTION BY RECOVERY METHOD

Source: "U.S. Energy Outlook," Oil & Gas Availability Report, National Petroleum Council, 1973

We believe, based on our review, that the most severe constraints at this juncture are (c) and (d); i.e., technical risks and price uncertainties. In respect to (a), the capital requirements for EOR, Lewin & Associates estimated the following:

- $5 billion/year out of $30 billion total for industry
- $5/Bbl, of which $4 is not for oil field equipment

We are of the opinion that these figures do not constitute a limitation in and of themselves. The limiting factor is more the industry's expected rate of return on investment in EOR, and the perception of the riskiness of EOR ventures vis-a-vis the alternatives available to the industry.

2.4 RESERVE ESTIMATES

Figure 2-3 shows the principal petroleum regions of the United States, as classified by the NPC. Table 2-5 indicates the estimated oil-in-place (OIP) discovered to 1/1/71, by regions; the NPC's 1972 appraisal of new discovery prospects for the period 1971-1985; and ultimate discoverable OIP. The 1975-76 consensus is that the total U.S. discovered oil in place, including Alaska and OCS, now amounts to 441 billion barrels, of which 106 have been produced, only 39 are proved reserves, 119 are considered EOR potential, and 177 are considered unrecoverable.

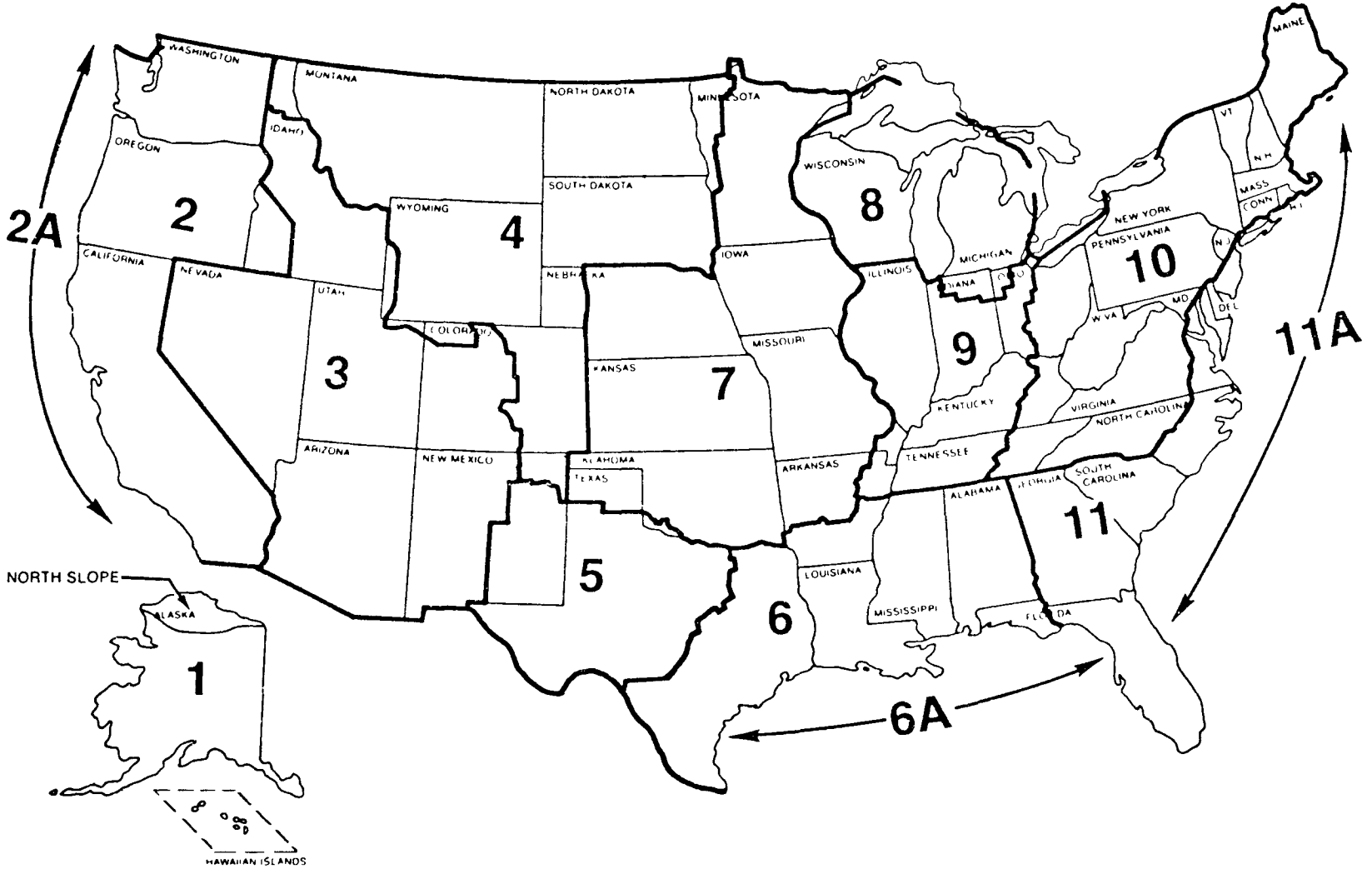
API and other authoritative estimates of reserves are based on perceptions about the state of current technology and economics, and thus will stand to be revised upwards or downwards as knowledge of fields, technology, and economics improves. "Proved reserves" represent the producers' best estimates of the volume recovered profitably from known fields with present technology--sometimes thought of in an economic sense as "current working stock or inventory of unrecovered petroleum that producers carry for the efficient accomplishment of their operations.*

Interestingly, the Securities & Exchange Commission may be entering the picture via its 1975 Proposed Amendments on "Disclosure of Oil and Gas Reserves" (Forms S-1, S-7, and 10-K). The instructions** for disclosing "Proved Reserves" stated that:

- Developed proved reserves from improved recovery techniques require a pilot program or equivalent confirmation, and must be keyed to current economic conditions.
- Undeveloped proved reserves associated with EOR require proof that fluid injection, etc. are effective.

*Cf. "Technology and American Economic Growth," by N. Rosenberg (Harper & Row, New York, 1972).

**See SEC Release 33-5588.



Regional Boundaries: Region 1 – Alaska and Hawaii, except North Slope, Region 2 – Pacific Coast States, Region 2A – Pacific Ocean, except Alaska, Region 3 – Western Rocky Mountains; Region 4 – Eastern Rocky Mountains, Region 5 – West Texas and Eastern New Mexico, Region 6 – Western Gulf Basin, Region 6A – Gulf of Mexico, Region 7 – Midcontinent, Region 8 – Michigan Basin, Region 9 – Eastern Interior, Region 10 – Appalachians, Region 11 – Atlantic Coast, Region 11A – Atlantic Ocean

Source: NPC, *Future Petroleum Provinces of the United States* (July 1970) – with slight modification.

FIGURE 2-3

PETROLEUM PROVINCES OF THE UNITED STATES

TABLE 2-5

A PRE-EMBARGO APPRAISAL OF REGIONAL
OIL-IN-PLACE DISCOVERED - TOTAL UNITED STATES

(Billion barrels)

Region		Ultimate Discoverable OIP	OIP Discovered to 1/1/71	OIP Discoverable 1971-85
Lower 48 Onshore				
2	Pacific Coast	101.9	80.0	3.4
3	Western Rocky Mountains	43.6	5.8	1.2
4	Eastern Rocky Mountains	52.4	23.9	5.2
5	West Texas Area	151.6	106.4	2.0
6	Western Gulf Coast Basin	109.0	79.7	3.1
7	Midcontinent	63.0	58.4	2.7
8-10	Michigan, Eastern Interior and Appalachians	36.5	30.5	2.1
11	Atlantic Coast	3.8	0.2	--
Total		561.8	384.9	19.7
Offshore and Alaska				
1	Southern Alaska including Offshore	26.0	2.9	4.7
2A	Pacific Ocean	49.6	1.9	3.7
6A	Gulf of Mexico	38.6	11.5	13.0
11A	Atlantic Ocean	14.4	0	--
Total		128.6	16.3	21.4
TOTAL UNITED STATES (Ex. North Slope)		690.4	401.2	41.1
Alaskan North Slope				
Onshore		72.1	24.0	0
Offshore		47.9	0	0
Total		120.0	24.0	0
TOTAL UNITED STATES		810.4	425.2*	41.1

Source: NPC's U.S. Energy Outlook, December 1972.

*Increased to approximately 440 as of 12/31/75.

Proved reserves are the source of producer earnings; and producer exploration, development, R&D and investment behavior may be presumed to be influenced by the potential additions to proved reserves. With these considerations in mind, we turn to a discussion of industry attitudes toward EOR.

2.5 INDUSTRY ATTITUDES TOWARD EOR

We see the status of EOR "At a crossroads..." as far as industry is concerned. It is ironic that much of the uncertainty is of a political/regulatory nature, in contrast to the indications of strong regulatory incentives during the Project Independence environment surrounding our first report. Translated into economic terms, this means that industry perceives greater financial risk with EOR today than it did two years ago (although the expected returns may be similar). There are, of course, significant technical uncertainties--more so, in this case, it seems, than is usually true in the application of new technology. Industry naturally wants a price structure high enough and/or cost structure low enough to profitably bear the risk of this uncertain technology.

2.5.1 The Major Issues

- The phasing out of the depletion allowance, the threat of divestiture, and the regulation by FEA, FPC, and EPA have increased the uncertainty about cost and price expectations.

- Some feel EOR is technology limited and that short-term production is not really affected much by price. Others say the opposite: technology is available, but there is not a sufficient price incentive. The clear consensus is that FEA regulations have not been and, as of mid-1976, were not an incentive to EOR development.*

- EOR cash flow characteristics are believed to be much different than for OCS. Also, the tax and accounting considerations are not favorable vis-á-vis OCS (see Appendix B). Finally, the statistical/actuarial basis for investment in EOR is absent, in contrast to OCS. Government policy can influence this.

- Technically, most new tertiary technology seems best suited to shallow reservoirs at low temperatures. The sooner one can start a tertiary program in a given field, and/or the greater the oil saturation, the better. Also, less injection fluids would have to be handled. The latter is important as far as potential environmental impact (EPA) is concerned, as well as from the standpoint of cost and oil field equipment capability.

*More recent decontrol of stripper well production was of course a boost.

2.5.2 Considerations for EOR Investment By Industry

- Nearly all oil companies' production operations are organized the same way. In that context, it is symptomatic of EOR development that EOR is still widely considered an R&D expense and not one of "Exploration and Development." This, of course, tends to affect EOR's position (priority) in the capital budgeting decisions.

- Companies generally assume that prices will follow costs. However, an EOR project usually must "fly" with rulings on "new" oil definitions and prices.

- Costs are very field specific, as EOR techniques are typically field specific in their performance. Whatever costs and prices are assumed, normal practice would require a project to indicate approximately a 10-15% real rate of return at normal levels of production risk.

- The going assumption is that, for new fields, oil costs including profit must be able to fall under the FEA ceiling of $13/Bbl in 1979. Many in industry have the basic sense that "EOR oil must cost more than primary." All things considered, today's managements will go after what's there now at a good price, i.e., new primary OCS.

- Regulatory policy is a very important factor in all this--e.g., for a domestic independent producer with refineries, EOR production might get lower tier FEA price, and the refinery would be buying entitlements under the FEA allocation program. Virtually all big producers have refineries, and their economic trade-offs are complicated by current regulations. OCS gas, regulated at 50¢ per MCF, is apparently not important to EOR economics. At $1.50 per MCF, it could constitute an important co-product or affect company attitudes towards OCS vs. EOR.

- The propensity to push EOR may be a function of the owner or lessee status of the producer, since natural repressurization is expected to take place eventually in many fields--say in about 25 years.

- Companies are looking at return on investment rather than addition to reserves. The recent period has seen much more development drilling--to produce existing fields faster ("extensions")--than exploratory drilling. Post-embargo strategy appears to be to take advantage of the high price of marginal crude (e.g., where a field is developed on 80-acre spacing) and to reduce geophysical investments which have longer payouts.

- OCS oil is apparently not yet expected by industry to offer much potential for EOR development.

2.6 THE ERDA PROGRAM IN EOR

The current ADL study focuses on updating and refining the estimates of benefits accruing from ERDA investments in EOR programs. As shown in Table 2-6, at the end of calendar 1975, ERDA was involved in 8 of the ongoing EOR field tests. That number is expected to increase to nearly 20 demonstration program contracts by the end of calendar 1976, with an additional 20 under consideration.

TABLE 2-6

ERDA SUPPORT OF EOR DEMONSTRATION PROJECTS

Method	EOR Field Projects Active in 1975	ERDA Funded through 1975
Thermal	106	2
Surfactant/Polymer	13	4
Polymer	15	1
Miscible Hydrocarbon	13	0
CO_2	9	1
Total	156	8

ERDA, at year end 1975, had budgeted over $50 million for the FY 1975-FY 1977 EOR field test program and supporting research. Total potential costs to ERDA for the EOR R&D and large-scale field projects demonstration program are currently estimated to be about $300 million through 1982.

In the framework of our benefits/costs analysis, it has been necessary for us not only to revise our estimate of the range of costs for EOR, to reflect 1976 values and uncertainties, but also to reexamine the status of OCS oil. That is, we have made revised estimates of the range of costs associated with new OCS oil, since these will affect the benefits associated with new OCS oil, since these will affect the benefits associated with the EOR R&D program. The range of costs for OCS oil has also widened considerably because of inflation and regulatory delays and uncertainties.

Given the industry attitudes, the uncertainties, and higher cost estimates in today's environment, for both EOR and OCS oil, our analysis continues to show positive benefit/cost ratios for EOR R&D. The scenarios and associated benefits are different than before (as will be discussed), but the conclusions are qualitatively the same.

3. BENEFIT TYPE A: NATIONAL SAVINGS FROM HAVING ENHANCED OIL RECOVERY METHODS AVAILABLE IN AN UNCERTAIN FUTURE

3.1 RATIONALE

These benefits are the savings to be realized by the Nation as a result of the probability of having cheaper supplementary oil available from EOR than would be otherwise available under certain alternative futures. Savings is defined as the differential in the total costs for a given supply of oil to the Nation between a scenario that assumes no federal support of EOR-related R&D by industry, and a scenario that assumes the presence of a significant federal R&D program in EOR technology.

Figure 3-1 presents our estimates of the EOR production outlook through the year 2000. Various EOR production scenarios over the period 1976-2000 were explored (Figure 3-1) and benefits were calculated using estimated probability distributions of the cost-per-barrel-produced for EOR oil versus that for OCS oil and imports. (See Figure 3-2.) The concept here is that there is a probability that some EOR oil will be cheaper than some OCS oil and imports, and that such EOR oil can either replace or displace an equal amount of OCS oil and/or imports. Government R&D accelerates the availability of cheaper EOR oil over a "no government R&D" or "industry only" case. If there is a permanent replacement of a quantity of OCS oil by cheaper EOR oil, the full benefit of the cost savings discounted to present value is realized. If, however, EOR displaces OCS oil rather than permanently replacing a quantity of OCS oil, the benefit is represented by only the present value of the interest earned on the EOR savings, computed for the period of the displacement.

3.2 DIFFERENT SCENARIOS

Other analyses have shown that regulated price levels will have a significant effect on future EOR production levels. At the time of this report, it had not been decided by regulatory agencies whether or rather how much oil produced with EOR technology will be priced at "lower tier" ($5.25/Bbl) or "upper tier" ($11.28/Bbl) prices. Hence, our cost/benefit calculations were done for two different price scenarios:

- assuming regulated wellhead prices for EOR oil at $5.25/Bbl; and
- assuming EOR oil prices at $11.28/Bbl.

For each of these two price scenarios high, low, and most likely projections of future EOR production levels were considered. In each scenario, the production was also considered relative to a production level deemed attainable by the industry alone without support of government R&D funding.

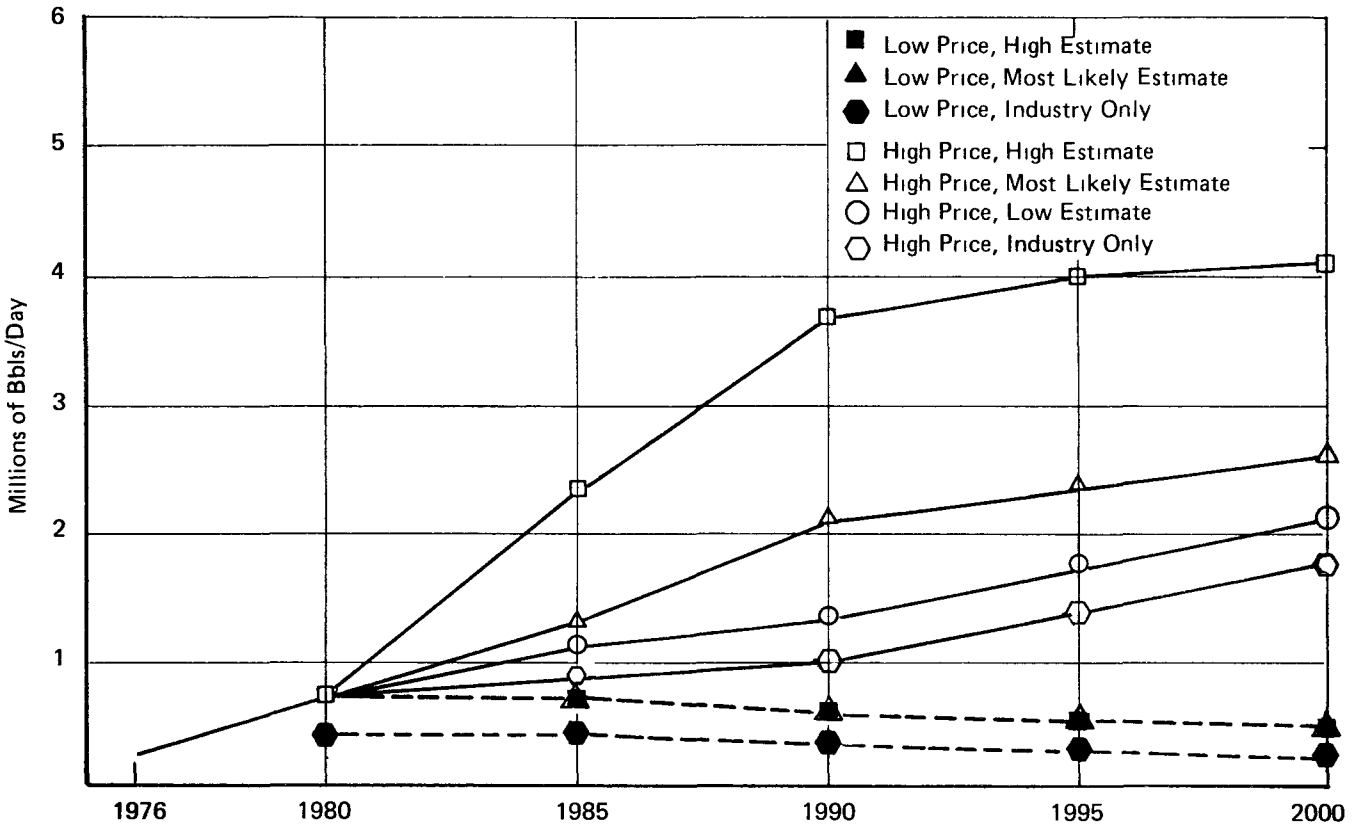


FIGURE 3-1

DIFFERENT LEVELS OF POSSIBLE EOR PRODUCTION UNDER A HIGH AND LOW PRICE SCENARIO

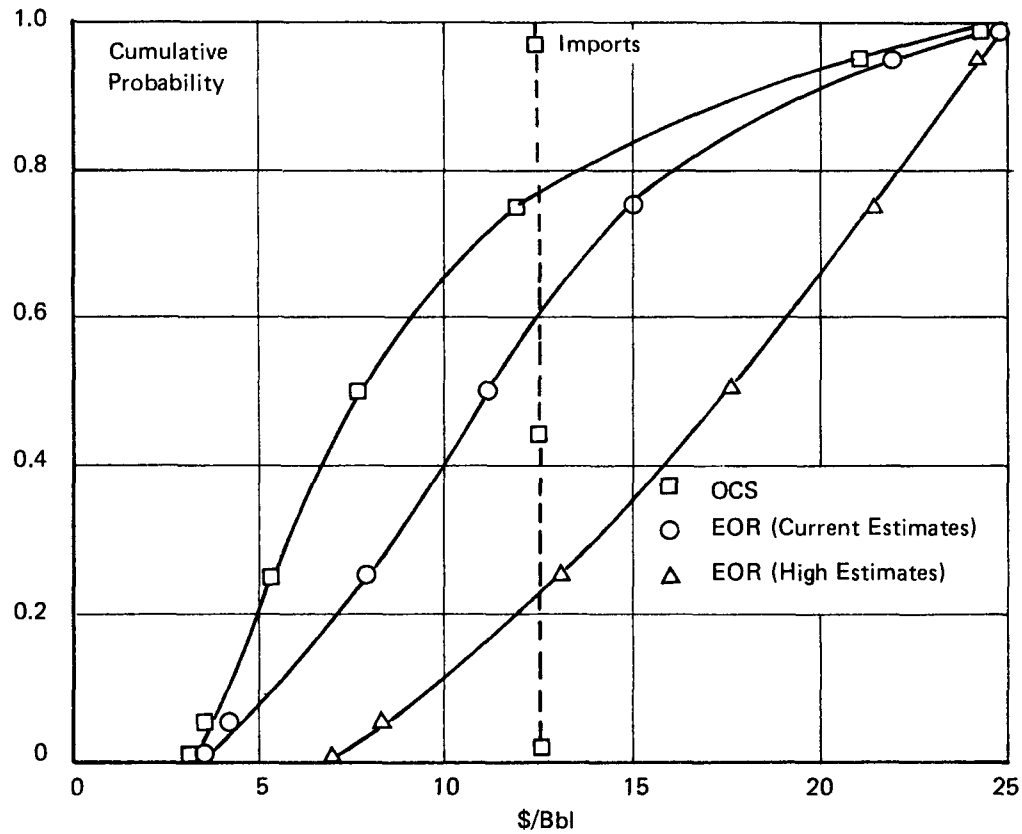


FIGURE 3-2

CUMULATIVE DISTRIBUTION OF MINIMUM REQUIRED PRICE[1] OF EOR, OCS, AND IMPORTED OIL

(1) Minimum required price, as used here, reflects average, after tax costs, allowing for a rate of return (15%/yr.) to find, develop, and produce the next field.

SOURCE: Arthur D. Little, Inc.

Increased government-funded R&D is expected to accelerate the availability of EOR as a proven recovery technology and benefits can then result from:

- EOR oil replacing more expensive OCS oil on a barrel-for-barrel basis; or
- EOR replacing more expensive imports on a barrel-for-barrel basis; or
- Earlier availability of EOR oil, delaying requirements for more expensive OCS production; or
- Earlier availability of EOR oil, delaying requirements for more expensive imports.

The benefits of government funding of EOR-related R&D spending were calculated in all cases by multiplying the net additional annual production of EOR oil, estimated to result over and above the "industry only" case, by the cost differential between EOR oil and the other more expensive type of oil. To allow for the uncertainty inherent in estimates of production costs of EOR oil relative to the estimated production costs of OCS oil, a high and low estimate of EOR cost distributions were used in the benefit calculations.

3.3 FUTURE OIL SUPPLY/DEMAND FOR THE UNITED STATES

It is assumed that total demand for oil products in the United States will continue to exceed total U.S. production of crude oil and natural gas liquids. Figure 3-3 shows "low" and "high" projections of total U.S. oil products demand; the low projection was derived by growing actual total oil product consumption for 1975 by one percent per year, and the high demand projection was derived by growing oil products demand at 3% per year relative to 1975 levels. Also shown are low and high projections of total domestic production from onshore and offshore areas, exclusive of potential production from new OCS areas and potential production through an increased use of EOR production methods.

A minimum estimate of the required amount of production from new OCS areas, EOR production and imports can be derived by subtracting production from onshore and existing offshore areas from the projected demand levels. It can be seen in Figure 3-3 that this supply shortfall is expected to be at least between 8 and 10 million barrels per day in the benchmark years of 1980, 1985, 1990, 1995, and 2000.

It is highly unlikely that new production from OCS areas plus additional production through the use of EOR methods will exceed 8 million barrels per day; the highest estimate for additional EOR production used in this analysis for later years is roughly 4 million Bbl/day.

Given this large expected shortfall in supply from conventional domestic oil production, the potential benefit of government funding of EOR-related R&D efforts could take on the following forms:

- In the first place, it is conceivable that long-term EOR production levels resulting from the increase in R&D effort funded by the government, would exceed EOR production levels if EOR R&D is left to industry alone. Under these circumstances, the net national benefit of government R&D funding could be represented by the savings between the production costs of the EOR oil and the cost of the more expensive alternative source of oil, which then might not be required;

- Secondly, government R&D funding would result in an earlier availability of cheaper EOR oil, which then would delay the requirement of the more expensive alternative types of oil.

The alternative or more expensive type of oil may be reviewed as either imported oil or oil produced from new OCS areas.

In order to show the range of all possible outcomes, the cost/benefit calculations were done for all four different possible combinations:

- Absolute (replacement) savings relative to OCS oil;

- Relative (displacement) savings relative to OCS oil;

- Absolute (replacement) savings relative to imported oil; and

- Relative (displacement) savings relative to imported oil.

3.4 PROBABILITY DISTRIBUTIONS OF OIL PRODUCTION COSTS

For the cost/benefit calculations it was necessary to represent the range of economic costs or minimum required prices(*) over which these costs can be expected to vary. Cumulative distribution of minimum required prices for EOR oil and OCS oil (Figure 3-2), were constructed using EOR data developed by Lewin and Associates(**) and OCS data development by

(*) Economic cost, or minimum required price, as used here, means the per barrel after-tax costs, allowing for a required rate of return, to find, develop, and produce a specific field.

(**) "The Potential and Economics of Enhanced Oil Recovery" by Lewin & Associates, Inc., for the Office of Policy, Federal Energy Administration, April 1976.

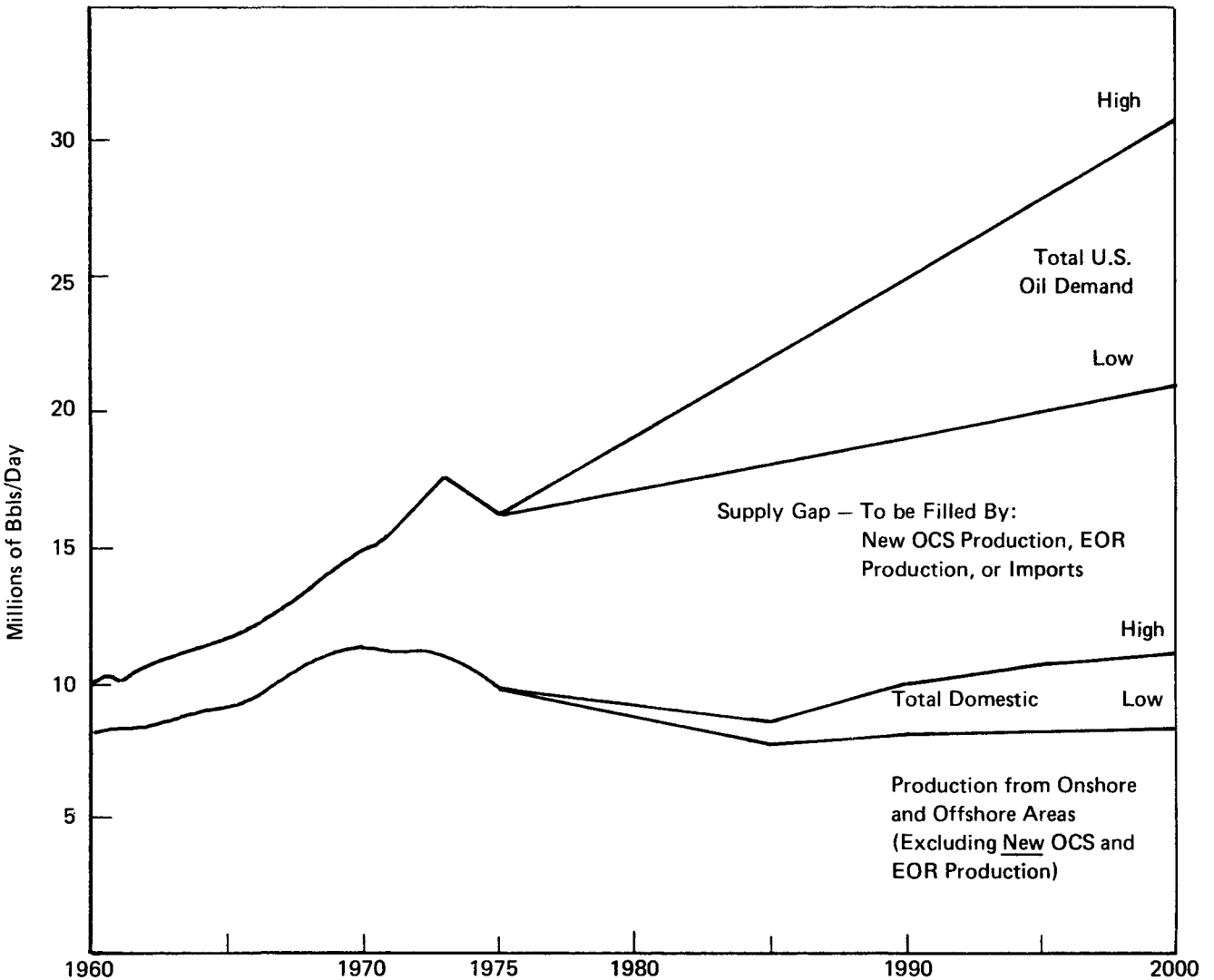


FIGURE 3-3

PROJECTIONS OF DOMESTIC OIL SUPPLY AND DEMAND

ADL(*) on the costs of finding, developing, and producing different sized fields in different representative areas. The curves in Figure 3-2 portray the costs to find, develop, and produce the next expensive OCS field or to develop and produce the next EOR field, including a 15% DCF rate of return.

In order to estimate the relative savings to be realized relative to crude oil imports, a price of $12/Bbl (i.e., a vertical line cumulative cost distribution) was used for imported crude oil.

To further allow for the possibility that existing EOR cost estimates are too low, a second distribution for EOR oil was used which assumed costs to be twice as high as in the first distribution.

Benefits from government R&D spending were calculated under each different scenario for low and high cost distributions for EOR oil versus either the cost distribution for OCS oil or the cost of imports.

3.5 FEDERAL R&D COSTS

The level of planned government R&D spending which is associated with the accelerated availability of EOR oil is shown in Table 3-1 as the "ERDA Plan." To show the implications of a far higher R&D spending level, some benefit calculations were also done assuming a spending level of five times higher than in the "ERDA Plan" (Table 3-1, "High Plan").

3.6 DISCOUNT RATES

It has not been our purpose to recommend what the proper discount rate should be in evaluating the present value of future benefits and costs in Federal R&D programs generally. It was our responsibility, however, to comment upon those factors which are peculiar to EOR, its marketplace, and our methodology of analysis which relate to the question of the proper discount rate in this area of technology.

Certainly the situation calls for a discounting approach to emphasize the importance of domestic self-sufficiency in oil supply. In this context, a discounting approach will assist in determining those technological options which promise greater value in the near term.

Our only hesitation in discounting future benefits relates to our analytical methodology. Our analysis of EOR economics and the rate of utilization of EOR oil has included our own conservative allowance for what are often optimistic projections and claims in a new technology

(*) "Outer Continental Shelf Oil and Gas Costs and Production Volume: Their Impact on the Nation's Energy Balance to 1990" Report to The Bureau of Land Management, Contract No. 08550-CTS-48, ADL.

TABLE 3-1

FEDERAL R&D EFFORT IN EOR
(millions of current $)

1976	1977	1978	1979	1980	1981	1982	TOTAL
			ERDA PLAN				
26	22	37	53	66	50	44	298
			HIGH PLAN				
130	110	185	265	330	250	220	1,490

area. To the degree, therefore, that a discounting approach to R&D evaluation represents an attempt to discount the future technical uncertainties of the technology, then there is the danger here of double counting by applying a discount rate on top of a conservative analytical methodology. To the degree that the time value of money is the primary purpose for discounting, our concerns about double counting are less.

3.7 EOR PRODUCTION LEVELS

The projections of possible future EOR production levels, as shown in Figure 3-1, remain highly speculative given the national lack of experience with large scale applications of the different EOR technologies currently under development. The wide range of projections thus reflects that uncertainty.

In the "Industry Only" case (Figure 3-1), EOR production is portrayed to peak in 1980 at around 300,000 Bbl/day from a current level of 250,000 Bbl/day and decline thereafter. Under the assumption of low tier pricing of EOR ("Low Price" in Figure 3-1), government R&D funding will only result in additional production from a few very attractive (i.e., high potential at relatively low costs) fields. This is illustrated in an increase of 1980 production, over and above the "Industry Only" production, of another 300,000 Bbl/day resulting in a total of 600,000 Bbl/day in 1980 and 1985 and then followed by a decline in production.

The substantially higher economic incentive, which can be expected to exist if EOR oil can be sold at an upper tier or new oil price ("High Price" in Figure 3-1), is estimated to result in EOR production levels of: 600,000 Bbl/day in 1980, 900,000 in 1985, one million in 1990, 1.4 million in 1995, and 1.75 million in 2000.

The "Low Estimate" of high tier prices is associated with an acceleration of EOR production, deemed achievable by the industry, in 1990, 1995 and 2000 by 10 years. The "Most Likely Estimate" assumes acceleration of industry-only EOR production by 10 years in 1985 and by more than 15 years in 1990, 1995, and 2000. The "High Estimate" assumes not only an acceleration of EOR production but also an absolute increase in overall production over that possible if the industry were to develop EOR technology on its own.

3.8 BENEFIT CALCULATION

The benefits were calculated by multiplying the incremental production of EOR oil over and above the "Industry-Only" case by the savings per barrel. The savings per barrel was calculated as the average difference berween the cost of EOR oil and the cost of either OCS oil or imported oil, calculated for those futures or situations where marginal EOR oil would be cheaper than the cost of OCS oil or imported oil which was replaced (or displaced) by EOR oil. This latter calculation was performed in Monte Carlo fashion from cost distributions in Figure 3-2.

The methodology assumes that the calculated per barrel savings will be the same for all of the benchmark years up to the year 2000. In the case where the savings are calculated relative to OCS oil, this assumption may overestimate those savings. Realizable production from OCS areas in the earlier benchmark years 1980 and 1985 can reasonably be expected to have a lower cost than in later years. On the other hand, in the case where the savings are calculated relative to imported oil and to the extent that the price of imported oil can be expected to continue to rise, the calculated savings relative to imported oil may underestimate the potential benefits.

3.9 RESULTS OF CALCULATIONS

Table 3-2 shows the results of the calculations for eight scenarios representing different assumptions about future regulated EOR price levels and the type of saving, i.e., replacement versus displacement in time of either OCS oil or imported oil. Under each upper tier price scenario the "Total Benefit" and "Benefit/Cost Ratio" were calculated relative to high, most likely and low estimates of potential future EOR production levels. As mentioned before, the relatively low improvement in production levels deemed possible under a low price scenario precluded further differentiation into low and high projections around the most likely case.

The upper and lower limit of each estimate of the "Total Benefit" and the "Benefit/Cost Ratio" reflect the uncertainty about relative costs of EOR oil which resulted in the use of "low" (corresponding with current estimates of EOR economics) and "high" (corresponding to a doubling of current estimates) estimates of those costs.

Further, these benefits are calculated on either a "replacement" basis (EOR instead of the alternative) or "displacement" basis (EOR only deferring use of the alternative).

The alternative assumption of a higher level of government R&D (i.e., the "High Plan") has been included as a better basis for assessing the B/C ratios for the higher EOR production scenarios.

The results show:

- First, how under an upper tier price scenario, a net positive benefit (i.e., B/C greater than one) is projected for all but a few cases. A B/C smaller than one occurs only in the unlikely case that:
  - additional EOR oil will only delay the need for equal volumes of imports by ten years (imports displacement scenario);

TABLE 3-2

SUMMARY OF (ADL) COST/BENEFIT CALCULATIONS - "TYPE A" BENEFIT

Note: Benefit defined as incremental savings, 1976-2000, over case of no further government R&D.

Scenario 1: High Tier Oil Price, OCS Replacement (1)

	Government R&D spending level					
	ERDA Plan (3) Discount Rate			High Plan (4) Discount Rate		
	0%	6%	12%	0%	6%	12%
Government R&D Spending ($MM)						
High	298	231	183	1490	1155	915
Most Likely	298	231	183	--	--	--
Low	298	231	183	--	--	--
Total Benefit ($Billion)(5)						
High	9.5-27.4	3.7-10.6	1.6- 4.7	9.5-27.4	3.7-10.6	1.6- 4.7
Most Likely	3.5-10.2	1.3- 3.9	0.6- 1.7	--	--	--
Low	1.5- 4.2	0.6- 1.6	0.3- 0.7	--	--	--
Benefit/Cost Ratio(5)						
High	32.0-92.0	16.0-45.0	9.0-25.0	6.0-18.0	3.0- 9.0	2.0- 5.0
Most likely	12.0-34.0	6.0-17.0	3.0- 9.0	--	--	--
Low	5.0-15.0	2.5- 7.0	1.4- 4.0	--	--	--

Scenario 2: High Tier Oil Price/OCS Displacement (2)

Government R&D Spending ($MM)						
High	298	231	183	1490	1155	915
Most Likely	298	231	183	--	--	--
Low	298	231	183	--	--	--
Total Benefit ($Billion)(5)						
High	0	1.6- 4.6	1.1- 3.1	0	0.3- 4.6	0.2- 3.1
Most likely	0	0.6- 1.7	0.4- 1.1	--	--	--
Low	0	0.2- 0.7	0.2- 0.5	--	--	--
Benefit/Cost Ratio(5)						
High	0	7.0-20.0	6.0-17.0	0	1.4- 4.0	1.2- 3.4
Most likely	0	2.6- 7.0	2.2- 6.0	--	--	--
Low	0	1.1- 3.1	1.0- 2.7	--	--	--

(1) EOR oil will, if less expensive, replace OCS on a barrel-for-barrel basis.

(2) EOR oil will, if less expensive, delay requirements for OCS oil by 10 years.

(3) Government R&D spending on EOR at $298 million from 1976 through 1982.

(4) Government R&D spending on EOR set at 5 x $298 = $1490 million through 1982 basis.

(5) The upper and lower limit correspond with, respectively, current and conservatively high cost estimates for EOR oil.

TABLE 3-2 (cont.)

Scenario 3: High Price/Imports Replacement (1)

	Government R&D spending level					
	ERDA Plan (3) Discount Rate			High Plan (4) Discount Rate		
	0%	6%	12%	0%	6%	12%
Government R&D Spending ($MM)						
High	298	231	183	1490	1155	915
Most likely	298	231	183	--	--	--
Low	298	231	183	--	--	--
Total Benefit ($Billion) (5)						
High	6.5-31.5	2.3-11.8	0.9- 5.0	6.5-31.5	2.3-11.8	0.9- 5.0
Most likely	2.4-12.0	0.8- 4.4	0.4- 1.9	--	--	--
Low	1.0- 4.7	0.3- 1.8	0.1- 0.8	--	--	--
Benefit/Cost Ratio (5)						
High	21.0-106.0	10.0-51.0	5.0-27.0	4.0-21.0	2.0-10.0	1.0- 5.0
Most likely	8.0-40.0	4.0-19.0	2.0-10.0	--	--	--
Low	3.0-16.0	1.5- 8.0	0.8- 4.2	--	--	--

Scenario 4: High Price/Imports Displacement (2)

Government R&D Spending ($MM)						
High	298	231	183	1490	1155	915
Most likely	298	231	183	--	--	--
Low	298	231	183	--	--	--
Total Benefit ($Billion) (5)						
High	0	1.0- 5.2	0.6- 3.4	0	1.0- 5.2	0.6- 3.4
Most likely	0	0.4- 2.0	0.24-1.3	--	--	--
Low	0	0.15-0.8	0.10-0.5	--	--	--
Benefit/Cost Ratio (5)						
High	0	4.0-22.0	3.0-19.0	0	0.8- 4.4	0.6- 3.8
Most likely	0	1.7- 8.0	1.3- 7.0	--	--	--
Low	0	0.7- 3.4	0.5- 2.9	--	--	--

(1) EOR oil will, if less expensive, replace imports on a barrel-for-barrel basis. Imported oil cost at $12/bbl.

(2) EOR oil will, if less expensive, delay requirements for imports by 10 years.

(3) Government R&D spending on EOR at $298 million from 1976 through 1982.

(4) Government R&D spending on EOR set at 5 x $298 = $1490 million through 1982 basis.

(5) The upper and lower limit correspond with, respectively, current and conservatively high cost estimates for EOR oil.

SOURCE: Arthur D. Little, Inc.

TABLE 3-2 (cont.)

Scenario 5: Low Tier Price/OCS Replacement (1)

	Discount Rate		
Government R&D Spending ($MM)	0%	6%	12%
Most likely	298	231	183
Total Benefit ($Billion)(3)			
Most likely	1.5-4.1	0.8-2.1	0.5-1.2
Benefit/Cost Ratio(3)			
Most likely	5.2-13.8	3.5-9.1	2.7-6.7

Scenario 6: Low Tier Price/OCS Displacement (2)

Government R&D Spending ($MM)			
Most likely	298	231	183
Total Benefit ($Billion)(3)			
Most likely	0	0.4-0.9	0.3-0.8
Benefit/Cost Ratio(3)			
Most likely	0	1.6-4.0	1.8-4.6

(1) EOR oil will, if less expensive, replace OCS oil on a barrel-for-barrel basis.

(2) EOR oil will, if less expensive, delay requirements for OCS oil by 10 years.

(3) The upper and lower limit correspond with, respectively, current and conservatively high cost estimates for EOR oil.

SOURCE: Arthur D. Little, Inc.

TABLE 3-2 (concl.)

Scenario 7: Low Tier Price/Imports Replacement (1)	Discount Rate 0%	6%	12%
Government R&D Spending ($MM)			
Most likely	298	231	183
Total Benefit ($Billion)(3)			
Most likely	0.9-4.1	0.4-2.1	0.24-1.24
Benefit/Cost Ratio(3)			
Most likely	3.0-14.0	1.8-9.1	1.3-6.7
Scenario 8: Low Tier Price/Imports Displacement (2)			
Most likely	298	231	183
Total Benefit ($Billion)(3)			
Most likely	0	0.2-0.9	0.2-0.8
Benefit/Cost Ratio(3)			
Most likely	0	0.8-4.2	0.9-4.6

(1) EOR oil will, if less expensive, replace imports on a barrel-for-barrel basis. Imported oil cost is $12/bbl.

(2) EOR oil will, if less expensive, delay requirements for imports by 10 years.

(3) The upper and lower limit correspond with, respectively, current and conservatively high cost estimates for EOR oil.

SOURCE: Arthur D. Little, Inc.

- the price of those imports will not rise beyond $12/Bbl;
- the cost of the cheapest EOR oil will be as high as $7.50/Bbl; and
- the additional production realized through government funding is only 200,000 Bbl/day in 1985 and 300,000 Bbl/day in 1990, 1995 and 2000.

- Second, how important it is to have upper tier prices for EOR oil instead of lower tier prices. Comparing the results under the most likely cases for the upper tier price scenario with the results for the most likely cases under the lower tier price scenario shows that the benefit to be expected from the same level of government R&D spending is reduced by a factor of two to three, if lower tier prices prevail.

4.0 OTHER BENEFITS

4.1 BENEFIT TYPE B: AVOIDING THE RE-ENTRY INTO CAPPED WELLS AT A LATER TIME

4.1.1 Rationale

Type A benefits (Appendix A) are primary ones which are usually appropriate to any new technology. Equally important, however, are benefits which are specific to a technology area because of the resource involved, its marketplace, or timing considerations. One such benefit appropriate to tertiary recovery technology was quantified in our earlier assessment. A review of this concept with industry people in the field has supported our retaining it as an alternate benefit type.

This benefit relates to the avoidance of capping wells and then having to either re-enter those wells at a later date or even losing economic access to those fields essentially forever. Since our analysis relates to the incremental value of the ERDA research program, our focus in quantifying this benefit is upon the period 1985 to 1995 where such avoidance of capping wells for purposes of enhanced recovery may be attributed to accelerated developments resulting from Federal R&D. We selected 1985 as the initial year for counting benefits of this type because we believe that it will be about that time at which oil field operators will begin to accept the "arrival" of enhanced recovery technology in their decisions to keep the wells open. In other words, it is at that point that we believe the technology will be viewed as clearly proven for widespread application.

4.1.2 Methodology

The first determination in this analysis is the appropriate number of wells which are annually abandoned but which would be kept open as a result of enhanced recovery capabilities. In this determination, we have assumed that the relevant situations are stripper wells. In the years 1945 to 1969 the average number of stripper wells abandoned were about 16,500. For this analysis, we assumed 15,000 per year as the relevant quantity.

A second determination is the amount of reserves recoverable (by tertiary methods) from each abandoned well. From industry statistics, we have estimated this at 130,000 Bbl/well.

Since enhanced recovery will not be appropriate in all cases, we assumed that two-thirds of the stripper wells or 10,000 per year would be able to benefit in this manner. Other economic determinations required for this analysis include the estimated redrilling costs per well and the incremental re-entry costs once a well has been shut down. We estimated the redrilling cost per well for these stripper well fields to be in the order of $90,000 per well. By other means, we have alternatively estimated a re-entry cost of $1.50/Bbl recovered.

We developed two methods by which a range of potential benefits may be calculated. The first multiplies the number of wells times the ten years of savings times the redrilling costs ($90,000) per well. The second method multiplies the number of wells times the ten years of savings times the barrels per well times the re-entry costs ($1.50) per barrel.

4.1.3 Benefit Type B Results

The results of this analysis calculated on the basis of two different methodologies are presented in Table 4-1. We believe that the benefits quantified here can be added to Type A benefits. Using no discounting or a 0% discount rate, the anticipated benefits range from $9 billion under Method 1 to $19.6 billion under Method 2 and non-discounted B/C ratios of 30 and 65. At 6% the B/C ratios are 16 under Method 1 and 34 under Method 2. Under the higher discount rate of 12%, the benefit/cost ratios range from 8 to 18.

4.2 BENEFIT TYPE C: BALANCE OF PAYMENTS VALUE

4.2.1 Rationale

The alternative benefits quantified here relate to the concept that the National value of tertiary-recovered oil lies in the nearer-term availability of reserves that can offset the need for imported oil and improve the National balance of payments. The value per barrel in this case is the price of imported oil and represents the avoidance of importing oil.

4.2.2 Methodology

The magnitude of the benefits will depend on the level of additional EOR production resulting from government R&D funding and the number of years which are gained in the availability of this additional production.

Given the estimates of the volumes of additional annual production over time and the number of years of earlier availability, a conservative estimate of the benefit can be calculated as the present value of the interest accrued on the balance of payments surplus resulting from having to import less foreign crude during the years over which the availability of EOR production has been accelerated.

This estimate will be conservative to the extent that government R&D funding will not only result in earlier availability of EOR oil production but also in additional EOR production, which would not have been produced if EOR-related R&D were left to the industry alone.

4.2.3 Benefit Type C Results

The benefits and benefit/cost ratios on this balance of payments basis are quantified in Table 4-2. We believe that these benefits are best viewed as an alternative measure of benefits as opposed to an additive quantity to be combined with the other benefits described herewith.

TABLE 4-1

TYPE B BENEFIT/COST RATIOS FOR ENHANCED RECOVERY PROGRAM

At 0% discount rate:

	Method #1	Method #2
Benefits ($B)	$9.0	$19.6
Benefit/Cost Ratios	30	65

At 6% discount rate: (discounting back from 1990)

	Method #1	Method #2
Benefits ($B)	$3.8	$ 8.2
Benefit/Cost Ratios	16	34

At 12% discount rate: (discounting back from 1990)

	Method #1	Method #2
Benefits ($B)	$1.6	$ 3.6
Benefit/Cost Ratios	8	18

TABLE 4-2

TYPE C BENEFIT/COST RATIOS FOR TERTIARY RECOVERY PROGRAMS

Scenario: Upper Tier Price for Tertiary Oil

	Discount Rate		
	0%	6%	12%
Government R&D Spending ($MM)			
High	298	231	183
Most likely	298	231	183
Low	298	231	183
Total Benefits ($B)			
High	0*	30.2	20.2
Most likely	0	11.3	7.5
Low	0	4.6	3.1
Benefit/Cost Ratio			
High	0	131	110
Most likely	0	49	40
Low	0	20	17

Scenario: Lower Tier Price for Tertiary Oil

Government R&D Spending ($MM)			
Most likely	298	231	183
Total Benefit ($B)			
Most likely	0	5.5	4.8
Benefit/Cost Ratio			
Most likely	0	24	26

*Benefits accrue only in a discounted context

Since the benefit lies in making the reserves usable to the Nation earlier in time, benefits only accrue in the context of a discounting analysis. On a non-discounted basis, a barrel of oil will have a value of $12.00/Bbl whenever it is developed. Therefore, the application of a discounting approach does not reduce the benefits in this particular case but in fact increases them (or makes them possible). Clearly the "balance of payments" benefits to be expected under the conservative scenarios considered are positive and very substantial: the B/C ratio ranges from 40 to 49 depending on the discount rate and (12% versus 6% respectively) under a scenario assuming upper tier pricing of EOR oil and a most likely level of production and it ranges from 24 to 26 under a lower tier pricing scenario.

4.3 BENEFIT TYPE D: VALUE FOR AN EMERGENCY STOCKPILE

4.3.1 Rationale

We initially considered this benefit to be "value as an emergency stockpile" and particularly speculative in nature. Further discussions caused us to modify the concept as discussed below. Indications are that there is indeed a potential benefit arising from the need--now a mandate under recent legislation--to establish a National petroleum stockpile, coincident or synergistically with a program to develop tertiary recovery methods.

Benefit D examines the dual National needs of developing EOR technologies, and, separately, achieving the mandated emergency stockpile of oil which might be tapped in a crisis. One measure of this benefit would be any assumed $/Bbl cost savings in the price at which the government could purchase available EOR oil compared to the market price for oil it would otherwise have to purchase (without the stimulus of ERDA R&D programs), times the storage quantity, and discounted to present value in the appropriate time frame. This benefit is included in Benefit Type A - National Savings.

Another measure would be simply the balance of payments savings in having additional tertiary oil supplies available, as a result of ERDA funding, so that less oil would have to be imported in meeting U.S. needs including the additional requirements for an emergency reserve. This benefit is included in Benefit Type C - Balance of Payments.

There is another concept of benefit associated with EOR in conjunction with an emergency stockpile program. This is the notion that extra funding of EOR--i.e., ERDA funding over the amount industry would normally be expected to support--is analogous to an insurance premium payment for coverage against a catastrophic loss. Let us assume, based on the estimates in this study, that approximately 300 million incremental barrels of oil will be available over the next seven years, which are taken to be the period of accumulation of an emergency reserve.*

* See Public Law 94-163, "Energy Policy and Conservation Act," 94th Congress, December 22, 1975.

We may consider the value of this incremental oil--its benefit in a National security sense, to be at least equal to the cost of imported oil which it would replace.* Expression of the incremental dollar benefit in relation to incremental ERDA funding cost, however, is not straightforward. A more meaningful way, perhaps, to handle this is to think formally in terms of insurance and portfolio values, as discussed in the next section.

4.4 BENEFIT TYPE E: INSURANCE AND PORTFOLIO VALUES

4.4.1 Rationale

Benefit Type E theoretically examines the insurance and portfolio values of ERDA participation in an EOR program. The notion here is that by increasing the number, N, of projects in the funded R&D program "portfolio," the risk that the outcome will differ substantially from that expected decreases, and the benefit per unit of risk increases, as $\sqrt{N}$. The benefit of parallel development efforts was found to be accepted through industry interviews. This is consistent with the GURC study which indicates a need for simultaneous testing of all known EOR techniques if ERDA objectives for increasing domestic reserves are to be met.

The insurance benefit of an N-project program can be expressed in terms of its failure probabilities and an assumed catastrophic loss.

The point is, there is an analogy between sponsorship of mission-oriented research and development and the purchase of insurance, and the insurance analogy may ultimately be quantified. Similarly, there is an analogy between designing a portfolio of risky securities (that is, ownership of stocks or other assets whose rates of return are uncertain) and designing a portfolio of research projects. Such an analogy is based upon the application of statistics and portfolio theory to the management of diversifiable risk. This analogy can also be drawn in quantitative terms.

The examination below is a condensation taken from our previous study. It provides the basis for extension by illustrative examples in dollar terms and some perspective in the context of the current R&D effort. A more elaborate analysis is required in the real case where project cost and parameters may differ widely from project to project.

4.4.2 Insurance Benefits and the Risk of Failure

In brief, the insurance benefits can be expressed in terms of an incremental expected benefit (or loss avoided) per unit of incremental research cost; the treatment of the insurance benefit carries with it the notion

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* Expected to be $11.80/Bbl per Wall Street Journal (p. 2, December 16, 1976) report of FEA intentions. The total investment in the reserve program is estimated at $8 billion.

of an optimal number of research projects, which is a function of the size of a "catastrophic loss" (e.g., in a National security sense) assumed to be possible in the absence of any research or if all research projects fail. Similarly, the optimal number of research projects depends upon the project failure probabilities--i.e., the higher the failure probability, the larger must be the research program.

The word "risk" can have various meanings. For the purposes of this section, we will define failure risk to be:

- The probability that all research projects in a research program will fail to achieve a given purpose.

If we use this definition of risk, it is appropriate to ask:

- How does failure risk vary with the number of research projects in a research program?

We cannot quantify an answer to this broad question in this study. However, it is useful to consider the following idealized example: If ERDA has opportunity to fund some number of projects, all of which have the same probability P_F of failure, and all of which are independent in the sense that the success of any one does not depend on the success of the others,

$$\left.\begin{array}{l}\text{The probability that all N}\\ \text{projects fail}\end{array}\right\} = (P_F)^N$$

Therefore:

$$P_0 = \left.\begin{array}{l}\text{The probability that at least}\\ \text{one project will succeed}\end{array}\right\} = 1 - (P_F)^N$$

and we can call P_0 the certainty of success. We might then ask (Table 4-3):

- How many projects should be supported if the certainty of one success must exceed some given amount?

4.4.3 The Risk in Uncertainty: Portfolio Benefits

The portfolio effect is based on the statistical properties of variances and co-variances among project outcomes and the combinatorial properties of the variance (i.e., the square of the standard deviation). In general, if there is little or no co-variances (correlation) associated with the outcome of projects in a research program, then the variability (a measure of risk) associated with the outcome of the overall program will be reduced as the number of projects is increased. This is analogous to the concept of diversification in a portfolio of securities where the diversifiable risk (non-market-related risk) can be reduced by increasing the number of holdings.

TABLE 4-3

Number of Projects Required

And the Probability of Success of the Individual Research Project is	If the Certainty of Success of the Research Program Must be at Least 99%	99.9%	99.99%
10%	44	66	88
20%	21	31	41
50%	7	10	14
90%	2	3	4

A somewhat more general concept of risk than that used up to this point is variability risk, which can be defined as:

- The probability that the outcome of a research program will differ substantially from what is expected.

One way to measure the variability risk is by the ratio of the standard deviation of the possible outcome to the average value of the outcome; the larger this ration, the greater the variability risk. It is then appropriate to ask:

- How does the variability risk of a research program vary with the number of research projects?

Variability risk in this case is affected by the number of projects that ERDA has the opportunity to fund, all of which have an uncertain outcome. If the expected value of the outcome of each one is μ, the standard deviation of the outcome of each is σ, the projects are independent, and the outcome of the program is the sum of the outcomes of the projects. The variability risk of an N-project program is then given by:

$$\frac{\sigma}{\mu\sqrt{N}}$$

and so decreases with the number of projects. This reduction occurs because the larger the number of projects, the better the chances of an unusually good outcome occurring to compensate for an unusually bad outcome. This is the simplest type of "portfolio effect."

4.4.4 Methodology

4.4.4.1 Insurance Benefits

Increasing the number of research projects is a way of "buying insurance" against the risk of failure. It is necessary to consider how much insurance of this type it is wise to buy, by considering the relative benefits of success and costs of failure. An example can illustrate this point. Suppose that each of the research projects requires a cost C, and that only one of the successful projects will be implemented to produce a benefit B. One approach to selecting the number of projects might be to attempt to maximize the expected value of the net benefits. If one or more projects are successful, the net benefit will be:

$$B - NC \Big\} \text{ benefit less cost of research program}$$

while if no project succeeds, the net benefit will be:

$$- NC \quad \text{cost of research program}$$

The expected net benefit of an N-project program will then be

$$\langle B_{Net} \rangle = B\,(1 - (P_F)^N) - NC$$

and the expected net benefit is maximized when

$$N = \frac{\ln\left(\frac{B}{C}\right) + \ln\left(-\ln P_F\right)}{\left(-\ln P_F\right)}$$

The values of N for several project benefit/cost ratios and failure probabilities are illustrated in Table 4-4 below.

TABLE 4-4

NUMBER OF PROJECTS WHICH MAXIMIZE EXPECTED NET BENEFITS

	If Benefit/Cost Ratio for Implementation of Any Successful Project is	
And Probability of Successful Implementation of Any Project is	100	1,000
10%	22	44
50%	6	9
90%	2	3

It is important to remember that

- The number of projects would be changed if the cost of program failure were greater than the simple loss of the research budget.
- Maximizing expected net benefits is not the only way to choose the number of projects and the concomitant certainty of success.

The expression for the expected net benefits is written on a probabilistic basis using only monetary rewards (e.g., savings), B, net of research program costs, NC, where N is the number of projects.

We can expand and modify the resulting expression to include two additional factors:

a) $V = N\Omega$ The estimated total societal value of the research program, in monetary equivalents, assuming a standard value Ω per project. The net cost per project is then $C' = C - \Omega$.

b) K = an additional (say, catastrophic) loss which could be assumed to occur to the United States if no R&D project succeeds.

Substituting in the derivation in terms of probabilities, its expected value is then

$$\langle B_{Net} \rangle = B\,(1-P_F^N) - NC' - KP_F{}^N$$

The change in this expected value with each additional project may be expressed as the first difference B (N+1) - B (N) and divided by the net cost of an incremental project, C′,

$$\frac{\Delta \text{ Benefit}}{\Delta \text{ Cost}} = \frac{\Delta E}{C'} = \left[\frac{(B+K)}{C'} \bullet (P_F)^N \bullet (1 - P_F)\right] - 1$$

The optimal N gets very large as the "catastrophic" loss K gets large. The quantity $\frac{\Delta E}{C'}$ will have a positive value until this optimum N is reached.

As an example, suppose that N = 10,

P_F = .8, B = \$200 MM (discounted) and C′ = \$50 MM (discounted)

$\frac{\Delta E}{C'}$	If K = 0	K = \$500 MM	K = \$1 billion
	= -0.6	= +0.3	= +1.3

Thus, with K = 0 and no loss other than the R&D costs from failure, ten programs is more than the optimum number to maximize net benefits; similarly, with a large catastrophic loss possibility, ten is less than the optimum--in this idealized example.

The cost of each additional project up to $N = N_o$ (o = optimum) results in additional expected net benefits; this cost may be thought of as buying additional insurance against a loss K.

4.4.4.2 Portfolio Benefits

A portfolio of projects may be well diversified or concentrated in one or two areas of technology. The risk that the outcome of a diversified R&D program will differ substantially from the project estimates is inversely proportional to $\sqrt{N}$, where N is the number of projects.

We may write the following expression for an R&D program of N independent projects, each with payoff, μ and uncertainty, σ :

$$\frac{\text{Benefit}}{\text{Risk}} \quad \alpha \quad \frac{\text{Expected Value}}{\sigma\sqrt{N}} \quad = \quad \frac{N\mu}{\sigma\sqrt{N}}$$

In changing the program from N_1 projects to one having N_2 projects, the Benefit/Risk ratio changes as the square root of the ratio of the number of projects, $\sqrt{\frac{N_2}{N_1}}$

Another expression for the Benefit ÷ Risk could be in terms of the variability coefficient $\frac{\sigma}{\mu\sqrt{N}}$. This is a dimensionless quantity and to convert into dollar terms, we need some concept for the cost of such risk. If we multiply the coefficient by a constant, γ, to account for this we may write

$$\frac{\$ \text{ Expected Program Benefit}}{\$ \text{ Cost of Diversifiable Risk}} = \frac{N\mu}{\left[\frac{\sigma}{\mu\sqrt{N}}\right]^{\gamma}}$$

and taking ratios,

$$\frac{(\text{Benefit})}{(\text{Risk})_2} \div \frac{(\text{Benefit})}{(\text{Risk})_1} = \left[\frac{N_2}{N_1}\right]^{3/2}$$

The point is that the cost of diversifiable risk decreases with the $\sqrt{N}$ and the total benefits increase with N, so that the ratio is increasing more rapidly than N.

4.4.5 Further Work

With additional efforts, the preceding discussion can be extended to the realistic case of the research program consisting of widely differing interdependent projects, to form the basis for a comprehensive program of risk control embodying both (a) the need for insurance against failure, and (b) the need for the provision of acceptable levels of certainty as to future benefits.

We have recommended that work along the above lines be pursued by ERDA. Definitions of project success and payoff (benefits) in common financial terms are necessary, as is an appropriate accounting framework in which to measure these benefits and the associated costs over time. Estimates of project failure probabilities are also required, as well as certain reasonable, but simplifying, assumptions which would enable the analysis to proceed to the point where it becomes an integral part of the RD&D program management process.

4.5 BENEFIT TYPE F: SYNERGISTIC OR BY-PRODUCT BENEFITS

4.5.1 Rationale

The conduct of an ERDA R&D program will, in and of itself, produce certain benefits in addition to those previously identified. Some of these benefits cannot be immediately related to oil costs and oil production, although they will have a beneficial impact in those terms.

The Type F benefits are the synergistic and by-product benefits of the ERDA research, which increase the stock of the nation's "know-how" and trained labor above the level which would likely be available without the ERDA program.

Specifically, consideration should be given to the following kinds of societal benefits which are likely to flow from the ERDA program (and to which GURC has also called attention):

- Additional manpower training and employment for the long-term development of domestic oil reserves, particularly those that require exotic production techniques;

- Information dissemination over a larger national audience, including petroleum companies, than would otherwise be likely;

- Increased competition via participation by companies in EOR which otherwise, because of financial, technological, or legal constraints, would not have become involved in this effort; and

- Increased knowledge of reservoir structures through EOR research could improve the techniques of primary recovery from new discoveries.

APPENDIX A

TYPE A BENEFITS: PROBABILISTIC NATIONAL SAVINGS FROM HAVING TERTIARY RECOVERY AVAILABLE IN ALTERNATIVE FUTURES

A.1 RATIONALE

A common analytical trap in evaluating the benefits of a new technology occurs when its most likely (i.e., single point estimate) economics are projected to be no better than the most likely economics of another technological alternative. It may be fallaciously reasoned therefrom that there is no value in pursuing an alternative which promises no better economics than another practical (or favored) alternative.

Such a conclusion ignores a basic context of R&D planning: uncertainty. In that context, the range of possible alternative future economics (i.e., representing different technical outcomes, different situations, etc.) is all important. In such a context, a new technology which on a most-likely-value-basis appears "merely equivalent" to an available alternative is, in fact, capable of improving upon the other alternative in half of the alternative futures which are possible. Further, the range of possible economics for a new technology need only overlap a part of possible economics of the available alternative in order to have the possibility for some positive probabilistic benefit.

In our analysis of tertiary recovery methods, an available alternative to tertiary recovery efforts in the next 10-15 years is the exploration for, and development of, OCS, (off-continental shelf) oil. Based on economic estimates for both of these alternatives, we have estimated that the range of economics possible for alternative future situations is as shown in Figure A-1.

A.2 METHODOLOGY

The benefit calculation uses the cumulative distributions for marginal costs of different parts of the resource base of, respectively, EOR and OCS oil as shown in Figure A-1. The marginal costs at any point on the curves reflect the average costs to find, develop and produce the next field(s). The corresponding cumulative distribution reflects the relative contribution of the corresponding fields--i.e., fields with an average cost corresponding to the shown marginal cost of that "slice" of the resource base--to the total resource base. In this context, the relative contribution of field reserves to total reserves can be assumed to reflect the probability of finding a "slice" of the total resources with marginal costs equal to the average costs of those particular fields which make up that "slice."

The benefit calculation assumes that the relative contribution of different fields with different marginal costs to total production (assumed to be realizable over time under the different scenarios) is reflected by the frequency distributions, which can be derived from the cumulative distribution.

To the extent that the cheaper parts of both resource bases can be expected to be developed at an earlier point in time, this assumption will have introduced some bias favoring the calculated benefit in the case of non-zero discount rates. As explained below, the calculation sums all savings of producing cheaper barrels of EOR oil versus more expensive OCS oil. If it is assumed that the OCS oil (which will not have to be produced because of the availability of cheaper EOR oil) can include oil costing as much as $25/Bbl, then savings will obviously be higher than if it is assumed that OCS oil can only cost up to $15/Bbl. Therefore, using a cost distribution which includes per barrel costs of up to $25/Bbl for both EOR and OCS oil for benefit calculations in the earlier benchmark years--i.e., 1980, 1985, and 1990--will tend to over value potential savings in the benefit calculations relative to OCS oil. On the other hand, in the alternative benefit calculations relative to imported oil using $12/Bbl as the cost of imported oil, the savings might have been underestimated for the later benchmark years, given the fact that the cost of imported crude oil might go up in the future.

The benefit calculation is based on the fact that the cumulative cost distributions as derived for EOR oil and OCS oil can be assumed both:

- to reflect the probability to find reserves with a certain cost; and
- to show the relative contribution to total reserves of fields at different cost levels.

The calculation goes through the following sequence of steps, and is illustrated by the simple discrete distributions shown in Figure A-2:

1. Assume that:
   - Relative contribution of EOR production at cost levels of, respectively, $13.75/Bbl, $17.50/Bbl, and $21.25/Bbl will be 0.25, 0.50, and 0.25 of total potential EOR production;/and that
   - The discrete probabilities of finding OCS oil at cost levels, respectively, of $7.50, $12.50, $17.50, and $22.50 are .125, .375, .375, and .125.

2. The first 25% of potential EOR production at a cost of \$13.75/Bbl could be cheaper than potential OCS production, given the probabilities of, respectively, .375 and .125 that OCS oil will cost \$17.50/Bbl and \$22.50/Bbl.

3. The per barrel potential expected cost savings of the first 25% of potential EOR oil production at \$13.75/Bbl rather than possibly more expensive OCS oil, then:

$$(.375 \times \$17.50 + .125 \times \$22.50)/(.375 + .125) - \$13.75 = \$5/\text{Bbl}.$$

4. Similarly the per barrel expected cost savings for the other 50% and 25% of positive EOR production at costs of, respectively, \$17.50/Bbl and \$21.25/Bbl are:

$$\frac{.125 \times \$22.50}{.125} - \$17.50 = \$5/\text{Bbl} \quad \text{and}$$

$$\frac{.125 \times \$22.50}{.125} - \$21.25 = \$1.25/\text{Bbl}$$

5. Consequently, the average per barrel cost savings for total potential EOR production in those futures in which OCS oil is more expensive than EOR oil will be:

$$0.25 \times \$5 \div 0.5 \times \$5 + 0.25 \times \$1.25 = \$4.06/\text{Bbl}$$

The calculations for the analysis itself were done with the help of a computer program which used the continuous cumulative distributions shown in Figure A-1 plus different projections of potential EOR production and a projection of intended government R&D spending over future years. Calculated future annual benefits, resulting from multiplying per barrel savings, calculated as discussed above, and projected additional production expected to result from government R&D funding over and above "industry only" production level, were discounted at different discount rates to allow for the time value(s) of money.

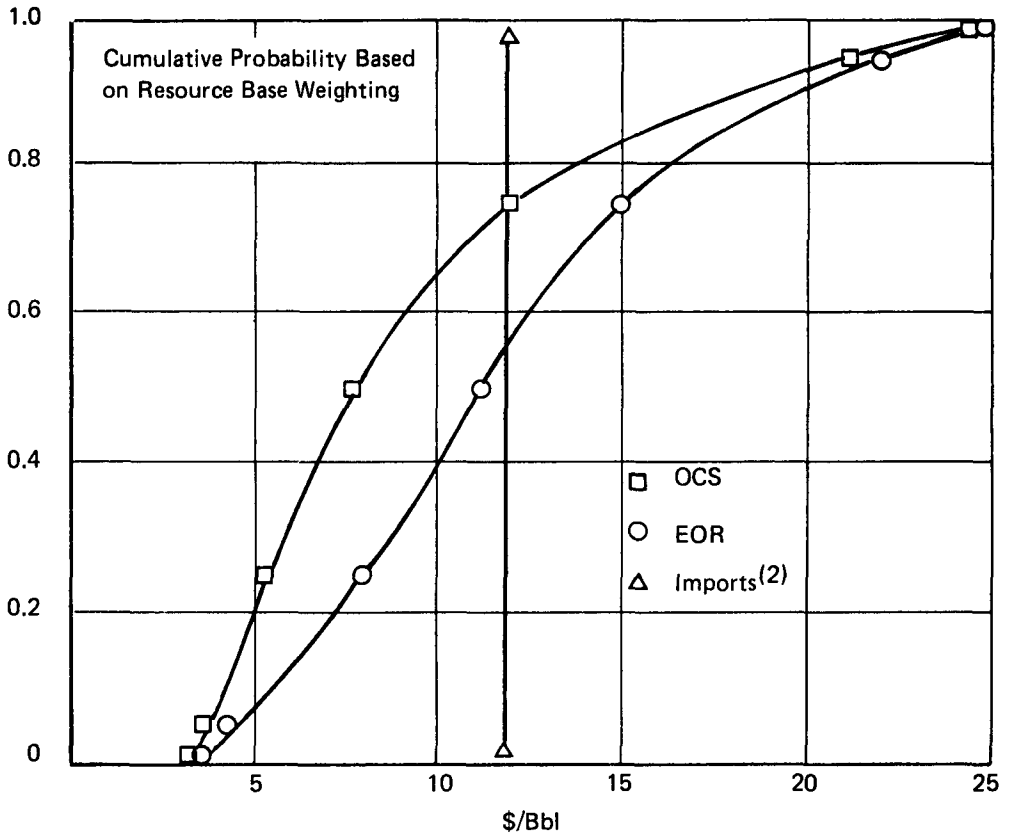


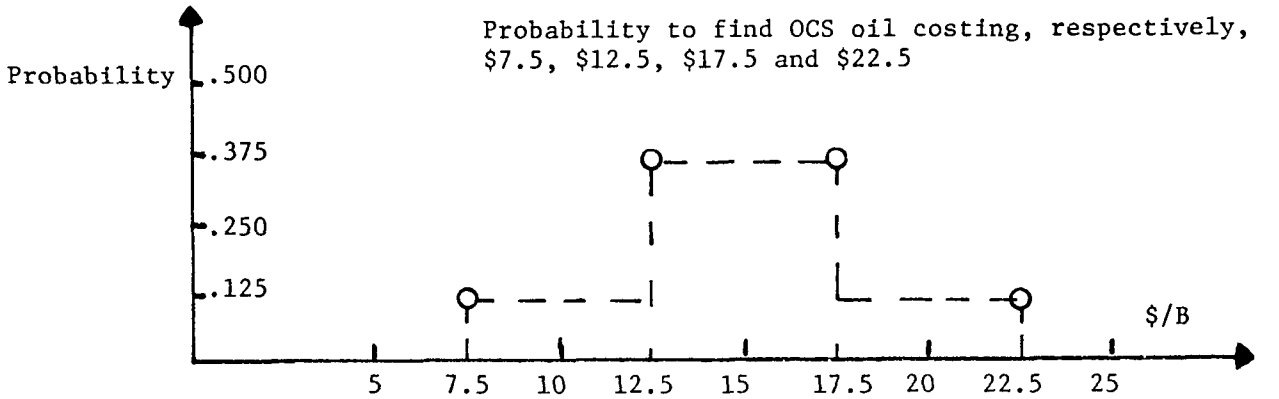
FIGURE A-1
CUMULATIVE DISTRIBUTION OF MINIMUM REQUIRED PRICE(1)
OF EOR OIL AND OCS OIL

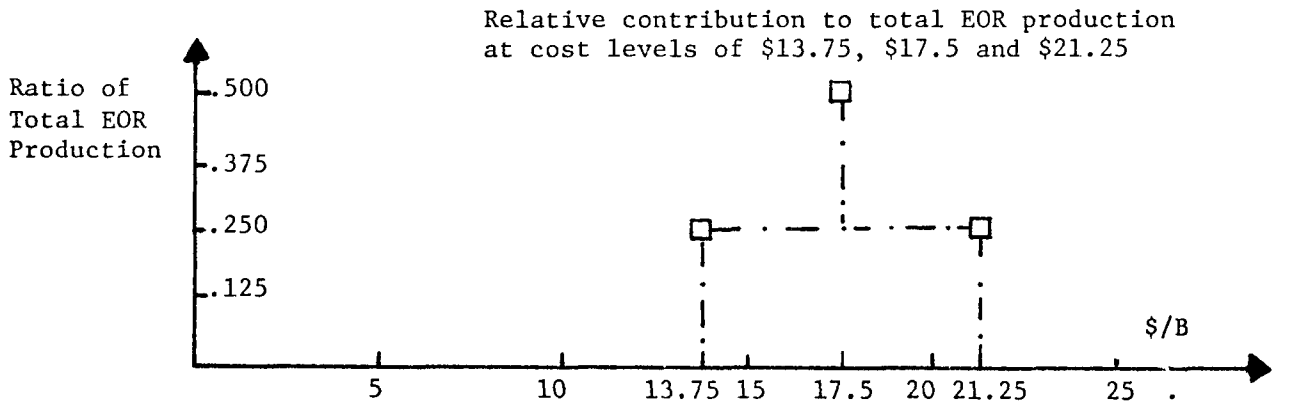
(1) Minimum required price, as used here, reflects average, after tax costs, allowing for a required rate of return to find, develop, and produce the next field.

(2) Imports at $12/Bbl (constant dollars).

SOURCE: Arthur D. Little, Inc.

Hypothetical EOR and OCS Cost Distributions





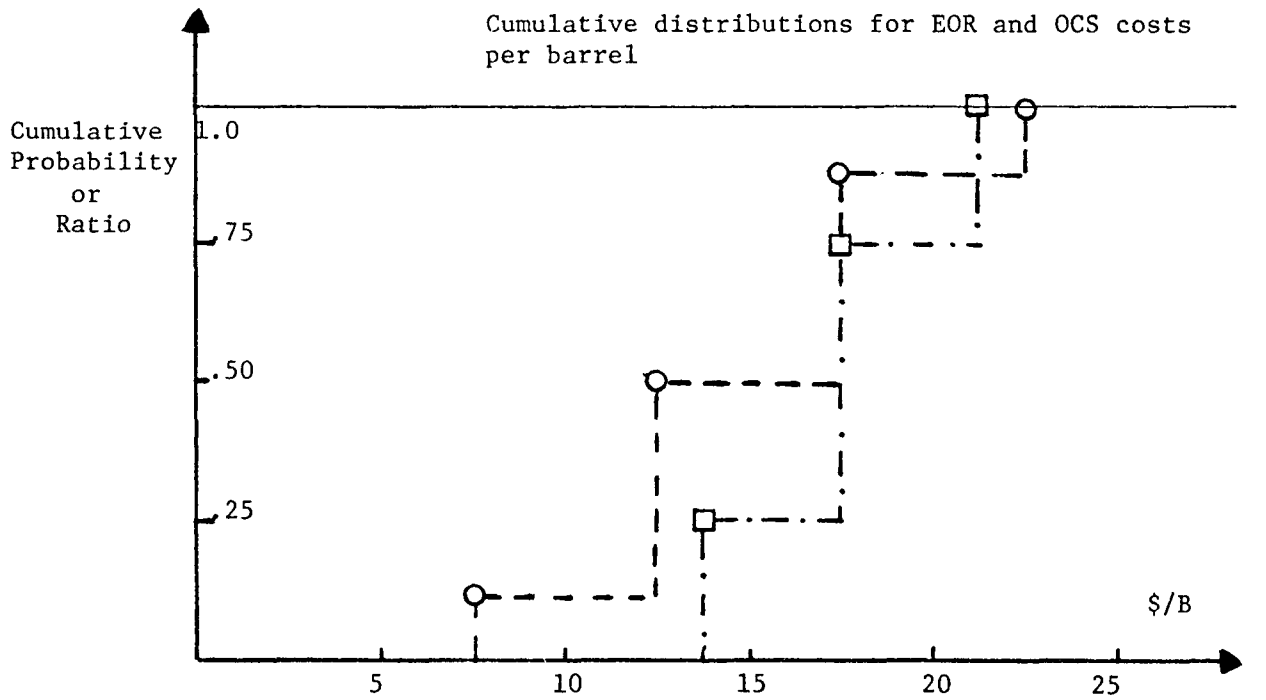


FIGURE A-2

APPENDIX B

ACCOUNTING AND TAX TREATMENT FOR OIL AND GAS PRODUCING COMPANIES

B.1 ACCOUNTING AND TAX TREATMENT FOR OIL AND GAS PRODUCING COMPANIES

Accounting and tax treatment for oil and gas producing companies was not directly within the scope of this updated benefit/cost analysis. However, because of important recent changes in the tax code and accounting rules, these considerations were quite relevant to our study.

We examined tax and accounting questions connected with offshore oil and gas (OCS) and enhanced oil recovery (EOR) activities in an attempt to learn if and how differences in their accounting nature and tax treatment might influence investment decision-making by oil companies. The views reflected here are our own and do not necessarily represent those of the accounting profession or tax counsel, i.e., those qualified to practice law or accounting. Nevertheless, our understanding is that:

- For *tax* purposes, oil companies have been permitted under the U.S. Internal Revenue Code to deduct most exploration* and intangible development costs (IDC) as incurred, in their determination of taxable income. For commercial fields, most companies capitalize intangible costs for book purposes. For financial statement *accounting* purposes, all or portions of intangible costs are capitalized, as explained further below.

- The traditional "Conservative Accounting" method of handling exploration and development costs has lost popularity and appears to have been largely abandoned. Under this approach, dry hole costs and related lease costs, and intangible drilling costs of producers are written off, i.e., expensed as incurred.

- "Successful-Efforts" accounting (Standard Accounting) is now used by most of the international majors including Exxon, Gulf, and Mobil. Under this approach, dry hole costs and related lease costs are expensed as incurred; tangible and intangible drilling costs of producers are capitalized and amortized by the unit-of-production method.

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* excluding bonus payments

- "Full Cost" accounting is, however, used by many of the smaller exploration-oriented companies. Under this approach, most exploration and development costs are capitalized and written off over the life of the various projects.

- In the case of OCS, bonus payments are usually capitalized for accounting purposes and carried on the balance sheet as capital investments in production and exploration. These may be written off by a formula, based on a company's history of exploration programs, to determine what percentage of the acreage is likely to be succesful. No amortization on the successful portion would usually take place until actual oil production commences. Then, upon commencement of production, this portion of bonus payments is written off on the unit-of-production basis over the life of the concession. The balance, i.e., the percentage of the acreage estimated to be unsuccessful, is written off over the anticipated life of the exploration program for that acreage prior to abandonment of the concession. This expected life of the exploration program is based on offshore drilling experience.

- As to the *federal income tax* treatment of OCS bonus payments, it is important to note that no tax deduction is allowed on the federal tax return for the amortization of the "unsuccessful" portion of capitalized bonus payments, until the company notifies the U.S. government that a lease is being abandoned. For the "successful" portion of the capitalized bonus payments, amortization does not begin until oil is produced. At that time, the depletion allowance remaining, if any, comes into play. Note that while the related portion of the bonus payments is amortized on the unit-of-production basis, the depletion allowance for tax purposes is calculated on the basis of either cost depletion or percentage depletion, whichever is <u>higher</u>. (Under percentage depletion, the allowance is the percent depletion rate times gross revenue from production [as specifically defined by the IRS] or 50% of taxable income computed without regard to depletion, whichever is <u>lower</u>. On the books of account, the quantity actually booked is cost depletion.)

Apparently, then, the first "taxable" event from the IRS point of view is either the point in time at which oil is brought up out of the ground (which is later than the date at which substantial discovery may occur), or upon notification that a lease is being abandoned.

- In the context of EOR, "Successful Efforts" and "Full Cost" accounting will tend over time to produce the same financial result since if a tertiary recovery venture is held to have failed (which can take several years to determine) the lease/tract will presumably be abandoned--which, for accounting purposes, must have the same effect as classifying it as a dry hole, i.e., a write-off.

  Putting it another way, all costs associated with a new venture would be capitalized under Full Cost accounting methods. Most costs would be capitalized and the rest expensed under Successful Efforts accounting. Costs will be charged to operations on a unit-of-production basis if it is successful and written off if it is not. Different accounting practices could produce a significant variation in the profit-and-loss statement. For large companies, this would not amount to a large overall perturbation. However, this characteristic could greatly influence small firm behavior and performance.

If this reasoning is correct, there are 16 alternative tax and accounting scenarios for tertiary recovery activity and 8 alternative tax and accounting scenarios for offshore drilling activity. (See Figures B-1 and B-2.)

Some of the major questions which we found to lack definitive answers in our discussions with industry are those concerned with (a) the allowable tax credits for intangible drilling/development costs (IDC), and (b) the allowance for the costs of EOR chemicals to be expensed as incurred.

B.2 RECENT CHANGES TO LAW ON PERCENTAGE DEPLETION

The recent changes due to the Tax Reduction Act of 1975, which have eliminated most of the aggregate tax savings to the producers, can be summarized as follows:

On March 29, 1975, Congress repealed percentage depletion for domestic and foreign oil production as of January 1, 1975, with the following exceptions:

There are 8 possible alternative scenarios depending on the tax treatments adopted for

a. % depletion
b. IDC costs,

and the accounting method used,*

[*Percentage depletion is not booked for accounting purposes; it only has a tax impact.]

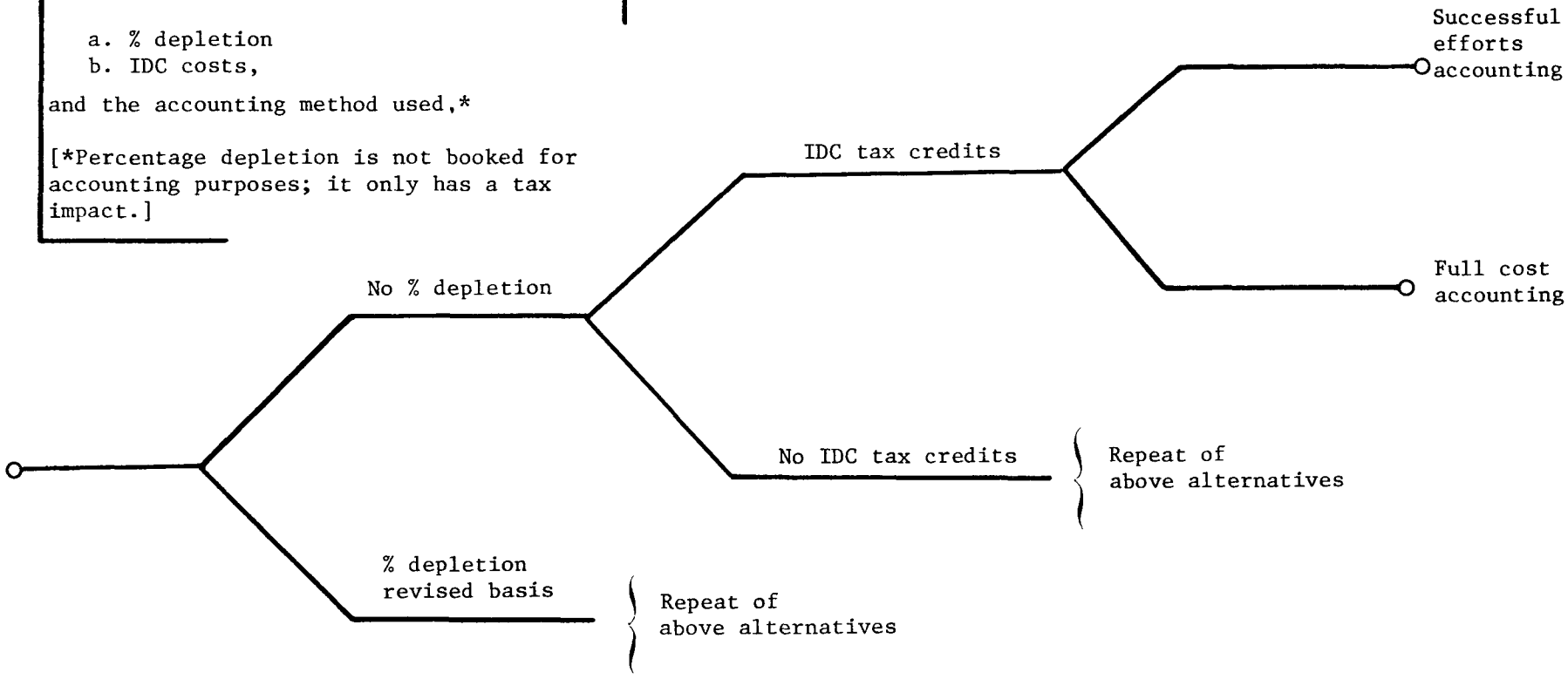

FIGURE B-1

OFFSHORE DRILLING: Tax and Accounting Alternatives

These are 16 possible alternative scenarios depending on the tax treatments adopted for

a. % depletion (tax effects only)
b. IDC costs
c. Costs of injected chemical
d. Chemical cash recoveries

Note: In the context of EOR it is believed that Successful Efforts and Full Costs accounting will produce much the same result in practical terms.

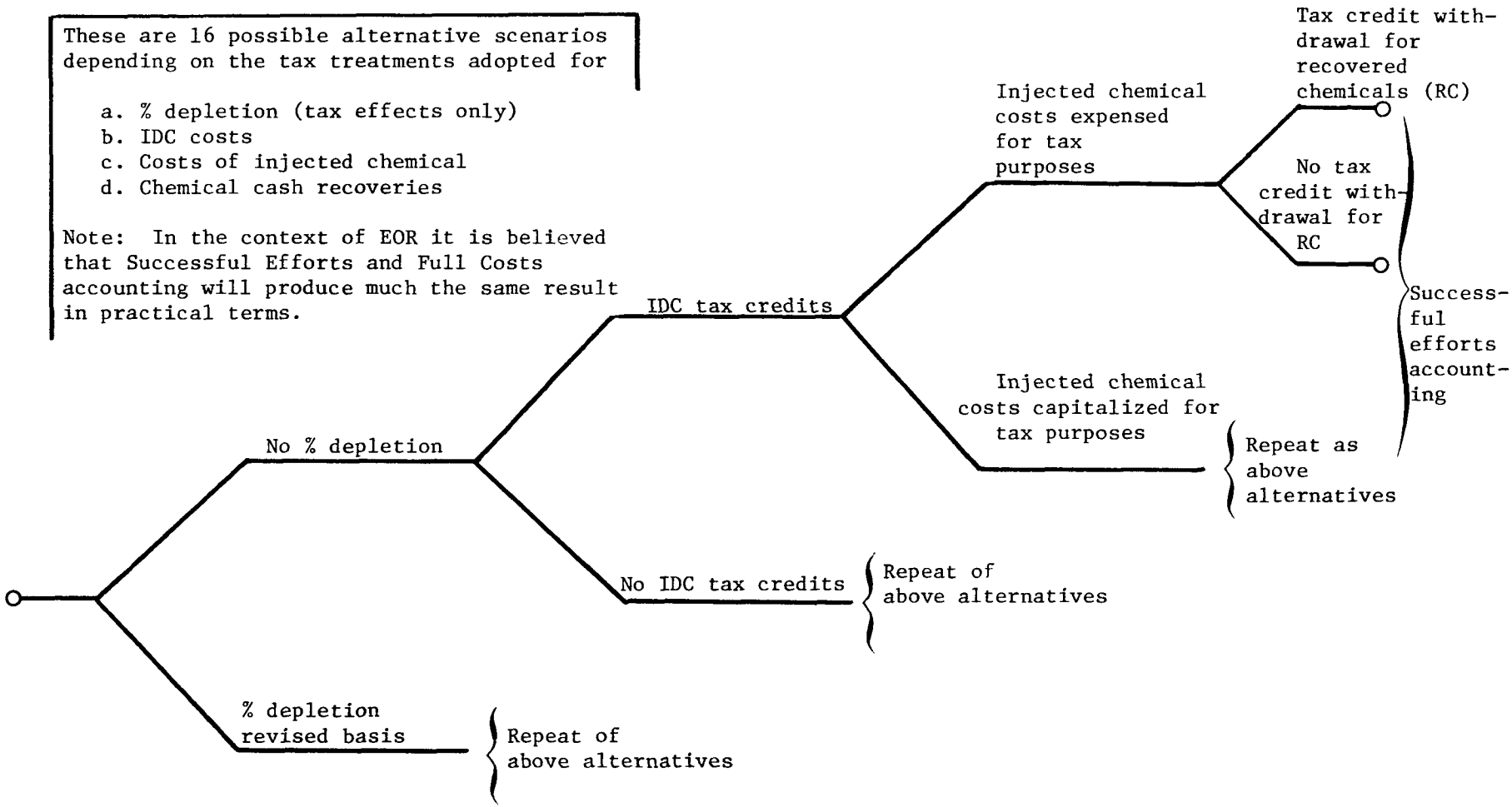

FIGURE B-2

TERTIARY RECOVERY: Tax and Accounting Alternatives

(a) Gas under a fixed-price contract made before February 1, 1975, where the price cannot be adjusted to reflect the increase in tax liabilities from depletion repeal.

(b) Regulated gas under control of the Federal Power Commission and produced and sold before July 1, 1976. (Any rate increase after February 1, 1975 is presumed to take into account depletion repeal, unless the producer can prove otherwise.)

(c) Domestic independent producers, who received a phased-down deduction starting at 22% for the first 2,000 Bbl/day oil or 12 million cfd gas in 1975. Each year, the oil exemption will be reduced 200 Bbl/day until it reaches 1,000 Bbl/day in 1980. Then, the rate will gradually be lowered to a permanent 15% in 1984. (See Table B-1.)

Current industry estimates indicate that in 1975 there were about 100 producers with oil production capability between 1,000 and 2,000 Bbl/day.

Producers who own or control more than 5% of a retail operation selling oil, natural gas, or their products, or refine more than 50,000 Bbl of oil on any one day of the taxable year are not eligible for the exemption.

The deduction for depletion on the new basis is limited to 50% of the producer's net income from each property and 65% of the producer's taxable income from all sources. For this purpose, taxable income is computed without regard to depletion, net operating loss carryback, and capital loss carryback. Unlimited carryover is provided for depletion which is unused due to the 65% limitation.

A significant feature of the IRS interpretation of the new depletion law is that it has proposed that the application of depletion to independent producers on the revised basis be limited to production that has been "significantly increased" as a result of EOR. This, as the Independent Petroleum Association of America (IPAA) has pointed out, would tend to exclude the results of any EOR activity that was begun early in the life of a well (when EOR can be done with the greatest benefit) and would also penalize a producer who had incurred

TABLE B-1

OIL EXEMPTION RATE FOR DOMESTIC INDEPENDENT PRODUCERS

	RATE %	Volume* OIL			GAS
1975....	22	First 2,000 Bbl/day	or	12	million cfd
1976....	22	First 1,800 Bbl/day	or	10.8	million cfd
1977....	22	First 1,600 Bbl/day	or	9.6	million cfd
1978....	22	First 1,400 Bbl/day	or	8.4	million cfd
1979....	22	First 1,200 Bbl/day	or	7.2	million cfd
1980....	22	First 1,000 Bbl/day	or	6	million cfd
1981+...	20	First 1,000 Bbl/day	or	6	million cfd
1982+...	18	First 1,000 Bbl/day	or	6	million cfd
1983+...	16	First 1,000 Bbl/day	or	6	million cfd
1984....	15	First 1,000 Bbl/day	or	6	million cfd

* Volume can include both oil and gas, but the combined total cannot exceed the equivalent of oil eligible for the allowance each year.

\+ For 1981-83, producer can receive 22% deduction rate for oil produced from secondary and tertiary recovery so long as the amount does not exceed the overall limit of 1,000 Bbl/day.

substantial expense on an EOR project but had achieved less than anticipated success.

(d) Producers can still claim cost depletion on capitalized intangible and leasehold costs.

(e) Royalty owners still retain the deduction for percentage depletion.

Looking now at the impact of the change in the depletion allowance on *accounting* for financial statement purposes, the accounting profession and the industry in 1975 took different positions relative to the proposals for complex accounting changes that would be incorporated in financial statements issued for 1975 operations. The essence of the disagreement was the status of provision for deferred tax reserves ("interperiod tax allocation") related to IDC, and the "interaction" with percentage depletion given the "fact that percentage depletion over the life of oil and gas properties was expected to exceed costs of that type that are capitalized and amortized in the determination of pretax accounting income*..."

In October 1975, the Financial Accounting Standards Board (FASB) adopted its Statement No. 9, which applies to company financial statements issued after November 30, 1975. As explained by a Wall Street Journal** article, Statement No. 9 requires companies to provide "deferred taxes" in reports to shareholders to reflect the different treatment of certain costs (mainly "intangible" drilling and development costs--a substantial category that includes labor, materials, fuel, power, equipment rentals and repairs) on tax returns.

> "Normally, when such 'timing' differences exist, accounting rules require companies to make a charge against current earnings for 'deferred' taxes." The taxes are deemed deferred because later, when the costs are charged off in reports to shareholders, there won't be any corresponding tax deduction, the item having been deducted previously.**
>
> "Oil companies haven't been required to make such charges, however. They were exempted because they also enjoyed percentage depletion as a tax-cutting device. In effect, the companies' 'deferred' taxes never fell due because the depletion allowance kept their taxes low."**

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* See "Accounting for Income Taxes - Oil and Gas Producing Companies," Exposure Draft, Financial Accounting Standards Board, April 25, 1975.

** Wall Street Journal, October 16, 1975. Page 17.

In the FASB view, when the Tax Reduction Act eliminated percentage depletion for major producers, it also eliminated the justification for the accounting exemption. The FASB proposed that oil companies begin making the tax charges. In addition, to allow for intangible costs already deducted on past year's tax returns but yet to be charged off in shareholder reports, the Board proposed a special, "catch-up" charge against 1975 earnings. These proposals encountered considerable opposition from the industry and accounting firms. The small independent oil producers, which generally capitalize a higher proportion of their costs, were bitterly opposed. (Indeed, spokesmen predicted the special charge would cut 1975 reported earnings 50% or more and reduce total equity 10%.)

The largest integrated oil companies became alarmed on another score: As the Journal put it, "They feared that the large, non-cash charge to earnings would feed public cynicism about the oil industry's accounting methods."

The FASB, in Statement No. 9, adopted what appears to be a less disruptive method, the "prospective net" approach. In simple terms, the "prospective net" method requires a company to provide, effective January 1, 1975, deferred taxes only on the difference between its current outlays on intangible drilling and development, and the amortization of costs capitalized previously.

B.3 COMMENTS ABOUT THE TAX TREATMENT OF TERTIARY OIL VERSUS TAX TREATMENT OF OCS OIL

For the operations in the U.S. jurisdiction, we believe that current tax and accounting considerations tend to favor OCS but are not controlling, in regard to corporate decisions on EOR vis-á-vis OCS at this juncture--given their respective stages of commercialization.

An interesting illustration of this is Figure B-3, depicting the currently estimated required price range as a function of different field sizes for OCS. (See "High" estimate and "Low" estimate curves.) As drawn, these lines have no relation with any existing areas, but they can illustrate the point. In the same figure is shown the range within which the minimum required price for tertiary oil is often quoted by companies; e.g., $15/Bbl to $20/Bbl. The minimum required price schedule in the case of tertiary oil is shown as relatively insensitive to the amount of reserves which can be expected recoverable through use of tertiary methods in a particular field. Also shown is the range of required price for tertiary oil for a hypothetical case in which tertiary would receive favorable tax treatment and would lower the required price by 10%.

Let us assume that in the near future the price of oil will indeed be near $20/Bbl. In that case companies can be expected to prefer OCS oil as long as they have reasons to believe that OCS fields remain to be found with more than 15 million ("Low" estimate curve) or less than 30 million ("High" estimate curve) barrels of recoverable reserves--depending on their economic evaluation of tertiary oil vis-á-vis OCS oil. In other

words, somewhere within the range of 15 to 30 million barrels of recoverable reserves lies the break-even point between tertiary oil and OCS oil given the above mentioned assumptions (See Figure B-3.)

Lowering of the perceived required price schedule for tertiary oil by, say, $2/Bbl through analysis of accounting methods and tax treatments would shift the OCS break-even from 15-30 million barrels to 17-35 million barrels recoverable reserves in this example. But, in other words, the mid-point of about 22 million barrels would be shifted only about 3 million barrels--which can be regarded as insignificant given the range of uncertainty here.

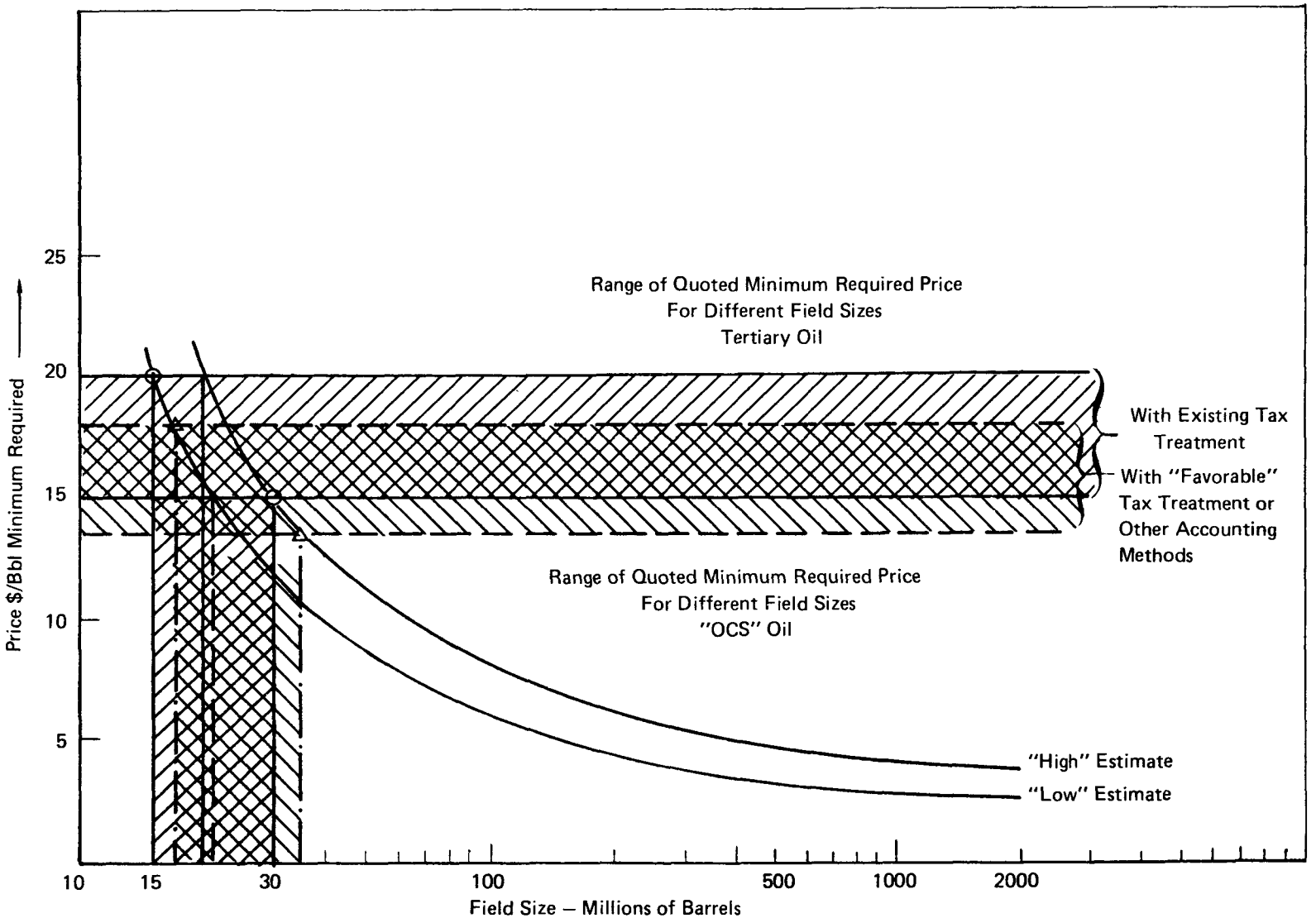

FIGURE B-3

TERTIARY OIL VERSUS OCS OIL - HYPOTHETICAL ILLUSTRATION