IV. Impacts of Price and Tax Policies on Oil Recovery

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Policy Considerations

With the advent of a new technology like enhanced oil recovery (EOR), two related factors often inhibit expansion of output. First, even with certainty of information about prices, costs, and production, careful analysis may indicate that production will not be profitable for early operators. prices may be too low or production experience may have been inadequate to reduce costs or increase efficiency sufficient to yield an acceptable return on invested capital. Second, as in any market situation, there will be uncertainty about many variables that can affect profitability. In the case of EOR, technical and economic uncertainty, coupled with some degree of aversion to risk by potential operators, can inhibit the speed and extent of process development.

Proposed public policy alternatives are, in essence, attempts to reduce the effects of these two factors on the private decision process, modify private market decisions, and remove barriers to EOR development. Although these two factors are obviously interdependent, the artificial distinction will be maintained for purposes of this analysis. First, the report evaluates alternative public policy options designed to foster private-sector development of enhanced recovery processes under the *assumption* **of information certainty. Point projections of production, price, and cost profiles for selected reservoirs** will be used. A second analysis, using subjective probability distributions of key input variables, describes the impact of policy alternatives designed to alleviate economic uncertainty.

Policy Options

A number of public policy alternatives have been suggested which could influence the development of EOR techniques, Implementation of these alternatives may affect private sector decisions on the development of specific EOR reservoirs or modify decisions regarding which process should be installed. Some policy options also may alter constraints which would limit the amount of EOR production nationally. Regardless of their specific focus, most public policy changes can be expected to influence the degree of uncertainty perceived by the private sector in future EOR activities.

A number of these potential public policy actions will be analyzed and evaluated. The principal proposals can be classified as:

1) alternative regulated and/or market price levels;
2) price and/or purchase guarantees for EOR over the lifetime of a producing facility;
3) alternative taxation policies, including changes in depreciation methods, investment tax credit rates, and expensing rules for various categories of investment and operating costs; and
4) public investment subsidies-Government payment of a percentage of private investment costs.

In addition, the effects of these alternative strategies can be determined under alternative leasing systems when the reservoirs being considered are located on the public domain.[1] For

[1] Another policy option **which could be considered for reservoirs located on the public domain is altering the lease terms to encourage** enhanced **oil recovery installations at an optimal point in the production time horizon. Analysis of this option, however, requires data not only on** EOR **costs and production profiles but on the synergistic effects with primary and secondary production. Since little experience is available on these elements, evaluation of the option would be difficult, if not impossible, at this time.**

analytical purposes, OTA **examined the various options** in conjunction with several leasing systems, including the current system and others that could be used in the future. These systems include:

1) The current cash bonus system;

2) Higher fixed royalty rate plus cash bonus; and

3) Fixed-rate profit share plus cash bonus.

The analysis was conducted under five different price assumptions for enhanced oil production:

1) The current regulated upper tier (new oil) price of $11.62 per barrel;

2) The current price of foreign crude oil landed in the Eastern United States—$1 3.75 per barrel (in 1976 dollars);

3) A price approaching the estimated cost of synthetic fuels—$22 per barrel;[2]

4) An intermediate price between the world oil ‘price and the synthetic fuels price—$1 7 per barrel; and

5) A rising real world oil price initially set at $13.75 per barrel and projected to rise at a 5-percent annual rate.

The first four alternatives assume a constant real price and the fifth alternative assumes a rising real price.

For each EOR **process, baseline evaluations were carried out using these alternative price** levels and currently permitted tax procedures (including the 10-percent investment tax credit, expensing of injection chemicals, and Unit of production depreciation). Then, the following policy alternatives were analyzed:

1) Price subsidies of $1 and $3 per barrel;

2) Price guarantees of $13.75 per barrel;

3) Investment tax credit of 12 percent compared with the current 10 percent;

4) Capitalization and subsequent depreciation **of** injection chemical costs;

5) Use of an augmented accelerated depreciation method; and

6) Government investment subsidy of 15 percent of initial capital investment.

Since several of these options (price subsidies and guarantees) are designed to reduce uncertainty, they were not evaluated under the assumption of information certainty.

Alternative leasing systems for public domain lands were tested with various options, including the current cash bonus—fixed royalty system, a cash bonus system with a 40-percent fixed royalty, and an annuity capital recovery-profit share system with a cash bonus bid. In this profit share system, investment costs are converted to an annuity over 8 years of 8-percent interest, and the annuity is subtracted from net profits before the Government share of 50 percent is taken. j

Analytical Approach

All reservoirs in a selected sample were tested, using cost and production profiles from the high-process performance case discussed in chapter III. As a check on these results, data from the low-process performance case were also analyzed. individual EOR processes were evaluated sepa-

[2]This price was **obtained from the report of the** Synfuels **Interagency Task Force.**

‘Other leasing systems have been suggested and could be evaluated. For example, variable rate options for both royalty and profit share systems may be desirable alternatives. However, the systems chosen appear to cover a range of possible results.

rately using baseline values and then using the policy options discussed above.[4] The entire analysis was conducted using a Monte Carlo discounted cash flow simulation model (Tyner and Kalter, 1976), modified to handle the EOR decision process as viewed by the private sector.

Analysis of Government Policy Options

Reservoir Sample

For purposes of policy analysis, a sample of up to 50 of the reservoirs assigned to each EOR process (see previous discussion) was selected for initial evaluation. Separate samples for onshore and offshore areas were drawn from reservoirs assigned to the CO_2 process. Sample selection was based upon a number of criteria including regional location, reservoir depth, residual barrels of oil per acre (available for tertiary production), reservoir size in acres, and, in the case of offshore fields, water depth, For each EOR process evaluated, fields covering a broad range of these characteristics were included.

After reviewing the range of values taken on by the various selection criteria, it was decided that a sample of 25 reservoirs for each EOR process would be adequate to cover the circumstances affecting economical development and provide an appropriate test of the various policy options. The only exception to a sample number of 25 was the case of onshore CO_2 where substantial EOR production was expected. Table 26 displays the number of reservoirs assigned to each process, the number selected for the sample, and the percentage of the reservoir data base sampled.

4Reservoirs subject to more than one EOR process were not evaluated with respect to the impact of policy options on each process or on process selection. The impact of alternative price levels and decision criteria on process selection was discussed in a previous section but data were not available to carry out a detailed analysis here. Since most policy options were analyzed at the world oil prices, this procedure should not affect the results (process selection was generally carried out at this price level).

Analysis Assuming Information Certainty

Price analysis

Given the sample selection, the first step in the analysis was to test the potential for profitable EOR development at various price levels under conditions of information certainty. Using production profiles, investment costs (and **timing), and operating costs developed for the high-process performance case, these tests were conducted under the assumptions that private industry would require a 10-percent net after tax, rate of return on invested capital and that currently permitted tax procedures (State and Federal) would be governing. Thus, a 10-percent investment tax credit, expensing of EOR injection costs, depreciation based on the rate of resource** depletion, and current State and Federal income tax rates *were* used.

Table 27 displays the number and percent of each EOR process sample that would be developed at various price levels under these conditions, as well as the percentage of potential EOR production (gross production less that used for EOR purposes) that would result from those developed. For example, development ranges from 6 percent of the fields at $11.62 per barrel for steam to 95 percent of all fields assigned to

Table 26
Number and Percent of Reservoirs Sampled by EOR Process

	Onshore					Offshore*
	Steam	In Situ	Surfactant	Polymer	CO_2	CO_2
Total reservoirs assigned.	20	20	92	20	190	294
Sample size	20	20	25	20	50	25
Percent sampled	100	100	27	100	26	9

* All offshore reservoirs were assigned to the CO_2 recovery process.

Tabie 27
EOR Reservoir Development and Production by Process and Price Levei

Process and price range (per barrel)	Sample size	Number developed	Percent developed	Percent potential production developed	Sample price elasticity of supply
Steam					
$11.62	20	6	30	41	
13.75	20	9	45	47	.99
17.00	20	11	55	75	3.10
22.00	20	14	70	85	,62
In Situ					
$11.62	20	14	70	89	
13.75	20	16	80	96	.52
17.00	20	18	90	100	.19
22.00	20	18	90	100	.00
Surfactant					
$11.62, ...	25	14	56	77	
13.75	25	19	76	85	.70
17.00. , ., . .	25	19	76	85	.00
22.00	25	22	88	94	.46
Polymer					
$11.62	20	14	70	94	
13.75	20	17	85	99	.32
17.00	20	17	85	99	.00
22.00	20	19	95	100	.05
CO_2--Onshore					
$11.62	50	12	24	22	
13.75	50	22	44	27	1.52
17.00	50	32	64	50	4.26
22.00. , ...	50	37	74	71	1.87
CO_2-Offshore					
$1“1 .62	25	9	36	24	
13.75	25	9	36	24	.00
17.00	25	15	60	‘35	2.21
22,00	25	19	76	50	1.99
Total					
$11.62	160	69	43	46	
13.75	160	92	58	52	.88
17.00	160	112	70	69	1.78
22.00	160	129	81	82	.81

polymer at $22 per barrel. production ranges from 22 percent of the total possible for onshore CO_2 at $11.62 per barrel to 100 percent for polymer and in situ at $22 per barrel. Current world prices of $13.75 per barrel result in up to 99 percent of possible production from the polymer process, and up to 24 percent of possible EOR offshore oil production for those reservoirs assigned to the CO_2 process. Overall, 43 to 81 percent of the sample reservoirs are developed over the price range analyzed, with 46 to 82 percent of possible EOR oil being produced,[5]

Of perhaps greater interest, however, is the price elasticity of supply (i.e., the percentage change in production for each 1 -percent change in price) Table 27 also lists these values (arc elasticities) for the sample over the price range analyzed.[6] Individual EOR processes, as well as total production from all processes, are shown. It is obvious that the price elasticities vary across both the process and the range of price changes. in the $11.62 to $22 per barrel range, the CO_2 and steam processes are price elastic. This is also true of all processes combined. In situ, surfactant, and polymer are, however, price inelastic to the point where higher prices will have little impact on production.

All processes, except offshore CO_2, exhibit the greatest price elasticity in the low and/or middle price ranges (to $17 per barrel). Offshore CO_2 exhibits *its* greatest elasticity over the middle price range ($13.75 to $17 per barrel), with substantial elasticity above $17 per barrel. These results suggest the greatest price impact on production will take place in the range of real prices from $11.62 per barrel to approximately $17 per barrel, except in the high-cost offshore regions. With real oil prices expected to increase in the future, an effective method for encouraging EOR development would be to allow prices for EOR oil to rise with the world price. This conclusion is further supported by the fact that those EOR processes with the greatest production potential also have the highest price elasticity.

Of the 31 fields (31 of 160 sample reservoirs) which did not develop at a $22 per barrel price, 21 developed at $27.50 per barrel or below, 6 between $27.50 and $50 per barrel, 2 between $50 and $75 per barrel, and 2 could not be developed unless price exceeded $75 per barrel. As a result, 94 percent of the potential EOR reservoirs in the sample can be developed at prices below $27.50 per barrel. Overall price elasticity is positive (1 .35) in the range of $22 to $27.50 per barrel, but almost zero above $27.50 per barrel. Some fields in the steam, in situ, and surfactant processes could not be developed at prices below $50 per barrel. These processes use a portion of the recovered oil in the recovery process, so higher product price also means higher production cost.

It could be dangerous to generalize from the sample (although the steam and in situ samples included almost all assigned reservoirs), and the supply elasticities calculated from the sample were therefore compared with those based upon all reservoirs assigned to EOR processes in both the low- and high-process performance cases. Such a comparison cannot be precise because of the different approach used in the overall analysis to address economic calculations. Furthermore, the policy sample contains a greater proportion of marginal fields than does the total data set.

In general, the results displayed in table 28 indicate that the tendencies apparent from the sample are supported when looking at the entire high-process performance data base, Surfactant becomes price elastic, along with CO_2 and steam, but onshore CO_2 appears somewhat less price sensitive and offshore CO_2 somewhat more price

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[5] Using production estimates based upon the low-process performance case would substantially reduce these values. For example, the surfactant process at world oil prices would be implemented on only two reservoirs in the sample (8 percent) and result in 7 percent of the potential net production. Similar calculations could be shown for other processes and price levels. However, the object ot this section is an evaluation of policy options. For this purpose, the high-process performance case is used as a basis with digressions to other cases only if policy conclusions would be affected. Also, the values change considerably when the analysis is conducted at the lower tier (old oil) price of $5.25 per barrel. At this price only 8 percent of the reservoirs with 14 percent of total possible production were developed.

[6] The elasticity formula used for all calculations was $(Q_1 - Q_0)/Q_0 \div (P_1 - P_0)/P_0$. Note that these values relate to ultimate net production and, thus, give no indication of the sensitivity of production profiles (or timing) to price.

sensitive than in the sample. No evidence is apparent which would argue for a change **in the previously discussed conclusions. As would be expected, the low-process performance case showed higher price elasticities** for a number of the processes. Only in situ remained price inelastic overall, while the price elasticity of steam dropped.

Analysis of Other Policy Options

Given the potential impacts of price on EOR development, the next question under the assumption of information certainty is whether other public policy options would change EOR economics. To answer this question, OTA analyzed four possible policy changes (three tax considerations and a public investment subsidy to encourage EOR development).

The tax options include the use of a 12-percent investment tax credit (2 percent more than the current rate), accelerated depreciation using the double declining balance method, and an option **in which injection costs are 100** percent depreciated rather than expensed. The latter option was conducted to evaluate industry's contention that the Internal Revenue Service must

Table 28
Price Elasticity of Supply Comparison

Process and price range (per barrel)	Policy analysis sample	OTA total reservoir assignment	
	High-process performance case	High-process performance case	Low-process performance case
Steam			
Overall ($11 .62-22.00)	2.32	2.42	1.92
$11.62 -13.75	.99	1.15	1.23
$13.75 -22.00	2.18	2.18	1.60
In situ			
Overall ($1 1.62-22.00)	.25	.25	.71
$11.62 -13.75	.52	.76	1.08
$13.75 -22.00	.10	.00	.38
Surfactant			
Overall ($1 1.62-22.00)	.48	1.47	12.93
$11.62 -13.75	.70	2,51	8.39
$13.75 -22.00	.28	.59	5.57
Polymer			
Overall ($1 1.62-22.00)	.11	.00	1.06
$11.62 -13.75	.32	.00	3.23
$13.75 -22.00	.06	.00	.00
CO_2-Onshore			
Overall ($11.62-22.00)	4.64	2.49	5.33
$11.62 -13.75	1.52	3.34	2.03
$13.75 -22.00	4.22	1.16	4.46
CO_2-Offshore			
Overall ($1 1.62-22.00)	2.26	7.06	—
$11.62 -13.75	.00	3.23	—
$13.75 -22.00 ...,	2.84	5.04	.
All processes			
Overall ($1 1.62-22.00)	1.70	2.02	4.50
$11.62 -13.75	.88	2.46	2.42
$13.75 -22.00	1.56	1.10	3.39

Table 29
EOR Development by Process and Policy Option

Process	Sample size	Number of Reservoirs Developed				
		$13.75 per barrel	12-percent investment credit	Accelerated depreciation	Depreciate injection costs	15-percent investment subsidy
Steam	20	9	9	9	6	9
In situ	20	16	16	17	16	18
Surfactant	25	19	19	19	4	19
Polymer.	20	17	17	17	15	17
CO_2-Onshore	50	22	22	22	13	22
CO_2-Offshore ., . . .	25	9	9	9	9	10
Total	160	92	92	93	63	95

permit the expensing of injection costs if EOR is to be economically viable. Depreciation was assumed to take place over the remaining production period in proportion to production. The investment subsidy option calls for the Government to pay 15 percent of all initial EOR capital investments (deferred investments and injection costs are paid fully by the producer).

Table 29 displays the result of these tests. All evaluations assumed current world market prices ($1 3.75 per barrel). As can be seen, the various options have relatively minor impacts on development and, consequently, on production. In fact, the 12-percent investment tax credit **results in no new development,** while the accelerated depreciation option adds one reservoir to the in situ process and increases total net production by only two-tenths of 1 percent. On the other hand, the requirement that EOR injection costs be 100-percent depreciated results in 30 (32 percent) fewer sample reservoirs being developed with a 29-percent reduction in total production. The reduced production is **concentrated** in surfactant, with some impact on the steam, polymer, and onshore CO_2 processes. The only policy option at all effective in encouraging development appears to be a 15-percent investment subsidy which would add three developed reservoirs at current world prices and result in a 1 -percent increase in net production. T

The various options do change the amount of above normal (1 O-percent rate of return) profit that can be expected from developed fields. Depreciation of injection costs would tend to reduce rates of return and the other options would increase them. If the introduction of EOR to potential reservoirs is paced on the basis of rates of return (as assumed previously), this change could have an impact on aggregate production profiles and the timing of recovery. The exact impact is impossible to quantify since firms will have different decision criteria and schedules for EOR initiation based on those criteria.

For policy analysis, these results need to be compared with the costs of the respective policies. In the case of a 12-percent investment tax credit, the Government revenue loss is not offset by additional tax revenues because no new output results. The accelerated depreciation option adds one additional reservoir, increasing production by more than 28 million barrels. At the same time, Government revenue actually increases due to the higher production and resulting tax receipts. The increase per barrel of production, however, is slight-less than 1 cent per barrel.

[7]Similar results were obtained when analyzing the low-process performance case. The number of reservoirs that developed at a 10-percent rate of return was obviously reduced by a substantial degree. However, the various policy options have little impact on changing these decisions. Taking surfactant as an example of a process which is often marginal, the various options resulted in only one addition to the two fields developed under free market conditions (see footnote 4). That development occurred when a 15 percent investment subsidy was introduced. Required depreciation of Injection costs, however, did not affect the decision to develop.

As would be expected, requiring the depreciation of injection costs increased Government revenue while the 15-percent investment subsidy reduced it. However, the impacts per barrel of incremental production were quite small.

In summary, it appears that no policy option is either very powerful in encouraging new production or very expensive in terms of Government cost per barrel produced. In fact, little appears to be gained (or lost) by attempting to accelerate EOR development at a pace faster than that likely to occur in current institutional setting. The question remains, however, whether such policy options are worth potential distortions in efficiency under conditions of information uncertainty. This question is explored in the next section.

Analysis Assuming Information Uncertainty

To evaluate the question of uncertainty in production, cost, and price values, the same sample of reservoirs was **used in conjunction with** subjective probability distributions on the key input variables. Table 30 lists the variables and the distributions used. The resulting range in production from the reservoirs was substantially less than that resulting from the high- and low-process performance assumptions discussed in chapter III. This result indicates that the degree of uncertainty implicit in the cost and production distributions was less than that incorporated in the two advancing technology cases. As a result, the policy tests can be considered conservative, in that a policy which will not affect development under these assumptions is unlikely to have any impact in practice.

Table 30
Input Variables and Subjective Probability Distributions Used for Monte Cario Simulations

Variable	Value
Price	
Original value ($/bbl.)	13.75
Mean of price change distribution	0.00
Standard deviation of price change distribution	0.01
Production	
Triangular contingency distributions	
Minimum	-.30
Most likely	-.10
Maximum	0.05
Investment and operating cost	
Triangular contingency distributions	
Minimum	-.05
Most Likely	0.00
Maximum	0.10

(Number of Monte Carlo Iterations: 200)

Options Designed To Alleviate Uncertainty

The effects of uncertainty were evaluated at the current world oil price. Because of the minor impacts exhibited by the tax options in the previous analysis, they were dropped from further consideration. Two other options, designed to reduce uncertainty, were added: (1) a price guarantee whereby the Government would assure a market price that did not fall below $13.75 per barrel; and (2) **an actual price subsidy (payment by the Government over and above market price) of $3 per barrel of** EOR oil produced.[8] In all evaluations, current tax rules and a 10-percent rate of return were assumed. Table 31 summarizes these evaluations.

The simulations provide interesting insight into the potential profitability of EOR development. Overall, it appears that up to 23 percent of the developable EOR reservoirs (and 23 percent of the producible oil) **would be available** at current market prices with very low risk of a less-than-normal profit to the operator. The remainder of the fields with some chance of profitability are spread more or less uniformly over the probability range of less-than-normal profit categories. However, because of variations in reservoir size, the remaining recoverable oil is not distributed uniformly, but is concentrated in the 26 to 50 percent and 75 to 99 percent chance-of-loss categories. Only 66 percent of the sample's producible EOR oil has some probability of being profitably exploited under the conditions simulated.

The policy options analyzed have little effect on these results. Only the $3 price subsidy adds a

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[8] A $1 per barrel subsidy was also evaluated but is not displayed because of its neglible impact.

Table 31
Monte Carlo Simulation of Policy Option Impacts in Reducing Uncertainty
(Analysis Based on High-Process Performance)

EOR process and policy *	Sample size	Number of reservoirs developed — Probability of less-than-normal profit: 0 percent	1-25 percent	26-50 percent	51-75 percent	76-99 percent	Total	Percent potential net production developed — Probability of less-than-normal profit: 0 percent	1-25 percent	26-50 percent	51-75 percent	76-99 percent	Total
Steam													
Base case	20	3	1	2	—	4	10	31	1	8	—	29	69
Price guarantee	20	3	1	2	—	4	10	31	1	8	—	29	69
Price subsidy	20	3	3	2	1	3	12	31	9	4	2	35	81
Investment subsidy	20	3	3	—	1	3	10	31	9	—	2	27	69
In situ													
Base case	20	10	2	—	2	4	18	69	1	—	19	11	100
Price guarantee	20	10	2	1	2	3	18	69	1	9	13	8	100
Price subsidy	20	11	2	3	2	—	18	69	11	17	3	—	100
Investment subsidy	20	11	1	3	1	2	18	69	1	22	5	3	100
Surfactant													
Base case	25	2	4	6	3	4	19	1	16	49	11	8	85
Price guarantee	25	2	4	7	2	4	19	1	16	50	10	8	85
Price subsidy	25	2	12	4	1	1	20	1	76	8	—	3	88
Investment subsidy	25	2	4	8	3	2	19	1	16	60	2	6	85
Polymer													
Base case	20	11	3	—	1	2	17	78	16	—	2	2	98
Price guarantee	20	11	3	—	1	2	17	78	16	—	2	2	98
Price subsidy	20	14	2	1	—	—	17	94	3	2	—	—	99
Investment subsidy	20	11	3	1	2	—	17	78	16	2	2	—	98
CO_2—Onshore													
Base case	50	4	3	4	4	7	22	12	2	5	11	11	41
Price guarantee	50	4	4	3	4	7	22	12	4	3	11	11	41
Price subsidy	50	9	11	2	2	7	31	16	22	2	1	6	47
Investment subsidy	50	4	6	4	5	6	25	12	6	9	10	5	42
CO_2—Offshore													
Base case	25	7	2	—	—	—	9	21	4	—	—	—	25
Price guarantee	25	7	2	—	—	—	9	21	4	—	—	—	25
Price subsidy	25	9	—	—	3	4	16	24	—	—	7	7	38
Investment subsidy	25	7	2	—	—	2	11	21	4	—	—	6	30
Total													
Base case	160	37	15	12	10	21	95	23	5	14	8	16	66
Price guarantee	160	37	16	13	9	20	95	23	6	14	7	16	66
Price subsidy	160	48	30	12	9	15	114	24	26	5	2	15	72
Investment subsidy	160	38	19	16	12	15	100	23	9	19	6	13	70

*Base case assumes a $13.75 per barrel oil price, price guarantee guarantees a $13.75 per barrel price, price subsidy is $3.00 per barrel of EOR oil, and investment subsidy is 15 percent of all initial EOR capital investments.

significant number of reservoirs to those potentially developed (20 percent), but this results in only a 6-percent increase in potential oil production. The impact is concentrated in the CO_2, steam, and surfactant processes. The 15-percent investment subsidy adds 5 percent to the potential reservoir development but only 4 percent additional oil. Only CO_2 processes were affected, however. In most cases, reservoirs added to those that would be potentially developed are in the high-risk (76 to 99 percent chance of loss) category.

All options, however, have some impact on reducing the risk of development for those reservoirs that are potential candidates under current market conditions. Again, the most successful policy in this regard is the $3 per barrel price subsidy with 55 percent of the potential production classified below 50-percent probability of a less than normal profit. This is a 31 -percent improvement over the base case and compares to a 2-percent improvement for the price guarantee option and a 21 -percent gain for the investment subsidy.

The impacts of the various policy options on individual EOR processes are similar to the overall results, with the greatest addition to potential EOR reservoirs and total production resulting from the price subsidy option. The reduction in risk for potential production (from the base case) **is greatest** for the onshore CO_2 process, followed by in situ combustion and surfactant flooding.

Although increases in potential EOR **production (from all risk categories) do not appear substantial for any of the options designed to reduce uncertainty, the possibility of changing the risk of development for those reservoirs included** in the base case warrants further investigation of a price subsidy. To accurately assess this option the potential benefits of increased EOR production must be balanced against Government costs. However, both the extent of increased production and the corresponding costs are difficult to quantify. Since the decision to recover EOR oil depends on a producer's risk-preference function, one must ascertain the appropriate decision rule used by the private sector in making development decisions before an accurate assessment can be made. Given that these decision rules will vary among firms and may change for a given firm with implementation of a policy subsidy, Government cost is difficult, if not impossible, to quantify. The cost of the $3 subsidy to all produced EOR oil will be offset to some extent by an increase in Federal tax revenue and, in the case of offshore fields, higher royalty collections. Without knowledge of the impacts under varying risk conditions and decision criteria, the magnitude of this change can only be an educated guess, For a range of possible conditions, the net present value cost of the subsidy appears to be in the area of $1.50 to $2 per barrel.

Analysis Assuming a Rising Real Price

The preceding analysis assumes that EOR oil will be priced at $13.75 per barrel and that such a price will continue, in real terms, throughout the productive life of an EOR project. Evaluation of this assumption could lead to the conclusion that the results discussed above are an inaccurate representation of future reality, If EOR oil prices are deregulated and world market prices maintain a moderate, but consistent, real growth rate, much of the uncertainty exhibited in the profitability of EOR projects may be eliminated.

To test this possibility, an analysis was performed on the sample which assumed an average annual real price increase of 5 percent (randomly selected from a normal price change distribution with a standard deviation of 3 percent). Table 32 displays the price deregulation impact and, compares it to the $13.7s price base case and **the** $3 price subsidy situation (from table 31). It can be seen that the rising price scenario test equal led or exceeded the results of the price subsidy in reducing uncertainty for all EOR processes. Overall, price deregulation led to a 34-percent increase in field development over the base case and an 11 -percent increase over the price subsidy analysis. Moreover, substantial shifts in the uncertainty category occurred for fields which were formerly in high-risk categories (greater than *50*-percent chance of loss). Price deregulation has a significant impact in all EOR processes except **in situ combustion.**

Thus, if a moderate annual increase in real oil prices obtained for EOR production could be expected with a high degree of assurance, special Government policies to reduce uncertainty may not be required. An equal or greater impact could be obtained with simple price deregulation.

Table 32
Monte Carlo Simulation of EOR Oii Price Deregulation
(fixed $13.75 per barrel price, and a $3.00 per barrel subsidy)

EOR process and policy	Sample size	Number of reservoirs developed					
		Probability of less than normal refit					
		0 percent	1-25 percent	26-50 percent	51-75 percent	76-99 percent	Total percent
Steam							
Base case.	20	3	1	2	—	4	10
Price subsidy. ... , ...	20	3	3	2	1	3	12
Price deregulation*.	20	3	5	3	2	—	13
In situ							
Base case.	20	10	2	—	2	4	18
Price subsidy.	20	11	2	3	2	—	18
Price deregulation*.	20	11	5	—	2	—	18
Surfactant							
Base case.	25	2	4	6	3	4	19
Price subsidy.	25	2	12	4	1	1	20
Price deregulation*.	25	6	13	—	1	2	22
Polymer							
Base case.	20	11	3	—	1	2	17
Price subsidy.	20	14	2	1	—	—	17
Price deregulation*.	20	14	3	—	—	2	19
CO_2 onshore							
Base case	50	4	3	4	4	7	22
Price subsidy	50	9	11	2	2	7	31
Price deregulation*	50	18	5	4	6	4	37
CO_2-Offshore							
Base case	25	7	2	—	—	—	9
Price subsidy	25	9	—	—	3	4	16
Price deregulation*	25	9	—	—	3	6	18
Total							
Base case	160	37	15	12	10	21	95
Price subsidy	160	48	30	12	9	15	114
Price deregulation* . .	160	61	31	7	14	14	127

*Assumes an annual price change distribution which is normal with a S-percent mean and a 3-percent standard deviation

Impact of Alternative OCS Leasing Systems

With the current widespread interest in OCS leasing activity, increased attention has **been** focused on alternative leasing systems. The United States currently uses, almost exclusively, a cash bonus leasing procedure in which the winning bidder for an OCS **lease** is the firm which **offers the Government the highest front-end payment** for exploration and development rights (the **cash bonus). This bid amount is not refundable** if recoverable resources are not found and, therefore, has no impact on subsequent development and production decisions (including the use of EOR technology). **In addition to the cash bonus, a royalty on gross production value of**

16.67 percent is paid to the Government by the producer. The previous analysis of policy options assumed this leasing method was in use for offshore CO_2 cases.

However, because of the substantial uncertainty that exists in offshore development and the capital requirements of cash bonus bidding, alternative systems have been proposed that would shift some of the risk to the Government, reduce capital requirements, and encourage competition.[9] As a result, Government revenue could increase with little or no loss in production. Such alternative leasing systems make greater use of contingency payments (which produce Government revenues based on the value of production) and usually employ a higher royalty rate or a profit-share technique. The cash bonus is retained as the bid variable to alleviate problems of speculation. The higher contingency payments, however, act to reduce the magnitude and importance of the bonus.

The viability of EOR under the alternative leasing systems was evaluated by comparing the profit share and higher royalty rate systems described above with the current system. Table 33 details the results of this analysis. It is clear that high fixed royalties will inhibit EOR development by increasing the risk of less-than-normal profits and by making some fields uneconomical for EOR development. These results confirm earlier studies on the impact of high royalties for primary and secondary production.[10] However, the profit-share system also has a tendency to increase the risk of a less-than-normal profit. This result is at variance with previous results on primary and secondary production and indicates that a profit-share rate of so percent is too high for EOR development on marginal fields. One option **in both situations** would be the use of a variable-rate royalty or profit-share approach, so that rates would be reduced automatically for marginal fields and increased in situations of higher productivity. If experiments with new leasing systems are contemplated, the effects of leasing systems on EOR production as well as primary and secondary production should be evaluated.

Administrative Issues

All of the policy options analyzed **in this section would provide special incentives** for production of oil using enhanced recovery techniques. The implementation of any **such incentives will** require administrative decisions concerning the qualification of particular projects or types of projects for the incentives. Those policies involving special price incentives will also require a further judgment about what portion of the oil produced from a field can be attributed to the EOR process, and what part would have been produced anyway by the continuation of primary and secondary techniques. The problem is to define this EOR increment in such a way that special incentives will encourage the application of EOR processes without significantly distorting decisions concerning primary and secondary production.

These problems will have to be dealt with if proposed price incentive policies are to be adopted. In 1976, Congress amended the Emergency Petroleum Allocation Act (through provisions in **the** Energy Conservation and Production Act) to direct the President to modify oil pricing regulations to provide additional price incentives for bona fide EOR techniques. Since then, FEA has published proposed regulations for comment and has held several public hearings on the subject. The basic approach proposed by FEA is to apply price incentives only to the increment of production attributable to an EOR process. The same approach is implied in the president's April 1977 National Energy Plan, which called for decontrol of the price of oil produced with EOR techniques.

[9] Robert J. Kalter and **Wallace E.** Tyner, *An Analysis of Selected OCS Leasing Options.* Report to the Office of Technology Assessment, U.S. Congress, June 1975.

[10] Robert J. Kalter, Wallace E. Tyner, and Daniel W. Hughes, *Alternative Energy Leasing Strategies and Schedules for the Outer Continental Shelf,* Department of Agricultural Economics Research Paper 75-33, Cornell University, 1975.

Decisions concerning the qualification of processes and production levels for special incentives involve highly technical judgments which will require personnel competent in EOR techniques. Such personnel do not at present exist in Government in the numbers required. The number of people available in the job market is quite limited and industry demand is large. While consultants might be used, this practice could raise potential conflict of interest problems, because consultants **must, in the long run, depend upon industry for their support.** An alternative approach, supported by industry in comments on FEA proposals, would be simply to apply price incentives to all oil produced from a field to which an EOR process was applied. While this would avoid the problem of defining an EOR increment, there would remain the problem of defining the level of effort required for a project to qualify as a bona fide EOR process, and monitoring to ensure that that effort is in fact maintained.

A more detailed analysis of the advantages and disadvantages of these and other incentive pricing options was beyond the scope of OTA's assessment of the potential contribution of EOR processes to national reserves. Because of the importance and complexity of the associated issues, however, Congress may wish to examine the problem of defining and monitoring EOR operations, and possibly hold oversight hearings on the proposed FEA pricing regulations for EOR production. If defining EOR incremental oil production and monitoring EOR operations are found to be critical issues, a mechanism could be developed whereby bona fide EOR projects could be certified and monitored. Certification and monitoring of EOR operations could be performed by the operator, a State regulatory group, a Federal agency, or a combination of Federal, State, and producer interests.

Table 33
Monte Carlo Simulation of OCS Leasing Systems and EOR Potential

EOR process and OCS leasing system	Sample size	Probability of less-than-normal profit					
		o percent	1-25 percent	26-50 percent	51-75 percent	76-99 percent	Total percent
		Number of fields developed					
CO_2-Offshore							
Current.	25	7	2	—	—	—	9
40-percent royalty	25	2	1	1	1	3	8
50-percent profit share	24	4	3	2	—	—	9
		Percent potential net production developed					
CO_2-Offshore							
Current.	25	21	4	—	—	—	25
40-percent royalty	25	3	6	4	1	9	23
50-percent profit share .	25	13	8	4	—	—	25

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V. Legal Aspects of Enhanced Oil Recovery