Energy Supply Strategy: Getting Technology Commercialized

- **Shale Oil**
- **Enhanced Oil Recovery**

December 1979

Prepared for:

U.S. Department of Energy
Assistant Secretary for Policy and Evaluation

Under Contract #EJ-78-5-02-4973-A000

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Available from:

National Technical Information Service (NTIS)
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5285 Port Royal Road
Springfield, VA 22161

Price:

Printed Copy: \$8.00

Microfiche: \$3.00

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The findings and interpretations expressed in this report are those of the investigators, based upon the aggregated perceptions and opinions expressed in interviews held with top corporate management of major oil companies and suppliers of chemicals for enhanced oil recovery. Events directly affecting both the status of shale oil and EOR have occurred during and especially since the obtainment of final feedback from industrial respondents regarding their positions as depicted here. Thus, this report, in its entirety, can be considered current only to June, 1979. The viewpoints and opinions expressed here do not necessarily reflect those of the Department of Energy.

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I. EXECUTIVE SUMMARY

This study was undertaken in response to the national interest in increasing domestic liquid hydrocarbon production and decreasing dependence on oil imports. Shale oil production and Enhanced Oil Recovery (EOR) from existing domestic oil fields are two promising opportunities for significantly increasing production of liquid fuels in the United States. Both government and industry recognize that several hundred billion barrels of oil are ultimately recoverable from domestic oil shale resources and from the application of EOR techniques to existing reservoirs. Current total EOR production in the United States is about 250,000 barrels/day and this can be increased substantially to help ease shortages in the nearer term. Shale oil production, on the other hand, can provide a stable supply for the longer term although current production is on a pilot plant basis only, with miniscule output. There are, however, economic, environmental, institutional/regulatory and technical barriers which severely impede the commercialization of shale oil processes and the acceleration of EOR production. Long lead times are characteristic of shale oil and EOR developments; these barriers must be removed now in order for shale oil and EOR production to have significant impact on the supply of liquid fuels by the end of this century.

The specific purpose of this project was to identify for DOE those factors which in the opinion of industry inhibit the investment of more of its own funds in the near term for producing oil from shale and through enhanced oil recovery; and, relatedly, to estimate, if possible, the investment and the production which would result if these deterrents were removed and suitable incentives were provided. The views presented in this report are based on information obtained through in-depth discussion with top management of oil companies (and their suppliers of chemicals for EOR) and review of previous and concurrent studies by other industry and government research organizations.

Despite the potential importance of shale oil and EOR, and much talk about an energy crisis in the United States, oil producers do not perceive rapid development of these resources to be a top priority policy of the federal government. It is our impression that industry considers this to be the principal "showstopper". DOE has staunchly declared its commitment to the accelerated commercialization of the shale oil and EOR technologies and has formed associated Commercialization Task Forces and identified Resource Managers. While there is acknowledgement that this is a step in the right direction, industry leaders remain unconvinced that the DOE can successfully unify the disparate policy-making agencies of government. This doubt is based on a perceived lack of positive leadership by DOE in the past, continual "flip-flopping" of policies within DOE, and conflicting and contradictory regulatory policies among different executive branch departments. Similarly, other federal and state agencies have done little to resolve the various economic, environmental, and institutional uncertainties relating, albeit differentially, to shale and EOR. Industry agrees with government that a genuine "oil crisis" is at hand, and many of its leaders

have suggested that an appropriate response to the critical need for substantially augmenting the domestic supply of liquid hydrocarbons is the singleminded determination and unified governmental support exhibited in the synthetic rubber program and the Manhattan Project of the 1940's, the AEC uranium procurement program of the 1950's, and the APOLLO Program of the 1960's.

In their attempts to assist commercialization through creating incentives or removing disincentives, federal and state governments have shown insufficient understanding of the fundamentals of investment, risk and return. Hydrocarbon discovery and production always has been a risky process and with the passage of time has become increasingly so in the United States. While many discoveries produce good returns on the investments in them, many others produce nothing at all to offset the expense involved. Overall return, the successes helping to offset the failures, is essential if capital is to be generated for further investment in energy production. When government fosters the image of "indecent profits", it renders a great disservice by misleading the public with respect to the fundamental economic realities involved, thus reinforcing psychological and political barriers to formulation of a constructive national policy.

Oil produced from shale or from the application of EOR techniques is even more costly and risky than conventional, primary and secondary oil production, but the private sector has shown initiative in developing shale oil and EOR prototype techniques, in several instances involving cost-shared funding with government. The private sector is willing and professedly able to embark on commercialization provided that a reasonable return on investment (ROI) can be anticipated. Simply put, industry will take high risk if there is potential for high reward. However, industry cannot now calculate, within prudent bounds of predictability, what its prospective ROI from commercial operations will be because of the many aforementioned uncertainties. It cannot even calculate the risk associated with any specific shale or EOR project because it cannot judge the probable outcome of politically sensitive issues that may affect each project differently. Furthermore, under the U.S. oil pricing structure which prevailed prior to the Administration's decontrol proposal of April 5, 1979, industry has had little incentive to aggressively pursue shale oil and EOR. Although oil produced from shale and, to a large extent, from EOR was or was proposed to be exempt from price control, the mere existence of a severe and exceedingly complex structure of price restraints has had a stultifying effect on industry's willingness to invest since in such an atmosphere there is an expressed concern that controls will extend eventually to production from new technologies.

In shale and EOR--and for that matter in any new technology--industry considers commercialization not to be a one-time demonstration of the technical capability of a commercial size process but rather sustained and economic manufacture and sale in the marketplace by multiple operations. In the case of shale, this means that each company seeks

access to sufficient reserves to build not just one plant, but many, with each additional one benefitting from prior experience. In the case of EOR, this means extension from pilot field tests to full-scale development, using applicable techniques with a high degree of confidence.

In this investigation of the barriers to the commercialization of shale oil and EOR, we have used a fairly standard classification of the principal issues into four broad categories although we recognize that these issues are strongly interrelated and not really possible to separate in an operational sense. These categories are listed below in the order of priority (decreasing) generally communicated to us by the industrial respondents:

- economic
- environmental
- institutional/regulatory
- technical.

It is evident that industry does not regard the technological problems associated with shale or EOR, in themselves, i.e., when distinguished from the other issues, to be critically restraining; technological progress and innovation will follow the removal of the economic, environmental, and institutional/regulatory barriers. It should also be pointed out that while the above ranking of issue categories applies to both shale and EOR, there are, in addition to some general similarities, fundamental qualitative and quantitative differences in the way they relate to and affect the two technologies. The clearest distinction between shale and EOR with regard to the barriers to commercialization and the manner in which they affect the two technologies is that higher price would virtually alone spur EOR development activity in contrast to the situation in shale oil in which factors in addition to pricing structure not only constrain but preclude significant development. For example, although some environmental constraints exist for EOR, they are not so severe, qualitatively or quantitatively, as those for shale. Indeed, environmental considerations taken in toto constitute, at present, a "showstopper" for shale.

The two subsections which follow are devoted to shale oil and EOR, respectively. In each section appears a brief list of major findings specific to each technology area. Following each list of major findings are more detailed adjacent lists of "barriers to investments" and their related "remedies" grouped by issue category. While individual barriers listed more or less correspond to the adjacent remedies, they are not in exact one-to-one correspondence and should not be interpreted that way. Both barriers and remedies were derived, in general, from our interviews with industry.

A. SHALE OIL

Surface retorting technology is the most advanced, though in-situ technology may be of great importance in the long run for recovery of reserves not amenable to conventional mining. Surface retorting processes may be commercialized during the remainder of this century; in-situ technology probably will not reach commercial status until 2000.

Many obstacles are preventing industry from committing investments in shale development. Therefore, it is presumptuous to assume that any single development, such as including shale under the entitlements program or allowing tax credits on production, will by itself cause a great rush to invest. The oil companies interviewed see the proposed production tax credit as a good first step and generally support this initiative. However, resolution of the more onerous environmental and institutional obstacles is also needed. Therefore, it must be understood by DOE and other executive and legislative agencies that establishment of the tax credit will not in itself spawn a shale industry. If and when the proposed tax credit becomes fact, the industry may require additional incentives and/or the removal of disincentives, particularly in the environmental and institutional areas.

The following main conclusions regarding shale commercialization have emerged from this study.

- General decontrol of oil prices is necessary to provide the proper climate for long term investments in shale oil development.
- There is great financial risk associated with a commercial oil shale venture due to uncertainties not within the capability of the private sector to mitigate because they are largely government created, controlled, and perpetuated. These uncertainties result in the unpredictability of ROI within the reasonably narrow range necessary for responsible investment. Thus, the private sector is and will remain unwilling to invest in pioneering shale plants so long as uncertainties which are non-economic per se and not within the normal bounds of commercial risk-taking preclude the prospect of reasonable ROI or even substantially higher world oil prices (\$16/bbl U.S. landed, June, 1979).
- In order to achieve a minimally acceptable ROI on initial ventures, the selling price for refinery grade shale oil will necessarily be higher than the current world price and probably higher than that which will prevail in the near term. Thus, economic incentives in addition to free market price will be required for shale oil development and the initiation of first generation plants. Industry prefers a production tax credit as the means for providing these incentives. It is not precisely known, however, whether the presently proposed \$3/bbl will be sufficient in view of continued cost escalation and anticipated additional environmental regulations.
- In addition to a favorable pricing structure, which is necessary but not sufficient to bring forth a commercially viable shale oil industry, other major, precluding obstacles include:

- lack of national commitment, backed up by federal policy, to development of shale resources;
 - unanticipated and constantly changing environmental standards which can result in tremendous cost overruns;
 - an environmental policy that invites legal challenges which can result in excessive delays;
 - the lease tract limitation of 5000 acres per company effectively precludes companies from building more profitable second generation commercial plants.
- Even with the removal of all major barriers, commercial production of shale oil will require at least five years' lead time. Government must provide the leadership to remove these barriers in order for shale oil production to contribute significantly to supply of liquid fuel by 1990.
 - Currently there is no commercial scale shale oil production. If the remedies suggested by industry are adopted in 1979, the information we have assembled from our industrial interviews indicate that shale oil production could be in the range of 100,000 to 300,000 barrels/day by 1990 and 500,000 to 1,000,000 barrels/day by 2000.

Following are the barriers to investment and their remedies which we derived from our interviews with industry.

BARRIERS TO INVESTMENT

REMEDIES

1. Economic

• The existence of price controls on domestic crude production is a perceived barrier even though production from shale is currently exempt (21)*. The concern is that political events change the ground rules so quickly that there is no assurance that shale oil will be exempt for a reasonable period following commencement of commercial production.	• Decontrol of domestic oil price is necessary to reduce the uncertainty in economic forecasts and shale oil price and consequent return on investment. • A production tax credit is needed to stimulate investment in pioneering projects for which the risks are especially large.

* Numbers in parentheses refer to correspondingly numbered items in a bibliography which appears in the main body of the report.

BARRIERS TO INVESTMENT

1. Economic (continued)

- The required selling price of clean shale oil from a pioneering commercial scale project is in excess of the current average world price of crude oil. The present estimate for refinery grade syncrude is \$20-25 per barrel (1978 dollars) compared to the landed price of \$16/bbl for Saudi crude oil (June, 1979). A major factor is that the minimum expected rate of return on investment must be set high because the risks are especially large for the first plant. This ratchets up the selling price because the capital investment per unit of output is large (\$20,000/daily barrel). Shale oil proponents believe the risk and consequently the minimum expected rate of return on investment would be lower for the second plant, but nobody wants to be first. Therefore, economic incentives are needed to encourage investment in the first plants. Although the majority of the interviewed companies supports the concept of allowing a tax credit on production, the proposed \$3/bbl tax credit will not by itself guarantee rapid commercialization. Indeed, new environmental and institutional rules can easily diminish or abrogate the effect of the credit. For example, additional waste disposal costs necessitated by the recently enacted Resource Conservation and Recovery Act (28) are estimated to be about \$1.50/bbl, which obviously will severely erode the benefit industry is hoping for from the proposed \$3/bbl production tax credit.

REMEDIES

- The DOE should develop, with due dispatch and with industry's collaboration, a credible economic analysis of a commercial oil shale project to provide a rational basis for establishing the magnitude of the tax credits required. The analysis should evaluate the sensitivity of schedule delays and belated pollution controls on the selling price of shale oil. The results should be forwarded to the Congress with a recommendation for the size of the tax credits required.
- Consider dedicated long-term (20 years) government purchase contracts to stimulate investment in first-generation plants (e.g., DOD consumes 250,000 bbl/day of jet fuels).
- Guaranteed purchase agreements should include sweeteners to increase return on investment on pioneering, first generation plants such as:
 - pay higher price for product,
 - underwrite part of the investment,
 - pay back loan with product.
- The U.S. House of Representatives Committee on Banking, Finance, and Urban affairs has passed, on May 8, 1979, HR3938 and is recommending it to the House for passage. This bill amends the Defense Production Act of 1950. Principal among its provisions is a new Section 305 which calls for the President to attempt to achieve a national production goal of at least 500,000 bbl/day crude oil equivalent of synthetic fuels not later than

BARRIERS TO INVESTMENT

1. Economic (continued)

- The development costs for commercial scale shale projects are very large relative to production capacity; unit investment costs for shale oil are on the order of \$20,000/daily barrel compared to \$5-10,000/daily barrel for North Sea and Alaskan oil (20). Given no near-term prospect for resolution of environmental and institutional uncertainties, the industry is not willing to make long term investments (>\$1 billion per project) in shale development. Until the risks can be made comparable to other investment opportunities, the industry at large is not likely to embark on full commercial-sized plants.

2. Environmental

- Environmental standards such as New Source Performance Standards have not been set for shale plants; hence industry cannot estimate costs of compliance. The EPA will not issue standards without emission data from commercial plants - a "Catch 22" situation. Compliance with the most stringent EPA standards will add at least \$6/bbl to the selling price of shale oil (2).
- Air and water quality and solid waste control standards are apparently subject to arbitrary change, by federal and state agencies, e.g., extending SMCRA* to shale mining. Hence, future requirements are not predictable by industry.

* Surface Mining Control and Reclamation Act is specific to coal.

REMEDIES

October, 1984. This remedy would create a subsidized market. However, industry points out that procurement levels of these synfuels by government agencies will be subject to annual budget appropriations and thus do not constitute a market that can be predicted with great certainty.

- Most companies feel that reasonable emission and other environmental standards should be set for which first generation plants could be designed. These standards can and should be established on the basis of best available engineering information and application of best available control technology.
- Once set, standards should be maintained without change for the normal working life of the plant, except where human health and safety are directly endangered. The experience obtained in the operation of the first plant can be used to set standards for future plants. Future standards should be justified on the basis of appropriate cost-benefit analyses.

BARRIERS TO INVESTMENT

2. Environmental (continued)

- Class II regulations for Prevention of Significant Deterioration (PSD) of air quality may limit the ultimate size of the shale oil industry before presently developed water supplies do.
- Since shale oil production requires massive movements of rock, land restoration and reclamation is a major issue. Industry has demonstrated with prototype on-site disposal and revegetation tests that it can adequately manage the problem with no significant permanent damage, provided environmental standards are rationally established, taking account of the 20% greater volume of spent shale.

3. Institutional/Regulatory

- Lack of consistent national policy with respect to federal leasing, exchange of lands, funding of water projects and coordination of regulations between agencies are all significant barriers to major private investment.

REMEDIES

- The major basins should be redesignated Class III. This authority will be vested with state governments.
 - The federal government should take steps to insure prompt resolution of environmental litigation as the President has proposed for the specific case of Sohio and Northern Tier pipelines, and once litigated, a case should not be permitted to be reopened or refiled over essentially the same issues.
 - New environmental regulations should not be applied to existing plants in the absence of demonstrable overwhelming risk to health and safety, unless the cost/benefit relationship clearly makes such action appropriate.
 - Requirements for restoration of mined lands should be established at levels which are reasonable considering the nature of the lands involved and potential future uses for other purposes.
-
- Congress should revise the Mineral Leasing Act of 1920 to permit block leases or lease extensions large enough to sustain multiple project development. Anti-trust laws should be relied upon to prevent dominance of the industry by any one company.

BARRIERS TO INVESTMENT

3. Institutional/Regulatory (continued)

- More access to leases for shale on federal lands is essential since withholding shale resources is both a physical and strategic barrier to development. Eighty percent of the rich deposits are on federally owned land. Due to restrictions in the 1920 Mineral Leasing Act, a developer can only acquire enough land (5120 acres) for one commercial-scale project. Knowing that process technology improvements are likely, some potential developers are reluctant to use up their only ticket on a pioneering project.
- Water available from existing reservoirs and claims can support a 500,000 to 1,000,000 bbl/day shale oil industry, but industry access is restricted due to lack of a defined policy regarding allocations for energy development. Access to additional water is necessary for development of a mature industry, i.e., greater than 1,000,000 bbl/day.
- According to several companies interviewed, federal policy on land exchanges is heavily skewed in favor of the government receiving much more value than they offer in return.
- Current permitting procedures now involve too many different agencies and excessive delay (The Colony project will require an estimated 130 permits.)

REMEDIES

- The Interior Department should recognize the defects in its shale leasing program and propose changes to the Congress for increasing the acreage allowance.
- The governmental policy toward land exchanges and lease-swapping should be reviewed and modified to permit aggregation of non-contiguous leases into single units of economic size.
- DOE should work with the Bureau of Land Reclamation and other government agencies to develop a water supply program to supply all essential uses, especially energy development. In particular, use of available, often brackish, groundwater should be permitted for wetting spent shale.
- The funding of pending and approved water projects (e.g., West Divide, Yellow Jacket) are necessary for the industry to expand beyond the 500,000 to 1,000,000 bbl/day range. These projects need to be scheduled to coincide with the growth in demand.
- The permitting process must be streamlined, and this should be a major priority of the Administration and DOE. A one-step permit system should be set up, with the federal government coordinating requirements of both national and state/local agencies, so that permits can be obtained expeditiously and with confidence of continued validity.

BARRIERS TO INVESTMENT

3. Institutional/Regulatory (continued)

- Court actions by public interest groups are expected, which could tie up projects in interminable legal proceedings, often repeatedly over the same issue.
- Concern over socio-economic impact of intensified regional development--by people not living in the affected area--has increased resistance towards development.

4. Technical

- Surface retorting technology is ready for scale-up to commercial capacity. However, continuous operation of commercial scale equipment is necessary to verify the operability and the economics. Such experience can be expected to generate significant engineering improvements.
- Experience is needed on a commercial-scale operation under private sector management, including all steps from shale mining through land reclamation and product sales, to demonstrate a true commercial capability.
- In-situ technology is not yet ready for commercial demonstration. Non-uniform rubblization of shale rock, low yields and ground water management are major problem areas. The current DOE development program does not encourage free exchange of information on in-situ R&D.

REMEDIES

- Limits to litigation of all issues other than tort should be imposed, as recommended above for environmental issues.
 - The federal government should work with state and local governments to anticipate socio-economic impacts which might result from industrial development in remote areas and to plan programs to mitigate such impacts.
-
- Large scale projects, such as proposed by Colony or Union, should be built to prove their technologies and to demonstrate their economic and environmental feasibility. This would put the OPEC cartel on notice that the U.S. is serious about reducing our dependence on foreign oil. Canada has already taken this action with respect to tar sands, and, like the Canadian enterprise, such ventures should be undertaken with close cooperation between industry and government.
 - DOE's R&D program should be coordinated with those of industry to further basic and early developmental research on problems involved in:
 1. Constructing underground retorts (e.g., improved rubblization techniques, management of underground water).

BARRIERS TO INVESTMENT

4. Technical (continued)

- Most industry representatives believe shale oil should ultimately be refined to middle distillate fuels (jet fuels, diesel, etc.). Raw shale oil must be upgraded to be compatible with existing refinery feedstock specifications. The degree of upgrading required will depend upon the process configuration of specific refineries and introduces another production cost variable.

REMEDIES

2. Operating underground retorts (e.g., uniform burning, optimization of yields).
3. Defining technical requirements for processing shale oil in existing refineries, and improving the upgrading (e.g., hydrotreating) and refining processes accordingly.
4. Mitigating environmental issues (e.g., collecting emission data, establishing impact of spent shale disposal on water quality).

In many cases cost-sharing of projects may be appropriate.

- DOE should not undertake demonstration projects on shale retorting or shale oil refining, though it should, under suitable circumstances, financially support such projects undertaken by industry.
- DOE should set up a more open program for disseminating information and data obtained from government funded R&D.

B. ENHANCED OIL RECOVERY

While certain EOR methods - specifically, steam drive and CO₂ flooding - are in limited commercial use, EOR is far from ready for universal application. On the positive side, EOR techniques are being used in fields that are amenable to such techniques in terms of depth, petroleum and reservoir characteristics, economics, and environmental constraints. In addition, EOR utilizes in-place infrastructure (wells, tanks, pipelines, supply and support facilities). On the negative side, the response characteristics of individual petroleum reservoirs to a given enhanced recovery process usually are not well known and can be determined only with field-by-field pilot testing conducted over a period of several years.

Thus, EOR, though holding ultimate promise for greatly adding to our ultimate production of crude oil, must be developed on a reservoir-by-reservoir basis with extensive study of the particular characteristics needed to facilitate selection and application of the most suitable enhancement processes and procedures. Such experimentation frequently involves very large "front-end" investment of capital before the potential return on this investment can be forecast with any degree of certainty. EOR, thus, is not a quick route to major augmentation of the Nation's crude supplies, nor to profits for those employing it, though the aggregate result could make a major contribution to both.

The following main conclusions have emerged from this study of enhanced oil recovery.

- Current EOR production is 250,000 bbl/day $\pm$ 20%. This excludes cyclic steam methods which are considered conventional, commercial techniques. Steam drive as applied to heavy oils is currently the pre-dominant EOR technique, accounting for 50% or more of the total, and is concentrated in California. Higher oil price and favorable test and infrastructure development should result in increasing emphasis on and wider geographical applicability of CO₂ miscible and surfactant-polymer flooding techniques by 1985.
- A consistent set of definitions is needed in regard to EOR terminology. "Enhanced oil recovery" is often used interchangeably with "tertiary recovery" although the former term has come to have a broader meaning than tertiary; in DOE parlance, EOR also connotes the newer, less developed recovery technologies (e.g., in-situ combustion), which may be applied in a primary or nonprimary mode.

- While secondary recovery was not a concern of this study, there is a natural interface between the conventional flooding operations of secondary recovery, which now accounts for about 50% of current domestic oil production, and tertiary recovery operations. Many EOR applications will be tertiary operations which can benefit from the existing secondary infrastructure. The present system of price controls risks a premature shutdown of some secondary production, with adverse consequences for initiation of tertiary projects which might otherwise be phased in as testing and economic conditions allow.
- There is already significant EOR commercialization activity using miscible gas injection techniques, with industry commitments of nearly \$1 billion expected by 1981. Most of this relates to CO₂ - miscible EOR projects.
- EOR production in 1990 is expected to be 1-1 1/2 million bbls/day under present conditions as perceived by industry. With complete removal of the economic, environmental, institutional, and technical barriers impeding commercialization, the level of EOR production could be some 40 to 100% higher or 1.4 to 3 million bbls/day by 1990 and could account for as much as 1/3 of U.S. production at that time.
- Because of the perceived higher cost and risk of EOR vis-a-vis conventional oil production, industry cites the need for higher prices than the current domestic oil price as the most important overall barrier to accelerated EOR investment at this time.
- Decontrol of oil prices would provide the kind of business environment more conducive to industry investment and would stimulate an immediate response in EOR activity of all types. At the time of this writing, June, 1979, decontrol alone would not cause an immediate sharp EOR production increase, and would not be sufficient incentive for the commercial applications of highest cost techniques, such as surfactant-polymer flooding.
- Political and economic trade-offs must be made between the desire to develop advanced EOR techniques which may result in greater ultimate recoveries but which require some lead time, and the desire to have greater domestic oil production in the short term to alleviate balance of payments problems and shortfalls in supply.
- Balance of Payments and Strategic Petroleum Reserve considerations may justify federal purchasing programs for oil produced by EOR in a manner analogous to those used in the synthetic rubber program or the uranium purchase program during the 1940's and 1950's.

- Industry believes that higher price would solve most of the EOR problems, in contrast to the situation in shale oil where factors in addition to higher price now constrain developments.
- Both major and small independent oil producers will play a role in EOR development, but by far the largest increment in production is likely to come from fields operated by majors or large independents.

The following are the barriers to investment for EOR and their remedies which we derived from our interviews with industry.

BARRIERS TO INVESTMENT

REMEDIES

1. Economic

- Enhanced recovery of oil costs more than primary or secondary production from the same reservoir and also involves greater perceived risk to the operator than conventional petroleum exploration and development. Several major companies interviewed mentioned the notion that EOR has less present appeal than new exploration and development, on the outer continental shelf (OCS), for instance. This refers to the fact that there are no big bonanzas in EOR and that an EOR investment has less immediacy relative to an opportunity to bid on an OCS lease which is not only transitory but usually offers higher profit potential and a more familiar, lower risk profile.
- Our interviews indicate that industry maintains that all production from fields employing EOR should be freed for sale at world crude prices-- implicitly assuming that world price will remain high and above the domestic controlled "old oil" price. (We note that a Draft Regulatory Analysis of the proposed ERA Rulemaking on Incentives for EOR Techniques, prepared by DOE's Resource Applications Branch in March, 1979, views this remedy as the least cost/effective of several alternatives they studied.)

BARRIERS TO INVESTMENT

1. Economic (continued)

- In absolute terms, EOR production ranges in cost from about \$6/bbl for steamdrive in certain California fields, to upwards of \$15-\$30/bbl for developmental methods (e.g., micellar-polymer) based on injected chemicals.
- Generally, a 10-20% (constant dollar) net return on the project investment must be foreseeable before proceeding with an EOR project--the higher the perceived risk, the greater must be its expected return. Furthermore, the risk-weighted return must equal or exceed that available from conventional exploration and development opportunities. Thus, many CO₂ flooding and micellar-polymer projects will not be economically attractive at world crude oil prices (of \$16/bbl, June, 1979), but they will look more attractive the higher the price.
- Current pricing uncertainties - involving various levels of pricing, production allowances for stripper prices, exceptions to given price levels, and consideration of gas prices - tend to defer EOR investments. For instance, experience with steam drive in California had a chilling effect on innovation: those who proceeded on their own initiatives have been denied price relief on the EOR oil so produced, whereas

REMEDIES

- Assistance with front-end costs, such as through guaranteed loans or tax credits, should be made available where needed, particularly in the absence of decontrol, and for the smaller producers. Industry is generally favorable toward ERA's recent proposal to amend the mandatory petroleum price regulations to provide an incentive for producers "with front-end money to initiate or expand certain types of tertiary recovery projects", but some believe it is too small, weak, short-lived, and otherwise conditional to produce an early impact.
- Industry clearly prefers complete decontrol of oil prices. That is, they are more comfortable with the risk and uncertainty of that economic environment than with a regime of constantly changing price regulation. Decontrol alone, at the time of this writing, will cause some but not a dramatic, increase in EOR production and will not suffice as an incentive for the widespread commercial application of the higher cost chemical injection methods. Much increased EOR activity, however, can be expected to follow decontrol, and continued world price escalation will eventually impact both the activity in and the application of even the highest cost techniques such as surfactant-polymer flooding.
- Our interviews and our previous work in this and other areas suggests that Balance of Payments and Strategic Petroleum Reserve considerations may justify selected federal EOR purchasing programs for enhanced oil in a manner analogous to those used in the synthetic rubber and uranium programs of the 1940s and 1950s.

BARRIERS TO INVESTMENT

1. Economic (continued)

those who came in late have been accorded the advantage. While industry continues to make other petroleum investments in ventures with long-term payouts, these typically involve receipt of the world oil price over the entire field, and/or the use of conventional technology.

- The IRS position that injection chemicals must be capitalized, rather than expensed, introduces a substantial cost penalty, perhaps as much as four dollars per barrel of oil produced, depending on the process selected.
- Timing of EOR development may be influenced by a company's ownership or lease position in any given field, and this timing may not always coincide with DOE's commercialization schedule.
- Major plants built to manufacture chemical injectants for EOR are operating at only a small percent of capacity because of unacceptable return on investment for the EOR operators whom they are intended to supply. Some of these plants may be converted to other uses, which could cause crucial short-falls following the expansion of EOR production. One chemical manufacturer said that it would not build new units without assurance that changes in government regulations would not once again "put us out of business".

REMEDIES

- IRS should permit expensing of materials and/or energy injected as part of an EOR project.
- Prompt removal of all economic barriers could result in incremental EOR production over that presently planned in as few as 1 to 3 years after such actions.
- Early initiation of EOR projects, by many companies, in many fields, is necessary if significant near-term impact on remaining reserves is to be felt.

BARRIERS TO INVESTMENT

REMEDIES

2. Environmental

- Air emission control standards are delaying thermal projects in California, in some cases shutting them down.
- Water quality standards with respect to the use and fate of injected water and chemicals are of concern to the EPA but to date little, if any, definitive statements have been made to guide operators in planning EOR projects.
- The likelihood of a "Programmatic Environmental Review" (10 CFR 1021) followed by individual Environmental Impact Statements under NEPA requirements is bound to further delay attempts to commercialize EOR.
- Uncertainty with regard to possible future standards makes business plans for long-term EOR projects very risky.
- Federal air emission standards and water pollution regulations should be rationalized and actual or potential conflicts with state agencies resolved.
- Permits should be issued through a "one-stop" process, coordinating the role of all agencies concerned and eliminating unnecessary delays.
- Projects approved and initiated in good faith under regulations existing and anticipated at the time should be exempted from future, more stringent regulations which would increase project cost retroactively. Similarly, limits to litigation of environmental issues other than tort should be imposed.

BARRIERS TO INVESTMENT

REMEDIES

3. Institutional/Regulatory

- There is substantial agreement between the DOE Commercialization Task Force (CTF) for EOR and industry views that federal price controls, environmental regulations, and IRS policy with respect to injection chemicals constitute significant institutional constraints on EOR activity. The views reflected by major integrated companies we have interviewed suggest less concern than the CTF for unitization requirements and for new refinery or related actions to deal with the heavy oil situation on the West Coast.
- We have also identified additional institutional issues not addressed by the CTF, viz.:
 - The national policy framework is lacking; there are apparent counterproductive disparities among Congressional interest in and support for EOR RD&D, the CTF strategy, OMB allocations and EPA concerns.
 - The efficacy of a strategy which emphasizes the role of small producers needs to be studied.
- There is as yet no standard definition or usage of the term "enhanced oil recovery" accepted by both industry and government.
- Decontrol of oil prices should be granted to all fields employing EOR.
- A clear, concise definition of EOR should be made within the context of the total process of oil production. A tentative definition of the stages of oil recovery based on our conversation with knowledgeable people in the oil industry is presented in the body of this report.
- Application of EOR to fields which would otherwise be abandoned should be expedited if technically sound procedures for obtaining additional production are available.
- Anti-trust policy toward cooperative RD&D efforts should be better articulated to industry and modified to accommodate certain projects if appropriate.
- Permits should be issued through a "one-stop" process, coordinating the role of all agencies concerned and eliminating unnecessary delays.

BARRIERS TO INVESTMENT

3. Institutional/Regulatory (continued)

- Administrative policies on pricing create confusion and uncertainty within the oil industry. The Economic Regulatory Administration of DOE has recently proposed new tertiary crude oil incentives. The Administration's proposal to phase in decontrol of all domestic oil production by October, 1981 overshadows these proposed incentives and makes them become less valuable as October, 1981 approaches. Congressional efforts to tax away earnings from decontrol of old oil production negate most of the gains according to the companies.
- Since many fields have multiple owners and operators, large and small, unitization is usually imperative in a secondary or EOR project. It appears that much of the unitization issue is related to the need for more uniform pricing regulations within a field, where both stripper wells and non-strippers are producing.
- The processes for obtaining permits for facilities pipelines, operations, etc., are multiple, complicated and repetitive. Simplification is needed.
- Anti-trust policy toward cooperative R&D or field evaluation and testing is uncertain.

BARRIERS TO INVESTMENT

Institutional/Regulatory (continued)

- EOR, in view of these inhibiting factors, is currently regarded by many oil operators as a postponable investment when compared to more certain prospects for achieving profits associated with new exploration and production activities.
- Premature termination of secondary recovery operations, due to unfavorable regulations, can harm prospects for tertiary EOR applications.
- DOE's policies appear to favor advancing tertiary recovery technology development rather than widescale application of existing technology. This is a barrier to both oil production in general and to steam drive in particular.
- In the short-term, U.S. refinery economics and limited West Coast capacity constrain the amount of steam-drive-produced heavy oil which can be handled.
- Streamlined price relief is needed to keep many of the secondary recovery operations in production and to provide the incentive to keep fields open for transition to tertiary recovery operations in the future.
- Industry comments to ERA on the definitions and eligibility criteria covering California steam drive deserve prompt attention.
- Additional refinery capacity or incentives are needed to exploit steam-drive potential.
- Both majors and independent operators view recent ERA actions regarding marginal properties and base production control levels as encouraging furtherance of secondary floods and enhancing prospects for tertiary.
- Implement liberalized patent policy as has been authorized in legislation such as the Non-nuclear Energy R&D Act and that potentially implied in the Federal Grant and Cooperative Agreement Act. Although patents were not given major emphasis by our respondents, it seems evident that patent policy significantly affects industry's attitude toward joint industry/government pilot and demonstration projects.

REMEDIES

BARRIERS TO INVESTMENT

REMEDIES

4. Technical

- In the great majority of fields believed to be EOR candidates, too little is known about the interrelationship of reservoir characteristics and the candidate EOR process(es). Among the factors to be considered are: heterogeneity, stratification, fracturing discontinuity, mineralogy, and type/size distribution of pore space in the rock; reservoir pressure and temperature; oil gravity and viscosity; oil/water saturation; gas/oil ratio; porosity, permeability, lithology; and chemical characteristics of the oil, water and gas. Not only do these factors vary from reservoir to reservoir they may vary within a single reservoir.
 - The timing of and extent of commitment to a given EOR process are important and dependent on, among other factors, availability and price of equipment (e.g., steam generators, injection pumps) and raw materials (e.g., detergents, carbon dioxide, polymers), and expected yield.
 - Knowledge about the nature and predictability of yield requires further R&D and field testing.
 - In many fields the infrastructure is deteriorating to the point where abandonment will be necessary in a very few years. Once a field is abandoned and the wells plugged, the oil remaining in place may become irretrievable, as redrilling for EOR operations would be prohibitively expensive
 - The principal EOR processes are characterized as thermal (steam-drive and in situ combustion), chemical (surfactant, caustic, and polymer injection), and miscible gas (e.g., CO₂ injection). Government funding of R&D should be continued. The fine cooperative programs, originally sponsored by the Bureau of Mines from its Bartlesville station, can serve as the base for an expanded program within DOE. Information exchange is a valuable part of these programs.
 - More R&D is needed, especially for miscible and microemulsion floods. Knowledge from extended secondary recovery operations will be beneficial for fields amenable to tertiary flooding techniques.
 - To accelerate EOR production and the advancement of the technology, pilot and field tests must be intensified, both in number and diversity. Such tests are needed in most of the 800 or so reservoirs which have been identified,* and costs are estimated to be at least several million dollars per pilot test. On the basis of comments made at public hearings held on May 1, 1979, industry is generally favorable toward the EOR incentive program promulgated by ERA. Under this program, any incremental oil from wells using specified EOR techniques can now receive world price. In addition, beginning in January, 1980, and extending 18 to 26 months if full decontrol goes into effect, producers can release lower tier oil to upper tier
- *Many additional such reservoirs are believed to exist, but little information concerning them is presently available.

BARRIERS TO INVESTMENT

4. Technical (continued)

with respect to the oil recoverable.

- In addition to the time required for R&D and field tests, EOR processes inherently involve time lags from the start of application to production of usable oil. The duration of time lags will depend upon the EOR technique used and the related performance characteristics of the oil field.

REMEDIES

price to finance up to 75% of front end expenses for "self-certified" tertiary production up to a maximum of \$20 million per field.

II. INTRODUCTION

The purpose of this project, as initially conceived in February 1978, was to identify the crucial uncertainties with regard to current and future government policies and to identify which were then commonly considered to be the primary inhibitors of private sector initiatives in commercializing both shale oil production and the use of enhanced oil recovery techniques. These uncertainties were to be identified through an iterative process of in-depth discussion and analysis of data with both private firms and relevant federal agencies. Further, the project was to identify possible changes in public policies designed to remove such uncertainties and to gauge the likely response by industry through increased and/or accelerated investment in the two target technologies. The team which was assembled to carry out the project is composed of groups from three organizations: School of Management, Rensselaer Polytechnic Institute (RPI); the Industrial Research Institute/Research Corporation (IRI), and Arthur D. Little, Inc. (ADL).

Events in the political arena and within both DOE and industry overtook the methodological process originally proposed. The contract for this project did not become operative until September, 1978. Within one month, the first draft reports of Commercialization Task Forces in DOE appeared, including one each for Shale Oil and Enhanced Oil Recovery. This required the project team to interact intensively and extensively with the Chairmen and members of the two relevant Commercialization Task Forces. While instructive by providing advance insights into DOE policy foundations, this interaction made it evident that DOE intended to move much more rapidly towards a commercialization strategy, under the guidance of Mr. Jackson Gouraud, Deputy Under Secretary, than envisaged when the project was submitted in March, 1978.

This in turn required the project team to depart from its plan for a pilot sample interview program and data analysis with two or three selected firms, before embarking upon work with a larger universe of both major and independent oil producers. Instead, a dozen organizations were selected to provide a reasonable representative base for obtaining informed judgments and related data. Interview guidelines were developed by the project team and approved by DOE. Field work with the selected companies was conducted during October through December, 1978. In May, 1978 a draft of the Executive Summary of this report (see Section I) was sent to various parties in DOE, including the Shale Oil and EOR Resource Managers. At the same time, it was sent to the industrial executives whom we had interviewed and to the IRI interviewer/consultants who had not participated directly in the writing of this report. From DOE we obtained feedback regarding the accuracy of our depiction of the DOE status regarding shale oil and EOR. From industry and the IRI interviewers, we obtained feedback regarding the accuracy and veracity of our recording of their original input. The comments of all responding parties were incorporated into the present Executive Summary and the report itself. Naturally, since their responses are aggregated, not

every position and perception can be reflected with complete accuracy of detail. The feedback obtained indicates, however, that we have fairly depicted the viewpoints of our respondents who were in general large oil companies and suppliers of chemicals for EOR.

Towards the end of this effort, it became evident that DOE was already making selections of energy technologies which it considered to be of high priority for commercialization in its National Energy Supply Strategy. Enhanced oil recovery and shale oil were among them. Early in 1979, DOE formally announced the appointment of "Resource Managers" for each of the technologies selected for accelerated commercialization. The project team, therefore, held meetings with the two Resource Managers for shale oil and for enhanced oil recovery so as to contribute whatever of value had been produced in its work to date to the efforts being made by the Resource Managers. Draft summary reports on work done to date, submitted to DOE/PEA in December, 1978 were made available for use and commentary by the Resource Managers. Both considered this preliminary material of value to them. At the end of January, 1979, the project team was shown final drafts of the Commercialization Plans for both Enhanced Oil Recovery and for Shale Oil. We had asked to see these before writing the present status report, in order to be able to present our findings in a manner that would be relevant to these commercialization plans prepared within DOE. We trust that the Resource Managers will so find them.

During the conduct of this work, specifically from August 1978 onward, significant events occurred in the political arena, which included:

- ERA published proposed rulemakings on EOR oil prices. These were critized as insufficient and unworkable by industry in public hearings held in September, 1978. New and revised rules, partially based on these hearings, have been proposed. New hearings were held in April, 1979, after the completion of the project team's interviews with industry. Representatives from the project team did attend the hearings, however, and an indication of industry's reaction to the proposals was obtained and is reported upon herein. It seems likely at the time of this writing (June, 1979) that these rules will be enacted.
- A bill to provide a \$3 tax credit for shale oil production died in the last days of the 94th Congress in October, 1978. A similar bill--embodying some additional provisions--has been re-introduced in the 95th Congress on 8 February 1979. At the time of preparing this report (June, 1979) the likely fate of this bill is unknown.

- The introduction of the President's phased decontrol of crude oil prices beginning in June, 1979, along with announced legislative initiatives including the proposed "windfall profits" tax.
- The new round of sharp price increases in foreign-supplied crude oil.

III. SHALE OIL

A. SUMMARY

Potentially recoverable oil from shale in the Western United States in excess of 150 billion barrels is available,* and recovery technology using surface retorting is sufficiently developed to be commercially feasible. Why then, has there been essentially no commercial deployment of this resource at a time when present supplies of hydrocarbons are unable to meet demand? The answer is complex because the issues involve the inherent risks of investing in a highly capital-intensive new technology, coupled to uncertainty of prospective returns on this investment, in a climate of unpredictable public policies and politics at both the federal and state levels.

In this study, we present the perceptions, expressed by prospective industry developers, of the principal barriers impeding commercial development of oil shale and their suggestions for actions on the part of the federal government that would stimulate industry to invest its own funds in commercialization of shale oil. The principal barriers and remedies are divided into four broad categories:

- Economic
- Environmental
- Institutional/Regulatory
- Technical

This provides a meaningful framework for our findings, recognizing that many issues involve the interaction of all four of these categories.

Surface retorting technology is most advanced, though in-situ technology will be of importance in the long run to recover reserves not amenable to conventional mining, and to reduce environmental impacts of shale oil production. Surface retorting processes may begin to be commercialized in the 1980's; in-situ processes require further technical development and will probably reach commercial feasibility in the 1990's.

Many obstacles (economic, environmental, institutional/regulatory and technical) are now preventing industry from committing multibillion dollar investments even for the first commercial-scale plants. Therefore, it is unreasonable to assume that only economic incentives, such as

*There are many extant estimates of recoverable shale oil, all in the hundreds of billions of barrels. Ours is intended to be a lower bound which considers the word recoverable to mean recoverable within reasonable bounds of technical and commercial feasibility. The DOE estimate based on U.S. Geological Survey figures is in excess of 400 billion barrels.

including shale under the entitlements program or allowing tax credits on production, will by themselves cause a great rush to invest. The oil companies we interviewed see the proposed production tax credit as a necessary first step and generally support this initiative. However, resolution of issues posed by the more onerous environmental constraints, by unlimited legal challenges, and by limited access to shale deposits, is also needed. It is essential, therefore, that both industry and federal and state agencies find common ground to resolve all these issues. In short, the proposed \$3/barrel production tax credit (as of June 1979, DOE's key incentive for industry) will not -- by itself -- buy an oil shale industry.

The Bottom Line

Present production from oil shale is essentially zero. In the collective opinion of senior industry executives interviewed in this study, if all the remedies recommended in the Executive Summary of this report were negotiated between the agencies concerned and were put into effect by the end of 1979, the results shown in Table III-1 could be expected for commercial shale oil production.

TABLE III-1

PROSPECTIVE SHALE OIL COMMERCIALIZATION

Time after Removal of Last Barrier (years)	5 (1985)	10 (1990)	20 (2000)
Daily Production above that Expected if Barriers Remained (thousand bbl/day)			
• Estimated by Industry	0-230	150-450	500-1000
• Study Team "Best Estimate"	0-60	100-300	500-1000
Private Investment, \$ Billion*			
• Based on Industry Production Estimate	0-6	4-8	12-24
• Based on "Best Estimate"	0-1.4	2.4-5	12-25

* In 1979 dollars, based on \$1.2 billion investment for each 50,000 bbl/day of production capacity, not allowing for any cost reduction in second and later generation plants.

A range of responses is shown for the industry estimates. A study team "best estimate" based on a consensus of its members is also shown. This estimate assumes that only Colony and Union* are likely to be operational by 1985. Some second generation surface retorting plants are projected to start up in the early nineties. Near the end of the century, the production could range from 500,000 to 1 million bbls/day depending on how soon in-situ technology becomes commercially feasible.

B. CONCLUSIONS

The major findings regarding the barriers to more rapid development of oil shale are summarized as follows:

- General decontrol of oil prices is necessary to provide the proper climate for long term investments in shale oil development.
- There is great financial risk associated with a commercial oil shale venture due to uncertainties not within the capability of the private sector to mitigate because they are largely government created, controlled, and perpetuated. These uncertainties result in the unpredictability of return on investment (ROI) within the reasonably narrow range necessary for responsible investment. Thus, the private sector is and will remain unwilling to invest in pioneering shale plants so long as uncertainties which are non-economic per se and not within the normal bounds of commercial risk-taking preclude the prospect of reasonable ROI at current (\$16/bbl landed in U.S. June 1979) or even substantially higher world oil prices.
- In order to achieve a minimally acceptable ROI on initial ventures, the selling price for clean shale oil will necessarily be higher than the current world price and probably higher than that which will prevail in the near term. Thus, economic incentives in addition to free market price will be required for shale oil development and the initiation of first generation plants. Industry prefers a production tax credit as the means for providing these incentives. It is not precisely known, however, whether the presently proposed \$3/barrel will be sufficient in view of continued cost escalation and anticipated additional environment regulations.

*The Colony Development Company, a joint venture between ARCO and TOSCO, proposed to build a 50,000 bbls/day shale oil facility on private land. Colony has an approved Environmental Impact Statement and could be in operation in about 4-5 years after a decision to build. Union Oil Company has announced that it will build a 10,000 bbls/day surface retort "module" if the \$3/barrel production tax credit is passed. This module could be on-stream by 1983 if a decision is made in 1979.

- In addition to a favorable pricing structure, which is necessary but not sufficient to bring forth a commercially viable shale oil industry, other measures must be taken to overcome obstacles such as:
 - lack of national commitment, backed up by federal policy, to development of shale resources;
 - unpredictable and constantly changing environmental standards which can result in 25-50% increases in shale oil price;
 - an environmental policy that invites legal challenges which can result in excessive delays and consequent price increases;
 - the lease tract limitation of 5000 acres* per company effectively precludes companies from building more profitable second generation commercial plants.
- Even with the removal of all major barriers, commercial production of shale oil will require at least five years' lead time. Government must provide the leadership to remove these barriers in order for shale oil production to contribute significantly to supply of liquid fuel by 1990.

Other concerns expressed by industry included:

- Permits - The permitting process is excessively protracted due to the number of permits required and the existence of dual environmental standards (state and federal).
- Water Availability - Water for pioneering plants is physically available. Administrative and political restrictions are preventing companies from gaining access to existing supplies. A comprehensive water policy with provisions for energy development is essential for a mature shale oil industry.
- Inflexible policy on land exchanges - The Department of Interior has concluded that it does not have authority to allow swaps of industry - owned land when mineral rights are involved, even though the Taylor Grazing Act permits such exchanges. Such swaps are necessary to attain contiguous acreage of shale deposits sufficient for commercial recovery.

The remedies proposed by industry for removal of these barriers are summarized in the Executive Summary of this report and discussed in the following sections.

*This so-called "5000 acre limitation" is actually 8 square miles or 5120 acres.

C. PRINCIPAL ISSUES

1. Introduction

a. Description

Oil shale is a sedimentary rock that contains an organic polymer called kerogen which decomposes on heating to produce shale oil. Even though significant deposits are known to exist in the United States, Brazil, The Republic of China, Sweden, and Russia, world production has been small. The Petrosix plant in Brazil is the largest shale oil facility, with a nominal capacity of some 2200 tons per day of shale with a 23 gallon-per-ton average.

Oil shale represents a vast, untapped, domestic source of hydrocarbons in the United States, as shown in Table III-2. About half of those reserves containing more than 30 gallons of oil per ton of shale now appear attractive for commercial recovery. This volume of oil is about the same order of magnitude as recoverable reserves in Saudi Arabia, or about 200 billion barrels. About eighty percent of the estimated U.S. reserves are located on federally owned land in the mountain states of Colorado, Utah, and Wyoming. Surface retorting technology for producing shale oil has been pilot tested in that area.

Shale oil cannot be recovered by normal crude oil production techniques. It is extracted by heating the shale to 900-1000°F and collecting the hydrocarbon fraction that is driven off. This process is called retorting.

Shale oil extraction processes are divided into two major types:

Surface Operations which involve conventional room and pillar mining of oil shale, which is transported to the surface where it is retorted in large vessels to produce raw shale oil.

In-Situ Operations which involve fracturing (rubblizing) and thermal stimulation (burning) of the oil shale underground. Raw shale oil collects at the bottom of the retort and is pumped to the surface. The major advantage is a large reduction in the volume of mined shale that must be handled and redeposited. This reduction is about 12,000 tons per 10,000 barrels of oil recovered for surface operations. Consequently, in-situ operations can be expected to have generally less environmental impact than surface operations. In-situ retorting also offers the potential to recover oil from shale that is not amenable to conventional mining operations.

TABLE III-2

OIL SHALE RESOURCES - GREEN RIVER FORMATION
(Billions of Barrels)

Location	Basin	Resource Classes				Total
		Class 1* Well-Defined >35 gal/ton	Class 2* Well-Defined >30 gal/ton	Class 3 Lesser Defined >30 gal/ton	Class 4 Poorly Defined 15-30 gal/ton	
Colorado	Piceance	34	83	167	916	1,200
Colorado & Utah	Vinta	-	12	15	294	321
Wyoming	Green River/ Wishakie	—	—	4	256	260
		34	95	186	1,466	1,781

*limited to deposits at least 30 feet thick

(SOURCE: National Petroleum Council)

b. Development History and Present Status

The existence of vast oil shale deposits in the West has been known for over 100 years. During the period from 1948 to 1955, the Bureau of Mines developed several surface retorting processes including the Gas Combustion Retort Process which is the basis for the Paraho and Petrosix Processes. Union Oil also began its research into oil shale retorting in the 1940's. Currently, there are potentially four surface processes available for retorting U.S. oil shales. These include TOSCO II, Union SGR, Lurgi/Ruhrigas and Paraho. All must be scaled up for a commercial size plant.

Field testing of in-situ production of shale oil began in 1966 under the direction of the Laramie Energy Research Center (LERC). Occidental Petroleum began a field test program on Modified In-Situ retorts in 1972. Six retorts have been ignited with mixed results. Non-uniform rubblization of shale and low oil yields have been major problems. In general, in-situ processes are much further from commercial status than surface processes.

A summary of major development activities on surface and in-situ processes is provided in Appendix A.

2. The Present Climate for Action

a. Current Programs of the Department of Energy (DOE)

The Energy Technology (ET) Division (Fossil Fuel Extraction) has an ongoing research and development program which focusses on in-situ processes since surface technology is believed to be ready for commercial testing at the demonstration plant scale. The program is a joint, cost-shared activity with industry that addresses major technological problems such as rubblization, and restabilization of retorts.

In 1976, the Federal Energy Administration (FEA) ruled that Congress did not intend shale oil and other synthetics to be priced as restrictively as conventional domestic crude oil (30). Therefore, shale oil can be sold for whatever price is established by the free market. Recently, the Economic Regulatory Administration (ERA) has issued rules (31) which allow shale oil to qualify for entitlements, thereby permitting it to reach parity with world market crude price allowing for quality and transportation differences.

Shale oil has emerged from the DOE Commercialization Task Force (CTF) reviews as a target technology for commercialization. Mr. Paul Petzrick is the designated Resource Manager in DOE for shale oil. This status for shale oil was established after our industry interviews had been completed and is thus not reflected in industry perceptions reported here.

Also, as of the time of writing this report (June 1979) some 23 proposals for government programs to commercially demonstrate synfuels, including shale oil, had just been proposed. These are listed in Appendix B. We did not have an opportunity to discuss their merits with industry.

b. DOE's Commercialization Strategy

DOE's Commercialization Task Force on shale oil recommended in December 1978 a development strategy based on government and the private sector performing their traditional roles under the free enterprise system. Major elements of the federal government program (1) would:

- Provide economic incentives as needed to promote orderly development of the oil shale industry to established goals by "off budget" incentives* which minimize federal involvement.
- Provide economic incentives for oil shale development through "on budget" incentives which maximize federal involvement.
- Integrate the marketing of shale oil into the national energy supply strategy and national transportation plans for crude oil.
- Provide leadership to resolve conflicting objectives of energy production and environmental protection.
- Coordinate the national commitment to oil shale development through a formal support plan that gives substance to this commitment.
- Facilitate industry's role through expedient handling of federal permits and easements and fair and consistent interpretation and enforcement of federal laws and regulations.
- Make federally owned oil shale resources available through responsive leasing and land exchanges.
- Make federal land available as needed for community growth and infrastructure support facilities.
- Continue the federal government's traditional role in planning and constructing major water supply projects if needed.
- Assist local communities that will be heavily impacted by the oil shale industry to obtain socio-economic impact funds.

*These can still affect the income side of the balance sheet (e.g., tax credits), so in that sense they are still on the federal budget.

The timetable for development suggested by the DOE Task Force is:

<u>Year</u>	<u>Production</u>
1985	100-300 thousand/bbls/day
1990	400-800 thousand/bbls/day
2000	1-2 million bbls/day

c. Industry's Views and the Implications of Effective Government Policy

To the oil industry -- as for any other industry -- commercialization means a business venture with an expectation of a reasonable return, adjusted for risk, on stockholders' equity. Commercialization as seen by the DOE seems more often to imply a research and development program on a large scale, which, if technically successful, denotes commercial readiness. Consequently, a definitional problem may exist. What industry desires is a business climate conducive to investing in--inherently--high-risk alternative energy production ventures, rather than government funds to conduct research projects to demonstrate the technical feasibility of production capability.

Realistically, commercial development of shale oil before the end of this century will probably be exclusively based on surface retorting (12) since the technology of in-situ retorting is still in the early stages of development. While technological risks are still involved in scale-up of surface retorts to commercial-sized plants, industry believes these are acceptable and can be managed, provided the other uncertainties are reduced to a level consistent with other investment opportunities available to the industry. This does not mean the oil industry is looking for a risk-free venture in shale oil production, but at present the perceived non-technical risks are too large relative to the potential rewards. Given the cost uncertainty of these risks, industry cannot effectively quantify them in the normal framework of venture analysis.

Not surprisingly, industry perceives the major obstacles to rapid commercialization to be related to economic uncertainty, environmental regulations and institutional issues. Free market oil prices are now (June 1979) approaching a level where raw shale oil could be produced at an equivalent price assuming normal project risk. However, the incremental costs associated with project delays, mitigating socio-economic impacts and complying with potential changes in environmental regulations are unpredictable and potentially large, as shown by the ultimate cost of the trans-Alaska oil pipeline. Consequently, an initially attractive venture could ultimately result in an unacceptable return for the private investor. The production tax credit is proposed to offset the incremental costs, but, though welcomed by industry, it needs to be augmented by other federal and state actions targeted directly on removing the other barriers.

A universal complaint of industry is that federal policy in energy development is inconsistent. Certain policies, like those of the National Energy Act, seek to encourage development. However, cancellation of water projects and withholding lease tracts convey a message to industry that the government is either disorganized or places little priority on shale oil development. Therefore, for a federally supported commercialization program to be effective, it is essential that government agencies, both federal and state, work in concert with each other -- and with industry.

d. Barriers and Action Matrix

Table III-3 shows the "commercialization profile" for shale oil which was used by DOE's Commercialization Task Force on Shale Oil. Items indicated by a (+) are those which most of the industry perceived to be significant. An institutional barrier and a required federal action which appeared significant, based on information gathered in our interviews, was added. These are shown with asterisks.

D. DISCUSSION OF BARRIERS TO COMMERCIALIZATION AND PROPOSED REMEDIES

The specific barriers to shale oil commercialization as perceived by industry are discussed below. These perceptions are industry views as interpreted by the study team, Rensselaer Polytechnic Institute, Arthur D. Little, Inc., and the Industrial Research Institute Research Corporation, and are based on interviews with major oil companies. A comparison of industry and government perceptions is made wherever possible. The discussion of important barriers and proposed remedies is presented in sequence under the following subject headings:

1. Economic Uncertainties
2. Environmental Uncertainties
3. Institutional Uncertainties
4. Technical Uncertainties

1. Economic Uncertainties

(a) Price Controls. The existence of price controls on domestic crude oil production has a negative impact on investments in shale oil even though production from oil shale is currently exempt. The exempt status is a result of a DOE (actually its predecessor, the Federal Energy Administration), ruling clarifying the price control legislation (30). However, the industry feels that this is less secure than it should be, considering the magnitude of the investments required. The concern is that government policies have a way of quickly changing the ground rules (e.g., Tetra Ethyl Lead phase down in gasoline, banning MMT,* tax incentives for gasohol). Therefore, so long as price controls exist,

*Methylcyclopentadienyl manganese tricarbonyl; ban has temporarily been lifted (until October 1979) to alleviate the Summer, 1979 gasoline shortage.

TABLE III- 3

III-11

INDUSTRIAL ATTITUDES AS CONFORMED TO THE
DOE CTF COMMERCIALIZATION PROFILE FRAMEWORK

Initial Deployment

	Technical			Economic				Environmental				Resource Availability		Institutional			
Barrier Importance		+		+	+	+	+	+				+	+	+	+	+	+
	BARRIERS																
FEDERAL ACTIONS REQUIRED	Surface Retorting Technology	Modified In Situ Technology	Shale Mining Technology	Uncertain Economics	Shale Oil Not Competitive	High Capital Cost	Env./Reg. Problems Affecting Economics	Unknown Emissions from Concn. Plant	Background Exceeds Standards	Contamination of Water	Spent Shale Disposal	Changing Environmental Standards	Shale Availability	Water Availability	Manufacturer Status	Lack of Oil Shale Policy	Land Availability
Information																	
Construct & Operate Commercial Module				+				+									
Fed. Govt. Support of In Situ R&D		+															
Evaluate Shale Mining																	
Analyze Permitting Process																+	
Obtain Data from Commercial Plant				+				+									
Environmental Research										+							
Resource Definition																	
Analyze Water Resources																	
Develop Water Supply Program																	+
Monitor Manufacturer Status																	
Federal Commitment to Oil Shale																+	+
Financial Incentives																	
Incentives for Commercial Module				+													
Spectrum of Incentives					+	+											+
Regulatory																	
Resolve Env./Regulatory Affect on Economics							+										
Variances for Pioneering Plants												+					
Stabilize Environmental Standards							+					+					
Land Reclamation Program																	
Accelerate Leasing																+	+
Expedite Land Exchange													+			+	
Expedite Clouded Titles																	
Reduce Permit Redundancy																+	
Stabilize Regulations																+	
Infrastructure Aid																	+
(*) Remove Acreage Limit													+				

(*) - Not listed in CTF matrix, but perceived by industry.

Env. Environmental
Reg. Regulatory

INDUSTRIAL ATTITUDES AS CONFORMED TO THE
DOE CTF COMMERCIALIZATION PROFILE FRAMEWORK
Developing Industry

	Tech.		Economics			Environmental			Resource Availability		Institutional						
Barrier Importance	+		+	+	+		+	+	+	+		+	+	+	+	+	
BARRIERS	Modified In Situ Technology	Shale Mining Technology	Shale Oil Not Competitive	High Capital Cost	Env./Reg. Problems Affecting Economics	Background Exceeds Standards	Contamination of Water	Spent Shale Disposal	Changing Environmental Standards	Shale Availability	Water Availability	Manufacturer Status	Lack of Oil Shale Policy	Land Availability	Permits	Infrastructure	Inconsistent Fed. (*) Policies
FEDERAL ACTIONS REQUIRED																	
Information																	
Fed. Govt. Support of In Situ R&D	+																
Evaluate Shale Mining																	
Environmental Research							+	+									
Develop Water Supply Program											+						+
Monitor Manufacturer Status																	
Federal Commitment to Oil Shale													+				+
Resource Definition																	
Financial Incentives																	
Spectrum of Incentives			+	+													+
Regulations																	
Resolve Env./Regulatory Effects on Economics					+												
Variances																	
Stabilize Env Standards									+								
Land Reclamation Program								+									
Accelerate Leasing										+				+			+
Expedite Land Exchange														+			
Expedite Clouded Titles														+			
Reduce Permit Redundancy															+		
Stabilize Regulations															+		
Infrastructure Aid																+	
(*) Remove Acreage Limit										+							

(*) Not listed in CTF matrix, but perceived by industry.

Env. = Environmental
Reg. = Regulatory

industry fears the possibility that controls could be extended to shale oil once the plants are running.

One of the key issues in a decision to invest in shale oil is the general outlook for free market crude oil prices. In particular, oil companies factor in the anticipated escalation of oil prices in future years to give the expected return on investment they require. The mere existence of price controls on crude production is viewed as a threat to future earnings from all hydrocarbon production. Decontrolling domestic oil prices would eliminate the uncertainty and industry concern over future pricing of shale oil.

(b) Large Economic Risk. The capital investment required to build a commercial scale (9000-10,000 bbls/day) demonstration module is in the range of \$100-200 million. A commercial size plant for 50,000 bbls/day production will cost in excess of \$1 billion in 1978 dollars (4). Capital costs per daily barrel are now about \$20,000, compared with \$8000-10,000 for North Sea oil and \$5000-10,000 for Alaskan oil (20). For some companies, this could mean a significant portion of their corporate assets being tied up in one shale oil plant in western Colorado. For a company to risk this much money on building the first pioneer commercial plant, there has to be a good economic outlook for a growing shale oil industry.

There is no question that the high cost of commercial-scale shale oil facilities and plant components has inhibited the commercialization of the technology. However, the magnitude of the investment per se is not the major issue because the industry has managed and financed large investments, including the Alaskan crude oil pipeline which ultimately cost about \$8 billion. In that case, there were two noteworthy differences:

1. In order to bring the output from the developed North Slope reservoir to market, the oil companies had to build a transportation system. In contrast, shale oil development is not essential to the on-going business of the oil companies.
2. The pipeline was built only after the Congress granted approval for the project, which considerably reduced the risk of delays due to legal suits.

In the case of shale oil, the economic problem is the coupling of a large investment with an especially large risk. The technical risk of scaling up to commercial-size plants is compounded because environmental and institutional uncertainties can lead to intervention by government and the public in unpredictable ways.

On paper, the investment opportunity in shale does not look that bad. The latest economics published by TOSCO (4) show that clean shale oil selling at \$16.10/bbl (1977) would produce a 10% discounted cash flow (DCF) rate of return on the plant investment. The landed price of Saudi Arabian crude is about \$16/bbl (June 1979). The basic problem is that a

10% DCF is not acceptable on a pioneering project because there is too much risk. Quoting industry, "Because the risks [of a pioneering plant] are especially large, the economics must be especially large, the economics must be especially good." The risks alluded to (as noted above) include:

- extra environmental costs due to changing standards;
- project delays due to court actions;
- unanticipated technical problems with first plants.

If the investment hurdle rate is increased to 15% DCF rate of return, the required selling price of shale oil increases to about \$25/bbl. There is a significant ratchet effect on the selling price due to raising the hurdle rate because the capital investment per unit of production is very large. At the expected selling price of shale oil, the return will not be commensurate with the risk involved in a pioneering plant. Therefore, some form of economic incentive is required, particularly for the first plants, to bring the return on investment in line with the risk.

Several forms of incentives have been suggested by industry. These include price supports and procurement guarantees. In addition, some developers would like to see GOCO (government owned/contractor operated) arrangements, at least for the initial plants. Another alternative is to have the Department of Defense support the price of shale-derived fuels. However, the incentive receiving most endorsement from the oil industry is the production tax credit. One advantage is that this incentive can be administered through a straightforward change in the tax laws which are well understood by the industry. In addition, it does not cost the public anything if there is no production.

There are certain provisions that should be included in the production tax credit to ensure maximum impact. The principal requirements from industries' perspective are:

- allowing the tax credit on total plant production (a 1978 bill restricted it to the first 20,000 barrels);
- tax credit available for life of project with provision for phase-out when world oil price reaches level where shale oil is competitive;
- all elements in the tax credit phase-out equation to be expressed in constant dollars including the average refinery acquisition cost of crude oil.

The National Energy Act (NEA) (8) legislation provides an additional 10% investment tax credit for synthetic fuel development. However, this incentive will expire January 2, 1983, before any commercial shale oil plants can operate. The timing for the elimination of this special

investment tax credit is particularly inopportune since the momentum to build initial plants is likely to occur in the early eighties. The proposed \$3/bbl production tax credit has more clout in terms of improving the DCF return, and at least one company has stated that they would proceed with a commercial scale project if the tax credit is enacted. If it fails, then an extension of the investment tax credit to 1990 with provisions for complete write-off before start-up has been suggested.

Another method of government support for shale oil development is to help finance the building of facilities and to provide long term contracts for the product. One of the more obvious routes is through the Department of Defense (DOD). A recent U.S. Air Force study (23) concluded that future jet fuel availability may depend on synthetic fuels and that shale oil is the most viable domestic source of these fuels.

The DOD is the largest single U.S. energy consumer, accounting for about 2.7% of the nation's petroleum consumption. About half of this (250,000 bbl/day) is used as JP-4 turbine fuel for USAF operations. Therefore, Air Force demand alone could support several commercial-scale shale oil projects. As might be expected, the oil companies are less interested in this form of direct government involvement in shale production, but see that it may be necessary to get the first plant in operation. One problem companies see with this approach is that the funds for purchasing synthetic fuel become a line item in the DOD budget, subject to the vagaries of approval by the Congress each year.

We were told by some of the prospective shale oil developers that they are not overly concerned about selling the product in a competitive, free market. Therefore, a guaranteed purchase agreement or financing arrangement is only of interest if there are some sweeteners such as:

- pay higher price for product to increase DCF for first plant and offset risk;
- front-end investment assistance with:
 - payback in product, or
 - no debt payback if no production.

Some developers are hopeful that second-generation plants will not require economic incentives since many of the current uncertainties will have been resolved with the experience gained in the first plants, and companies should therefore be willing to accept a lower return on investment. In support of this view, one corporate executive pointed to Canadian tar sands development and commented that the main reason U.S. oil companies are now investing heavily in Alberta tar sand projects is because Sun Oil had demonstrated the commercial feasibility of this alternate fuel in its first plant.

Based on the analysis in the DOE Commercialization Task Force Report and discussions with Task Force participants, it is evident that the DOE understands the need for economic incentives and is essentially supporting industry on this issue. The Department began circulating its own draft version of a tax credit bill in May 1979. In addition, the DOE is currently evaluating the economics of a commercial scale shale project using the Dupont venture analysis model and the Colony capital investment estimate. The results of this analysis will provide the documentation to support the production tax credit concept.

There does appear to be a feeling at DOE that including shale oil under the entitlements program was a tremendous incentive. This Economic Regulatory Administration (ERA) change (31) went into effect in 1978 and put shale oil on the same pricing basis as imported crude oil, which was a positive step. However, entitlements are scheduled to disappear with decontrol of domestic crude prices in 1981, well before any significant shale oil production can be expected. Further, the oil industry in general is not enamored with the entitlements program. The entitlements program is an administrative device to equalize the acquisition price of crude to the refiners. In practice, companies with a large proportion of domestic crude runs (low acquisition price) end up paying (buying entitlements) companies with a high percentage of foreign crude runs (high acquisition price). However, this does not affect the total income of the industry since this is determined by product prices. Extending this to shale oil means that if the shale oil producer is not the first purchaser, he may end up buying more entitlements and thus return some of the sales revenue received from the sale of shale oil.

(c) Uncertain Market. In approaching a shale oil venture, one of the initial questions is what product(s) should be made. This leads to another question, namely, who are the users? The DOE Commercialization Task Force indicated that raw shale-oil from demonstration projects might be used as boiler fuel. Since the raw oil contains 2% nitrogen and 1% sulfur, it would have to be blended with distillate fuel oil to meet airborne emission standards for combustion sources. This application is not viewed by most proponents as the best use of shale oil: "You might as well mine coal (not oil shale) and use it as boiler fuel directly."

Due to the chemical composition and boiling range of shale oil, it is very suitable for making mid-range distilled fuels for use in jet and diesel engines. However, in raw form, it cannot be readily processed in existing refineries. Yet for ease of marketing, shale oil should be compatible with petroleum crude so that it can be refined and distributed in the usual manner.

The major quality problems with raw shale oil is that it is high in nitrogen content (~2 wt. %) and contains sufficient iron and arsenic to cause deactivation of hydrotreating catalysts unless the raw oil is pre-conditioned (13). Hence, in its raw form, shale oil cannot be readily commingled with petroleum crude oil and processed in existing refineries.

There are several alternative options for resolving this problem:

1. Do not upgrade shale oil; burn it under boilers (but see above counter-argument).
2. Build new grassroots refineries to process shale oil and other syncrudes exclusively.
3. Upgrade raw shale oil to a quality that will permit it to be processed by existing refineries.
4. Process raw shale oil to standard fuel products as part of primary recovery project.

Option 1 is a "cop out" since it does not address the issue of supplying transportation fuels. Option 2 is feasible, except in reality the prospect of getting approval for a new grassroots refinery is very small. This leaves Options 3 and 4. The Colony approach is essentially based on Option 3, the major product being low sulfur, low nitrogen syncrude. Option 3 would allow shale oil to be processed by a majority of the existing refineries. However, technology for upgrading and product specifications questions are not completely resolved. Option 4 might be implemented as the industry matures and the "standard" shale plant size increases.

For Option 3 there are several possible processing routes for refining shale liquids [cf. (19)]. One upgrading approach investigated by Chevron (13) is bulk hydrotreating of the whole shale oil to reduce the nitrogen content to 500-1000 ppm (about 95% removal). Feed arsenic is partially removed in an alumina guard bed ahead of the hydrotreater, the remainder accumulates on the hydrotreating catalyst and eventually causes its deactivation.

The properties of hydrotreated shale oils are shown in Table III-4. Properties of Arabian crude are included for comparison. Not all existing refineries will be capable of processing upgraded shale oil. However, this is also the case for conventional crude oil feedstocks. But, according to the authors of the Chevron report (13), a large number of existing refineries should be able to refine the hydrotreated product to jet and diesel fuel. Most of the companies interviewed agreed with this assessment, and thus confirm that technology for upgrading shale oil is available.

Upgrading raw shale oil will increase product costs. An economic evaluation of process requirements based on the Chevron pilot plant results was made. The cost of bulk hydrotreating was estimated to be \$6.50/bbl expressed in 1978 dollars. Similarly, using other refinery processing schemes and grassroots investment costs, Chevron estimated the cost of making standard products from raw shale oil, i.e., Option 4. They concluded that processing to gasoline and diesel fuel would increase the product price by \$8-10/bbl above raw shale oil cost.

TABLE III-4
ANALYSIS OF SHALE OILS

	Hydro-Treated		Arabian Light Crude
	<u>Colony</u>	<u>Paraho (via Chevron)</u>	
Gravity, °API	40	35.7	33.4
Specific	0.825	0.846	0.858
Sulfur, wt. %	0.01	0.004	1.80
Nitrogen, wt. %	0.06	0.065	--
Composition, % vol.			
IBP/400°F	17	14	29
400°F/650°F	25	41	24
650°F/800°F	--	23	--
650°F/950°F	35	--	27
800°F/EP	--	22	--
950°F/EP	<u>23</u>	<u>--</u>	<u>20</u>
	100	100	100
Pour Point, °F	+50/60	+80	-30
Viscosity, SSU @100°F	35	46	47

Source: Refs. 4, 13, 15.

(d) Shale Oil not Competitive. Estimated selling prices for raw and hydrotreated shale oil are summarized in Table III-5. To make a 15% DCF return on investment, the required selling price of syncrude from shale is still above world oil price. The average landed price of OPEC crude is close to \$16/bbl (June 1979). This is nearly enough to support the production of raw shale oil if there were no quality difference between shale oil and Arabian light crude. However, raw shale oil is not comparable to crude oil in regard to "processibility" at the refinery as noted above. Therefore, the refinery will not value shale oil on a par with Arabian crude until the quality is more like hydrotreated shale. This adds \$5-6/bbl to the required selling price of shale oil and places the indifference price at about \$23/bbl (1978 dollars) assuming a 15% DCF return on investment. Consequently, to get shale oil into the transportation fuel pool will require a subsidy to make it competitive with foreign oil. The proposed \$3/bbl production tax credit will have the effect of increasing the DCF return at the prevailing selling price of shale oil, which would be in equilibrium with Arabian oil, allowing for quality differences.

TABLE III-5

SHALE OIL REQUIRED SELLING PRICE ESTIMATES

Basis: 15% DCF Return on Investment

(\$/Barrel)

Source of Estimate	<u>Raw Shale Oil</u>	<u>Hydrotreated Shale Oil</u>	<u>Dollar Basis</u>	<u>Reference</u>
TOSCO	19.20*	24.50	3rd Q, 1977	(4)
Chevron	15.40 [†]	22.70	1st Q, 1978	(13)
DOE	--	18.40	1978	(1)
Arthur D. Little, Inc.	--	23.70	1978	(18)

*Bottomless shale oil.

[†]Excludes resource development cost which would add another \$1/bbl.

2. Environmental

(a) Changing Environmental Standards. A major obstacle in regard to initial commercialization is the concern that environmental regulations and standards will change over the life of the projects, and retrofitting of additional control systems will be required. The added cost for these systems is not quantifiable until the control level is promulgated. However, it has been estimated (2) that for a "worst case" scenario the incremental cost of meeting more stringent standards could add \$6/bbl to the price of shale oil. Industry sources confirmed that their estimates are at least this large. This adds more uncertainty (risk) to the overall economics which are marginally attractive in the first place.

In addition to the direct impact on capital and operating costs due to more stringent standards being imposed, there is the potential for introducing schedule delays, which cause cost increases. These schedule delays are a result of not being able to fix the design basis and to proceed with engineering of the control systems.

A parallel problem in this regard is that, because no commercial plants have yet been built, the emission rates for commercial shale oil plants are unknown. At the moment the developers of surface retorting technologies only have emission data from their pilot scale operations upon which to base control system designs to meet existing standards. The EPA has the responsibility for setting the control requirements, but physical and chemical data on emissions are required to determine Best Available Control Technology (BACT) for compliance with New Source Performance Standards (NSPS). Since commercial data is lacking, there exists a "Catch 22" situation, i.e., no standards without commercial data; no commercial plants without standards. Using approved calculating procedures on the emission data acquired from the pilot operations, it has been shown that a commercial scale plant can meet the current Prevention of Significant Deterioration (PSD) Class II regulations with appropriate control measures (16).

Industry's basic position on this issue is to exempt a few pioneering shale oil plants from further changes in the environmental regulations for the life of the project (except when public health and safety are endangered). This would allow projects such as those proposed by Union and Colony to be built and operated, and the necessary emission data to be collected. The environmental concerns could then be quantified and BACT defined in a rational manner. Second generation plants would have to meet the new standards adopted from assessment of the operation of initial plants. This approach was also generally favored by the Commercialization Task Force for shale oil,* although specific suggestion of an emission regulation "status quo" for initial plants is not directly evident.

(b) Constraint to Mature Industry. Another serious barrier is that current air quality standards (PSD in particular) could place an upper limit on the size of the shale oil industry (production capacity) that can be located in Colorado. In 1974, an interagency shale oil task force (led by the Department of Interior) attempted to quantify the shale oil production limit resulting from the National Ambient Air Quality Standard (NAAQS) for sulfur dioxide (3). The analysis

*Reference (1), p. 32, and Appendix B, p. 68.

compared atmospheric-dispersion-model-predicted SO_2 concentrations (annual average) with the NAAQS value of $80 \mu\text{g}/\text{m}^3$. The conclusion was that if the then proposed State of Colorado standard of $10 \mu\text{g}/\text{m}^3$ were implemented, it was unlikely that shale oil development in the Piceance Basin could exceed 200-300 thousand bbls/day.

Under current PSD regulations, the Federal Class II standard for SO_2 has been reduced to $20 \mu\text{g}/\text{m}^3$ (annual average). The implication is that current PSD regulations will place a limit on shale oil development before production capacity reaches 500-600 thousand bbls/day.* The proposed State of Colorado Class II standard is even lower, viz. $10 \mu\text{g}/\text{m}^3$. Also, there are some Class I (pristine areas) areas in the Green River region not too distant (60 km) from proposed shale oil projects. The PSD increments for Class I are very small and could be a serious limitation depending on specific location of shale oil plants.

It should be noted that the determination of a maximum industry production capacity based on ambient air quality standards involves an inexact procedure which utilizes atmospheric dispersion models to predict ground level concentrations. In general, the validity of dispersion models is often a key issue. The problem is more acute in cases where the impacted areas is located in rough terrain and 60 km from the source.

These uncertainties notwithstanding, the major shale oil developers do see the PSD air quality regulations limiting the size of a mature shale industry before water availability becomes a limiting factor (see discussion under "Institutional uncertainties"). A solution to removing this barrier is reclassification of the shale oil bearing regions as Class III which would increase the allowable PSD increments. The state and federal regulations should be made consistent. This still leaves the problem of the neighboring Class I regions. Redefining these areas or the Class I increments would likely take something equivalent to wartime authority of the President. Hopefully, plants can be sited to avoid impacting these areas.

(c) Myriad of Regulations and Duplication. The essence of this problem is very aptly stated in the Environmental Readiness Document (2) on oil shale:

"The oil shale industry must comply with regulations and standards including requirements of the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, the Federal Nonnuclear Energy Research Development Act, and the National Environmental Policy Act as well as applicable state laws. While other concerns emphasize technical, biological, or socio-economic problems, this concern is oriented toward the relationships between these problems and procedural and substantive provisions of laws and regulations. Failure to comply has the potential of halting all progress toward commercialization.

*A direct correlation between ground level concentration (GLC) values and production capacity is tenuous since the dispersion models used by the DOE CTF and those currently approved by the EPA are not the same.

Because the individual states are often charged with implementation of the regulations and have authority to issue stricter standards, the interpretation of the regulations is difficult and sometimes ambiguous. In addition, the administration of the regulations requires companies to interface with government at two levels, which quite often involves different procedures and appears as an unnecessary duplication of effort.

A good illustration of this problem is presented in considerable detail in (10). It involves the disparity between the federal and State of Colorado PSD ambient air quality standards for particulates and SO_2 , which are summarized in Appendix C. The Colorado 24-hour maximum standard for sulfur dioxide of $50 \mu\text{gm}/\text{m}^3$ is half the federal standard and is particularly difficult to achieve. Conversely, the federal 24-hour maximum standard on particulates is the more restrictive. In addition, the EPA and the State of Colorado have different methods of analyzing for compliance with the standards (10). The State assumes that the standard is enforced within the boundary of private property and the EPA does not. Furthermore, the State includes fugitive dust in the calculation of ground level particulates, while the EPA does not. This example deals with air quality regulations. The same kind of bureaucratic tangle exists for water and solids disposal.

The industry believes it is essential that the procedures be streamlined to reduce the number of agencies involved and the overlap between the two levels of administration. A one-stop permitting procedure has been recommended (21). (See discussion under "Institutional Uncertainties - Permits".) The industry would like to see DOE take responsibility for coordinating with other branches of government to provide such a one-step comprehensive permit.

(d) Spent Shale Disposal. U.S. oil shale yields about three quarters of a barrel of oil per ton of rock. Consequently, a commercial scale plant produces an enormous amount of spent shale. In addition, oil shale expands during retorting so that the spent shale occupies more volume than the mined shale. Satisfactory disposal of this material has been a concern to EPA and environmentalists.

Considerable effort has been expended by the developers to address the issues associated with spent shale disposal, particularly revegetation and leaching of salts. On-site disposal has been carried out experimentally and has been monitored and the disposal areas successfully revegetated with indigenous plant life (3). Surface retorting operations plan to use retainment barriers (dams) to hold leachate from spent shale impoundment areas; the retained water will be re-used (3). The industry believes it has shown that the problems can be managed provided environmental interest groups do not take an extreme position.

3. Institutional

(a) Lack of National Policy. It is becoming increasingly apparent that one of the major contributors to the nation's energy problems is our reliance on the automobile as the predominant mode of personal transportation (16). Conventional automobile engines are designed to use fuels derived from crude petroleum. Both

world supply and price of crude oil are controlled by foreign interests. Furthermore, conservation alone will not solve the supply/demand crunch. Alternate sources of liquid fuels must be developed or the individual mobility of the population will be curtailed.

Therefore, given that

- (1) it is in the national interest to reduce dependence on foreign energy supplies, and
- (2) that transportation grade fuels are a priority concern.

the options available to the country, which utilizes domestic resources, are in order of technical and economic practicability (25):

- (1) conventional oil,
- (2) enhanced oil recovery,
- (3) oil shale and tar sands,
- (4) coal liquefaction.

Shale oil is preferable to coal liquids for transportation fuels because it is a bottomless oil (95 vol. % distills below 1050°F) with a higher hydrogen content (fewer aromatics) than coal liquids. Consequently, shale oil is a better feedstock for making jet and diesel fuels. Therefore, shale oil development should have a higher national priority than coal liquefaction.

The industry perspective is that coal conversion technology development has received much more government support than shale oil. The cynical interpretation of this emphasis is that there are many more states with coal deposits than states with shale oil and therefore coal development has more friends in government than shale oil. The perception is that politics are impeding progress towards shale oil development. This lack of urgency naturally tends to permeate the government agencies involved in issuing permits. It also lends support to anti-developmentalists of many cults.

There is a general industry concern over the intertwining of energy development and social policies. In particular, some companies have echoed the sentiments of Harvard Energy Project Director, Robert Stobaugh, regarding the proposed windfall profits tax on decontrolled oil (26): "...The argument has been framed as to whether the oil companies need these revenues to find oil. What's really going on is a raw political fight over tens of billions of dollars. On the one side are those who give heavy weight to the sanctity of private property and rewards for investment. On the other are those who lean toward income distribution."

A basic problem with current efforts of the DOE to accelerate commercialization of shale oil is that DOE is not pivotal in the decision-making process. The real power resides with the elected representatives and the President (9) and the oil

companies know this. They also recognize that until the politicians make up their minds to develop the resource, real progress is going to be very slow. The lack of consistency among the branches of government and within and among different executive agencies is emphasized by industry as a "showstopper" for shale oil.

Because of these political undercurrents, government statements on energy policy are given little weight by industry. At this point in time (June 1979) the oil companies need to be convinced, at the highest levels, that the government is in truth 100% behind the development of shale oil. We have been told by the oil companies that this is a very real requirement in order to get management approval for development projects in shale oil.

Some benefit might be obtained by studying synfuel development in Canada (14). Canada already has two commercial-scale tar sands projects operating with a combined capacity of 150,000 bbls/day of syncrude. Exxon is planning a commercial in-situ recovery project for Cold Lake heavy crude* with a capacity of 160,000 bbls/day. Clearly, Canada is positioning itself so that it will have alternative oil supplies in the eighties when world crude prices will justify having developed these resources. The cooperative action of Canada's federal government and of Alberta's provincial government play a major role in bringing this about.

As stated before, lack of consistency at various levels of U.S. government and among the different federal agencies has given industry the impression that powers in government do not want a shale oil industry. For example, availability of water in the Green River Basin is an acknowledged concern, yet the President cancelled water projects that could alleviate this problem. In addition, the Bureau of Reclamation has failed to act on petitions from developers requesting contracts for water from existing supplies. Another area where current policy is inconsistent with espoused goals is resource (shale) availability. Both the moratorium on further lease sales and the hard-line approach to land swaps is an industry concern.

One of the recommendations of the DOE Commercialization Task Force on this issue is to "demonstrate visible interagency federal commitment to shale oil" (1, p. 26). Industry strongly concurs with this recommendation.

(b) Resource Availability. Except for Colony, Union and the lease tracts, all the high grade shale deposits are located on federal lands (about 80% of reserves). The withholding of federal lands from lease sales is seen by many companies as both a physical barrier and a lack of government commitment to shale oil development. The best privately held reserves amenable to surface retorting are owned by Colony and Union. Because of tract size limitations (5120 acres) and depth of deposits, the Colorado leasees are developing modified in-situ processes. More than one company withdrew its participation in pioneering projects because their reserve position was not sufficient for a multiple plant venture and the future prospects of leasing more land seemed rather dismal.

*A deeper Canadian tar sands deposit, less amenable to conventional mining.

Although one would not expect this issue to be a factor affecting initial commercialization, the unlikely prospect of acquiring more reserves is a deterrent to industry investment in commercialization. The principal cause is the provision in the 1920 Mineral Leasing Act, which restricts shale oil leases to 80 acres for any one company. This acreage is only sufficient to support one commercial scale shale oil project. This means that the experience gained by a private investor on a pioneering plant cannot be exploited in a second plant. Therefore, some potential developers are reluctant to use up their only ticket on a pioneering project, the philosophy being, "Let someone else prove the technology." This issue is discussed in the DOE Commercialization Task Force report (1). However, its importance to initial commercialization was underestimated therein.

Increasing the size of the lease tracts is an unresolved issue, since it would require amending the Mineral Leasing Act. Industry believes that the Department of Interior should recognize the defects in the present leasing program and should recommend changes, particularly in the acreage limit, for Congressional approval.

Another problem industry has experienced is exchanging private land holdings for public lands. For example, Exxon owns 10,500 acres of oil shale but the holdings are in about 30 non-contiguous tracts. "Blocking-up" could be done by an equitable exchange of private and public lands. However, despite seeming authority to make such exchanges under the Taylor Grazing Act, the government has been reluctant to make such exchanges where mineral values are involved.

(c) Water Availability. For initial commercialization the water availability issue is more political than physical. It involves the seniority of water rights in the Colorado River and claims on reserves in Bureau of Land Reclamation (BLR) water projects. In the spring when the Colorado River runs full, there is enough water for foreseeable needs. However, after the spring run-off is past, the river flow decreases and eventually usage by shale oil plants would be curtailed based on the seniority of the rights. This means that during certain months of the year, the shale plants must arrange for a supplemental supply of water. Most of the proposed shale oil projects have identified their preferred alternative for water supplies.

A review of water availability by Felix Sparks (6), retired director of the State of Colorado Water Conservation Board, indicates that in the Grand Valley area, there is an adequate water supply from existing BLR projects to support a shale oil industry capacity of 500-600 thousand bbls/day. By including supplies from authorized BLR projects, the industry size could reach at least 1 million bbls/day. Water availability in the Piceance Creek Basin is of more concern and significant amounts of water will have to be imported or some way of utilizing the extensive groundwater supplies must be permitted. About 30% of the water required in shale oil processing is used for moisturizing the processed shale. Low quality water can be used for this purpose. For instance, underground saline water (non-potable), which is quite plentiful in the region (6, 16), could be used.

Some companies have been trying to obtain contracts from the BLR for furnishing water from federal water projects to cover their supplemental needs. The BLR has been approached but no action has been taken. In addition, the State of Colorado has the right to veto the BLR decision. This represents a potential problem since Denver politicians tend to be against development.

Industry would like to see the following:

- more action on part of the federal BLR and the interstate Colorado River Water Conservation District in issuing contracts for supplemental water supplies;
- administration of water projects in a manner consistent with energy development objectives including shale oil.

This latter statement refers to the cancellation of funds for federal water projects by the current Administration. This was taken by the industry as yet another sign that the government is not yet serious about developing shale oil.

(d) Permits. Most developers concur that the permitting process is cumbersome, time consuming, and generally exasperating. Major permits required for commercial shale projects include:

- air quality (PSD),
- water discharge,
- mine land reclamation (state).

In addition, numerous minor permits are required. The Colony project, for instance, will require an estimated 130 permits. Although the number of major permits is small, there are various aspects of the permitting process which needlessly delay projects and thus increase the investment cost. The most severe aspects include:

- Agency Overlap - essentially dual permitting required (state and federal) for air quality (cf. Appendix C). Applicant has to deal with many agencies to get one major permit.
- Sequencing of Permits - for example, applicant must demonstrate that water discharge permit will be issued before action taken on mine land reclamation permit.
- Bureaucracy Factor - different interpretation of the regulations by state and federal agencies, and interfacing with each other causes much delay.
- Litigation - the U.S. system allows, and, in fact, invites legal challenges on environmental grounds. Such challenges can be expected as the rule, often repeatedly over the same issue, and can cause severe delays which further escalate the high cost and financial risk of shale projects. In the extreme, projects may be shut down because the sponsor sees no prospect of an end to such proceedings.

Interagency coordination is required to streamline the permitting procedures and reduce redundancy. The industry proposes that a single agency such as DOE should issue one comprehensive permit with time and refiling restrictions on legal and administrative challenges. This is basically the approach used by the provincial government of Alberta in Canada (21) with respect to tar sands.

(e) Infrastructure. A large shale oil industry would bring considerable socio-economic changes to the region with associated infrastructure requirements. This issue has polarized the people of Colorado into two camps. The East Slope (Denver) population is against development and therefore this issue becomes a major problem. The West Slope is basically pro-development and would welcome more employment opportunities.

Industry recognizes the potential impact of urban growth due to energy development. A prime example of how development can overtake a community is provided by the Syncrude Project at Fort McMurray, Alberta, Canada (24). As a result of this tar sands project, the population of Fort McMurray tripled to 24,000 in 5 years with an attendant disruption of social patterns and high housing costs. However, both the companies and the provincial government concluded that this need not be the rule in the future with pre-planning and proper management.

The shale oil developers generally recognize the need for additional infrastructure and have made allowances for providing certain elements of infrastructure in their investment estimates. The infrastructure issue was not discussed with representatives of the local communities since this study is concerned with the industry viewpoint.

Certain industry representatives see a need for some federal assistance programs to mitigate the social impact of resource development. Funds should be made available for housing, community improvement projects, and recreational facilities.

In general, all of the major institutional issues were addressed by the Commercialization Task Force (CTF) report and the recommended actions were basically consistent with industry requirements. One notable exception was that the CTF report placed much more importance on the infrastructure issue than did industry (1). This may have been influenced by discussions with Colorado East Slope representatives whom we did not interview.

4. Technical

(a) Surface Retorting Technology. Pilot-scale testing of aboveground retorts has demonstrated that several processes, viz, solid-solid, hot gas, gas combustion, are operable. However, the retorts and ancillary equipment used in these processes must be scaled-up to achieve economical recovery of shale oil from a commercial plant. This will involve considerable applied engineering to improve the equipment and process control systems employed. Most of the process developers believe these technology problems can be solved, but will require extensive engineering. However, in today's investment climate with changing ground rules developers postpone even these engineering efforts.

There is a detectable difference of opinion on the status of the technology between developers and potential users. Most of the developers are outwardly bullish on their technologies, whereas potential technology licensees are much more skeptical. Developers concede that better processes will evolve as experience is gained on commercial scale systems. In order to advance surface retorting technology, commercial scale modules must be built and operated to obtain experience with the systems. Based on previous refinery technology advancements (i.e., fluid catalytic cracking), process improvements will evolve once the processes are commercialized. However, just operating a commercial scale retort does not address all the technical issues related to mining, processing, waste disposal and product upgrading. These can only be answered by operating a commercial size plant (50,000 bbls/day). The only rational approach is to encourage and support some pioneer projects to "prove" the technology needed to develop this enormous national resource.

(b) Modified In-Situ Technology. Major problems must be solved in the development of a commercial in-situ retorting process. In particular, the construction of massive underground chambers with appropriately sized rubble is a very difficult technical problem. Successes in this area seem to have eluded the developers so far. Cave-ins and poor rubblization have been experienced. More basic research on rock mechanics and rubblization was suggested. Establishing a stable flame front without by-passing and producing reasonable yields are other major problem areas. The presence of substantial groundwater and the potential for contamination after retorting is complete is a major concern.

It will take many years to commercialize this technology. Some rate the probability of success at this time at no better than 50%. However, because in-situ technology offers the potential of being less injurious to the ecology of the region and of being used on deposits not amenable to conventional mining techniques, development work should proceed on this process. The "ultimate" shale oil industry may well be a combination of surface and in-situ retorting technologies.

One noteworthy concern expressed by industry was that there was not enough exchange of information on government-funded development projects for modified in-situ technology. This means that one developer cannot learn from the mistakes of another. A compounding problem is that when the reports finally issue, the information is at least a year old.

(c) Shale Mining Technology. The technical uncertainty with room and pillar mining is not a matter of the mining technology but the nature of the shale deposits within the Piceance Basin. Nearly all of the conventional shale mining has been done at the rim of the basin where the deposits are closer to the surface and dry. Consequently, the hydrology, rock strength, and depth of overburden are reasonably well defined. Therefore, the required pillar size which is the principal determinant of rock recovery, can be projected with reasonable certainty. One company is projecting a 60% recovery factor for the mining operation.

At the center of the basin, the Rio Blanco experience had demonstrated that the shale deposits are deeper and contain large amounts of water. Consequently, yields from conventional mining may be smaller (larger pillars) and the removal of ground water will add considerably to the mining cost. The presence of water, although potentially more serious for in-situ recovery, is not a technological problem for mining but is rather a treatment and disposal problem.

Although concerns about rock mining exist, they are definitely subordinate to the economic and environmental concerns expressed by industry. This is particularly true for the first plants that will be operating at the rim of the basin.

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IV. ISSUES IN COMMERCIALIZATION OF ENHANCED OIL RECOVERY

A. INTRODUCTION AND SUMMARY

This Section summarizes industry's perceptions of the major barriers to fuller commercialization of enhanced oil recovery (EOR). The perceptions, interpreted by the Project Team, are based primarily on interviews with a representative sample of major oil companies, and supplemented by interviews with smaller, independent producers, and with suppliers. The opinions of specific companies and individual executives might vary somewhat from the aggregate viewpoint presented herein. A comparison of industry and government perceptions is made wherever possible, based on additional information gathered by the Project Team, including, for instance, the industry/government discussions at Economic Regulatory Administration hearings on incentives for EOR.

Following the Conclusions given in Part B, a discussion of the Principal Issues is presented in Part C under the following section headings:

- Background
- The Present Climate for Action

In part D, Barriers and Proposed Remedies are addressed under the headings:

1. Economic
2. Environmental
3. Institutional/Regulatory
4. Technical

Finally, Part E focuses more specifically on issues of concern to independent producers.

The discussion comments on and places in perspective, for comparisons, the estimates of incremental EOR production under various economic conditions, as estimated by industry, government, and independent sources.

Table IV-1, "Alternative Estimates of Enhanced Oil Recovery Production," presents a comparison of recent estimates prepared by the Department of Energy (DOE) and those derived from industry in this study. The first line in the table is the DOE baseline case and may be interpreted as the "business as usual" scenario. Through 1990, these figures are roughly the same as the 1976 National Petroleum Council base case⁽⁵⁾, and within the range of the Office of Technology Assessment 1977 estimates at the then current world oil price for EOR oil⁽⁶⁾. The block immediately below contains DOE's estimates of incremental EOR production under various regulatory alternatives⁽¹⁹⁾.

ALTERNATIVE ESTIMATES OF ENHANCED
OIL RECOVERY PRODUCTION

Alternative	Ultimate Recovery (Billion Barrels)	Production Rate (MBbls/D)			
		1985	1990	1995	2000
DOE Baseline Planning ^{/a}	9.8	630	1300	1280	700+
<hr/>					
Additional Production Expected From:					
1. Alternative DOE/ERA Tertiary Incentives ^{/a}					
-Proposed Regulatory Change	8.9-16.1	70-190	420-890	840-1400	n.a.
-Capital for Small Producers	0.7	20	100	90	n.a.
-Subsidy for Production	2.3-3.2	40-50	230-360	300-440	n.a.
-Release of all Project Production	3.8	100	340	910	n.a.
<hr/>					
2. Commercialization Plan ^{/b}	16.8	260	900	1470	2300
3. Complete Barrier Removals ^{/c}	--	100-500	400-1000	900-2300	800-2400

NOTES:

- a. Keyed to \$15/barrel constant (1978) dollar oil price
- b. Keyed to world oil price, in constant (1978) dollars
- c. As determined in this study, and normalized to \$17-\$25 constant (1979) dollar oil price. Cumulative additional private investment in EOR techniques, based on \$17/barrel (constant 1979 dollars) and all barriers removed, is expected to be about \$5 billion in current dollars by 1985, \$20-30 billion by 1990, and \$80-250 billion by the year 2000.

SOURCE: Department of Energy Commercialization Plan for EOR, January 1979; Draft Regulatory Analysis of Proposed Rulemaking on Incentives for Enhanced Oil Recovery Techniques, March 1979; Resource Applications, Office of Oil and Natural Gas Supply Development, DOE; and Arthur D. Little, Inc. estimates.

The line referring to the DOE commercialization plan was derived from another study by DOE and is an estimate of the incremental production using DOE's preferred R&D and regulatory strategy (21). This latter set of estimates, with only minor adjustments, is consistent with the second line of figures presented in the table.

The last set of estimates is a normalized set derived from our industry interviews and information developed for this study. It is the estimated (additional) industrial response from removal of all industry-perceived barriers to further commercialization of EOR.

The total EOR production for the listed years is not shown on the table, but can be calculated by adding to the baseline figure the additional production associated with any of the alternative scenarios shown. Thus, EOR production by 1990, with all barriers removed, could approximate 2.3 million bbls/day; assuming there were no major new discoveries brought into production, this could represent about 1/3 of domestic production of, say, 7 million bbls/day at that time.

During the course of this study, the industry consensus appeared to be that U.S. crude oil production would be in a decline from 1978 levels of about 8 million bbls/day, reaching perhaps 4-5 million bbls/day in 1990, as indicated in the National Petroleum Council and Office of Technology Assessment reports (4, 5, 6). As this report was being written (June, 1979), however, indications were that the advent of decontrol, higher OPEC oil prices, and the reinvestment tax credit feature of the "windfall profits tax" proposals have caused an upward revision in industry's forecasts of new exploration and development activity. Thus, 1990 conventional production could be significantly higher than 4-5 million bbls/day, and the contribution of EOR to the total could be less than 1/3. It should be emphasized, however, that there is considerable uncertainty in these point estimates. The important point is that EOR production could expand tenfold, given the right conditions.

Certain EOR methods, i.e., steam drive, CO₂, and other miscible gas flooding, are in limited commercial use, but EOR is far from ready for wide-spread application. On the positive side, it is presently being used in fields that are amenable to such techniques in terms of depth, petroleum and reservoir characteristics, economics, and environmental constraints. In addition, EOR utilizes in-place infrastructure (wells, tanks, pipelines, supply and support facilities), although the costs of maintaining these resources increase as fields become older. On the negative side, the response characteristics of individual petroleum reservoirs to a given enhanced recovery process are usually not well known and can be determined only with pilot tests in each reservoir conducted over a period of several years. The uncertainty of response characteristics of the hundreds of reservoirs not yet tested makes the data for additional production shown in Table IV-1 an "informal estimate" at best.

Thus, EOR, though holding ultimate promise for significantly adding to U.S. crude oil production capability, must be developed on a reservoir-by-reservoir basis with extensive study of the particular characteristics needed to facilitate selection and application of the most suitable enhancement processes and procedures. Such experimentation frequently involves very large "front-end" investment of capital before the potential return on this investment can be forecast with any degree of certainty. EOR therefore is not a quick route to major augmentation of the Nation's crude supplies, nor to profits for those employing it, though the aggregate result could make a major contribution to both.

Exhibit IV-1 indicates the general "commercialization profile" for EOR which was used by the DOE's Commercialization Task Force (CTF) (1). We have indicated by a (+) those items which the major producers perceived to be significant. We have added items which appear significant based on information gathered in our interviews. These are shown with asterisks.

There appears to be substantial agreement on the following points:

- The major technical barrier may be expressed as lack of knowledge of reservoir characteristics and performance, and lack of predictability of performance under application of EOR techniques. The remedy is more R&D, pilot projects, and field tests, which take time and money. A significant increase in activity beyond that now authorized would be required for a vigorous commercialization effort.
- The economic barrier, simply put, is that oil recovered by tertiary methods typically costs significantly more than primary production and presently cannot command an assured price sufficient to make it attractive, with the exception of some steam drive and miscible gas flooding projects. (There, environmental consideration may negate otherwise attractive economics. For example, in California, some steam drive production is reportedly shutting down due to air pollution control compliance costs.) The remedy is de-control of oil prices and/or some type of financial incentive to reduce risk and/or increase the expected return to the private sector investor, or, for the short term, to make use of the ERA "exceptions and appeals" process, a piecemeal approach at best.
- The environmental barriers are manifold:
 - uncertainty in regulations and regulatory agency jurisdiction;
 - air emission control standards affecting thermal EOR techniques;
 - potentially expensive water quality standards and injection materials standards;

		TECHNICAL			ECONOMIC						ENVIRONMENTAL				RESOURCE AVAILABILITY***				INSTITUTIONAL								
		BARRIER IMPORTANCE			Reservoir Performance	Volume & Distribution of Oil	Geological Definition of Reservoir	High Front End Cost	Adequate Rate of Return	Cost of Injectant	Cost of Injectant Facilities	Lead Times*	Rate of Return Predictability*	Air Emission Standards	Fresh Water Demand	Ground Water Contamination	Predictability*	Oil Field Equipment & Drilling Rigs	Skilled and Unskilled Labor	Availability of Injectant	Price Controls	Pipeline & Facility Permits	Unitization Procedures	Gravity Differential	Heavy Oil Market (West Coast)	IRS Policies*	Antitrust**
		FEDERAL ACTION																									
INFORMATION:	Process R&D	+																									
	Equipment R&D (F,P)																										
	Injectant R&D (F,P)																										
	Strategic** Information Dissemination (F,P)	+	+	+										+												+	
INCENTIVES	Loan Guarantee (F)							+																			
	Front End Assistance (F)							+	+																		
	Long Term Price Provisions (F) or Procurement**								+												+	+					
	Injectant Subsidy (F)																										
TAXES	Investment Tax Credit (F)							+	+		+														+		
	Injectant Expensing (F)								+	+	+														+		
REGULATION:	Modify Air Quality Standards (F,S,L)													+													
	Expedite Transport & Export Permits (F,S,L)																				+			+			
	Develop Unitization Guidelines (F,S)																										
	Refinery Incentives																							+			
	Set Water Qual. Std.**															+											

Legend:

*Barrier not listed by CTF, but perceived by industry

**Action not listed by CTF, but suggested by Industry contacts

***This barrier could be accounted for under Technical, Economic, Environmental and/or Institutional

F denotes Federal, S denotes State, L denotes Local, P denotes Private sector actions.

-difficulty in planning for project permits.

The remedies here are to streamline and expedite the promulgation of firm regulations, so that an EOR project will be assured of stable environmental rules within which to plan for facilities investments and project operations.

- Institutional barriers include:

- the federal oil price control regulations and administrative policies;
- IRS policies on capitalizing or expensing injectant costs in an EOR project;
- antitrust policy toward industry cooperative agreements;
- the complex permitting process, e.g., for CO₂ pipeline facilities.

Remedies to overcome institutional barriers include government action at several levels. There is ample precedent for the kinds of obvious actions which would be helpful. What is lacking is the political consensus. In addition to the above, which represent both industry and government positions, the present heavy oil "glut" on the West Coast and unitization procedures are viewed by both DOE and some producers to be major institutional barriers, the former relevant to steam drive. Most companies, however, ascribe much more importance to the environmental barrier (emission standards for steam generators) facing steam drive and other thermal projects such as in situ combustion.

B. CONCLUSIONS REGARDING ENHANCED OIL RECOVERY

- Current EOR production is 250,000 bbl/day + 20%. This excludes cyclic steam methods which are considered conventional, commercial techniques. Steam drive as applied to heavy oils is currently the predominant EOR technique, accounting for 50% or more of the total, and is concentrated in California. Higher oil price and favorable test and infrastructure development should result in increasing emphasis on CO₂ miscible and surfactant-polymer flooding techniques by 1985 and wider geographical applicability.
- A consistent set of definitions is needed in regard to EOR terminology. "Enhanced oil recovery" is often used interchangeably with "tertiary recovery" although the former term has come to have a broader meaning than tertiary; in DOE parlance, EOR also connotes the newer, less developed recovery technologies (e.g., in-situ combustion) which may be applied in a primary or non-primary mode.

- While secondary recovery was not a concern of this study, there is a natural interface between the conventional flooding operations of secondary recovery, which now accounts for about 50% of current domestic oil production, and tertiary recovery operations. Many EOR applications will be tertiary operations which can benefit from the existing secondary infrastructure. The present system of price controls risks a premature shutdown of some secondary production, with adverse consequences for initiation of tertiary projects which might otherwise be phased in as testing and economic conditions allow.
- There is already significant EOR commercialization activity using miscible gas injection techniques, with industry commitments of nearly \$1 billion expected by 1981. Most of this relates to CO₂ miscible EOR projects.
- With complete removal of the economic, environmental, institutional/regulatory, and technical barriers impeding commercialization, by 1990 the level of EOR production could be raised tenfold to account for as much as 1/3 of U.S. production.
- Because of the perceived higher cost and risk of EOR vis-a-vis conventional oil production, industry cites the need to see prices higher than the current oil price as the most important overall barrier to accelerated EOR investment at this time.
- Decontrol of oil prices would provide the kind of business environment more conducive to industry investment. At the time of this writing, however, decontrol alone would not cause much immediate EOR production response, and would not be sufficient incentive for commercial application of the highest cost techniques such as surfactant-polymer flooding. Decontrol along with dramatic increases in world price may result in a correspondingly dramatic increase in EOR activity, including surfactant-polymer flooding techniques.
- Political and economic trade-offs must be made between the desire to develop advanced EOR techniques, which may result in greater ultimate recoveries but which require some lead time, and the desire to have greater domestic oil production in the short term to alleviate balance of payments problems and shortfalls in supply.
- Balance of Payments and Strategic Petroleum Reserve considerations may justify selected federal EOR purchasing programs for enhanced oil in a manner analogous to those used in the synthetic rubber program or the uranium purchase program during the 1940's and 1950's.

TABLE IV-2
EOR PROJECTS AND PRODUCTION

	<u>Projects in Operation</u>		<u>Projects Under Consideration</u>	<u>Current Level of Oil Production Barrels per Day (B/D)</u>
	<u>1970</u>	<u>1977</u>		
<u>Thermal</u>				
Steam Drive (<u>ex</u> cyclic)	22	43	10	128,000 ^c
In Situ Combustion	38	16	8	10,000
<u>Chemical</u>				
Surfactant-Polymer	5	22	4	400
Polymer	14	21	3	2,600
Caustic	0	3	4	---
<u>Miscible Gas</u>				
Hydrocarbon Miscible	21	15	1	20,000
Carbon Dioxide	1	14	4	40,000 ^a
Inert and Flue Gas	1	6	1	28,000 ^b
TOTAL	102	140	35	229,000

NOTES: (a) includes Kelly-Snyder Sacroc Unit (Texas), representing approximately 35,000 B/D primary production
 (b) excludes Texas "Block 31" project, representing approximately 16,000 B/D enhanced production
 (c) includes approximately 50,000 B/D attributable to Getty Oil at Kern River Field (Cal.)

Source: Oil and Gas Journal Annual Production Issue, March 27, 1978; Department of Energy; and Arthur D. Little, Inc.

- Industry believes that higher price would solve most of the EOR problems in contrast to the situation in shale oil where factors in addition to higher price will constrain developments.
- Both major and small independent oil producers will play a role in EOR development, but by far the largest increment in production is likely to come from fields operated by majors or large independents.

C. PRINCIPAL ISSUES

1. Background

Enhanced oil recovery (EOR) refers to the techniques used to recover oil from known reservoirs that is left by conventional primary and secondary production practices, i.e. tertiary recovery, and also to the application of some of these techniques to stimulate new primary oil production. The three main categories of EOR techniques can be classified as follows (1):

Thermal processes involve applying heat to decrease the viscosity and increase the mobility of the oil in the reservoir. They include steam drive and in situ combustion.

Chemical processes involve injecting materials such as detergents, caustics, and polymers to modify the chemical and physical interaction of oil with its surroundings and increase mobility of the oil. They include surfactant-polymer, polymer, and caustic flooding.

Miscible gas processes involve injecting fluids which dissolve the oil forming a single oil-like liquid that can flow through the reservoir more easily than the original crude. They include hydrocarbon miscible and carbon dioxide (CO₂) miscible flooding.

Current EOR production in the U.S. is estimated to be 250,000 bbl/day + 20%. The number of active EOR projects and approximate EOR production are shown in Table IV-2. Steam drive is presently the dominant technique and, in fact, enjoys commercial status in some fields. However, it represents less than 2% of U.S. oil production. EOR methods represent a developing and relatively unproven technology. Almost 50 percent of the EOR potential production is expected to result from miscible gas and chemical flooding. These two technologies have received only limited field testing. Since each reservoir presents a unique and separate problem, the technique and treatment must be matched to the reservoir (1).

2. The Present Climate for Action

Getting EOR technology commercialized requires government actions and incentives to overcome the barriers now perceived by private industry. These barriers may be classified as economic, environmental, institutional/regulatory, and technical. The incentives and actions to deal with them

will have to take place at the macroeconomic level, where decision points will arise outside of the routine control of the firms in the industry and demand certain national responses; and at the microeconomic level, e.g., the implementation of pilot tests, site-specific pollution control regulations, and field pricing incentives.

a. Industry's Attitudes and the Implications for Effective Government Policy

Investments made by producers to develop and/or acquire reserves are made within a particular risk-return framework - one acceptable to the industry and its owners and creditors. Industry wants to maintain a flexible approach by expanding the range of choices available to it for adding to petroleum reserves. The two basic ways to add reserves are from new primary discovery/development and improved recovery from existing, known reservoirs. Oil companies have been concentrating on producing oil from new primary offshore discoveries on the outer continental shelf (OCS) at a known and acceptable level of risk. The very large "up front" cash bonus payments companies are making to the federal government for OCS leases are testimony to this. These payments are an order of magnitude greater than total federal and industry spending on EOR. As evidenced in the ERA's hearings on EOR price incentives and confirmed by our interviews, the limiting factors in EOR are the industry's need for an expected rate of return of 10%-20% on investment and the perception of the added riskiness and lesser profit potential of EOR ventures vis-a-vis other available alternatives such as offshore oil exploration and diversification. We have also found that the timing of EOR investment and development may be influenced by a company's ownership or lease position in certain fields. This timing may not coincide with the schedule implicit in DOE's commercialization strategy. Economic trade-offs may be complicated by other current and proposed regulations (e.g., those for natural gas) which could affect company attitudes toward the timing of various projects.

Some industry experts feel that EOR is technology-limited and that short-term production cannot really be affected much by price. Others say the opposite: technology is available, but there is not a sufficient price incentive. There is a consensus, however, that, with the exception of decontrol of stripper well prices, price constraining and other regulations have been a disincentive for EOR. For example, favorable IRS rulings regarding the tax treatment of injection expenses would increase the attractiveness of EOR. Some informed industry opinion is that this would be equivalent to a price increase of \$3-4/barrel. On the other hand, even removal of price controls and overcoming environmental barriers most likely would not result in a great rush to EOR, but it would likely cause a substantial increase in field testing activity. This is so because companies basically wish to acquire and develop new primary reserves and stage the development of resources such as EOR to coincide with both technical progress and the advancing price of oil. In an unregulated environment such an approach should, over time, result in additions to

productive capacity at lowest costs. The DOE has recognized to some extent that accelerated investment in EOR will follow "when the economics are right" [cf. (1)], but although DOE sponsored or supported R&D and field testing is accepted as contributory, economic incentives which foster capital formation within the private sector are preferred by industry. In this regard, we have observed that the EOR incentive program presently being promulgated by ERA (24), while not being wholly free from criticism, has gained a generally favorable reaction from industry and is considered to be a step in the right direction.

The independent producers may account for a significant amount of the EOR production potential given the right incentives, economic conditions, and technical support. The reservoir evaluation data from Lewin's (4) analysis could be correlated usefully with the picture emerging about the independents' potential in EOR and with that of the major producers to achieve the most effective federal incentives program for commercializing EOR technology. (Such an incentives study is underway in connection with DOE's ERA proposed rules (24,25) in which special financial incentives are to be considered for independent producers.)

While the present federal program recognizes the potential significance of the independents, it is geared to a much longer-term time scale for technology development than that which industry believes is necessary if the U.S. simply wants more oil quickly. Both independents and majors suggest that the latter goal can be achieved without substantial reliance on EOR, i.e., through greater domestic primary and secondary production, given a decontrolled price. Indeed, the independent producers have recently gone on record, in a letter to President Carter of February 28, 1979, offering increased production of 400,000 bbls/day in 1981 and 2 million bbls/day in 1985 in return for decontrol of upper tier oil on June 1, 1979, and phasing out controls on lower tier oil by September 30, 1981. The DOE policy as it presently stands would rather, it seems, develop EOR technologies to have "on the shelf" capability, with the expectation that there will be commercial production at a price and that a publicly-owned technological resource will be created to serve national needs which may grow more severe over time.

b. Current Programs of the DOE

The DOE's current overall program regarding EOR has three major components. Firstly, DOE's Division of Energy Technology has had an on-going research and development program designed to improve EOR processes and demonstrate their application in difficult reservoirs. This program is a joint, cost-shared activity with industry that seeks to focus funds on major technological problems not otherwise being addressed by industry. Table IV-3 indicates the scope of this effort, and the levels of funding. Secondly, EOR has been identified as a technology targeted by DOE for commercialization. A Commercialization Task Force (CTF) for EOR has been established under the cognizance of Mr. Lisle Reed as "Resource Manager".

TABLE IV-3

U.S. Department of Energy EOR Funding

<u>EOR TECHNIQUE/CATEGORY</u>	<u>Government Funding Level</u>				<u>Government/Industry Jointly Funded Field Tests (Number)</u>
	<u>1976</u> ----	<u>1977</u> Million Dollars	<u>1978</u> -----	<u>1979</u> -----	
A. Chemical					
Surfactant-polymer	10.6	10.0	12.5		7*
Polymer and caustic flooding	2.4	1.3	3.5		3
	-----	-----	-----	-----	-----
Sub-total	13.0	11.3	16.0	n.a.	10
B. Miscible Gas					
CO ₂ flooding	2.6	6.1	6.6	n.a.	4
C. Thermal					
In-situ combustion	6.2	5.4	12.0		2
Steam drive					0
	-----	-----	-----	-----	-----
Sub-total	6.2	5.4	12.0	n.a.	2
D. Environmental Studies and Other Support					
Sub-total	4.2	5.6	11.5	n.a.	n.a.
	=====	=====	=====	=====	=====
TOTAL	25.7	28.4	46.1	46.7	16**

NOTE:

* DOE commitments represent about 60% of the combined total federal and private operator commitments to these projects.

** The current DOE/ET program included many additional projects, including R&D technical pilots, as well as large field tests. DOE has reported that projects range in cost from \$0.5 to \$44 million, with the average cost being \$8.8 million (see Draft Regulatory Analysis prepared by RA, Office of Oil and Natural Gas Supply Development, for ERA, March 1979).

SOURCE: Oil & Gas Journal survey, March 27, 1978; and Arthur D. Little, Inc.

Thirdly, the ERA has been developing "Final Rules and Guidelines on Tertiary Enhanced Recovery Techniques." ERA's program had been keyed to the concept of granting the world price for all incremental crude produced from a "certified" EOR project, but, as previously mentioned, new initiatives by ERA (24) which include mechanisms for "self-certification" and the financing of front end expenses, were announced during the preparation of this report.

The CTF has recommended (1) that DOE take the following approaches for EOR:

- Adopt a pricing policy which would encourage an optimum number of quality EOR projects and level of tertiary production. (The qualifier optimum is not explained in the CTF report. Our interviews suggest a policy of rigorously defining oil that will qualify for EOR pricing.)
- Determine if intervention with the IRS on the side of expensing of injection chemicals or other taxing changes is necessary.
- Continue a technology development program to reduce the risk inherent in the newer EOR technology(ies) and develop processes which will result in significantly higher recoveries.
- Devise a federal loan guarantee program and analyze its impact on the development of EOR projects by independent producers.
- Determine if any federal and state agencies are causing unnecessary delays by withholding permits or clearances and devise a method to expedite any such permitting procedures.
- Develop national guidelines and press the various states to enact unitization legislation for EOR projects.

The Task Force further suggested that DOE should devise a policy, utilizing some or all of the approaches listed above, to achieve EOR production levels which were estimated to be comparable to the level which could be achieved at the price of alternate fuels (estimated at roughly \$24/bbl in 1978 dollars). It estimated that this policy could result in EOR production which in 1985, would be 200,000-1,000,000 bbls/day greater than under 1978 policies; 300,000-1,500,000 bbls/day greater in 1990; and 600,000-1,400,000 bbls/day greater in 1995. Table IV-4 presents an estimate of how much EOR production may be achievable under the 1978 DOE commercialization program plan. This may be compared with Figure IV-1 which indicates the supply envelope as a function of oil price and the nature of government/industry involvement.

It remains to be seen whether the program which finally emerges from the CTF recommendations will affect industry attitudes towards EOR.

TABLE IV-4 EOR PRODUCTION PROJECTIONS - COMMERCIALIZATION PLAN

	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>	<u>Ultimate Recovery</u> <u>(Billion Barrels)</u>
	----Millions of Barrels per Day---				
Expected From Industry Under 1978 Conditions	0.56	1.23	1.21	0.70	9.1
Increment From DOE Commercialization Plan	0.26	0.90*	1.47	2.30	16.6
Total Production	0.82	2.13	2.68	3.00	25.7
- Comprised of:					
Steam drive	>0.35	~1.0	>1.3	N.A.	
Miscible Gas & Chemical Flooding	<0.45	~1.0	<1.3	N.A.	

* May be achieved earlier under special pricing incentives.

SOURCE: Department of Energy Commercialization Plan (1973)

This is because, under the present regulatory regime, there are complex interactions of the composite price determination, tertiary incentives, stripper well definition, and decline curve determination, all administered by the ERA whose policies, programs, and actions have been the source of much industry frustration and complaints.

The goal of the proposed "tertiary crude incentive" rules now being formulated by ERA is to encourage the initiation of a larger number of EOR projects in a wide range of reservoirs utilizing a variety of techniques in order to expand the applicability and efficiency of EOR techniques. The proposed incentives directly assist the industry by providing funds "up-front" through release of otherwise price-controlled primary/secondary production from lower tier to upper tier pricing up to \$20 million per certified EOR project to defray up to 75% of the costs incurred in initiating and/or expanding such a project. "Because this incentive reduces the amount of capital that must be placed at risk, the industry should be willing to undertake diverse projects to test processes which could expand the applicability and efficiency of EOR techniques" (19). The reasoning therefore, is that the increase in field testing of improved techniques, in conjunction with continuing industry and government research and development, should result in improved levels of technology and earlier field application with greater success.

Importantly, ERA has, as part of this rule-making, officially confirmed industry's view with the finding that certain EOR techniques are per se not an attractive investment without such incentives (24). The proposed definitions of the EOR techniques which would qualify under this criterion, subject to modification as a result of hearings, are presented in Exhibit IV-2:

The ERA's proposed tertiary pricing incentives approach "is essentially an attempt to obtain a shift in the supply curve for EOR production. The other incentives will tend to encourage use of conventional EOR techniques. Thus, these approaches simply move up the EOR supply curve" (19). DOE believes that, given the relatively low level of EOR technology, a program which shifts the supply curve by accelerating improvements in process performance and widening geological applicability is likely to have greater impact than a program which simply moves along the same supply curve.

Figure IV-1 illustrates the wide range in EOR production estimates, depending on both price and the nature of government-industry activity. The present estimates of EOR production - with or without barrier removals - are bounded by the curves in this figure. The top curve represents an earlier Lewin and Associates estimate based on a higher price ("alternate fuels") case with government RD&D support and removal of various barriers (4) (14). The bottom curve represents a National Petroleum Council estimate with low price and minimal government support (5). Table IV-1 and Table IV-4 indicate the EOR production now expected. Keeping in mind the uncertainty in all estimates, the indications are that industry expects 1990 EOR production to be on the order of 1 million bbls/day (or less) with the present barriers operative, and to be capable of expansion to 2-3 times this amount, assuming the proposed remedies are generally negotiated and implemented starting now.

Definition of Enhanced Oil Recovery Techniques for
which Self-Certification is Available

PROPOSED APPENDIX A TO 10CFR § 212.73 OF THE
MANDATORY PETROLEUM PRICE REGULATIONS

(Techniques for which a general finding can be made that the technique is not an attractive investment opportunity without tertiary incentive revenues, as proposed for comment by the Department of Energy, Economic Regulatory Administration, Further Notice of Proposed Rulemaking and Public Hearing, Docket No. ERA-R-77-1, F.R. 44 No. 62, March 29, 1979.)

(1) Miscible fluid displacement means an oil displacement process in which gas or *alcohol is injected into an oil reservoir*, at pressure levels such that the injected gas or alcohol and reservoir oil are reasonably expected to be miscible. The process may include the concurrent, alternating, or subsequent injection of water. The injected fluid may be natural gas, enriched natural gas, a liquified petroleum gas slug driven by natural gas, carbon dioxide or alcohol. The injected fluid must, with reasonable expectations, be more than 25 percent of the reservoir pore volume being served by the injection well or wells (in the case of gas injection), or more than 10 percent of the reservoir pore volume being served by the injection well or wells (in the case of *alcohol injection*).

(2) Steam drive injection means the continuous injection of at least 50 percent quality steam into one set of wells (injection wells) to effect oil displacement toward and production from a second set of wells (production wells). This applies only to steam drive projects with an average depth greater than 3000' or steam drive projects which recover oil with a gravity less than 10° API or greater than 25° API.

(3) Microemulsion, or micellar/emulsion, flooding, technique in which a surfactant system is injected in order to enhance oil displacement toward producing wells. A surfactant system normally includes a surfactant, hydrocarbon, consurfactant, and electrolyte and water, and polymers for mobility control. The size of the micellar slug (not including the polymers) must be more, with reasonable expectations, than 10 percent of the reservoir pore volume being served by the injection well or wells.

(4) In situ combustion means combustion of oil in the reservoir, sustained by continuous air injection, to displace unburned oil toward producing wells, provided that such combustion must be intended to continue until at least 15 percent of the reservoir volume being served by the injection well or wells has been burned.

FIGURE IV-1 ILLUSTRATION OF THE ENVELOPE OF ESTIMATES OF POTENTIAL EOR PRODUCTION

(Based on Studies by the National Petroleum Council and Lewin and Associates, as Normalized and Presented by Arthur D. Little, Inc.,⁽¹⁵⁾ and subsequently Modified For This Report.)

D. DISCUSSION OF BARRIERS AND PROPOSED REMEDIES

1. Economic

a) Barriers

We found industry's position on EOR economics in general to be accurately reflected by the National Petroleum Council's (5) report as follows:

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

Moreover, the same National Petroleum Council report noted that investment in EOR processes will have to compete for available funds with other activities, such as primary oil exploration, which also have the potential to increase domestic petroleum resources. "Higher real oil prices would provide increased incentives for all such activities, including EOR," (5) but not as much so for EOR. With the exception of a few thermal applications in unusually favorable reservoirs, the upside potential for EOR project economics is limited, even when the project is technically successful. Thus, again quoting from (5):

"There are no bonanzas in EOR. To the degree that exploration, or other alternatives, offer higher upside potential (with comparable risk and profitability expectations), they may continue to receive the majority of available funding, even if general economic conditions improve. [Emphasis added]

While industry continues to make other petroleum investments in ventures with long-term payouts, these typically involve receipt of the world price for the entire field's production and/or employ conventional technology.

Lack of predictability of regulation, price controls, retroactive decisions by government, and regulatory delays were cited by companies as major economic barriers. Industry would like to see projects "grandfathered," i.e. not subject to change in regulation after project initiation. High "front end" costs, particularly for smaller companies, constitute a barrier in the sense that they are coupled with expected rates of return which are not commensurate with perceived risks in many cases. The recent incentives proposed by the ERA could significantly contribute to lowering this barrier, although the relative attractiveness

of these incentives to any particular company can vary considerably and may be overshadowed by the expectation of a general decontrol of oil prices, presently scheduled for completion in 1981. On the other hand, the ERA's exceptions and appeals process for applying ROI criteria has limited the profitability of the successful projects and implies "eating the failures." Such ERA "fine tuning" of economic rewards is opposed by industry.

Generally, a 10-20% (constant dollar) net return on the project investment must be foreseeable before proceeding with an EOR project -- the higher the perceived risk, the greater must be its expected return. And the risk-weighted return must equal or exceed that available from conventional exploration and development opportunities. Thus, many CO₂ flooding and micellar-polymer projects will not be economically attractive at current world crude oil prices (approximately \$16/barrel, June 1979); they will, of course look more attractive the higher the price. In absolute terms, EOR production ranges in cost from about \$6/bbl for steam drive in certain California fields to upwards of \$15-\$30/bbl for developmental methods (e.g., micellar-polymer) based on injected chemicals.* For the latter, industry has been pushing for IRS approval to expense the cost of injectants. Indications are that the tax savings may be equivalent to an oil price increment of \$3-4/barrel and a corresponding increase in ROI.

The current pricing uncertainties--involving various levels of pricing, definitions, production allowables for stripper well oil price, exceptions to given price levels, and consideration of gas prices--tend to defer EOR investments. For instance, experience with steam drive in California could have a chilling effect: those who proceeded early on their own initiatives have been denied price relief on the EOR oil so produced, whereas those who come in later could be accorded advantage under ERA definitions and regulatory interpretations. Indications are that this problem may be easily solved with new definitions and/or decontrol. Other things equal, the EOR production we can now expect, based on our field interviews, is reasonably consistent with recent DOE commercialization plans (21, 19), which in turn are in reasonable agreement with the National Petroleum Council(5) and Office of Technology Assessment studies(6). Due to the sensitivity of estimates of EOR potential to the assumptions made in regard to oil price, technical performance, and rate of return requirements, point estimates of the producing rate are very imprecise. For example, industry estimates of the potential EOR production in 1990 ranges from about 2-3 million bbls/day (with better than expected performance), with an "expected performance" yield of roughly 1.5 million barrels/day, assuming an oil price of \$15/bbl (constant 1976 dollars), and a 10 percent minimum discounted cash flow rate of return. Assuming no major new domestic oil discoveries are

* Recent DOE estimates have been published and are consistent with these figures (see Financial Times, "Energy Review", June 15, 1979.)

brought into production, conventional primary and secondary production is expected to decline to 4-5 million barrels/day by 1990 (5,6). Even if major new conventional production results from expanded exploration and development activity, such that total U.S. production remains constant through 1990 at about 8 million bbls/day, it is obvious that the expected EOR production would represent a significant addition to U.S. crude oil supply.

While the longer-term projections are very sensitive to oil price, world oil price would not do much for EOR production from chemical and CO₂ methods in the near-term, due to their inherently higher relative costs and lead time requirements, compared to steam drive. There is already significant EOR commercialization activity using miscible gas injection techniques, with industry commitments of nearly \$1 billion expected by 1981. Most of this relates to CO₂ - miscible EOR projects. The major barrier to rapid expansion of carbon dioxide flooding is the availability of low cost carbon dioxide injection fluid. The most plausible source of adequate volumes of CO₂, at a cost low enough for economic flooding, appears to be from existing known and undeveloped sources of naturally occurring CO₂ or from future discoveries. There are some sources in Mississippi, Texas and Wyoming, but by far the largest amounts of naturally occurring CO₂ is in the Four Corners area of Utah, Colorado, Arizona and New Mexico, with CO₂ reserves reported to be at least 10 trillion cubic feet. There is also known CO₂ production from natural gas fields in the Delaware basin and Val Verde basin areas of southwest Texas, but most of this gas appears to be committed to existing projects; this CO₂ is transported by 16" pipeline 200 miles north to the Kelly-Snyder field (SACROC) and North Crossett Unit in Texas, with deliveries of about 200 million cubic feet/day.

Lewin and Associates have studied this situation for DOE's Energy Information Administration: Their low price case assumes construction of two additional pipelines from the Four Corners area to the Permian Basin in Texas and Oklahoma by 1985, increasing capacity to 1 billion cubic feet/day. Their other price scenarios assume that EOR by CO₂ flooding is not constrained by the availability of injection materials (22).

A consortium headed by Shell is planning to spend over \$500 million for an incremental 280 million barrels of tertiary oil from a CO₂ flood. (cf. Chemical Week, April 9, 1979, page 31). The critical commercial decisions are expected in 1980. The scale of this project could suggest that this technique would then be "commercialized".

b) Special Economic Considerations

i) Unitization

Joint ventures and pooling are common among the oil companies, large and small. Unitization is not seen by the large companies as an issue and is usually no problem when the regulatory environment and rules are understood. The Office of Technology Assessment report (6) presents an excellent summary of the legal considerations. Further comments are

provided in this report under the sections dealing with the independent producers and institutional/regulatory barriers.

ii) Secondary Recovery and Infrastructure Considerations

While secondary recovery was not a concern of this study, there is a natural interface between the conventional flooding operations of secondary recovery, which now accounts for about 50% of current domestic oil production, and tertiary recovery operations. Many EOR applications will be tertiary operations which can benefit, albeit not without additional facilities, from the existing secondary infrastructure. Surfactant and polymer methods especially are in this category. The present system of price controls risks a premature shutdown of some secondary production, with adverse consequences for initiation of tertiary projects which might otherwise be phased in as testing and economic conditions allow.

In regard to chemical-based tertiary methods, some plants built to manufacture chemical injectants for EOR are operating at very low percentages of capacity because of unacceptable EOR investment conditions as seen by the oil companies, who are the potential customers. These plants may be diverted to other uses; the result could be some delay to duplicate such facilities needed for EOR production. One chemical manufacturer said that it would not build new units without assurance that changes in government regulations would not once again "put us out of business". However, while care should be taken to avoid material supply constraints, it should be noted that the oil companies themselves have substantial, potential captive, EOR chemicals production capacity. The lead time to bring new chemicals capacity on stream should be matched to the lead time associated with surfactant-polymer flooding.

iii) Field Abandonment

In general, state laws require cementing of abandoned wells. Once shut down, no field has ever been re-entered for secondary recovery only. The value of avoidance of such shutdown by having EOR technology available is an area of widespread government-industry agreement (2, 15).

c) Proposed Remedies

Our interviews indicate that industry believes that all production from fields employing EOR should be freed for sale at world crude prices. This position, of course, implicitly assumes that world price will remain high and above the controlled domestic "old oil" price. The Draft Regulatory Analysis of the proposed ERA Rulemaking on Incentives for EOR

Techniques, prepared by DOE/RA in March, 1979, viewed this economic remedy as the least cost/effective of several alternatives they studied. As explained earlier in this report (Section C, Part 2b), the DOE position is that "given the relatively low level of EOR technology," world price alone tends to encourage exploitation of conventional technology, i.e. simply moving "up the EOR supply curve," instead of shifting the supply curve upward via a program which accelerates improvements in process performance and widens geographic applicability.

Decontrol of oil prices would provide the kind of business environment more conducive to industry investment. That is, industry is more comfortable with the risk and uncertainty of that economic environment than with a regime of constantly changing price regulation. At the time of this writing, however, decontrol alone would not cause much immediate EOR production response and would not be sufficient incentive for the highest cost techniques such as surfactant-polymer flooding. Decontrol along with significant increases in world price may result in a corresponding increase in EOR activity, including surfactant-polymer flooding techniques.

Our interviews and studies have also led us to conclude that Balance of Payments and Strategic Petroleum Reserve considerations may justify selected federal purchasing programs for enhanced oil, in a manner analogous to those used in the synthetic rubber program or the uranium purchase program during the 1940's and 1950's.

Assistance with front-end costs, such as through guaranteed loans or tax credits, should be made available where needed, particularly in the absence of decontrol and for the smaller producers. While industry is generally favorable toward ERA's recent proposal (March, 1979) to amend the mandatory petroleum price regulations to provide an incentive for producers "with front-end money to initiate or expand certain types of tertiary recovery projects," some believe it is too small, weak, and conditional to produce an early impact.

IRS should permit expensing of materials and/or energy injected as part of an EOR project.

Prompt removal of all economic barriers could result in incremental EOR production over that presently planned in as few as 1 to 3 years after such actions.

2. Environmental

a) Uncertainties

The environmental impacts of EOR are expected to be similar to current production operations, with some exceptions. Combustion of oil in thermal processes produces pollutants which may exceed air emission standards. Some EOR processes require large volumes of fresh water, which could stress local water supplies. Chemical flooding, through old wells, has the potential of introducing some of the chemical into fresh water aquifers, with potentially deleterious results (6).

Oil companies view environmental regulations as ever-changing. In addition to the direct cost of controls, they are also concerned about the cost of delays resulting from permitting requirements.

Any "significant federal action" in respect to EOR will trigger a "Programmatic Environmental Review" under 10 CFR 1021 NEPA requirements(12), and probably a series of Environmental Impact Statements or the equivalent. This process, in and of itself, is bound to delay EOR commercialization.

Some disparity in emphasis is reflected by the DOE Commercialization Task Force and Office of Technology Assessment reports (1,6), on the one hand, and the DOE's separate "Environmental Readiness Document" on the other (12). That is, the latter delegates much more detailed and specific areas of environmental concern to the Environmental Protection Agency (EPA).

EPA has taken the position that there are

- "known carcinogens" pumped down into wells,
- potential concerns over biocides (needed to protect polymers used in flooding operations);
- severe air pollution problems for thermal processes.

More information needs to be developed by EPA, DOE and the oil companies on prospective environmental control costs. The industry, therefore, needs to know what standards will prevail.

We were told by industry respondents that OSHA believes the benzene environment in the oil fields is dangerous and needs to be controlled.

As for state plans for implementation of environmental standards, air quality is of particular concern in California, especially for thermal processes. In Oklahoma, water quality is of special concern; and indications are that environmental concerns have been heightened in Texas.

b) Constraints on Applying Steam Drive Technology

Our interviews with oil companies indicated that limitations on increasing recovery of heavy oil stem from stringent California environmental constraints on pollution from steam generators, and from marketing constraints due to the availability of better quality Alaskan crude.

In the Lewin "Low Price Scenario"(22) these constraints were assumed to restrain production of heavy crude by steam drive to current levels of 150,000 bbls/day through 1995. In the "Medium Price Scenario" the constraints are assumed to be overcome gradually as the problem of surplus Alaskan crude on the West Coast is solved and price increases permit an economic solution to the environmental problems, raising 1990 production to 1 million bbls/day. In the "High Price Scenario" the analysis assumes that by 1990 an alternate fuel, either natural gas or coal, would provide the heat source, and thus the total (gross) production of steam drive derived from heavy crude oil would be available in California. This production is estimated by Lewin to be 1.4 million bbls/day in 1990.

c) Summary

Barriers

We may summarize industry's perceptions of the environmental barriers and the proposed remedies as follows:

- Air emission control standards, reportedly coupled with DOE pricing regulations, are delaying thermal projects in California, in some cases shutting them down (cf. Oil and Gas Journal, March 26, 1979, page 53, on Getty Oil Co.'s plans).
- Water quality standards with respect to the use and fate of injected water and chemicals are of concern to the EPA but to date little, if any, definitive statements have been made to guide operators in planning EOR projects.
- Any requirements for Environmental Impact Statements required (under NEPA) for EOR commercialization projects are bound to further delay attempts to commercialize EOR.
- Uncertainty with regard to possible future standards makes business plans for long-term EOR projects very risky.

Remedies

- Federal air emission standards and water pollution regulations should be rationalized and actual or potential conflicts with state agencies resolved.

- Permits should be issued through a "one-stop" process, coordinating the role of all agencies concerned and eliminating delays.
- Projects approved and initiated in good faith under regulations existing and anticipated at the time should be exempted from future, more stringent regulations which would increase project cost retroactively, except when public health and safety are endangered.

3. Institutional/Regulatory

a) Definitions

Uncertainty and confusion arise from the fact that there is as yet no standard definition or usage of the terms "enhanced oil recovery" in industry or government. The Economic Regulatory Administration uses precise language in reference to tertiary recovery in its administration of federal oil price control regulations, and such distinctions between tertiary oil, EOR, and other oil production are contained in the Energy Conservation and Policy Act and related legislation. The U.S. Geological Survey and industry tend to think of the "conventional" processes applied to recover oil, after dissipation of the natural forces in primary production, as secondary recovery; and tertiary recovery as the techniques applied after secondary recovery ceases to be effective. The General Accounting Office, in its examination of tertiary recovery, noted that the terms secondary recovery and tertiary recovery are often used synonymously with enhanced recovery. For simplicity, GAO stated (7), "We will define secondary recovery to include the already economically and technically proven techniques of pressure maintenance, traditional water flooding, and cyclic steam injection. Tertiary oil recovery -- will be defined to include the newer less widely used techniques."

EOR, as the term appears to be understood by DOE, applies not only to tertiary production, but also to those processes applicable to virgin oil fields, e.g., to new primary production of heavy crude from advanced thermal techniques such as steam drives and in-situ combustion. However, DOE and GAO include caustic and polymer-augmented water flooding under tertiary or enhanced recovery, whereas many in industry would consider these as natural extensions of conventional secondary recovery.

The institutional problems this causes relate to the role of ERA in the "decline curve" determination (for oil fields) in setting price incentives for EOR (3). To some companies, the distinction ERA makes between EOR and tertiary, and between tertiary and secondary, is not particularly meaningful. There is thus some confusion in the magnitude of the incremental tertiary production potential, and the difficulty in setting the appropriate commercialization incentives is exacerbated.

We do not know the effect of this ambiguity in definition on the results of federal analyses performed to date. However, industry's perception of ERA's position has apparently impeded some steam drive production which did not qualify for tertiary price. If and when oil prices are decontrolled, the ERA role in decline curve determination would cease. However, DOE is likely to continue to be involved in funding RD&D and thus a consistent government-industry set of definitions is needed.

b) Main Issues

A major issue is the DOE perception that advanced technology commercialization, through DOE-supported pilot field tests and R&D, is the preferable way to increase the capability for domestic oil production, rather than through decontrol of oil prices to stimulate more production through a mix of conventional and enhanced technologies. This institutional/regulatory posture is reflected to various degrees in the following areas:

i) Pricing Regulations

Aside from wanting the incentive of the world price for oil, industry's main problem with pricing regulations has been their complexity and instability.

With respect to the Economic Regulatory Administration's (ERA's) July 26, 1978 tertiary pricing incentives, the oil companies stated that the policy, viz., that the first sale of incremental crude oil produced from a qualified and certified tertiary enhanced recovery project could occur at the market-clearing price, did not, in fact, constitute an EOR incentive. First, and most important, there was a repayment provision. Also, while stripper wells had been granted exemption from price controls, there was still some concern that participation in an EOR project could cause production to rise to a level which would, in fact, result in loss of stripper well status. However, this latter problem has reportedly been solved by ERA's "once a stripper always a stripper" provision, and the "imputed stripper well crude" regulation (Federal Register Vol. 43, No. 33694, August 1, 1978).

Industry feels that the documentation and reporting associated with ERA incentives are onerous. The latest ERA incentives proposal (24) provides some relief in terms of a self-certification feature; however, other reporting requirements would be instituted.

In any case, oil companies have argued that decontrol of the whole field, rather than the incremental oil produced via EOR techniques, would provide a significant incentive at the world price. This is basically consistent with the National Petroleum Council report (5). However, given the long lead time in EOR projects, a major uncertainty exists about the constancy of price regulations during any EOR project -- due to a perception that government agencies cannot make binding long-term commitments.

The regulatory posture can also be counter-productive in regard to EOR process innovations: some companies which pioneered steam drive for heavy oil, prior to 1972/73, were in effect penalized for developing their technology through pricing regulations and base production control levels, combined with definitions of what constitutes tertiary or "enhanced" oil (3,6)*.

ii) Unitization

The notion that unitization is a problem is held by government but not shared by the large major producers. We are given to believe that this is due to a disproportionate influence on government by small independent producers who have concern over loss of certain of their prerogatives if unitized. The unitization issue should be examined further. We note that ERA has recently granted administrative relief on price to stripper well oil produced within a unit (i.e., under the "imputed stripper well crude" regulation, a producer would not lose stripper status when joining a non-stripper unit), so that the issue may be of changing importance.

iii) Small Independent Producers and Related Issues

The greater number of existing wells are strippers; but stripper wells account for only about 12% of domestic production (8). While independents own most of these wells, the major integrated companies control nearly 70% of the domestic reserves; small independent producers control about 20%. There is considerable uncertainty over what the potential of EOR is for small producers and how they are responding to the present EOR incentive/price situation (9,17). The change proposed in stripper well definition announced as this report was being completed, is important to monitor, as is related proposed legislation (8,16).†

Indications are that the government could get the small independent producers involved in EOR at relatively low cost by putting some money up front. However, their technical capabilities and limited oil reserves are likely to be constraints. The DOE strategy relies heavily on pricing and other incentives, e.g., loan guarantees to stimulate pilot projects, with considerable concern for smaller, independent producers. It also envisions "massive" field test sponsorship over the next several years.

*Cf. also "President's Decontrol of Price of Heavy Oil Awaits Government Definition of the Product," Wall Street Journal, July 18, 1979, and, "Getty to Boost Output of Heavy Oil as U.S. Permits Higher Prices," Wall Street Journal, July 19, 1979.

†The regulation was recently promulgated in terms of a definition of "marginal property", and allows for increasing levels of stripper production as the well depth increases below 200 feet, (44 Federal Register 22010 - effective June 1, 1979).

Our impression is that the DOE commercialization strategy had some misplaced emphasis, but that this has been substantially corrected as a result of the recent study performed by Lewin and Associates in connection with ERA's proposed new "front end" money incentive (24).

iv) Heavy Oil Market

At the time of this writing, there was surplus Alaskan crude relative to refining capacity on the West Coast. This constrains the market for heavy oil produced from California steam drive projects, as discussed under the Environmental section.

v) Tax Policy

Both the DOE Commercialization Task Force and industry cited the uncertainty posed by IRS in regard to tax treatment of injection chemicals used in EOR. Industry contacts furthermore claim that IRS refused even to give advance rulings on the definition of injection chemicals used in an EOR project.

vi) National Policy toward EOR

Senator Bellmon has made the point that Congress has always appropriated more money for R&D on EOR than the Department of Interior and now DOE and OMB want to spend (10). This suggests some inconsistency in national policy toward EOR. For example, our impression is that the current OMB posture provides scant funding for the large number of pilot and field test demonstration projects that could add significantly in the near term to industry's own efforts, which are carried on mainly by the major companies. And the uncertainty surrounding all the existing and prospective ERA and EPA regulations may swamp the risk-reducing goal of ERA's tertiary incentive program.

While environmental regulations per se are recognized as an uncertainty and an actual and potential constraint on increased EOR, they also entail an institutional barrier in the form of the multi-agency jurisdiction associated with their enforcement.

Thus, through our industry interviews, we have identified these additional institutional issues, i.e. not addressed previously in DOE studies of EOR:

The national policy framework is confusing: there is an apparent mismatch between Congressional interest in and support for RD&D on EOR, the DOE Commercialization Task Force strategy, OMB budget allocations, and EPA concerns.

- The efficacy of a commercialization strategy which is seen by industry as emphasizing the role of small producers needs to be studied.

vii) Anti-trust

Anti-trust policy toward cooperative R&D or field evaluation and testing is uncertain. This constitutes a barrier generic to U.S. industrial cooperative R&D and was highlighted in an earlier study by RPI/IRIRC (23). In the present study, we got the impression that it was perceived by oil companies as a significant, but not major, barrier to EOR commercialization.

c) Remedies

Our conversations with knowledgeable people in the oil industry lead us to suggest tentative definitions of the stages of oil recovery including EOR:

DEFINITIONS

- Primary Recovery - Use of the reservoir's naturally available energy (pressure), augmented as appropriate by artificial lift, e.g., rod pump, gas lift, hydraulic pump, centrifugal pump.
- Secondary Recovery (Water Flood or Pressure Maintenance) - Injection of large volumes of water, natural gas, or inert gas, which usually occur naturally in the oil reservoir itself, to maintain pressure or to repressurize the reservoir. The use of materials associated with the primary oil production in large volumes is critical to the definition. That is, surfactants, CO₂, polymers, refined products or heat above initial reservoir temperature are not thought of as occurring naturally in "large amounts" and the use of such extraneous materials is not to be considered as an application of secondary recovery.
- Enhanced Oil Recovery - (To include the presently used term tertiary recovery.) Injection of large amounts, say more than ___%* by volume, of materials or forms of energy other than natural gas and water and not occurring naturally in the reservoir or similar reservoirs. Moreover, the injection is designed to enable, enhance or improve ultimate recovery beyond that otherwise obtainable with primary and secondary recovery combined. Such materials or energy forms would include CO₂, air, oxygen for in situ combustion, polymers, surfactants, hydrocarbons, alcohols, steam and heat, often in conjunction with water, but in such quantities as to make it readily apparent that the project would not be successful

*Not yet defined; to be specified by industry-government agreement.

otherwise and such that their net cost of procurement, use and recovery/reuse/discharge is "significantly greater"* than that which would occur with primary and secondary recovery efforts. Natural gas and flue gas may be considered at pressures high enough to cause miscibility. In situ combustion is also deemed to be enhanced oil recovery.

The principal institutional/regulatory remedy recommended by industry is that decontrol of oil prices should be granted to all fields employing EOR. And, application of EOR to fields which would otherwise be abandoned should be expedited, if technically sound procedures for obtaining additional production are available.

Streamlined price relief is needed to keep many of the secondary recovery operations in production and to provide the incentive to keep fields open for transition to tertiary recovery operations in the future. Both majors and independent operators view recent ERA actions regarding marginal properties and base production control levels as encouraging furtherance of secondary floods and enhancing prospects for tertiary.

Industry comments to ERA on the definitions and eligibility criteria covering California steam drive deserve prompt attention. Relatedly, additional refinery capacity or incentives are needed to better exploit steam drive potential.

Anti-trust policy toward cooperative RD&D efforts, on the one hand, should be better articulated to industry. On the other hand, a liberalized government-patent policy, as has been authorized in legislation such as the Non-nuclear Energy R&D Act, and potentially implied in the Federal Grant and Cooperative Agreement Act of 1977, should now be implemented. Although patents were not given major emphasis by our industry respondents, it was evident that patent policy significantly affects industry's attitude toward joint industry/government pilot and demonstration projects.

4. Technical

a) Barriers

The technology presently available, or which is likely to be achieved by current R&D and field testing, includes steam drive in shallow, heavy oil reservoirs; in-situ combustion; CO₂ miscible injection in Southwest and Rocky Mountain carbonate reservoirs; surfactant/polymer flooding in shallow and homogeneous reservoirs; and polymer-augmented water flooding.

*Not yet defined; to be defined by industry-government agreement.

In the great majority of fields believed to be EOR candidates, however, too little is known about the interrelationship of reservoir characteristics and the candidate EOR process(es). Among the factors to be considered are: heterogeneity, stratification, fracturing, discontinuity, mineralogy, and type/size distribution of pore space in the rock; reservoir pressure and temperature; oil gravity and viscosity; oil/water saturation, gas/oil ratio; porosity, permeability, lithology; and chemical characteristics of the oil, water and gas. Not only do these factors vary from reservoir to reservoir, they may vary within a single reservoir. Thus, knowledge about the nature, and predictability of yield requires further R&D and field testing. Thus, while the potential from each major reservoir and technique has been under intensive study, for the last several years at least, under the sponsorship of DOE and its predecessor agencies,* there is wide agreement that there is considerable uncertainty about the amount of oil remaining in a reservoir after conventional recovery operations and about the fraction of the remaining oil that can be recovered by a particular EOR process even after the process has been successfully pilot tested in that reservoir. This is in contrast to conventional oil production in which, guided by geophysical exploration and development drilling statistics, risks can be actuarially estimated. In other words, any "crisis of doubt" occurs predictably and early in respect to primary discoveries, but one might have to wait an uncomfortably long period in connection with EOR applications.

With regard to the assessment of overall EOR potential, the industry consensus was that the National Petroleum Council (5) study was more technically conservative than the Lewin Study (14) in the potential from EOR technologies. Lewin's study has been adopted by the Office of Technology Assessment (6) and by DOE (both in the EOR Management Plan and in ERA). This creates the possibility of a divergence between actual industry activity and possibly over-optimistic goals to be attained through DOE's commercialization strategy as described in (1).

Related to the uncertainty associated with assessing EOR potential in a particular field is that associated with the determination of the oil field production decline curve. The decline curve is an essential component of present (June, 1979) DOE regulatory policies which affect pricing for EOR production. The Office of Technology Assessment report (6) shares a concern with the oil companies that the capability to make such determination is lacking in the federal government, and -- even given such capability -- the consensus is that this is the wrong way to go. That is, the ERA's dependence on decline curve determination is not technically sound and can lead to counter-productive policies. There is thus a need for a better way to get ERA "certification" for EOR projects. This need would disappear with decontrol of oil prices.

*See Table IV-5 which summarizes the status of these studies. Also at the time of this writing, DOE's Bartlesville Energy Technology Center released a draft interim report (May, 1979) on technical constraints limiting application of EOR techniques (26). Figure IV-2 presents the relative state of EOR technology, in terms of the number of active projects, as presented in that report.

Table IV-5
ANALYSIS OF TECHNOLOGY AND CONSTRAINTS
IN ENHANCED OIL RECOVERY

Technique/Reservoir Class	Role in Technological Development	Level of Risk	Level of Recovery	Date for Field Application	Pace of Development
A. Steam Drive					
• Shallow, Heavy Oil:					
-- Current Case	Industry	High	Regular	Current	OPT ⁽¹⁾
-- Base Case	Industry	Conventional	Regular	Current	OPT
-- Advanced Application	DOE/Industry	Conventional	Improved	1983	OPT
• Deep, Heavy Oil	DOE/Industry	High Risk	Regular	1983	OPT
• Shallow, Light Oil w/ Substitute fuels	DOE/Industry	High Risk	Improved	1982	OPT
B. In Situ Combustion					
-- All cases	Industry	High Risk	Regular	Current	PESS ⁽²⁾
C. Carbon Dioxide Miscible					
• S.W. & Rocky Mountain Carbonates					
-- Current Case	Industry	High	Regular	Current	PESS
-- Base Case	Industry	Conventional	Regular	Current	PESS
-- Advanced Application	DOE/Industry	Conventional	Improved	1985	PESS
• Other Carbonates	DOE/Industry	High Risk	Regular	1985	PESS
• Gulf Coast Sandstones:					
-- (High Dip)	DOE/Industry	High Risk	Improved	1982	PESS
-- (Low Dip)	DOE/Industry	High Risk	Regular	1985	PESS
• Other Sandstones	DOE/Industry	High Risk	Regular	1985	PESS
• Offshore, Gulf of Mexico	DOE/Industry	High Risk	Improved	1983	PESS
D. Surfactant/Polymer					
• Shallow/homogeneous Sandstones					
-- Current Case	Industry	High	Regular	Current	PESS
-- Base Case	Industry	Conventional	Regular	Current	PESS
-- Advanced Application	DOE/Industry	Conventional	Improved	1984	PESS
• California Sandstones	DOE/Industry	High Risk	Regular	1985	PESS
• Gulf Coast Sandstones	DOE/Industry	High Risk	Improved	1985	PESS
• Other Sandstones	DOE/Industry	High Risk	Regular	1985	PESS
E. Improved Waterflooding					
-- Current and Base Case	Industry	High Risk	Regular	Current	PESS
F. Other Programs and Special Targets					
• Overcoming Environmental/ Market Problems ⁽⁴⁾ in California					
-- Current Case	Industry	--	--	Current	--
-- Base Case	DOE/Industry	--	--	1980	--
	DOE/Industry	--	--	1985	--
	DOE/Industry	--	--	1990	--
• Obtaining adequate supplies of CO ₂ for S.W. and Rocky Mountain Reservoirs ⁽⁴⁾					
	Industry	--	--	1980	--
	Industry	--	--	1985	--
-- Base Case	DOE/Industry	--	--	1990	--
	DOE/Industry	--	--	1995	--
• Substitute Lower Cost ⁽⁴⁾ Non-Petroleum Fuels	DOE/Industry	--	--	1983	--
• Virgin/Near Virgin Reservoirs	DOE/Industry	--	--	1982	--
• Low Recovery Reservoirs	DOE/Industry	--	--	1985	--
• Non-Flowing Oils (Tar Sands)	DOE/Industry	--	--	1990	--

(1) Optimistic

(2) Pessimistic

(3) Cumulative Capacity

(4) Increasing price projections for the medium and high price scenarios will enable DOE/Industry to overcome the environmental/market problems in California and the CO₂ supply problem in the Rocky Mountains.

*Numbers reflect total number of active projects

Source: Bartlesville Energy Technology Center, U.S. Department , Energy (26).

FIGURE IV-2 RELATIVE STATE OF EOR TECHNOLOGY (DOE Viewpoint)*

These technical uncertainties also feed back into economic or regulatory uncertainties due to the different ways companies treat EOR. Some treat EOR, in effect, as secondary production; some as tertiary; some as assisted recovery production; some as R&D plus pilot production. These different attitudes or classifications of EOR affect corporate budgeting decisions in regard to EOR at the individual company level. Again, decontrol of oil prices would obviate the effect of these distinctions.

Technically, the sooner EOR programs can be initiated in a presently producing field, and/or the greater the oil saturation, the better should be the response. Moreover, well casings are in better condition; also less injection fluids would have to be handled. The latter is important so far as environmental impact is concerned, as well as from the standpoint of cost and existing infrastructure and oil field equipment capability. For chemical surfactant-polymer processes, process designs attempt to incorporate temperature- and brine-resistant chemicals; these are particularly significant when fields are fresh-water limited (20). In many fields the infrastructure is deteriorating to the point where abandonment will be necessary in a very few years. Once a field is abandoned and the wells plugged, the oil remaining in place may become irretrievable, as redrilling for EOR operations would be prohibitively expensive with respect to the oil recoverable. Moreover, corrosion and other deterioration in the underground hardware can cause changes in parts of the reservoir structure and lead to uncontrolled flooding.

In any case, there are inherent time lags in the application of EOR techniques, due to the nature of the technology, as well as the need to field test. The duration of time lags from the start of application to production of useable oil will depend upon the EOR technique used and the related performance characteristics of the oil field.

b) Remedies

- Action should be taken immediately to maximize the near-term impact of EOR on domestic supply.

To accelerate EOR production and the advancement of the technology, pilot and field tests must be intensified, both in number and diversity. Such tests are needed in most of the 800 or so reservoirs which have been identified,* and costs are estimated to be at least several million dollars per pilot test.

Government funding of R&D should be continued. The fine cooperative programs, originally sponsored by The Bureau of Mines from its Bartlesville station, can serve as the base for an expanded program within DOE. Information exchange is a valuable part of these programs.

More R&D is needed, especially for miscible and microemulsion floods. Knowledge from extended secondary recovery operations will be beneficial for fields amenable to tertiary flooding techniques.

*These 800 have been identified as having EOR potential by the National Petroleum Council, Office of Technology Assessment, and DOE. Many additional reservoirs are believed to exist. There is as yet little information available about them in regard to EOR potential.

E. THE INDEPENDENT PRODUCERS' POINT OF VIEW

The independent sector of the oil and gas producing industry is highly fragmented, containing some 5,000 operators of which about 1,500 have come into being since 1971. The privately and publicly owned independents fund about \$1.6 billion of annual expenditures for exploration with another \$2.2 billion funded by gas utilities, diversified industrial companies, and publicly subscribed drilling funds. The major integrated companies account for about \$3.8 billion of annual expenditures for exploration and production. They control about 67% of U.S. reserves. The small independent producers, i.e., those with less than 10,000 bbl of production, control about 20% of the reserve base.

Since limited study budget was directed toward evaluating the independents' views of EOR commercialization opportunities, the small number of independents surveyed precludes firm conclusions with respect to the independents in general. We note that the independent group is so varied with respect to size and mode of operation that a very large sample would likely be required before definitive conclusions for the group could be drawn.

1. Economic Barriers

An inadequate price for oil is the common problem mentioned by the independents interviewed. Problems with respect to technology and regulation produced a less uniform response, largely reflecting the heterogeneity in operators with respect to their prior histories, present operations, and outlooks. There is some suggestion that, in any case, the smaller companies do not have the financial flexibility to tolerate EOR project cash flow delays; large companies, while also eschewing such delays, can better cope with them in their capital planning cycles.

2. Institutional/Regulatory

a) Unitization

Independent operators' disinclination to be involved in units led, in the late '40s, to a number of compulsory unitization fights. There are some states who still have forced pooling or unitization requirements which, based on the very high percent of required participation of working interest and royalty owner participation, renders the compulsory aspect of unitization ineffective. This led to the Interstate Oil Compact Commission (IOCC) recommending support, when interviewed, for a broader statutory unitization requirement. We learned as well that in every state where there was a post-war fight over unitization, the major oil companies favored unitization and the independents opposed it. In states where there are now compulsory unit requirements, IOCC feels that if an attempt were made to repeal them today, the independents who formerly did not want them would fight just as hard to preserve them. The general observation made with respect to unitization, however, was that unit deals are not really big problems although they are almost always thorny ones to put together.

Nearly half of the production in the U.S. is from fields under water flooding (secondary recovery). Unitization is usually a must in these projects, and thus is already a precedent for a tertiary project. Under recent ERA regulations, however, stripper wells qualify for higher price than non-stripper wells producing "old oil" and this can cause the smaller operators disincentives to unitize if it means loss of stripper status. Such situations have been granted administrative relief by ERA, and would not be an issue with decontrol.

3. Technology

Our industry interviews suggested that technology is really not available to the smaller independent producer and that what we are seeing now in EOR is a repetition of the history that attended water flooding after World War II. In that case, the independent was reluctant to involve himself since he basically did not understand the technology. This led to the unitization fights, previously discussed. The operating companies interviewed had different attitudes on technology availability, which varied from indicating that it was not a problem since it could be acquired by the use of consultants, to the position that technology is a problem because the company would want the expertise required to engage in EOR to be largely, if not wholly, in-house (implying they might not be able to afford it) so as to control more effectively the technological/capital investment that was being made.

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APPENDICES III-A, III-B AND III-C

APPLY TO SHALE OIL ONLY

SURFACE RETORTING PROCESSES

*Sun, Phillips, Sohio

Source: Reference (1), p. 165

IN SITU OIL SHALE CONVERSION
MAJOR PROJECTS

Source: Reference (1), p. 166

APPENDIX B

SUMMARY OF

PROPOSALS FOR GOVERNMENT PROGRAMS TO COMMERCIALY
DEMONSTRATE SYNFUELS FROM COAL, OIL SHALE, BIOMASS
AND OTHER ENERGY SOURCES

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SUMMARY OF

PROPOSALS FOR GOVERNMENT PROGRAMS TO COMMERCIALY
DEMONSTRATE SYNFUELS FROM COAL, OIL SHALE, BIOMASS
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July 3, 1979

SUMMARY OF PROPOSALS FOR GOVERNMENT PROGRAMS TO
COMMERCIALLY DEMONSTRATE SYNFUELS FROM COAL, OIL SHALE,
BIOMASS AND OTHER ENERGY SOURCES

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SUMMARY* OF PROPOSALS FOR GOVERNMENT PROGRAMS TO
COMMERCIALLY DEMONSTRATE SYNFUELS FROM COAL, OIL SHALE,
BIOMASS AND OTHER ENERGY SOURCES

I. Introduction

Gasoline lines, liquid fuel shortages and rapidly rising OPEC and consumer prices for petroleum have contributed to a renewal of the "energy crisis" atmosphere in Washington, an atmosphere last seen during the 1973-1974 embargo and OPEC-production cuts and price increases.

The crisis atmosphere has, among other things, led to the introduction of a large number of proposals for rather dramatic action by the Federal Government to stimulate early construction of some commercial-scale facilities to produce liquid and gaseous fuels from coal, oil shale, tar sands, heavy oils, biomass and other energy sources.

As of June 28, 1979, more than 20 different proposals have been surfaced, though some of these have common elements. Most of the proposals have come from members of Congress but others have come from prestigious people and groups outside the government, and some have come from the Executive Branch.

Briefly, the proposals involve:

- . Various forms of government incentives, encouragement or requirements for private sector actions.
- . Actions by existing government agencies.
- . Creation of wholly-owned government corporations to either help finance private sector activities or to engage in energy production.
- . Actions to reduce delays in securing Federal, State and local decisions on permits and other governmental approval.

One major bill (the Moorhead bill) has been passed by the House of Representatives and hearings are underway or will be held soon in the Senate on several proposals.

The Administration apparently is now engaged in a thorough review of synthetic fuels and other energy matters and will be submitting proposals to the President for decision within the next few days.

As one step in participating in the complex public policy debate about synthetic fuels, the NCA staff has prepared this summary of the various proposals that have been surfaced thus far.

*The summaries in this paper are unofficial staff summaries based on a relatively quick review of the various proposals--rather than a detailed line-by-line analysis. The proposals, themselves, should be referred to for authoritative information.

II. What types of Actions have been proposed?

The various proposals that have surfaced involve one or more of the types of actions listed and described briefly below.

A. Incentives, Subsidies and Risk Sharing.

1. Candidate Groups for Sharing risks or providing Incentives or Subsidies: There are three different but overlapping "groups" with whom financial risks associated with synthetic fuels production can be shared:

All taxpayers to the Federal Government. This is the effect of such approaches as government guaranteed purchases and/or prices; federal direct loans or loan guarantees; tax incentives; and Government ownership.

All consumers of a particular product. This is the effect of covering the financial risks through a tax on particular commodities or services (e.g., the Administration's proposed excise tax on domestic crude oil -- the so-called "windfall profits tax" or an import duty on petroleum) where the receipts from that tax are earmarked for specific projects or purposes (e.g., the Administration's proposed "Energy Security Fund").

Customers served by firms building a particular project. This is the case in such approaches as "rolled-in pricing" and "all-events tariffs" which have the effect of passing any unusual risks or costs to the customers served. As expected, the larger the number of customers served, the lower the risk that any one carries.

2. Forms of Incentives, Subsidies and Risk Sharing: The various forms of incentives, subsidies and risk sharing that have been proposed, may have different application depending on the technology involved, the potential market, the degree of financial risk, technological difficulties, and future marketing considerations. The forms include:

a. Guaranteed Market or Price - This incentive would protect against risks associated with future market conditions. The arrangement calls for government to purchase synthetic fuel at a previously agreed upon price, or, if delivery is refused, to pay the difference between the market value and a guaranteed price.

b. Loan Guarantees - Government would assure repayment of loans for debt capital associated with a demonstration project. Loan guarantees could protect lenders to firms or consortia building and operating synfuels projects, particularly those which are thinly capitalized,

are regulated and/or have high debt/equity ratios. Loan guarantees usually provide full protection for the lenders and, in some cases, may provide partial protection to equity investors.

- c. Direct Loans - Government would provide debt capital from U.S. Government funds.
- d. Completion Undertaking - Government would provide financial protection to both equity investors and lenders against unforeseeable events such as events precluding completion and/or operation of a facility, an inoperable facility or an unsatisfactory product.
- e. Tax incentives - This includes either favorable write-offs, increases in investment tax credits and/or production tax credits (e.g., tax credit for each barrel of oil produced from shale). Projects with a strong equity base and a certain future market may require no additional financial incentive. (Energy Tax Act of 1978 provides an additional 10% investment credit, but it expires in 1982--making it of little value for major projects requiring long lead time.)
- f. Rolled-in Pricing - This approach is intended to spread costs over the full market served by a distributor. It would protect against high expected or unexpected costs of producing the product. This approach is usually proposed for regulated (price and/or supply allocation) industries, so that the firm or consortium can distribute the costs among all customers.
- g. "All-events tariff" - Would permit recovery of all or partial costs (perhaps debt and not equity) up to and including total failure of a project -- without direct federal assistance. The cost would be passed on to the ultimate customers by way of higher rates. This approach applies only to cases where the product is subject to rate regulation.

B. Direct Actions by Existing Government Agencies.

Three different forms of direct actions by existing government agencies have been proposed:

- 1. Ownership of a facility by existing government agencies. This approach calls for some existing agency (perhaps DOE or DOD) to finance and construct and own a facility to produce synthetic fuels--with the option of having the facility managed by government personnel or under contract. (This approach has long been used with government-owned facilities for producing enriched uranium which are now under DOE's control. The Navy has long sought support for building government-owned oil shale conversion facilities on Naval Oil Shale Reserves.)

2. Federal Funding for all or Part of Synfuels Facility Costs. This approach, the most common now in use, involves direct government financial assistance to pay all or a share of the costs of designing, constructing and beginning operations of facilities. Depending upon the contractual arrangement, title to the facility and shares of operating revenue may flow to the government or the private contractor. (This approach is often used for development and less-than-commercial scale demonstration facilities in current DOE programs.)

3. Mandated Use of Specified Shares of Synfuels. Some proposals involve action by law and regulation to require the use of specified shares of synthetic fuels at various stages of energy production or distribution; e.g., a refinery might be required by law or regulations to use a synthetic fuel to supply a specified percentage of the input to the refinery.

C. Creation of Government Corporations for synthetic fuels commercialization.

This approach calls for creating new government entities managed by appointed Boards. (TVA is a government corporation.) Such corporations may have authority to carry out a variety of programs--sometimes using government appropriations and sometimes using funds coming from operating revenue or borrowed from private capital markets.

Proposals have been surfaced for government corporations to:

- . Explore, develop and produce energy minerals.
- . Purchase, store, transport, enrich energy fuels.
- . Develop and/or demonstrate synfuels technologies.
- . Select federal energy lands for development or for leasing to others.
- . Construct, lease and/or operate synfuels facilities.
- . Finance construction and/or operation of facilities.
- . Act as exclusive bargaining agent for all purchases of energy outside the U.S.
- . Guarantee prices and markets for synthetic fuels.

D. Expedite Government Decisions.

Several proposals have been made to expedite governmental decisions on permits and other approvals that are necessary to the construction and operation of synfuels facilities. These proposals seem to recognize that:

- Dozens or hundreds of separate Federal, State and local approvals are required for a project and the absence of any one may stop the project.

- Delays and roadblocks often frustrate plans to build facilities.
- Delays add to project costs (e.g., inflation; interest cost on borrowed capital) and thus increase the cost of producing a product.

Among the proposals that have been advanced are those to:

- . Speed up government decisions.
- . Speed up environmental impact statement processes.
- . Limit judicial review of government decisions.

III. What are the Specific Proposals?

The different forms of government action are provided for in one or more specific proposals from members of Congress, the Carter Administration or outside sources. Some of these proposals are not limited to synthetic fuels. Appendix I is a two-page table showing in "matrix" form the principal provisions of the proposals.

Appendix II includes a brief narrative description of each of the proposals, showing sponsors, status of the proposal and principal provisions.

The proposals summarized in the appendices include:

- #1. Amend Defense Production Act (Moorhead, et al) to specifically authorize government actions to commercialize synfuels -- including guaranteed purchase and price, loans and loan guarantees and creation of a government corporation, if necessary. (Appendix Pages II-1 & II-2) This approach was amended somewhat on the House floor and passed on June 26, 1979, and is awaiting consideration by two Senate Committees.
- #2. Amendment to DPA. The Moorhead bill, as reported by the House Banking Committee, has also been introduced in the Senate. (Page II-3)
- #3. Zukert-Ignatius-Cutler Proposal for a government corporation to construct synfuel facilities and finance others. (Page II-4)
- #4. Committee for Economic Development (CED) proposal for a variety of government incentives including tax incentives, guaranteed purchase and price, loan guarantees and expedited environmental reviews. (Pages II-4 & II-5)
- #5. Jackson Bill (S. 1308) - A "catch-all" energy bill including loans and loan guarantees; guaranteed prices; government-owned shale conversion plants; direct federal funding for synfuels projects; and mandatory use of specified shares of synthetic fuels. (Many other proposals not involving synfuels.) (Pages II-5 to II-7)

- #6. Forced Use of Synthetics as Motor Fuel (Jeffords, Anderson, et al). House bills and one title of S. 1308 would have DOE come up with a program for development of synthetics from various sources and require that increasing percentages be substituted in motor fuel. (Pages II-7 & II-8)
- #7. Oil Shale Tax Credit. This Carter Administration proposal would give \$3.00 per barrel tax credit for oil from shale. (Page II-8)
- #8. Great Plains Gasification Project. This is a proposal for minimum government involvement--consisting of government regulatory decisions permitting rolled-in pricing and "all-events" tariffs to cover debt financing--for entirely private venture Hi-Btu Gasification plant. (Page II-8)
- #9. Federal Energy Management Authority. This proposal by Congressman Tim Lee Carter calls for a TVA-like government corporation to engage in all phases of energy development and production (including R&D) for coal and synfuels from coal. (Pages II-8 & II-9)
- #10. Energy Company of America. This is another proposal for a government corporation to engage in all aspects of energy production and supply; R&D; purchase energy abroad; and develop energy from federal lands (Pages II-9 & II-10)
- #11. Energy Bank of America. This is a proposal for a government corporation to finance energy developments that are unable to secure financing from other sources. (Page II-10)
- #12. Synthetic Fuels Production Act (Domenici, et al) would create a Government corporation with \$25 billion in capital and \$50 billion in borrowing authority to fund or carry out synfuels projects; expedite federal energy project approvals; and set 1990 goals for producing synfuels from various energy sources. (Pages II-11 to II-14)
- #13. Synthetic Fuels Production Act (Luken) Identical to Senator Domenici's bill. (Page II-14)
- #14. Synthetic Fuels Manpower Training and Synthetic Fuels Reserve Corporation (Perkins, et al) Authorizes CETA grant funds for manpower training; creates a government corporation to produce or provide assistance for producing 5 million barrels per day crude oil equivalent of synfuels; and requires use of synthetics as motor fuel -- as in #6, above; provides tax incentives of \$3 per barrel of liquid; rapid amortization and other tax incentives. (Page II-15)
- #15. Oil Independence Act of 1979. (Spence) Authorizes the Secretary of Agriculture to carry out research and make loan guarantees for synfuels to public, private and cooperative organizations. (Page II-16)

- #16. National Energy Self Sufficiency Act (Bailey) Would impose a duty on imported crude oil equal to difference between imported price and average price of synthetic fossil fuels. (Pages II-16 & II-17)
- #17. Refinery Sale of Synfuels; Tax Incentives for Synfuels. (Walker) Sets minimum percentages of synfuels for products sold by refineries; authorizes the secretary of energy to modify requirements of law administered by DOE, EPA and Interior which impede synfuels development; provides rapid amortization and other tax incentives. (Page II-17)
- #18. Synfuels amendment to EPCA (Dingell). Authorizes many of the same steps provided for in the Moorhead bill (#1) except done as amendments to Energy Policy and Conservation Act rather than the Defense Production Act. Limits amount paid for synfuels to 110% of cost of imported petroleum-derived fuel or feedstock. (Page II-18).
- #19. Synfuels Amendment to EPCA and Priority Energy Projects (Dingell) Identical to #18 above plus priority energy projects, gasahol and electric power transfer provisions of Jackson Bill - S. 1308--in #5 above. (Page II-18)
- #20. National Program for Full Development of Energy Supplies. (Dingell) Six titles identical to certain titles in Jackson Bill (S. 1308)--#5 above, near term synfuels commercialization projects, covering synfuels demonstration projects; oil shale commercialization; oil & gas leasing; renewable energy resources; and study of world oil supply and production. (Page II-19)
- #21. Priority Energy Projects Act (Udall) Similar to Title II of Jackson's S. 1308 (#5 above); seeks to expedite federal decisions on designated (6 per year) priority energy projects. (Pages II-19 & II-20)
- #22. Priority Energy Projects Act (Bentsen) Somewhat similar to Title II of Jackson's S. 1308 (#5 above) but with provision for overriding of existing Federal, State and local laws. (Page II-20)
- #23. International organization to promote energy technology. Press reports indicate the Carter Administration propose some kind of international organization to promote and finance the development of alternatives to petroleum. Status and details are not yet available. (Page II-21)

PROPOSALS FOR GOVERNMENT INVOLVEMENT IN SYNTHETIC FUELS COMMERCIALIZATION

PROPOSAL AND ITS PROPONENT(S)	Incentives and Risk Sharing						Direct Federal actions			Create a New Government Corp. to								Expediting Gov't Decisions		OTHER FEATURES AND COMMENTS
	Federal Guaranteed Purchase and/or Price Guarantee	Federal Loan Guarantees	Direct Federal Loans	Completion Undertaking	Tax Incentives	Roll-in Pricing for Product	"All-Events" Tariff	Ownership and/or Management of Facilities by existing Government Agency	Federal Funding for all or part of Facility Costs	Mandatory Use of Specified share of synfuel (e.g. by refineries, distributors)	Explore, Develop & Produce energy minerals	Purchase, store, transport, enrich energy fuels	Develop and/or demonstrate synfuels technologies	Select Federal energy lands for development or lease	Construct, lease and/or operate synfuels facilities	Finance construction and/or operation of facilities	Act as exclusive bargaining agent for purchase of energy outside U.S.	Guarantee Prices & Markets	Attempts to speed up Federal, State and/or local gov't approvals of energy facilities	
1. Amend Defense Pro- duction Act (DPA) as passed by House S.932 (HR 3930)	X	X	X									X	X		X				X	
2. Amend DPA (S.1409)	X	X	X									X	X		X					
3. Zukert-Ignatius- Cutler Proposal															X	X		X		
4. CED Proposal	X	X		X	X		X													
5. Jackson Bill (S. 1308)	X	X	X					Shale Oil	X	X									X	X
6. Forced Use of syn- fuels for motor fuel (HR 4334, etc)										X										
7. President's Oil Shale Tax Credit					X															
8. Great Plains Gasification Pro- ject						X	X													
9. Energy Development & Mgmt. Authority (HR3671; 4434)											X	X	X	X	X					
10. Energy Company of America (HR3885, 4669; S580)											X	X	X	X	X		X			
11. Energy Bank of America (S. 581)																X				

APPENDIX I

PROPOSALS FOR GOVERNMENT INVOLVEMENT IN SYNTHETIC FUELS COMMERCIALIZATION

2 - I

PROPOSAL AND ITS PROPOSER(S)	Incentives and Risk Sharing						Direct Federal actions		Create a New Government Corp. to								Expediting Gov't Decisions		OTHER FEATURES AND COMMENTS		
	Federal Guaranteed Purchase and/or Price Guarantee	Federal Loan Guarantees	Direct Federal Loans	Completion Undertaking	Tax Incentives	Rolled-in Pricing for Product	"All-Events" Tariff	Ownership and/or Management of Facilities by existing Government Agency	Federal Funding for all or part of Facility Costs	Mandatory Use of Specified share of synfuel (e.g. by refineries, distributors)	Explore, Develop & Produce energy minerals	Purchase, store, transport, enrich energy fuels	Develop and/or demonstrate synfuels technologies	Select Federal energy lands for development or lease	Construct, lease and/or operate synfuels facilities	Finance construction and/or operation of facilities	Act as exclusive bargaining agent for purchase of energy outside U.S.	Guarantee Prices & Markets		Attempts to speed up Federal, State and/or local gov't approvals of energy facilities	Speed up Environmental Impact Statements (EIS); short cut EIS process; limit judicial review.
12 & 13--Synthetic Fuels Production Act (S.1377; H.R.4588)															X	X			X	X	Sets nat'l syn fuels produc- tion goals
14. Synfuels Reserve Corp Act (HR4514)					X					X			X		X	X		X			
15. Oil Independence Act (HR4533)		X																			Research grants
16. National Energy Self-Sufficiency Act (HR4484)			X																		Revenue from import duty on petroleum
17. Refinery Sale of Synfuels; Tax Incentives (HR494)					X					X											Study of im pediments
18. Synfuels amend. to EPCA (HR4474)	X	X	X																		
19. Synfuels amend. to EPCA; Priority Energy Act (HR4499)	X	X	X							X									X	X	Also non-syn- fuels pro- visions
20. Full Development of Energy Supplies (HR4500)	X	X	X					Oil Shale	X												
21. Priority Energy Act (HR4573)																			X	X	
22. Priority Energy Act (SI415)																			X	X	
23. International Energy Tech.Group																					Would finance projects to commercialize new technology

RECENT PROPOSALS FOR FEDERAL GOVERNMENT INVOLVEMENT IN
COMMERCIALIZATION OF SYNTHETIC FUELS
(Unofficial Summaries; Consult Bill for language)

1. S. 932
HR 3930

Defense Production Act Amendments of 1979

.Sponsors:

S. 932, as it passed the Senate, was a simple 2-year extension of the Defense Production Act, which expires on September 30, 1979.

S. 932, as it passed the House is really HR 3930, as amended and passed by the House on June 27, 1979.

.Status:

House:

On June 27, 1979, the House substituted the words of HR 3930, as amended, for S. 932, asked Senate for a Conference and appointed House Conferees, who are: Reuss (D-WI); Moorhead (D-PA); Ashley (D-OH); Wright (D-TX); Blanchard (D-MI); Vento (D-MN); Stanton (R-OH); McKinney (R-CT); and Kelly (R-FL).

Senate:

S. 932, as passed by the House was, on June 28th, referred jointly to the Committees on Energy & Natural Resources and Banking, Housing & Urban Affairs. The Banking Committee has scheduled hearings for July 27-29.

.Provisions: Amends the Defense Production Act of 1950 to:

.Specify that greater energy independence is necessary to national defense preparedness and national security; explicitly provides that DPA covers energy.

.Directs the President to achieve a national production goal of at least 500,000 barrels per day crude oil equivalent of synthetic fuels and synthetic chemical feedstocks within 5 years and 2,000,000 barrels per day within 10 years.

.Defines synthetic fuels and chemical feedstocks as those "produced by the conversion of renewable and nonrenewable resources, including, but not limited to, products produced from coal liquefaction, shale, tar sands, lignite, peat, solid waste, and other mineral gasification, liquefaction or other conversion, and the conversion of any organic material into fuel" (includes heavy oils).

.Provisions:
(cont'd)

- .Directs the President to buy synfuels produced in facilities in the U.S. for government use, stockpile or resale for defense or domestic needs and to make up differences (if any) between contract price and prevailing market price at time of delivery from a \$3 billion fund authorized for this purpose. Also may transport, store, and have processed or refined the products purchased.
- .Limits to no more than 100,000 barrels per day equivalent purchases from any one person. Contracts for more than 75,000 barrels per day equivalent cannot be awarded until each House of Congress has 30 days of continuous session for a resolution of disapproval.
- .Authorizes the President to create government corporations (subject to one House veto) which can then purchase and acquire synfuels and chemical feedstocks; or purchase, lease, build, and expand plants for such products.
- .Provides for loans up to \$38 million per loan and loan guarantees (up to \$48 million per guarantee) to private sector producers (from regular Defense Production Act appropriations) to acquire or improve synfuels facilities and equipment. Limits may be exceeded if the House and Senate Armed Services Committees are notified and no resolution of disapproval is passed with 60 days of continuous session.
- .Directs each federal official or agency with permit or approval authority for synfuels facilities, to the maximum extent practicable, to expedite permits, approvals and authorizations, and to take steps to complete action within 12 months of receipt of application.
- .Authorizes appropriation of an amount not to exceed \$3 billion from general funds or fund hereafter established to pay for any excess of contract price for synfuels over current market prices for such fuels.

NOTE: Availability of funds for any program authorized in the bill (e.g., guaranteed purchase or price, loan or loan guarantee) depends upon congressional passage of separate appropriations acts providing funds.

1A. H.R. 4349,
4355, 4336,
4568

Defense Production Act Amendments of 1979:

These bills are identical to H.R. 3930 as reported by House Banking Committee. First three were introduced June 6; H.R. 4568, introduced June 21.

- .Sponsors: Riegle (D-MI); introduced on June 26, 1979.
- .Status: Referred to Senate Committee on Banking, Housing & Urban Affairs.
- .Provisions: Identical to H.R. 3930 as originally introduced by Moorhead, et al, in house: i.e.:

.Specify that greater energy independence is necessary to national defense preparedness and national security; explicitly provides that DPA covers energy.

.Directs the President to achieve a national production goal of at least 500,000 barrels per day crude oil equivalent of synthetic fuels and synthetic chemical feedstocks within 5 years.

.Defines synthetic fuels and chemical feedstocks as those "produced by the conversion of renewable and non-renewable resources, including, but not limited to, products produced from coal gasification, coal liquefaction, shale, lignite, peat, solid waste, and other mineral gasification, liquefaction or other conversion, and the conversion of any organic material into fuel."

.Authorizes the President to buy synfuels for government use, stockpile or resale and to make up differences (if any) between contract price and prevailing market price at time of delivery from a \$2 billion fund authorized for this purpose. Also may transport, store, and have processed or refined the products purchased. (No more than 100,000 barrels per day equivalent from any one person.)

.Authorizes the President to create government corporations (subject to one House veto) which can then purchase and acquire synfuels and chemical feedstocks; or purchase, lease, build, and expand plants for such products.

.Provides for loans and loan guarantees to private sector producers (from regular Defense Production Act appropriations) to acquire or improve synfuels facilities and equipment.

NOTE: Availability of funds for any program authorized in the bill (e.g., guaranteed purchase or price, loan or loan guarantee) depends upon congressional passage of separate appropriations acts providing funds.

3. Zuckert-Ignatius Cutler Proposal Government created "Petroleum Reserve Corporation."

- Sponsors: Proposal made in articles and speeches by Messrs. Paul Ignatius, Eugene Zuckert and Lloyd Cutler.
- Status: Not specifically introduced but proposal is receiving attention in Congress and the Administration.
- Provisions: Creation of Government Corporation with authority and funding to:
- .Design and execute a program to create up to 5 million barrels of petroleum and alcohol per day.
 - .Issue federally-guaranteed bonds.
 - .Build new plants to be owned initially by the government (financed by its bonds or "windfall profits tax") and operated by private industry under leases or contracts.
 - .Enter into market guarantee agreements for new plants to be built and owned by private industry with government commitment to buy output not commercially sold; pay subsidy needed to make commercial sales; order shutdown and pay standby fee to cover amortization of debt and reasonable profit -- with the right to order reopening at any later time.
 - .Finance building of plants in Canada (e.g., tar sands) and perhaps elsewhere.
 - .Enter into joint financing arrangements with other nations.
 - .Focal point for assessing environmental issues requiring prompt resolution by the President.

4. CED Proposal "A Program for Developing Synthetic Fuel Plants Now"

- Sponsors: Committee for Economic Development (draft proposal)
- Status: Formal report still in draft but proposal is being discussed publicly by Franklin A. Lindsey (Chairman of Itek Corp. and of the Research & Policy Committee of the Committee for Economic Development (CED))
- Provisions: Federal Government actions consisting of incentives and guarantees, including the following:
- .Continuation of existing investment tax credit, including extension of the additional 10% credit provided in the Energy Tax Act of 1978 beyond its current 1982 expiration.
 - .Adoption of the proposed \$3.00 per barrel tax credit for oil from shale.
 - .FERC approval of "all-events" tariff proposal for Hi-Btu gasification plant.

CED Proposal

Continued

- .Authority to enter into guaranteed price contracts for product and, thus, a guaranteed market.
- .Protection of lenders and, in some cases, equity holders against inability to complete projects.
- .Government guarantee of debt.
- .Authority for the government to buy out and close down a facility under defined conditions, as an alternative to paying for its completion.

5. Jackson Bill

"Energy Supply Act" S.1308 (HR4622)

June 11, 1979

Sponsors: Senators Jackson(D-WA); Bradley(D-NJ); Bumpers(D-AR); Byrd(D-WV); Church(D-ID); Cranston(D-CA); Domenici(R-NM); Durkin(D-NH); Ford(D-KY); Hatfield(R-OR); Huddleston(D-KY); Johnston(D-LA); Magnuson(D-WA); Matsunaga(D-HI); Metzenbaum(D-OH); Moynihan(D-NY); Randolph(D-WV); Stevens(R-AL); Tsongas(D-MA); Weicker(R-CN)

Nelson's (D-FL) H.R.4622, June 27, 1979, is identical to S.1308

Status: Introduced June 11, referred to Committee on Energy and Natural Resources.

Provisions: A broad, "catch-all" bill consisting of:

Title I - findings & purpose

Title II - "Priority Energy Project Act" consisting of authority for:

- Secretary of Energy to (1) designate proposed facilities as "priority energy projects", upon application by facility owner, publishing of notice, comment by public, and evaluation by DOE; and (2) issue "project decision schedule" with deadlines for all agencies to complete review of applications, but can schedule in existing law only in exceptional situations.
- Presidential decisions when agencies do not meet deadlines.
- Request for similar actions by state and local governments.
- Limits on judicial review of approved projects.

Title III

Mandatory issuance within 6 months by DOE of requests for proposals for commercial scale demonstration of technologies listed in Sec. 6(b)(3) of the Federal Non-Nuclear Energy R&D Act of 1974:

- Productive use of waste.
- Recycle of materials.
- Improved data and building designs.
- Technologies for producing low sulfur fuels.
- Improved methods for generating, transmitting and storing electricity.
- Commercial demonstration of synfuels technologies from all sources, geothermal energy, solar energy, environmental controls, fuel cells.

Jackson BillContinued

Proposal may use any form of assistance set forth in Sec. 7 of the Act:

- Jointly funded R&D.
- Contracts
- Guaranteed federal purchase or prices.
- Loans
- Incentives for inventors.

Secretary is to review and send recommendations to Congress within 3 months of submission of proposals.

Title IV - Authorizations for construction of specific energy facility projects now being considered by DOE. Total authorizations add to \$4.7 billion with proviso that no more than \$286 million shall be appropriated in 1980.

<u>Project</u>	<u>Amount</u>	<u>Project #</u>
-SRC I	\$500 million	78-2-d
-SRC II	\$700 "	78-2-d
-High-Btu gasification	\$600 "	76-1-b
-Low-Btu gasification		
for fuel gas	\$ 75 "	78-2-c
-50 MWe Geothermal	\$175	76-3-d
-50 MWe Geothermal	\$ 60 "	Loan guaran- tee & borrow- ing authority
-High Btu Gasification	\$600 "	77-1-b
-Low/Medium Btu Gasif.		
large industrial	\$250 "	76-1-c
-Low Btu Gasif. utility	\$400 "	77-1-c
-Fluidized bed combust.	\$300 "	76-1-d
-2nd 50 MWe Geothermal	\$175 "	76-3-b
-Oil Shale above ground		
retort	\$150 "	
-Urban & Industrial		
waste conversion	\$360 "	Loan guaran- tee & borrow- ing authority
-Oil Shale - In Situ	\$130 "	
-Fuel Cells	\$250 "	

Title V - Oil Shale Commercialization Test Program:

A federal program leading to construction of three government owned oil shale conversion plants on federal lands -- preferably Naval oil shale reserve lands; also includes a related impact assistance program, special patent provisions; creation of "Commercialization Test Special Fund" (a trust fund); and special provisions for taxes on state and local bonds.

Title VI - A study of opportunities for supply and production of oil from countries outside OPEC -- to be sent to Congress in 6 months.

.Title VII - A five year program for exploration and leasing for oil and gas on onshore federal lands.

.Title VIII - A "Gasohol" program with 5-year production goal of 5% of projected consumption of gasoline by 1985 and phased up percentage requirements for alcohol as a share of motor fuel -- starting with 1% in 1981 and reaching 10% by 1990.

.Title IX -

Fuel Switching: Additional provisions for switching existing industrial and utility facilities from oil to natural gas or coal, with some authority to override State air quality implementation plans.

Wheeling of power: Authority for DOE to order transfers of electrical power. Limits on percentage adders for transferred power.

.Title X - Renewable Energy Resources Program consisting of solar information dissemination; solar use in government, Federal use of gasohol, Power Marketing Administration authority to purchase and market power from non-federal entities; solar energy loans; and wind energy initiatives.

6. Forced-Use
of Synthetics
in Motor Fuel
H.R. 4345,
4401; S. 1399;
Amendment to
H.R. 4514

Replacement Motor Fuels Act of 1979

.Sponsors:

H.R. 4345: Jeffords (R-VT); Minetta (D-CA); Anderson (R-IL); Simon (D-IL); Perkins (D-KY); Glickman (D-KS); Emery (R-ME); Bedell (D-IA); Gradison (R-OH); Neal (D-NC); Wampler (R-VA); Heckler (R-MA); Moorhead (D-PA); Leach (R-IA); D'Amours (D-NH); Baldus (D-WI); Madigan (R-IL); Johnson (R-CO); Richmond (D-NY); Panetta (D-CA).
H.R. 4401: Minetta (D-CA) (Identical to H.R. 4345).
S. 1399: Introduced June 25, 1979. Ribicoff (D-CT); Nelson (D-WI); Randolph (D-WV); Baucus (D-MT); Domenici (R-NM).

H.R. 4514 Amendment: On June 20, 1979, Jeffords introduced language identical to H.R. 4345 as an amendment to H.R. 4514 as introduced on June 20, 1979, by Perkins, as a substitute for his original H.R. 4514.

.Status:

House: H.R. 4345 and 4401, introduced June 6th and 8th respectively, and referred to Committee on Interstate and Foreign Commerce.

Senate: S. 1399, introduced on June 25th, and referred to Committee on Energy & Natural Resources.

- .Provisions: .Calls on DOE Secretary to promote the development and use of replacement fuels for motor fuel with energy from coal, shale, biomass, etc.
 .Secretary must set goals with minimum no less than 10% of motor fuel by 1987-89 and goal of 20% by 1992.
 .Prescribes enforcement penalties.
7. Oil Shale Tax Credit President Carter's Proposed Oil Shale Tax Credit
.Sponsors: Proposed by President on April 5, 1979
.Status: Being considered by House Ways & Means Committee
.Provisions: A tax credit of \$3 per barrel would be allowed for each barrel of oil produced from shale to be paid from the proposed "Energy Security Fund" derived from the proposed excise tax on domestic crude oil.
8. Private Hi-Btu Project Great Plains Gasification Project
.Sponsors: Consortium of five natural gas distributing companies in the upper mid-west, led by American Natural Gas Company.
.Status: Proposal turned down by FERC Administrative Law Judge but final decision up to members of FERC.
.Provisions: Private financing and construction of full-scale hi-btu gasification plant using North Dakota Lignite with financing assured through rolled-in pricing for product from plant and "all-events" tariff.
9. H.R. 3671; - 4434 Federal "Energy Development & Management Authority"
.Sponsors: Congressman Tim Lee Carter (R-KY)
.Status: H.R. 3671, introduced on April 24, 1979, and H.R. 4434, a revised proposal introduced on June 12, 1979, have been referred to the House Interstate and Foreign Commerce Committee.
.Provisions: H.R. 3671 called for creation of a Government Corporation called the "Energy Development & Management Authority" (EDMA) -- which amounts to applying the concept of TVA to a government effort to:
 -Explore for, develop and market coal, oil, natural gas and shale oil on Federal lands.
 -Develop and demonstrate on a commercial scale technologies to produce liquid or gaseous fuel from oil shale or coal.

Provisions
(cont'd)

- Sell fuels produced below cost if necessary (with the government paying the difference) to promote use of alternative fuels.
- H.R. 3671 would also reserve 50% of federally-owned coal and oil shale for development by governmental units.

H.R. 4434 would establish a nonstock, nonprofit federally-owned Energy Development and Management Authority, governed by a 5-member Board appointed by the President and confirmed by the Senate. The EDMA could:

- Establish an Office for the Production of Energy from Coal (OPEC) which shall
 - .Initiate & conduct research on coal conversion technologies;
 - .Explore for and purchase coal for research and conversion to synfuels.
 - .Construct and operate synfuels facilities.
 - .Sell fuels at average market prices as determined by the Secretary of Energy, with sales priorities for State and local governments and publicly-owned utilities.
- Provide financial and technical assistance to private industries to help increase energy supplies.
- Request the right to explore and develop coal on federal lands.
- Be exempt from State and local statutes (except those required to comply with federal statutes) which interfere with purposes of the Act.
- Incur debt by bonds or other obligations of \$50 billion.
- Be authorized appropriations of \$100 billion.

10. H.R. 3885
H.R. 4669
S. 580

Energy Company of America

.Sponsors: H.R. 3885--Minish (D-NJ); H.R. 4669--Atkinson (D-PA);
S. 580--Stevenson (D-IL).

.Status: H.R. 3885, May 2, 1979, and H.R. 4669, June 28, 1979, referred to Interstate and Foreign Commerce; Interior and Insular Affairs; Science and Technology and Ways and Means Committees.

Status
(cont'd)

S. 580, March 8, 1979, referred to Government Affairs
Committee.

- .Provisions: Create a government corporation called "Energy Company of America"--exempt from all taxes to:
- Explore for, develop, produce, import, purchase, enrich, store, transport and sell oil, natural gas coal and uranium in the U.S. and throughout the world on its own or through joint ventures with private companies.
 - Act as exclusive bargaining agent for the U.S. for energy purchased outside the U.S. when U.S. interests so require.
 - Research and develop new methods and technologies; obtain and operate pilot plants, demonstration facilities and experimental commercial-scale installations incident to such R&D.
 - Select up to 30% of federal land acreage for lease or for ECA development.

11. S. 581

"Energy Bank of America"

- .Sponsors: Stevenson (D-IL); Moynihan (D-NY)
- .Status: Referred to Committee on Banking, Housing & Urban Affairs.
- .Provisions: Creates a Government corporation known as the "Energy Bank of America", exempt from all taxes, which would be authorized to provide financial assistance:
- In the form of advances, extension of credit, investment, participation or guarantees, including loans, loan guarantees, guarantees of price purchase and leaseback of facilities and the purchase of convertible or equity securities--but excluding grants-in-aid.
 - To any entity not otherwise able to secure commercial financing engaged in or proposing to engage in energy R&D or production--to finance ownership, construction, conversion or expansion of productive facilities; acquire equipment, plant machinery, supplies, lands, mineral rights; or to provide working capital.

Assistance in excess of \$60 million per entity would be submitted to Congress and could not be given unless 25 legislative days passed without resolution or disapproval.

Comprehensive Energy Plan to be developed by Secretary of Energy within 1 year to set priorities for financial assistance.

12. S. 1377

"Synthetic Fuels Production Act of 1979"

- .Sponsors: Domenici (R-NM); Ribicoff (D-CT); Hatfield (R-OR); Johnston (D-LA); Stevens (D-AK); Sasser (D-TN); Moynihan (D-NY); Stone (D-FL); Randolph (D-WV); Nelson (D-WI)
- .Status: Introduced June 19 and referred to Committee on Energy and Natural Resources. Committee hearings on S. 1308 are also giving some attention to S. 1377.
- .Provisions: Title I: Findings & Purpose
.Findings on energy independence, national security, need for capital beyond traditional sources; need to resolve regulatory and licensing issues promptly.
.Purposes to encourage flow of capital to sectors developing domestic non-nuclear energy; expedite licensing and regulatory decisions; provide financial assistance in the form of guaranteed loans; hasten non-nuclear energy R&D; develop domestic energy sources; supplement -- not compete with -- private capital; set goals for 1990 for synthetic and alternate fuels; and create a self-liquidating corporation to assist.
- Title II: Corporate Status; powers, subsidiaries and tax status
.Creates a Syn-Fuels and Alternative Fuels Technology Authority (governed by a Board of Directors appointed by the President and confirmed by Senate).
.Authority can create subsidiaries to carry out functions of the authority.
.Authority exempt from all Federal, State, and local taxes except that (i) real property shall be subject to taxes; and (ii) entities created or activities undertaken by authority involved in energy production, etc., shall be subject to Federal and other taxes.
- Title III: Financial Assistance
.Authority may provide financial assistance (defined as advance, extension of credit, investment, participation, or guarantee including loans, guarantees of obligations, guarantees of price, purchase and lease-back of facilities and purchase of convertible or equity securities -- but excluding grants-in-aid); to business concerns for projects specified. To the extent practicable, assistance shall be in the form of loans and loan guarantees rather than equity investment or guarantees of price.
.All contractual commitments backed by full faith and credit of the U.S.

Provisions
(cont'd)

- . Authority may provide financial assistance to those projects which would not otherwise receive sufficient financing upon commercially reasonable terms from other sources
 - employ or stimulate application of non-nuclear technologies not in widespread domestic use.
 - employ technologies which are in widespread use by (i) are of such size as not to otherwise be undertaken; or (ii) involve new institutional or regulatory arrangements.
 - employ or stimulate technologies for environmental protection.
- . Authority shall share in profits commensurate with risk assumed.
- . Financial assistance shall not unduly enhance recipient's competitive position.
- . No assistance for projects in R&D or management not considered adequate.
- . May assist projects for regulated markets under specified conditions.
- . No one firm can get more than 10% of authorized funding.
- . Interest rates for loans determined by Authority but not less than the greater of:
 - Estimated borrowing costs for comparable loan plus administrative expense;
 - Interest paid by credit worthy borrower from private lenders for similar projects.
- . Authority may guarantee any lender against loss of principal and interest on securities, obligations or loans to business concerns.
- . Total financial assistance outstanding at any one time (shall not exceed authorized capital (\$25 billion) and authorized borrowing (\$ 50 billion)).
- . Authority may make high risk loans or direct investments or provide product price guarantees or other direct financial assistance provided adequate reserves are created to meet such contingent liabilities.
- . Authority shall not acquire or retain control of operating assets except where acquired by foreclosure (and then not for more than 4 years) or where prior to commercial operation (and then not for more than 2 years after beginning commercial use).

Title IV: Capitalization and Finance

- . Capital Stock of \$25 billion, subscribed by the Secretary of the Treasury. Appropriations of \$25 billion authorized to the Secretary for this purpose.
- . Authority is authorized to have \$50 billion outstanding at any one time in notes, debentures, bonds or other obligations (with first right of purchase to the Treasury or Federal Financing Bank).

.Receipts and disbursements not included in U.S. budget or governed by limitations.

Title V: Management

- .Five directors appointed by the President, subject to Senate confirmation and serving at the pleasure of the President (not fixed terms). Chairman must be fulltime. Compensation at levels determined by the President.
- .Other provisions cover employees, conflict of interest, delegations, reviews and audits, reports and records of outside contracts.

Title VI: Priority Energy Project Act of 1979

- .This title is almost identical to Title II of Senator Jackson's S. 1308 except that authorities are vested in the Synthetic Fuels and Alternate Fuels Production Authority and the Secretary of Energy or, in some cases, only in the Authority; also covers nuclear.

Title VII: Production Goals of the Authority

Synfuels Production Goals

- The Authority shall establish a comprehensive set of goals of commercial production for synthetic fuels from various energy sources that should be met by 1990; submit goals and timetables to Congress within 90 days after Board is approved.
- Congress has 45 days to concur or send its recommendations to the Authority in a Joint resolution.
- Authority publishes goals and timetables within 30 days.

Ownership Powers

- The Authority may supervise construction, management, operation and production of fuels from an Authority-owned synthetic fuels facility to meet part of DOD's fuel needs if (i) no eligible private firm has applied for financial aid for a process considered necessary by the Authority; (ii) that matter is reported by the Authority; and (iii) the President concurs and neither House objects.
- The President may order the Authority to construct, manage and operate a facility in national emergency.
- Planning, engineering and construction to be done by private firms.

.Oil Shale Production Goals: Goal shall be at least 500,000 barrels per day by 1990 and all power of Act shall be used to achieve goal.

.Coal Gas Production Goals of the Authority: Goal shall be at least 500,000 barrels per day equivalent by 1990, using all powers to achieve. Priority to be given to processes most apt to meet goals and to facilities located in states where governor will help expedite necessary approvals -- with equal weight given to availability of coal in a state.

.Coal Liquids Production Goals of the Authority:
Goal shall be at least 500,000 barrels per day by 1990. All powers of Act to be used to achieve. Preferences as in Coal Gas, above, except no reference to availability of coal.

.Production Goals for other Synfuels and Alternate Fuels: Goals and timetables to be developed after investigating processes. Processes may be exempt if they hold inadequate promise or are too experimental or limited in scope.

Title VIII: Unlawful Acts & Penalties

.Covers false statements, forgery, misappropriation of funds and unauthorized activities, name infringement, unlawful contracts.

Title IX: General Provisions

.Covers coordination, severability.

.Termination and liquidation of the Authority.

-No new commitments after September 1986 and no new financial assistance after September 30, 1989.

-Directors take all practicable and reasonable steps to liquidate affairs between 9/30/86 and 9/30/89 including sale or transfer of assets to U.S. agencies, or sale to public.

-Authority shall terminate September 30, 1989, unless extended by the President by Executive Order to provide more time for orderly liquidation.

-Following termination, responsibility for remaining liquidation goes to Secretary of Treasury.

-Provision of financial assistance shall be considered a "major Federal action" for NEPA purposes.

-Exempt from laws governing public contracts and public buildings and works except Davis-Bacon.

-Securities laws do not apply to Authority.

-Government Corporation Control Act not applicable.

-Authority may acquire federal minerals and lands in accordance with Mineral Leasing Act and OCS Act.

3. H.R. 4588

Synthetic Fuels Production Act of 1979.

.Sponsors: Luken (D-OH); Heftel (D-HI)

.Status: Introduced on June 22, 1979, and referred jointly to Committees on Banking, Finance and Urban Affairs, and Interstate and Foreign Commerce.

.Provisions: Identical to S. 1377 introduced by Senator Domenici, et al.

14. Substitute Synthetic Fuels Manpower Training and Synthetic Fuels
For H.R. 4514 Reserve Corporation.

.Sponsors: Perkins (D-KY)HR 4514, June 18, 1979 covered only CETA.

.Status: Reported by the House Agriculture Committee on June 28, 1979. Rules Committee probably will refer to several other House Committees.

.Provisions: Title I: Amends the Comprehensive Employment and Training Act (CETA) to authorize the Secretary of Labor to make grants to state or local public agencies to train individuals for jobs in synthetic fuels industry; and authorize appropriations of \$100 million for each fiscal year--1980, 1981 & 1982.

Title II:

- Creates a wholly-owned Government "Synthetic Fuels Reserve Corporation" to produce or provide assistance for production of liquid or gaseous synthetic fuels equivalent to 5 million barrels of crude oil per day.
- .Sources to include coal, shale, lignite, peat, solid waste, other minerals or organic materials (other than oil, gas or derivatives).
- .Corporation authorized and/or directed to:
 - conduct R&D
 - sell synthetic fuel to government or others for use in the U.S.
- .Difference between costs of production and prevailing market price to be paid by government.
- .Government acquires synthetic fuel from any entity receiving assistance if such fuel is unable to be sold within 3 months of offer at cost of production.
- .Five member Board - appointed by President with Senate approval -- with fixed terms.
- .Corporation may:
 - Make loans, guarantee loans, make grants to assist in establishment and operation of synfuels facilities.
(Obligations, loans and loan guarantees not to exceed \$200 billion at any one time.)
- Issue bonds, notes, debentures and similar obligations.
 - .Payment of interest and principal guaranteed by the U.S.
 - .Principal and interest on obligations issued by corporation exempt from state or local taxes (and not a part of gross income for federal taxes).
- Board shall have a division to assist the Corporation and other entities in obtaining permits, approvals and licenses from Federal, State and local governments.

Title III: Identical to Replacement Fuels Act of 1979 covered in H.R. 4345, 4401, S. 1399.

- No environmental requirement greater than best available technology shall be required.
- Tax Incentives include:
 - .Provides a \$3 per barrel tax credit for each barrel (equivalent) of synthetic fuel produced in the U.S. not to exceed amount of tax owed.
 - .Extends Sec. 48(1) of IRC to equipment for synfuels production.
 - .Provides rapid amortization -- as in the case of pollution control facilities (under Sec. 169 of IRC).
- Authorizes appropriations of \$5 billion per year.

15. H.R. 4533

"Oil Independence Act of 1979"

.Sponsors:

Spence (R-SC)

.Status:

Introduced June 19, 1979, and referred jointly to Committees on Agriculture; Banking, Finance & Urban Affairs; Interstate & Foreign Commerce; and Science & Technology.

.Provisions:

Amends Sec. 509 of the Rural Development Act of 1972 (7 USC 2669) to authorize and direct the Secretary of Agriculture to:

-Formulate and carry out a program for the production and marketing of industrial hydrocarbons and motor fuels derived from agricultural commodities, forest products, coal, coal tars and solid wastes -- to stabilize and expand markets for commodities and products and contribute to hydrocarbon and motor fuel supply.

-Provide for construction of at least 20 plants by guaranteeing loans not to exceed \$15 million per plant to public, private or cooperative organizations for not to exceed 20 years.

Amends Sec. 1419 of the Food & Agriculture Act of 1977 (7 USC 3154) by:

-Expanding to cover solid waste.

-Providing that 50% of the funds appropriated in any fiscal year for grants under Sec. 1419 be for research on production of industrial hydrocarbons and motor fuels from agricultural commodities, forest products, coal, coal tars and solid waste.

16. H.R. 4484

"National Energy Self-Sufficiency Act of 1979"

.Sponsors:

Bailey (D-PA)

.Status: Introduced on June 15, 1979, and referred to Committees on Ways & Means; Banking, Finance & Urban Affairs; and Interstate and Foreign Commerce.

.Provisions: .Imposes a duty on imported crude oil equal to difference in imported price and average price of synthetic fossil fuels.
 .Secretary of Treasury (in consultation with Secretary of Energy) determines average prices, to be redetermined monthly, and notifies customs officers who collect duties.
 .Reserves go to a trust fund to be used for loans to finance up to 50% of the cost of constructing synfuels facilities.

17. H.R. 4594 Refinery Sale of Synfuels; tax incentives for synfuels

.Sponsors: Walker (R-PA)

.Status: Introduced on June 22, 1979, and referred to the Committees on Ways & Means; Interstate & Foreign Commerce.

.Provisions: Directs the Secretary of Energy, by rule or order to:
 .Require each refinery in the U.S. selling any refined petroleum product to sell not less than the following percentages of synthetic fuels (from oil shale, tar sands, coal or biomass):
 - 1985 - 5%
 - 1990 - 12%
 - 2000 - 20%
 .Undertake a study of nature and extent of delays and impediments under Federal, State or local law reducing the amount of synthetic fuels produced in the U.S.
 .Authorizes the Secretary of Energy to modify requirements of law administered by him, EPA or Interior if effect is reduction of synfuels production.
 .Extends definition of shale oil equipment in paragraph 7 of Section 48(1) of IR Code to cover tar sands as well as oil shale.
 .Provides for amortization of any qualified fuel-producing facility over 24 months.

18. H.R. 4474 Synfuels amendment to Energy Policy and Conservation Act (EPCA)

.Sponsors: Dingell (D-MI)

.Status: Introduced June 14, 1979, and referred to Committee on Interstate and Foreign Commerce.

.Provisions: Declares national goal for domestic synthetic fuels and synthetic chemical feedstocks equivalent to 500,000 barrels of crude oil per day.

If necessary to achieve goal, the President shall:

- .Enter into contracts to purchase or commit to purchase synfuels and synthetic chemical feedstocks.
- .Use to meet government needs, transfer and store in the Strategic Petroleum Reserve or exchange for products to be stored in SPR.
- .Contract price not to exceed 110% of comparable imported petroleum-derived fuel or feedstock (disregarding entitlement). Can pay higher price if necessary to meet goal and after notice in Federal Register and 60 day opportunity for public comment.
- .President can refuse delivery and pay difference between contract and market price.

Other provisions of H.R. 4474 are essentially similar to H.R. 3930 as reported by House Banking Committee, but are cast as amendments to EPCA rather than Defense Production Act.

19. H.R. 4499 Synfuels Amendment to EPCA and Priority Energy Project Act

.Sponsors: Dingell (D-MI)

.Status: Introduced June 15, 1979, and referred to Committees on Interstate and Foreign Commerce and Interior & Insular Affairs.

.Provisions: Title I: Amendments to EPCA identical to H.R. 4474 (No. 17 above).

Title II: Priority Energy Project Act of 1979 - is identical to Title II of Senator Jackson's S. 1308 (and also nearly identical to Title VI of Senator Domenici's S. 1377).

Title III: Would amend Section 408 of the Public Utilities Regulatory Policies Act of 1978 to change the definition of a small hydroelectric power project.

Title IV: Is identical to Subtitle B of Title IX -- (Orders for Transferring Electrical Power) of Senator Jackson's S. 1308.

Title V: Gasohol is identical to Title VIII of Senator Jackson's S. 1308.

20. H.R. 4500 National Program for Full Development of Energy Supplies
- . Sponsors: Dingell (D-MI)
- . Status: Introduced June 15, 1979, and referred jointly to the Committees on Armed Services; Banking, Finance & Urban Affairs; Government Operations; Interior & Insular Affairs; Interstate & Foreign Commerce; Public Works & Transportation; Science & Technology and Ways and Means.
- . Provisions: Title I: Demonstration of near term Technologies Identical to Title IV of Senator Jackson's S. 1308. Basically, directs the Secretary of Energy to utilize existing authority of Secs. 6 and 7 of the Federal Non-Nuclear Energy R&D Act of 1974 -- which provides a wide range of federal assistance and incentives (including guaranteed market and purchase, loans, loans guarantees and others) to commercialize most any energy technology. Secretary would have to request proposals within 6 months and submit them to Congress with recommendations within 3 months of receipt.
- Title II: DOE Synfuels RD&D Project authorizations. Identical to Sec. 401(a) of Title IV of Senator Jackson's S. 1308.
- Title III: Oil shale commercialization Test Program. Identical to Title V of S. 1308.
- Title IV: Oil & Gas Leasing. Identical to Title VII of S. 1308
- Title V: Renewable Energy Resources: Identical to Title X of S. 1308.
- Title VI: Study of World Oil Supply & Production Opportunities. Identical to Title VI of S. 1308.
21. H.R. 4573 Priority Energy Project Act of 1979 (Udall)
- . Sponsors: Udall (D-AR)
- . Status: Introduced June 21, 1979, and referred jointly to Committees on Interior & Insular Affairs, and Interstate & Foreign Commerce.
- . Provisions: Very similar to Title II of Jackson's S. 1308. Differences include:
 . Number of projects designated as priority is limited to 6 per year.

- .Criteria are slightly different.
- .Agency decision is to be made in 9 months, but President can grant 120 day extension.
- .Deputy Secretary carries out part of DOE responsibility, rather than a specially created Office.

22. S. 1415 Priority Energy Project Act of 1979 (Bentsen)

- .Sponsors: Bentsen (D-TX)
- .Status: Introduced June 26, 1979, and referred to the Committee on Energy & Natural Resources.
- .Provisions: Titles I & II (Purpose, Definitions and Priority Energy Projects (are similar to Secs 201-216 of Title II of S. 1308 (Jackson) -- with some important exceptions. Differences include:
 - .Deputy Secretary of DOE handles much of responsibility instead of a separate office.
 - .Secretary publishes notice of request for designation in 15 rather than 30 days.
 - .Sixty rather than 45 days to make determination as to whether a project is designated a priority project. If no decision by secretary, project is automatically so designated.
 - .Slightly different criteria for designation.
 - .Sets one year deadline for decisions and overrides schedules in other law.
 - .President may grant 120 extension to agency.
 - .Requires rather than requests state and local cooperation.
 - .Secretary sets decision schedule for state and local action, which schedule can override schedule in State or local laws.
 - .Subject to one House veto, President may waive requirements of state or local law which are impeding energy projects.
- Title III - Sets up procedure, including schedules set by Secretary of Energy for expediting certification decisions by FERC on interstate natural gas pipelines.
- Title IV - Judicial Review -- appears to be identical to Sections 218 - 222 of S. 1308 (Jackson).

23. International Initiative

"International Organization to Promote Energy Technology"

Sponsors: Carter Administration

Status: Possible proposal for Tokyo Economic Summit.

Provisions: Press reports indicate that the U.S. Government is considering, as part of its recommendations for the Tokyo Economic Summit in late June 1979, to propose an international cooperative effort to coordinate R&D and promote commercial application of emerging technologies to use such energy resources as heavy crude oil, tar sands, coal, biomass, and others.

INDEX TO PROPOSALS
BY NUMBER AND SPONSOR

APPENDIX III

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Administration's Oil Shale Tax Credit			7	II-8
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* Was changed during House floor action and passage as S.932.

APPENDIX C

IMPACTS

FEDERAL AMBIENT AIR QUALITY STANDARDS

Particulate Matter and Sulfur Dioxide
(Micrograms per cubic meter - $\mu\text{gm}/\text{m}^3$)

Prevention of Significant Deterioration Regulations

<u>Pollutant</u>	<u>Class I</u>	<u>Class II</u>
Particulate Matter		
Annual Geometric Mean	5	19
24-Hour Maximum (a)	10	37
Sulfur Dioxide		
Annual Arithmetic Mean	2	20
24-Hour Maximum (a)	5	91
3-Hour Maximum (b)	25	512

- (a) A 24-hour maximum of any 24-hour period and must not be exceeded more than once in a 12-month period.
- (b) A 3-hour maximum of any 3-hour period and must not be exceeded more than once in a 12-month period

Source: "Final Environmental Impact Statement, Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado," Vol. I., Prepared by Bureau of Land Management, Dept. of Interior, pp. IV-30,31.

APPENDIX C

CLIMATE & AIR

AMBIENT AIR STANDARDS FOR THE STATE OF COLORADO

Suspended Particulate Matter and Sulfur Dioxide (Micrograms per cubic meter - $\mu\text{gm}/\text{m}^3$)

<u>Suspended Particulate Matter (a)</u>	<u>Non-Designated Areas</u>
Short-Term (b)	150
Long-Term (c)	45

- (a) Measured at ambient conditions.
- (b) A 24-hour maximum of any 24-hour period and must not be exceeded more than once in a 12-month period.
- (c) An annual arithmetic mean of all 24-hour concentrations.

<u>Sulfur Dioxide (a)</u>	<u>Maximum Allowable Increment Over Baseline</u>	
	<u>Category I</u>	<u>Proposed Category II</u>
Annual Mean (b)	2	10
24-Hour Maximum (c)	5	50
3-Hour Maximum (d)	25	300

- (a) 0° Centigrade - 760 mm Hg.
- (b) An annual arithmetic mean of all 24-hour concentrations.
- (c) A 24-hour maximum of any 24-hour period and must not be exceeded more than once in a 12-month period.
- (d) A 3-hour maximum of any 3-hour period and must not be exceeded more than once in a 12-month period.

Source: "Final Environmental Impact Statement, Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado," Vol. I.,
Prepared by Bureau of Land Management, Dept. of Interior,
pp. IV-30,31.

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