CHAPTER 6

Economic and Financial Considerations

Contents

List of Tables

List of Figures

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Introduction

The loss of oil imports from Iran coupled with large OPEC price increases during 1979 once more emphasized the vulnerability of the United States to its continued dependence on imported oil. Rapidly escalating world oil prices combined with uncertain supplies and dwindling domestic reserves have seriously affected the balance of payments, the rate of inflation, and the general health of the economy. While expert opinions may differ about prices in the immediate future, they agree that supplies will remain uncertain and prices will continue to rise. The recently renewed interest in shale oil (and other synthetic fuels) as contributors to the domestic fuel supply has arisen in response to these uncertainties.

The present debate over the proper economic policy to pursue with respect to oil shale development centers around the following:

- the potential it may have for alleviating the Nation's energy-supply problems;
- the financial, environmental, and socioeconomic costs and risks that could be encountered in developing an oil shale industry;
- a comparison of its benefits and costs with those of other energy strategies such as conservation, solar, increased direct use of coal, other synthetic fuels, expanded domestic exploration and production, or continued reliance on foreign oil:
- the implications of both alternative production goals and the rate at which the industry is established for maximizing the benefits and minimizing the costs and risks of commercialization;
- the relative advantages and disadvantages of different financial mechanisms for achieving various production levels and minimizing private and Government risk; and
- the major commercial and institutional risks and obstacles that currently hamper commercial development, which of these can be predicted, and in which cases is information insufficient to adequately evaluate policy options.

Considering the amount of capital that would need to be invested and profitably returned over long periods of time, a rational and informed choice about the commercial production of shale oil (or any synthetic fuel) requires making reasonably confident estimates of the following factors and relationships:

- the required capital and operating costs for various levels of shale oil production, and a comparison of these costs with those for alternative strategies for obtaining equivalent benefits;
- the future effect of OPEC pricing policies;
- the corporate perceptions of specific risks and deterrents that currently inhibit private commercialization;
- the subsidies and incentives that would most effectively, and at least cost, sufficiently reduce uncertainty to promote development; and
- the temporary or permanent subsidies that would be required to maintain an industry.

These are all complex issues open to a variety of interpretations. Several of these questions may be unanswerable at this time with the information available.

The Nature of the Investigations

This chapter reports the results of the following analyses:

- The capital and operating costs have been estimated for commercial-size facilities in third-quarter 1979 dollars. This has been done for both surface retorting and modified in situ (MIS) technologies. The total costs of various production levels have been calculated for industries based on both generic technologies. The accuracy of current cost estimates has been evaluated in the light of the prior unreliability of such projections, and an attempt has been made to disaggregate the factors responsible for the escalating cost estimates for these facilities.
- The effect of uncertain prices for OPEC crude on shale oil commercialization has been examined, a variety of projections for these prices evaluated, and a probable rate of increase for future real prices described.
- OTA has undertaken extensive qualitative and quantitative examinations of the relative effectiveness and outcomes of various possible financial incentives for stimulating commercial development. These were based on independently conducted mathematical simulations of industry economics, as well as on extensive discussions with private consultants, Government financial administrators, and industry representatives.
- The relative advantages and the merits of several different strategies, development schedules, and production targets have been examined with respect to their comparative costs, risks, and benefits.
- A detailed study has been carried out of the impact on capital availability and pricing of oil shale development at several levels of production. The investigation indicates the probable impacts that alternative levels of oil shale production will have on the cost and availability of capital, both for the U.S. energy sector and the economy as a whole, given a variety of different growth and demand characteristics for investment capital, This examination also considers the relative impact that different Federal incentives will have on capital markets.
- The effect of various levels and paces of oil shale development on the level of employment, the balance of payments, the rate of inflation, and Federal tax generation,

Summary of Major Findings

The major conclusions of OTA's economic analysis of the oil shale industry are as follows:

- The commercialization of oil shale has been generally impeded in the past by several uncertainties. Among the most important are large and unreliable plant capital cost estimates, the insufficient number of high-grade private oil shale tracts plus limited access to Federal oil shale lands, uncertainty about present and future environmental regulations, and uncertainty over future prices for oil.
- It is likely, given current market conditions, resource availability, and the regulatory climate that without additional Federal action a shale oil production capacity of 100,000 bbl/d will be online by 1990-92. It is probable, given similar conditions, that the production of 200,000 bbl/d by that date will require financial incentives, direct Government participation, or major changes in the regulatory environment of the industry. The same would be even more the case for a 400,000 -bbl/d industry. Furthermore, the deployment of this size industry by 1990 could require additional land ex-

changes or Federal leases. The deployment of a 1-million-bbl/d industry by the same date would require aggressive action in all of these areas.

- Given recent increases in the price of oil, the potential marketability of shale oil improved substantially during late 1979 and early 1980. In narrow economic terms, the production of shale oil may be price competitive with foreign crude at this time. However, this conclusion is subject to several critical limitations, It assumes that current capital and operating cost estimates are within 20 percent of actual costs, that the price for oil will continue to rise throughout the rest of this century by at least a real 3 percent per year, and that developers require a real discount rate of no more than 12 percent. (The economics of shale oil and its potential selling price are extremely sensitive to the discount rate assumed by the developers.)
- If financial incentives to private industry are to be employed, production tax credits, purchase agreements, and price supports have the most economic merit based on a variety of criteria. However, it should be noted that the subsidy effect of purchase agreements and price supports are dependent on the contract price that is set. Consequently, the success of these two incentives will depend on how they are constructed and administered. Small and moderate firms will require some kind of front-end subsidy if they are to significantly participate in oil shale development. If such participation is an important goal of Government policy, debt guarantees or debt insurance are probably the most efficient vehicles.
- The deployment of a 400,000-bbl/d industry by 1990 would begin to markedly strain the capacity of U.S. manufacturers to supply heavy equipment to developers. To deploy a 1-million-bbl/d industry by that time would use between 15 and 30 percent of current U.S. annual production of this equipment. There would be a similar strain on the capacity of large integrated architectural/engineering firms capable of undertaking major process plant construction.
- Existing capital markets and lending institutions are able to supply sufficient capital for even the rapid development of a large industry (1-million-bbl/d by 1990) without significant perturbations,
- Oil shale development would provide a number of economic benefits such as contributions to the national fuel supply and direct substitution for foreign oil imports. A production of 500,000 bbl/d would reduce the balance-of-payments deficit by about $5 billion current dollars if the price of foreign crude were $31/bbl.
- Oil shale development, even at high rates of deployment, would have an insignificant impact on national prices and rates of employment. However, the production of even 200,000 bbl/d by 1990 would noticeably increase local rents, land prices, and labor costs. Even moderate developmental rates would favorably affect local employment levels and this effect would extend to the region with the deployment of a 400,000-bbl/d industry by 1990.

Development, Commercialization, and Deployment’

In this assessment, the term commercialiuation is used to designate the process by which private industry adopts a technology for commercial use after most of the technical uncertainties affecting its economic feasibility have been resolved. In the United States, commercialization of new technologies is primarily undertaken by private firms without direct Federal intervention. Nevertheless, during the past decade the amount of direct Government involvement has risen sharply. If Congress and the administration decide to stimulate the commercialization of oil shale, it will be necessary for their attention to be focused on the period between the time when the major technical problems have been solved and the time when the technology is commercially self-sufficient—the initial phase. Once a decision about the advisability of intervention has been made, the question then is how the commercialization of the initial phase can best be accomplished.

Government sponsored development programs consist primarily of research and development (R&D) to solve the technical problems of a process. Thus far, such programs for oil shale have been directed to developing specific techniques for mining, retorting, rubbling (in MIS processing), removing of impurities, and hydrotreating the shale oil.

Commercialization, in which a technology is adopted and made economically viable by private industry, involves the resolution of the institutional and economic deterrents that affect profitability. Efforts by the Government to promote commercialization assume that the adoption by private industry of a process, which is temporarily not commercially viable, will be expedited. The rationale is that such assistance will enable an industry to become self-sufficient and profitable without further subsidy. A Government-sponsored deployment program differs from one to promote commercialization in that it does not assume that an industry will ultimately be self-sufficient or that incentives are temporary. The deployment of the synthetic rubber industry during World War II is a well-known example of such a program. In this case the industry subsequently became profitable without subsidy, but this was not the main objective of the program.

Both deployment programs and commercialization support for synthetic fuel plants have been proposed. Although they have similar goals, these strategies imply very dissimilar relationships between Government and industry. Deployment programs are governmentally controlled. The function of private firms is restricted to advising, constructing, and, in some instances, operating the facilities. Private corporations provide services for a fee to the Government, which buys the products and services and retains ultimate authority over the planning and the pacing. Commercialization, on the other hand, implies that the private sector makes the final decisions about adopting a technology.

The Rationales for Federal Intervention

From an economic point of view, Government involvement in commercialization may be justifiable when private industry declines to undertake an enterprise that meets major social needs or benefits society. The penalty for governmental inaction may take the form of a forgone social benefit, such as a decrease in national security because of insufficient domestic suppies of oil, or of increased costs to society, such as environmental damage because of inadequate regulation. Society would also have to pay if, as a consequence of the Government's failure to intervene, the price of a resource increased at a later time.

The deliberate stimulation of a significant level of oil shale production could be expected to have a number of social benefits. It would help reduce dependence on foreign oil. It would position the United States several years closer to the deployment of a major shale oil industry should this be made necessary by future political or economic events. Stimulated production might also have a moderating effect on oil price increases, although it is not clear what level of production would be needed for this to happen.

Private industry declines to invest in an enterprise when it lacks confidence in the prospects for profitability. Higher expected profits are required of very risky projects than of more certain ones. Three types of risk for oil shale are discussed in this chapter:

1. the possibility that capital and operating cost estimates may seriously underestimate a project's cost and thus jeopardize its profitability or that the technology will not perform as planned,
2. the possibility that world oil prices may fluctuate in such a way that product marketability will be interrupted at some point in the time period required to recoup the initial investment, and
3. the possibility that regulatory delays or a change in environmental standards may adversely affect project economics.

If the Government is already intervening in such a way as to penalize a new technology, the private sector may be discouraged from pursuing it, despite its usefulness. For example, the regulation of the prices of domestic petroleum and natural gas that is now being phased out undoubtedly penalized oil shale development.

It is widely believed in oil shale industry circles that the overall impact of Government policy (e.g., regulations, permitting processes, preferential treatment of conventional petroleum, and limitation of access to shale resources on Federal land) has been one of the most important impediments to oil shale development,

A variety of groups and individuals oppose Government stimulation of the oil shale industry (or other industries) because they believe that the free play of market forces will make much more efficient and productive market decisions than will any federally inspired stimulation program. Those sharing this perspective argue that favorable alteration of oil shale economics by the Government will inhibit the use of the most efficient energy sources, encourage less efficient management of the industry itself, increase the cost of energy, and foster continued dependence on fossil fuels. However, those who would allow the market to decide whether shale oil should be produced, also tend to argue that taxes on developers, restrictions on resource acquisition, and regulatory constraints should also be radically reduced.

It does not necessarily follow from the failure of market mechanisms to promote commercialization that the Government will or can do it better. Government intervention is justified only if its benefits (appropriately computed) are greater than its actual real costs. Since the choice is not between efficient markets and inefficient Government or efficient Government and inefficient markets, but rather between inefficient markets and inefficient Government, the question is which will be more effective in a particular situation.

Impediments to the Commercialization of Oil Shale*

The successful commercialization of a new technology ultimately depends on its profitability. Commercialization will not take place, despite Government encouragement, if developers are unable to obtain a return on their investment commensurate with returns available to them from other investments. Consequently, in determining the proper course to pursue with respect to oil shale development, the Government needs to give careful consideration to the prospects for profitable operation. An industry that requires permanent subsidies is a different economic proposition from one that needs them only for the first commercial-size facilities. There are three types of factors that influence self-sufficient profitable operation: technical, economic, and institutional.

Technical uncertainties primarily refer to the difficulties associated with scaling up a new process from pilot to commercial size. This usually involves solving technical problems that could adversely affect operation and thus increase the risk of financial loss, e.g., a component may be required to perform beyond the capacity of available equipment, or existing mining techniques may be inadequate for the scale of commercial-size operations. With MIS technologies, the need to properly rubble shale in order to achieve necessary burn characteristics (and thus a high rate of shale oil recovery) is such a technical problem. With surface retorting, an example would be scale-up of 10 to 20 times of complex reaction systems handling massive quantities of solids.

Economic uncertainties are different for those technologies that produce a substitute for an older product than they are for those that produce primarily new products. The economic risks associated with shale oil center around whether it can be produced and sold with sufficient profitability to compete with conventional crude. Uncertainty about capital and operating costs has continually beset corporate decisionmaking with respect to oil shale commercialization. In addition, developers are unable to accurately predict shale oil's marketing potential because of uncertainty over future prices for OPEC crude. The recovery cost of most world oil is unquestionably far lower than that of shale oil, and will remain so over the life of a first-generation shale oil facility. Oil price increases have begun to make shale oil very attractive. However, since these prices are, in part, set by a cartel and bear little relation to the cost of production, there is no certainty that they will continue to rise in real terms. *

Commercial shale oil facilities producing 50,000 bbl/d require investments of around $1.5 billion (third quarter 1979 dollars). In order to recoup this investment, they will have to function profitably for 10 to 15 years. Given the 4 or 5 years such plants take to become operational, it is clear that even the largest private developers would want to be confident about the trend of international prices over the next 15 years in order to undertake commercial operations.

Institutional uncertainties occur because all technologies and economic activities take place within an institutional context that can act to facilitate or impede their commercialization. The extent to which this happens depends on the extent to which the technology and its costs create conflicts over basic values or the use of scarce resources. At issue is whether the aggregate impact of Government policies such as leasing arrangements, taxes, incentives, and environmental regulations would be applied more or less favorably to oil shale development than they would be to other forms of energy. Clearly, Government policy does not treat all energy sources "neutrally."

*Many analysts believe that the OPEC cartel has lost much of its power to set prices and that OPEC price decisions are now follow ing rather than preceding market trends. Recent evidence of market prices rising above OPEC-established prices supports this belief. So does the outcome of the December 1979 OPEC meetings,

Although not as severe as the polarization that has been taking place over nuclear power, the debate over the development of oil shale and other synthetic fuels is significant. Proponents of solar power and conservation continue to oppose fossil-based synthetic fuels because their development supposedly diverts funds from the pursuit of "soft" energy strategies and discourages conservation. Environmental groups oppose development because of the possible deleterious effects on air, water, and land. Fiscal conservatives oppose Federal intervention on the grounds that Government money should not be used to subsidize private development. Although it has been argued that the populace of the oil shale region is generally in favor of development, local communities are concerned about the impact that these facilities might have on their quality of life and the local environment.

Developers believe, virtually without exception, that delays and costs associated with the permitting process are a major disincentive to oil shale investment. They argue further that the possibility of new or more strict regulations in the future is a severe impediment to development. The imposition of new regulatory rules or standards after a plant is in construction or operation could require extensive and costly modification of the facility's design or operation. These expenses could seriously harm a project's economics, and in extreme cases force the suspension of operations. The need to compensate for significant regulatory risks and disincentives is one of the primary arguments used to justify Federal subsidies.

To understand the prospects for successful commercialization, it should be recognized that many of the technical, economic, and institutional impediments are interdependent. In general, the potential for successful commercialization is limited by the margins available to accommodate a technology to these impediments without encountering barriers. Thus, if the relative economic advantage of a process is very large, then extensive adjustments to environmental standards can be made without reaching an economic barrier. When a process has relatively low technical performance requirements, it may be possible to reduce economic or institutional barriers by upgrading technical performance. However, if technical performance goals are high, production costs are close to or exceed the selling price for competitive products, and institutional barriers are restrictive, then the technology will encounter serious difficulties. Under these conditions, the usual response of industry would be to postpone commercial commitment while waiting for technical improvements, reduced institutional barriers, or improved market prices for the product.

Technical problems can be reduced through further R&D. Economic uncertainty can be averted through some form of subsidy. Institutional barriers can be minimized through altering administrative or regulatory rules and timetables.

Although other considerations are extremely important (e.g., overall cost to the Government, financial exposure, and administrative burden), the risks presented in commercializing a particular industry must be seen, at least in part, from the point of view of present and potential developers. The success of any Government program to stimulate the commercialization of a new technology depends, to a large degree, on the extent to which the policy incorporates the developers own perceptions of the risks, benefits, and uncertainties associated with production.

Surface oil shale technologies are comparatively well-understood with only a few remaining technical uncertainties. They are, in fact, very much the same today as they were 20 years ago, and present little room in which to maneuver with respect to changing their scale of operations or improving their performance. For example, there is apparently no alternative to large-scale mining and the disposal of sizable quantities of spent shale. In real terms, these technologies are unlikely to become significantly less costly than they are now. Thus, the possibility of technical tradeoffs from the technology itself is reduced, and the improvement of overall commercial prospects must come through the reduction of economic and institutional barriers.

Risks, Uncertainties, and Impediments Associated With Oil Shale Development

The commercialization of oil shale faces three primary economic risks and uncertainties:

- the uncertainty over the costs of building and operating commercial facilities;
- the risk of unfavorable recovery-cost differentials relative to conventional crude (except possibly those from such frontier areas as Outer Continental Shelf development); and
- the uncertain future selling prices of world oil.

These are compounded by the partial connection between the costs of oil shale facilities and the rising price of energy,

There are three additional uncertainties related to the carrying capacity and response of the institutional systems within which the oil shale industry operates that could seriously affect the economics of the industry. They are:

- the possibility (under conditions of rapid large-scale deployment) of bottlenecks and shortages of equipment, architectural and engineering construction capacity, and trained manpower for constructing and operating facilities;
- the possible scarcity of available and reasonably priced investment capital during the period of construction; and

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- the potentially unfavorable effects of present or future Federal and State regulatory policies on commercial development.

Plant Capital Cost Estimates

A 50,000-bbl/d oil shale facility would require a capital investment of around $1.5 billion in 1979 dollars. Operating costs are estimated by industry at $8 to $13/bbl of crude shale oil processed, exclusive of capital recovery. Such an investment would be undertaken cautiously even if the estimates of capital and operating costs for oil shale plants were known to be accurate. However, during the past 10 years, capital cost estimates have increased much more rapidly than has the general rate of inflation, and still do not appear to be totally reliable. The experience of Colony Development is illustrative but not exceptional. Its direct capital cost estimates for a 43,000-bbl/d facility increased from $225 million in 1972 to $1.3 billion in early 1979, and were $1.7 billion in February 1980. (See table 22.)

Cost escalations of this magnitude are not unusual for large, capital-intensive facilities involving complex novel technologies. As demonstrated by experience with light water reactors, many coal gasification plants, Canadian tar sands, and various weapons systems, cost estimates are likely to rise rapidly as a process advances from initial to definitive engineering designs. Also, as with similar projects, oil shale development is highly vulnerable to changes in the cost of capital and labor. These costs have increased more rapidly in recent years than the composite rate of inflation. In addition, oil shale development will be particularly subject to regulatory requirements, permitting procedures, and possible environmental litigation that could delay or arrest construction and substantially add to costs.

A number of hypotheses have been offered to explain these cost estimate increases. Some argue that since the historically most accurate method of estimating the price of shale oil is simply to add $5 to the price of imported oil, oil shale companies are exaggerating their costs in order either to prepare the market for high selling prices or to get large governmental subsidies. This charge has its basis in the observation that the rise in shale oil cost estimates has paralleled foreign oil prices, and seems to increase each time the Government gives serious consideration to industry subsidies, Neither this nor any other investigation has produced evidence that cost increases are contrived, Most of the variations in cost increases and estimated prices for oil shale can be explained by examining four significant variables:

- increases in the general rate of inflation,
- escalations in the real costs of plant construction.

Table 22.–Cost Estimates for Oil Shale Processing Plants[a]

Time of estimate	Estimated cost $ million	Data source	Scope and detail of estimate
1968	$ 138	Department of the Interior	Initial
1968	144	The 011 Shale Corp	Initial
1970 . ,	250	National Petroleum Council	Initial
1973	280	Department of the Interior	Initial
1973 : :	250-300	Colony Development Operation	Initial
Early 1974. .	400-500	Colony Development Operation	Detailed (early version)
Late 1974,	850-900	Colony Development Operation	Detailed
1976	960	The Oil Shale Corp.	Update
1977	1,050	The Oil Shale Corp.	Update
1979 : :	1,350	OTA	Update
1980	1,700	The 011 Shale Corp.	Update

[a]Plants use underground mining and above-ground retorting to produce approximately 50000 bbl/d Of shale 011 syncrude

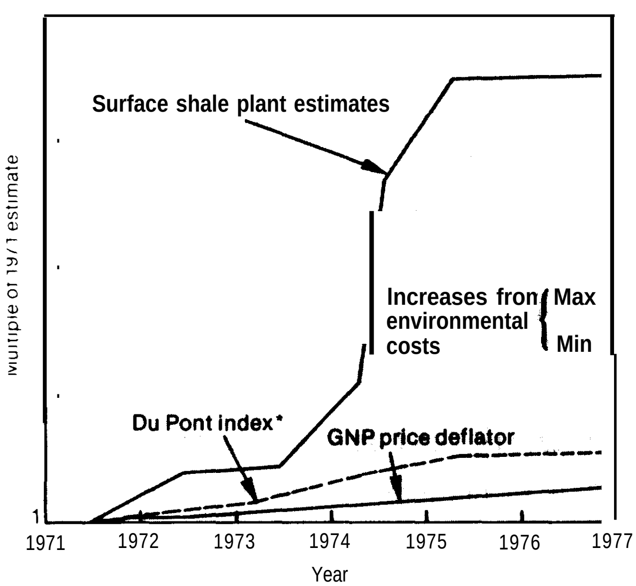
SOURCE Office of Technology Assessment

- more stringent environmental standards for oil shale operations, and
- increases in estimates as a consequence of more complete and detailed knowledge of a facility's actual design,

Increases in the General Rate of Inflation

Many developers believe that chronic inflation during the last 10 years has been the primary cause of the exceptional cost escalations. Although inflation rates were very high between 1972 and 1976, this view is apparently incorrect. For oil shale developers facing nominal rather than adjusted real prices, the overall impact of dollar inflation would appear quite large. The rate of general price inflation also tends to drive up the interest rates on construction loans. However, as shown in figure 51, during the period from 1972 to 1977, not more than 12 percent or approximately $100 million of the cost estimate increases were due to changes in the general price index. The rate of general inflation is important because of the way it affects the perceptions of developers. The factors that influence relative price changes are, however, considerably more significant.

Figure 51 .—Increases in Capital Cost Estimates



*Dupont index This index gives the gradient of change for Industrial process plant costs Although not entirely appropriate for 011 shale plants, it is the best available index However it probably somewhat understates plant cost escalations

SOURCE Edward W Merrow *Constraints on the Commercialization of Oil Shale* 2293 DOE September 1978

Escalations of Plant Costs

Large plants are vulnerable during periods of extreme inflation when the demand for necessary equipment and services rises sharply relative to their supply. Such a period existed in 1974. From mid-1973 to 1975 the general price index increased in excess of 20 percent, but chemical industry equipment increased by approximately 70 percent, and certain key items such as compressors and heat exchangers increased by almost 100 percent. It was during this period that the cost estimate for the Colony oil shale plant approximately doubled.

The effects of severe sectoral inflation on project costs are even greater than those suggested by the above numbers, which are based on list prices that are often discounted. Discounts are eliminated as industry inflation accelerates.

In a crash program for synthetic fuels, there will almost certainly be real cost escalations and overruns. The first few plants committed could contract for a significant part of the available U.S. manufacturing capacity for key items such as valves, pumps, compressors, and pressure vessels. As additional plants reach the procurement stage, equipment suppliers would be forced to quote longer and longer delivery times. These entail higher price contingencies for contractors to cover unknown increases in supplier costs, and can have a devastating impact on large capital projects. Almost half the total per-barrel cost of synthetic fuels is estimated to be solely the carrying cost of the capital investment. project owners will, therefore, be willing to bid up the prices for essential equipment in order to save time. A single week's delay could increase costs by millions of dollars.

Because of the potential for extreme sectoral inflation, costs could increase dramatically in a crash program. Building 20 plants could cost considerably more than twice the cost of building 10 plants. Any savings in design costs by building duplicate plants would be wiped out by cost increases. Plant construction costs during an all-out crash program are likely to increase in real terms by 50 percent or more.[3]

Increases Due to Environmental Regulations

The environmental legislation passed during the late 1960's and early 1970's, along with the provision of substantial enforcement power to the Environmental Protection Agency, altered the context in which large-scale industrial development may now take place. Without question, this legislation, which has been paralleled by similar State laws, has been and will continue to be very costly to industry. It is not possible, however, to accurately ascertain what the actual costs of meeting these standards are, because the costs are both direct and indirect. Most estimates usually include only the former cost category. Cost estimates for meeting some of the standards are discussed in detail in chapter 8.

In 1978, the RAND Corp. estimated that the direct costs of pollution control technologies for oil shale developers ranged between 6.5 and 15 percent of total capital costs. These were primarily for eliminating hydrocarbons, particulate, and hydrogen sulfide from the retorting process, and for dust control and spent shale disposal. By assuming a zero value for environmental costs in 1971, RAND goes on to estimate that between 8 and 20 percent of the increases in estimated capital costs or $65 million to $165 million between 1971 and 1978 were caused by environmental factors.

These estimates do not include the possible indirect environmental costs that might occur because of:

- necessary siting changes,
- alterations of mining plans,
- disruption of construction schedules,
- less efficient facility operation, and
- costs of potential litigation.

Each of the above can have enormous impacts on plant economics; delays occurring late in the construction stage are particularly costly. A 6-month delay in the middle of construction could add more than $100 million to costs. Additional environmental equipment can substantially reduce reliability and the on-stream factor, * if operations must cease when environmental equipment fails. A reduction in the on-stream factor of 5 percent will increase the required selling price of the product by 7 percent. A construction delay such as might be caused by environmental litigation can be extremely costly after ground has been broken. The costly delays and disruptions described here will probably characterize only a fraction of the projects undertaken. Nevertheless, they constitute a significant risk that must be included by developers in their contingency plans.

Environmental regulations add to developers' estimates of uncertainty and risk. The uncertainty is over how present regulations will be interpreted, administered, and enforced; and the risk derives from the possibility of future regulations. Rather than making an attempt to predict with some degree of accuracy what might be the indirect effects of environmental standards on plant economics, developers have increased the size of their estimates as a hedge against uncertainty, based on their informal sense of general risk. Although environmental regulations have significantly augmented industry's capital cost estimates, they nonetheless are responsible for less than than 20 percent of the overall cost estimate escalations since 1971.

The Learning Curve for New Plant Design

The escalations due to improved knowledge about costs, as a consequence of more complete engineering designs, appear to be responsible for the largest increases in capi-

*The on-stream factor is the proportion of operating days per year.

tal cost estimates. Between 40 and 50 percent of the estimated increases between 1971 and 1977 were of this kind.

Forecasting the costs of constructing a commercial facility for a new technology is normally based on a series of engineering design estimates, each of which is presumably more detailed and accurate than the previous one. There are four types of such estimates. They start with initial estimates, which are "back of the envelope" predictions that give only a rough indication of eventual costs; proceed through the preliminary design estimate in which the plant's subsystem flows are defined, but component subprocesses are not defined; continue with the detailed design in which estimates are prepared for specific materials and components; and end with the final design estimate in which precise costs for all materials, components, and labor are pulled together. The final design estimate should accurately locate the cost of immediate construction to between plus or minus [usually plus) 15 percent of the eventual cost.

The cost of preparing a final engineering design estimate for a commercial-size oil shale facility is between $12 million and $20 million. To date, only detailed design estimates have actually been carried out. The intention of this iterative estimation process is to provide continually better design forecasts based on continually more precise technical data derived from increasingly larger developmental tests, As the designs become more complete and the technical data improve, the costs become clearer.

The cost estimate escalations that took place between 1973 and 1976 occurred, in part, because prior to the middle of 1974, no final or detailed engineering design estimates had ever been prepared. Colony Oil Shale Development Corp. 's detailed design estimate represented an 80-percent increase over the preliminary design estimate made 10 months earlier. The subsequent experience of other developers with their more detailed designs was similar,

Cost estimation increases are by no means limited to oil shale facilities. Similar increases have characterized the development of coal gasification, coal liquefaction, Canadian tar sands, light water nuclear reactors, and a variety of new weapons systems. However, several characteristics of oil shale plants present particular design and estimation problems. First, such plants are highly site specific. The costs of transporting, mining, handling, and disposing of shale all depend on the nature of a site's topography, geology, and surrounding terrain. Second, the estimation of oil shale plant costs requires an array of engineering, architectural, economic, and technical skills possessed by only a few architectural and engineering firms.

The reliability, or on-stream factor, for the plant after it is constructed, figures significantly in the eventual cost of production. Cost estimates compute the cost of building the plant, and then assume that it will be on-stream about 90 percent of the time. There is a high probability, however, that pioneer plants will not operate as planned for some time, or until such time as additional investments are made to correct their problems. For this reason, companies tend to build only those designs that are known to work, even though new but untried approaches may promise appreciable savings.

As technical data improve and developers complete more detailed design estimates, the gradient for real cost escalations will level off. It is probable, but not certain, that current cost estimates are fairly realistic and that there will be no further substantial increases, other than normal inflation. However, no commercial-sized facilities have been built, and cost estimates are unlikely to become stabilized without industry experience in constructing and operating such facilities.

Uncertain Future Prices of World Crude

The market price of premium grades of conventional crude oil is a major determinant of the highest possible profitable selling prices for syncrude from shale. Therefore, present and future prices for conventional crude are among the basic factors that will condition the economic viability of the oil shale industry. A developer who commits $1.4 billion to $1. i' billion to a shale oil plant with a very long payback period must be reasonably confident that the market value of the product will exceed its production costs. Uncertain future prices of international oil prevent firms from accurately predicting market values for shale oil. Since the Arab oil embargo of 1973-74, the actions of the OPEC cartel and high international demand have pushed the price of world oil far above recovery costs.

Between September of 1979 and February of 1980 the prices of world oil increased by over 30 percent. In March of 1980, the posted prices of the premium grades of conventional crude (the counterpart of upgraded shale oil) stood between $34 and $38/bbl. Their spot-market prices (e.g., for Wyoming Sweet and the best grades of Nigerian and North African oil) are currently between $40 and $52/bbl. Sweet crude oils were recently sold from the Elk Hills and Teapot Dome Petroleum Reserves for $43 and $50/bbl respectively. These increases, along with the probability of further escalations in the future, have substantially improved shale oil's economic attractiveness. The future viability of shale oil is predicated on the assumption that increases in its production costs will lag behind the rising price of world market crude. On the basis of the best current capital and operating cost estimates (compiled between November of 1979 and February of 1980), it appears that shale oil may have reached parity with conventional oil without subsidy. However, this conclusion is subject to several critical limitations.

First, this finding assumes that current capital and operating cost estimates are, in real dollar terms, within 20 percent of being accurate. Given that such projects have never been previously undertaken, still lack final engineering design estimates, and are prone to possibly severe inflation because of associated heavy equipment costs, this may be a very risky assumption.

Second, most analysts expect international oil prices to increase by 3 or 4 percent per year, over and above inflation. This will mean that the price of oil will double, in real terms, by 2000. However, because international oil prices are still set, in part, by a cartel, the future of the market cannot be predicted with any certainty. Increasing or continued high demand, decreasing world reserves, and OPEC or producer-state governmental policies directed at conserving their reserves through price rationing could result in sustained price inflation for imported oil. On the other hand, prolonged recession in the industrial West or reduced international demand could limit oil price increases in the future. Recent events strongly indicate that OPEC's capacity to set international oil prices has been substantially weakened. Nevertheless, the play of market forces is still likely to maintain upward pressure on prices. In any event, future incremental price increases are not likely to be regular. Instead, temporary periods of oversupply and soft markets are likely to alternate with shortfalls and high demand. Therefore, short periods of stable prices will probably alternate with rapid price increases.

Finally, the question of whether present and future oil prices will allow profitable selling prices for shale oil without subsidy depends on the discount rate that firms are assumed to require in order to undertake development. The average real aftertax returns on investment of U.S. industrial firms is generally between 6 and 10 percent. Given the risks associated with a pioneering industry, oil shale developers will require a larger profit than that obtained from less risky projects. Industry sources generally maintain that this would mean a real aftertax expected profit of between 12 and 15 percent. Breakeven selling prices for shale oil are extremely sensitive to the discount rate, which at 12 percent would make shale oil competitive with conventional petroleum according to OTA's analysis. However, if developers require a is-percent rate of return to undertake investment, then subsidies will probably still be necessary.

Choosing Goals for Oil Shale Development

The Federal Government has a variety of options available to stimulate oil shale development. In order of increasing Government involvement, these include:

- continuing present policies and providing no additional incentives;
- encouraging precommercial modular plants;
- building and operating a number of Government-owned modules;
- encouraging a few commercial-sized plants; and
- deploying a major industry.

Each option differs with respect to the cost to the Treasury, the level of shale oil production, the risks of cost overruns and inefficiency, and the impacts on the physical and social environments. They also vary with respect to the extent and types of financial incentives that would be most effective.

There are two major policy goals to be met by an oil shale industry. One is to deploy enough production capacity to answer the remaining uncertainties related to economic and technological feasibility and environmental impacts, The other is to quickly displace foreign oil imports.

Information Base Goal

Because no oil shale process has as yet been commercialized, the economics, technical operability, and environmental impacts of each of the processes are still not fully known. If the most promising processes were operated at either the precommercial modular scale or at commercial capacity many questions could be answered and comparisons among the various processes would be possible, Operating experience could be acquired by providing incentives to industry, by operation of Government-controlled modular test facilities, or through some combination of both. A1though some questions could be answered by research, a moderate development and production program would reliably answer most of the remaining technical, economic, and environmental questions. It would also facilitate the selection of the most feasible oil shale and synthetic fuel technologies available today; provide information for rational decisions regarding oil shale commercialization; and put the United States several years closer to full-scale production capacity.

A modest program for stimulating the construction of a limited number of commercial or modular facilities would be less likely to fail, Such a strategy reserves judgment concerning the ultimate extent of development until the processes have been tested. This has the advantage of allowing policymakers to evaluate commercial results and consider alternatives for further reduction of oil imports prior to contracting for additional facilities, and should improve the chances of ultimately establishing a self-sufficient oil shale industry. It should be noted, however, that the information base strategy tends to ignore the fact that technology is not static but is continually changing, By gathering data on "today's" processes, this approach may ignore possible (probable) future process developments. It is possible that complete information could be obtained on several processes in the next 10 years only to discover that a new process may be more productive. Should policy be to repeat the cycle and obtain more information, or to build the obsolete plant? From an economic standpoint the choice is not a simple one.

In the absence of time limitations, the overdemand for scarce capacity in construction companies, in skilled labor, in plant materials, and in architectural engineering firms would be reduced or even avoided. When these are placed in short supply, costs escalate, the quality of design is lowered, and fewer plants may be constructed.

ICF in a recent study for the Budget Committee of the U.S. Senate[4] summarized the benefits of proceeding with development in a two-phased strategy by maintaining that such an approach would:

- be an effective symbolic action showing the seriousness with which the United States intends to reduce energy imports;
- provide the opportunity through follow-on stages of development to reduce energy imports directly through shale oil production, while maintaining the option to consider more cost-effective ways of import reduction; and
- provide the flexibility that has been found to be critical in advancing new technologies to a commercially viable stage.

An information base strategy initially followed by review and possible subsequent additions, as discussed in this chapter, has also been suggested by the RAND Corp., ICF, Cameron Engineers, Booz-Allen, and the Congressional Budget Office. It assumes that the principal goals are to create a viable industry, minimize the cost to the taxpayer, and maximize the efficient use of capital.

If, however, the primary goal is to reduce dependence on foreign oil by 1990, then the extensive development of a large oil shale industry might be more advisable. Economic analysts have examined whether producing additional oil shale (or other synthetic fuels) is more cost-effective than alternative approaches such as conservation. Their analyses depend on the assumption that the desirability of synthetic fuels is chiefly a matter of price rather than availability. Another OPEC oil embargo could change this assumption.

Foreign Oil Displacement Goal

If present trends continue, the United States could import around 12 million bbl/d of oil by 1990. It is beyond the scope of this report to examine whether this import dependence could be reduced to the President's target of 8.5 million bbl/d through conservation, synfuel production, and conversion from oil to coal. To estimate the desirability of the contribution that shale oil could make to reducing import reliance requires examining: 1) how cost-effective shale oil development is compared with other energy strategies in achieving import reductions; 2) whether the costs and risks of a crash program to develop a large industry outweigh its potential benefits and whether such a program would achieve its production goals; and 3) if a rapid development strategy would have unacceptable environmental costs.

Establishing a large industry to replace foreign oil would have both positive and negative effects. On the positive side, the economy and national security would benefit from a reduction in oil imports; and in the oil shale region, employment would rise and an increased tax base would provide revenues for community development. On the negative side, such a program would be extremely costly. It would necessitate investing in numerous plants, each with a capital cost of around $1.5 billion. Technologically inferior processes might be used because of insufficient time for supporting technical R&D, and the accelerated construction schedule could lead to cost overruns and managerial inefficiency. (The use of a "technologically inferior" process could, however, be compensated by the inflation savings; a better process built 10 years later would probably cost much more in real terms because of inflation of plant costs.) Capital availability for other economic sectors could be restricted. It is also questionable that mining and processing equipment could be supplied within the construction time frame. Furthermore, it is possible that the lack of supporting environmental R&D could lead to a conflict with environmental standards. On balance, the socioeconomic effects could well be more negative than positive.

There is general agreement among the engineering and construction firms contacted by OTA that a program to establish a large oil shale industry (over 500,000 bbl/d by 1990) would entail sizable cost overruns because of high inflation in critical supply industries. It would also impose severe time constraints on a developer's operations. Contractual agreements for these facilities would have to begin immediately and continue under conditions of tight scheduling for the next 8 to 12 years. Various studies of the consequences of Federal funding to stimulate the commercial adoption of new technologies, including the 1976 study by the RAND Corp.,[5] report that subjection to severe time constraints has rarely resulted in the establishment of a viable industry. Furthermore, a rapid development effort would probably require the commercial operation of facilities before the technologies and their economics were fully understood.

A major Government effort to establish an industry based on a new technology under time constraints does not allow sufficient time to review progress, make cost-benefit tradeoffs, and modify plans in response to new knowledge, When a pressing national emergency requires a crash program, the resultant inefficiencies entailed by these restrictions may be justified. However, when the primary purpose is to establish a self-sufficient industry, crash programs should be avoided.

A Comparison of Alternative Financial Incentives

Before oil from domestic shale can significantly supplant imported supplies, any development program must take into account the major technological, environmental/regulatory, and economic uncertainties that discourage private firms from undertaking such investments. To overcome these uncertainties, Congress is contemplating implementing an incentive program that would share in the risks or subsidize the economics of oil shale development. In evaluating alternative incentives and their probable effects on oil shale development, the reactions and preferences of developers must be taken into consideration.

In conducting this analysis, 10 alternative incentive structures were examined:

- Construction grant. The Government provides a direct grant to cover a prespecified percentage of total construction costs, both a 50- and 33-percent construction grant were analyzed.
- Production tax credit. The developer receives a tax credit for each barrel of shale oil produced, a $3/bbl credit computed on shale oil prior to upgrading was analyzed.
- Low-interest loan. The Government lends the developer a prespecified percentage of capital costs at an interest rate below the prevailing market rate; the analysis assumed 70-percent Government financing at 3 percentage points below the market rate.
- Price support. With this incentive, the Government guarantees the developer a certain price for shale oil; the analysis assumed $55/bbl of hydrogen-upgraded syncrude (hydrotreated shale oil). If the market price for the product falls below the guaranteed price, the Government would make up the difference.
- Purchase agreement. The developer contracts with the Government to sell shale oil at a price higher than the prevailing market price; the analysis assumed a price of $55/bbl of upgraded product.
- Increased depletion allowance. The developer is allowed to claim a 27-percent depletion allowance (at present it is 15 percent).
- Increased investment tax credit. The developer can claim an additional investment tax credit of 10 percent,
- Accelerated depreciation. The firm is allowed to depreciate its investment over 5 years.
- Loan guarantee. The Government would agree to pay off a loan in the event that the firm defaults on its loan: the firm would typically receive a lower interest rate than that prevailing in capital markets.
- Government participation. The Government would become an equity participant in an oil shale project.

To evaluate how effectively the different incentives will promote the development of a viable oil shale industry, each was analyzed in relation to three fundamental objectives of the congressional incentive program. * These objectives are:

- Subsidizing the economics of shale oil production. The mechanism by which each incentive affects the perceived economics of oil shale development and how well it functions as a subsidy was analyzed.
- Sharing in project risks. The extent to which each incentive allows the Government to share in the risks of oil shale development, and the extent to which it reduces the variance of the present value of the aftertax income from a project was analyzed. To conduct this analysis, a project risk was assigned for four specific categories: the risk of unsuccessful project completion, which stems largely from technological and regulatory uncertainties; the risk associated with uncertain investment costs; the risk associated with uncertain operating costs; and the risk associated with uncertain future prices for oil from shale.
- Facilitating access to capital. The extent to which each incentive would sufficiently induce capital markets to lend the large sums of money that will be required to develop an oil shale industry was examined. This consideration is particularly important for understanding which types of firms would benefit from specific incentives (i.e., whether an incentive will benefit less well-capitalized firms or those with limited ability to incur debt).

Once it was determined how well each incentive met each of the program's objectives, it was examined in the context of two important policy guidelines:

- Efficient use of the Nation economic resources. To make efficient investment decisions,** oil shale developers should pay the same prices for resources (i.e., land, labor, capital, and materials) that are paid by firms engaged in other production activities in the general economy (i.e., the prices paid should equal the value of these resources in alternative uses). Similarly, the price received for the shale oil by producers should equal its value to the economy. This will be the marginal price of crude oil, because upgraded shale oil and crude oil are almost equally substitutable. Therefore, OTA analyzed the extent, if any, to which each incentive would interfere with developers' perceptions of the market prices of the productive resources consumed in shale oil production or the market price for the final product.
- Minimal administrative burden. The cost of administering an incentive program represents a loss to the economy that falls on the public and private sectors alike. In addition, the administrative burden affects the time required to implement a program as well as its overall effectiveness. Therefore, OTA analyzed the administrative requirements for each of the incentives.

Finally, the analysis was structured to assist Congress in developing an incentive program to meet a third policy guideline: to promote a healthy state of competition in the industry, Because of the potential multiplicity of objectives for an incentive program, and the variety of types of firms involved, it is probably necessary that the incentive program consist of a package of incentives. This should allow firms in differing financial, technical, and tax circumstances all to benefit.

To clarify the competitive implications of a program consisting of a combination of incentives, the kinds of firms that would most benefit from each incentive were identified based on the analyses of the incentives, a review of industry statements, and discussions with industry representatives. Specific examples of firm preferences for the different incentives have been documented. The effects of the various incentives on the program objectives and the policy guidelines are sum-

*Congress, before designing an incentive program, should specify the relative emphasis to be placed on each objective.

**This definition of efficiency is in the somewhat narrower sense of its use in economics.

marized in table 23. The rank-order preferences of different shale oil developers for the various financial incentives are summarized in table 24. In order to make a comparison of the incentives and evaluate their contributions to the objectives of the total program and the policy guidelines, a computerized simulation model developed by Professors Wallace Tyner (Purdue University) and Robert Kalter (Cornell University]" was used to test and measure each of them against the case in which no incentive is offered. The present calculations with the Kalter-Tyner model were prepared for OTA by Resource Planning Associates, Washington, D.C. A complete description of the simulation model, its capabilities, limitations, and how it was employed can be found in appendix B. Using the model, it was possible to estimate the following four variables (for all but the production tax credit and loan incentives):

- Expected profit. Expected economic profit is defined as expected return in excess of a company's minimum required aftertax return on its oil shale investment. * OTA calculated both expected profit and the change in expected profit relative to the no-incentive case.
- Risk. The risk of the investment refers both to the probability of the investment resulting in an economic loss (i. e., earning less than the minimum required rate of return), and to the degree of variation in possible profit outcomes, OTA measured this variation in absolute terms (i.e., the ratio of change in expected profit to standard deviation of expected profits).
- Breakeven price. The breakeven price is the constant price for hydrotreated** shale oil at which it would just earn its minimum required rate of return.
- Cost to the Government. The expected cost to the Government of providing the incentive is the gross subsidy to the firm less increased tax payments to the Government. * An incentive increases tax receipts if the present value of the tax payments is larger with the incentive than if an equal investment was made without the incentive. OTA estimated both the actual cost to the Government and the ratio of the change in expected profit to cost.

With these computations, the way in which a firm's marginal tax rate** (and, for a low-interest loan, its cost of borrowed funds) influenced expected profits was assessed, and the sensitivity of expected profits to different discount rates (defined as the minimum rate of return necessary to induce private development) was determined,

The numerical results of this analysis, which are summarized in tables 25 and 26, were calculated using the best available data for the cost of commercial oil shale facilities. They thus provide a reasonable approximation of the magnitude of the probable effects of each of the incentives. While these outcomes would not be expected for the operation of an actual facility, they would be for the average operations of a number of facilities. Because of the uncertainties inherent in the estimation, the most useful application of these quantitative results is for establishing comparisons among the incentives.

Congress is currently considering 10 major kinds of incentives to be included in a domestic oil shale development program. The analysis of the specific effects of each of these on the three program objectives and the three policy guidelines is summarized below. The discussion also includes a quantitative evacuation of the impact on expected profits, on

*Profit was measured as the sum of each yea r's cash flows, discounted using the company's minimum required aftertax rate of return as a discount rate (see app. B).

**In hydro treatment the physical properties of raw shale oil are improved by adding hydrogen and removing nitrogen and sulfur. The product is often referred to as syncrude.

*Government cost was calculated in present value terms as was private profit. Net cost for each year (i. e., subsidy less increased tax revenues) was discounted at the Government's discount rate (assumed to be 10 percent in real terms). The resulting present value calculations were summed for all years.

**The marginal tax rate is the rate at which income from an additional investment (e. g., an oil shale facility) is taxed by the Government. For most firms, this is 46 percent. However, a firm with excess tax deductions or credits from other operations would apply the excess to the oil shale investment, thereby reducing its marginal tax rate.

Table 23.–Evaluation of Potential Financial Incentives for Oil Shale Development

	Effect of incentive on program objectives			Extent to which incentive meets policy guidelines			
						Promotion of competition	
Incentive	Subsidy effect	Risk-sharmg effect	Financing effect	Promotion of economic efficiency	Minimization of administrative burden	Effect on firms	Firm preferences
1 Production tax credit ($3/bbl)	Strong, subsidizes product price	Moderate, shares risk associated with price uncertainty (If tax credit varies with product price)	Slight, improves project economics	Slight adverse effect, distorts product price	Minimal administrative burden	Benefits firms with large tax liability and strong financial capability	Supported by relatively large firms
2 Investment tax credit (additional lo%)	Strong, subsidizes investment cost	Moderate: shares risk associated with Investment cost uncertainty	Slight, Improves project economics	Moderate adverse effect; distorts input costs, favors capital-intensive technologies	Minimal administrative burden	Benefits firms with large tax liability and strong financial capability	Supported very strongly by most firms; however, firms that would not be able to use the investment tax credit do not favor its enactment
3. Price supper	Strong, subsidizes product price (If con tract price is higher than market price)	Moderate; shares risk associated with price uncertainty	Moderate; improves borrowing capability	Slight adverse effect, distorts product price	Moderate administrative burden	Benefits all firms except those with very weak financial capability	Moderately supported by a wide range of firms
4 Loan guarantee	Slight, subsidizes Investment cost	Moderate, shares risk of project failure	Strong; improves borrowing capability	Slight adverse effect; distorts input costs: favors capital-Intenswe technologies	Moderate administrative burden	Benefits firms with weak financial capability	Supported by firms with limited debt capacity
5 Subsidized Interest loan (70% debt at 3% below market rate)	Slight; subsidizes Investment cost	Moderate: shares risk of project failure	Strong, Government provides capital	Slight adverse effect; distorts input costs, favors capital-intensive technologies	Moderate administrative burden	Benefits firms with weak financial capability	Supported by firms with limited debt capacity
6. Purchase agreements	Strong, but less than price supports	Strong: shares risk of price uncertainty	Moderate; improves financial capability	Slight adverse effect, distorts product price supports)	Moderate (normally more than price supports)	Benefits all birms but those with very weak financial capability	Moderate, but less than for price supports
7. Block grant (33 & 50% of plant cost)	Strong, neutral subsidy	None	Strong; Government provides capital	No adverse effect	Moderate administrative burden	Benefits all firms	Supported by firms in widely varying financial circumstances
8. Government participation	Slight	Strong, shares all project risks	Moderate, reduces firm's capital requirement	No adverse effect on firm decisions; however, active Government Involvement may lead to inefficiency	Major adminstrative burden	Benefits firms that are very averse to risk (e. g., smaller, less well-financed firms)	Little support
9 Accelerated depredation (5 years)	Moderate, subsidizes Investment cost, maximum subsidy effeet is limited by Federal corporate income tax rate and interaction with the depletion allowance	Moderate, shares risk associated with Investment cost uncertainty	Slight, improves project economics	Moderate adverse effect, distorts input costs, favors capital-Intenswe technologies	Minimal administrative burden	Benefits firms with large tax liabilities and strong financial capability	Supported by large, integrated oil companies
10 Percentage depletion allowance (27%)	Moderate, subsidizes product price, value of subsidy Increases as the need for the subsidy decreases	None, Increases risk associated with price uncertainty	Slight, improves project economics	Moderate adverse effect, distorts product price in a variable and undesirable manner	Minimal administrative burden	Benefits firms with large tax liabilities and strong financial capability	Not supported

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Table 24. –Summary of Companies Ordinal Preferences for Incentives

Company	Production tax credit	Investment tax credit	Price guarantee/ purchase agreement	Loan guarantee	Low-Interest loan	Block grant	Accelerated depredation	Government participation	Liberalizing leasing and land management terms	Percentage depletion
Union Oil	2	1	3	4	4	—	—			.
Colony project										
Tosco	2	3	4	1	1		3	.	—	
ARCO	1	2	3	4	—	—	—	—		—
Superior	2	1	3	1	1		—	—	1	—
Occidental	2	4	3	1	1	—	—	—	—	
Rio Blanco project										
Gulf	1	2	3	—	—	3	2			—
Standard (Indiana)	4	2		5	5	3	1		—	—
SOHIO Natural Resources	4	5	3	2	2	1	—	1	—	—
EXXON	—	—	—	—	—	—	—	—	1	—
Standard (California)	3	1	4	—	—	—	2		—	—
Conoco	3	1	4	—		—	2	—	—	—

NOTE No company indicated any preference for the percentage depletion incentive
Rank ordered by preference 1 = most preferred etc

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Table 25.–Subsidy Effect and Net Cost to the Government of Possible Oil Shale Incentives[a] (12-percent rate of return on invested capital[b])

Incentive	**Total expected profit[c] ($ million)**	Change in expected profit ($ million)	Standard deviation[d] ($ million)	Ratio of change in expected profit to standard deviation	Probability of loss	**Breakeven price ($)**	Total expected cost to Government ($ million)	Ratio of change in expected profit to Government cost
Construction grant (50%)	$707	$487	$205	2,4	0.00	$34.00	$494	98
Construction grant (33%)	542	321	210	1 5	0.00	38,70	327	98
Low-interest loan (700/0)	497	277	219	1 3	0 0 0	43.40	453	61
Production tax credit ($3)	414	194	219	0,9	001	42.60	252	77
Price support ($55)	363	42	171	0.8	001	NA	172	.83
Increased depletion allowance (27%)	360	40	247	0 5	0,05	45.70	197	71
Increased Investment tax credit (20%)	299	79	216	0.4	0.05	45.80	87	90
Accelerated depredation (5 years)	296	76	215	0 4	0,05	46.00	79	96
Purchase agreement ($55)	231	11	126	0 1	0,03	NA	0	NA
None	220	0	219	0.0	0.09	48.20	0	NA

[a] All monetary values are in constant 1979 dollars
[b] With 12 percent annual inflation a 12 percent real discount rate is approximately a 24-percent nominal aftertax rate of return The calculations assume a $35/bbl Price for conventional Premium crude that escalates at a real rate of 3 percent per year Thus the predicted $48/bbl breakeven price for the 12-percent discount rate will be reached In 11 years or in the fifth year of production Therefore in narrow economic terms oil shale plants starting construction now which assume a 12-percent discount rate will be profitable over the life of the project without subsidy (See discussion for caveats concerning this conclusion) The calculations are for a 50 000-bbl d plant costing $1 7 billion
[c] Expected profit is the return in excess of a 12 percent discounted cash flow rate of return on investment
[d] Standard deviation is a measure of the dispersion of possible profit outcomes around expected profit

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firm risk reduction, on breakeven prices, and on the cost to the Government.

Production Tax Credit

In the 96th Congress (1979), the Senate Finance Committee approved a production tax credit for alternative forms of energy. Under this proposal, producers of shale oil would receive a $3/bbl credit on Federal income taxes. Projects operating after April 20, 1977, and in production between 1979 and 2000, would be eligible. The $3/bbl credit would be defined in real terms; that is, the credit would increase with inflation. This proposed credit will be phased out on a sliding scale as the price of imported oil increases.

Table 26.–Subsidy Effect and Net Cost to the Government of Possible Oil Shale Incentives[a] (15-percent rate of return on invested capital[b])

Incentive	Total expected profit[c] ($ million)	Change in expected profit ($ million)	Standard deviation ($ million)	Ratio of change in expected profit to standard deviation	Probability of loss	Breakeven price ($)	Total expected cost to Government ($ million)	Ratio of change in expected profit to Government cost
Construction grant (50%) .	$281	$477	$135	3 5	0.00	$40.60	$494	96
Construction grant (33%)	119	315	140	2,2	0 1 9	47.70	327	96
Low-interest loan (70%)	81	277	153	1.8	0 2 3	54.70	453	61
Production tax credit ($3)	-61	135	153	0,9	0 6 3	58.30	252	.54
Price support ($55). ., ...	-88	108	122	0 9	0.77	NA	172	63
Increased depletion allowance (27%) .	-110	86	170	0.5	0,75	57.20	197	44
Increased Investment tax credit (20%),	-131	65	150	0,4	0.77	58.80	87	75
Accelerated deprecation (5 years) .	-127	69	149	0.5	0 7 6	58.90	79	87
Purchase agreement ($55).	-150	46	102	0,4	0 9 2	NA	0	NA
None. . . .,	-196	0	153	0.0	0.93	61.70	0	NA

[a] All monetary values are in constant 1979 dollars
[b] With 12-percent annual inflation a 15-percent real discount rate is approximately a 27-percent nominal aftertax rate of return
[c] Expected profit is the return in excess of a 15-percent discounted cashflow rate of return on investment
[d] Standard deviation is a measure of the dispersion of possible profit outcomes around expected profit

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This tax credit will strongly subsidize the production of shale oil. By reducing a firm's tax liability, it effectively increases the unit product price by an amount equal to the tax credit per unit of production (i.e., per barrel) divided by 1 minus the firm's Federal corporate income tax rate. For example, if a company's tax rate is 46 percent, a $3/bbl credit becomes an effective price boost of $5.60. At current imported oil price averages of $35/bbl, the effective price with the credit would be $42.60. This price boost could substantially improve a project's economics by creating a higher aftertax cash flow throughout its producing life, and a higher return on investment.

Although the production tax credit does not share in the risks of project noncompletion or price and cost uncertainties, it would decrease the risk of incurring a loss by improving project economics. Therefore, it may slightly improve the ability of firms to acquire capital financing. However, this tax credit alone would not encourage financial institutions to lend to a financially less secure oil shale developer.

A production tax credit has a function similar to a price guarantee. Depending on lender expectations about investment and operating costs and the resultant project profitability, it may provide a sufficient asset base against which firms may borrow for project financing. However, it will not assist project financing as strongly as a purchase guarantee or a debt guarantee.

The production tax credit also can enhance economic efficiency, because it does not distort a firm's perception of the market prices for the economy's productive resources (i.e., land, labor, capital, and materials), that are consumed in development and production. Moreover, if subsidizing oil shale development meets national objectives, this tax credit with a sliding-scale phaseout can be used by firms as a baseline for making their decisions. To promote efficient investment and production decisions, the price subsidy afforded by the tax credit should reflect the premium society is willing to pay to encourage the development of oil shale resources.

Because it works through the existing tax framework, implementing a production tax credit should be relatively straightforward, necessitating little or no administrative overhead. The chief administrative policies would be to define a reference price for determining the value of the credit, to set an inflation adjustment formula, and to develop a mechanism for ensuring that firms accurately report the amount of shale oil produced. (However, reliance on tax-based incentives would tend to reduce the Government's control over production levels.)

Large, integrated oil companies will most readily benefit from this incentive (i.e., those firms having both a sufficient Federal income tax liability to use the credit and a strong ability to raise debt). Moreover, in trying to secure a competitive advantage in the oil shale development industry, those firms that have already undertaken investment in oil shale, and that can accept exposure to the risks of project noncompletion and investment and production cost uncertainties, may favor production tax credits over all other incentives,

The production tax credit is supported by most of the larger firms involved in oil shale activities. The Atlantic Richfield Co. (ARCO), Gulf, Union, and Occidental, all companies with current oil shale investments, rank it either first or second in their incentives preference lists. However, Standard of Indiana, which is Gulf's partner in Rio Blanco, ranks it last, preferring incentives that deal with the front-end investment uncertainties. Chevron, which is just starting its oil shale development activities, directly opposes it in favor of an investment tax credit that addresses the investment cost risks, which Chevron feels are considerable, (See table 24.)

In calculating the quantitative effect of this incentive, the unit value of the subsidy (established as $3/bbl of unrefined shale oil) was multiplied by the entire annual output; that product was then subtracted from the income tax obligation for each year of production. * The results indicate that the $3/bbl tax credit ranks fourth, behind the 50- and 33-percent construction grants and the low-interest loan, in its tendency to increase profitability and reduce the risk of loss. In addition, because obtaining the tax credit is simpler administratively than obtaining a grant, it might be preferred by some firms.

*In OTA's analysis, the tax credit was calculated on shale oil output prior to hydrotreating. Because of processing losses, the output of hydrotreated oil is 12 to 15 percent lower.

Expected Profit

In comparison with no incentive, the $3/bbl tax credit would increase the expected profit of the 50,000-bbl/d facility by $194 million. This increase was the fourth highest of the incentives tested. With the tax credit, the expected profit of such a facility would be $392 million, more than enough to induce its development. Moreover, this tax credit would retain its high ranking irrespective of a firm's marginal tax rate, unless it has excess tax credits (i. e., the tax credit expires before the firm has earned enough income to offset it). Although some firms might hold excess tax credits at the outset of production, few, if any, would hold them over the entire lifetime of a project, given the eventual large annual income that can be expected, Therefore, an excess credit situation would be likely to exist for no more than a few years of the tax credit's duration which could be short or long depending on the phase-out provisions.

The production tax credit is highly sensitive to the discount rate, however, because the subsidy is spread over a project's entire lifetime, In fact, over the range of rates tested, this incentive is one of the most sensitive to the discount rate: averaged over the discount rates, each percentage point drop in the discount rate resulted in a $20 million increase in expected profit.

Risk

Because the production tax credit does not reduce the variation in possible future prices and costs, it does not reduce the overall variation in possible profit outcomes. However, it significantly reduces financial risk because it boosts the expected profit. For this reason, the production tax credit ranks fourth behind both construction grants and the low-interest loan in reducing the probability of loss in the variation in profit relative to the change in expected profit.

Breakeven Price

In the absence of an incentive, the breakeven price was $48.20/bbl of hydrotreated product, with the production credit it was $5.60 less, or $42.60/bbl. This price ranks third behind the breakeven prices for 50- and 33-percent construction grants and the low-interest loans; nonetheless, it is still within the commercially feasible range, given the average discounted price of oil—$53.00/bbl—over the production period.

Cost to the Government

The cost to the Government is commensurate with the credit's strong effect on profitability. Overall, it is the fourth most costly incentive, ranking below the 33- and 50-percent construction grants and the low-interest loan. Moreover, the production tax credit is one of the least cost-effective (as measured by the ratio of change in expected profit to Government cost). It ranks below most of the other incentives, including construction grants. However, it offers two advantages over construction grants. First, the cost to the Government would be spread more evenly over time; the production tax credit would require about $49 million per year over a 20-year production lifetime, compared with $170 million per year over a 5-year construction period for the 50-percent grant. Second, it would be much easier to administer for both oil shale developers and the Government. Developers would simply file for the credit on their tax return, thus making the Government audit of production records straightforward.

Construction Grant

Under a construction grant program, the Government transfers a sum of money to a firm undertaking an oil shale development project. In return, the firm must only fulfill its obligation to undertake the project within some period of time. The size of the grant would be some prespecified fraction of the investment costs. Alternatively, the Government could hold the inverse of a bonus-bid lease auction (i.e., firms could bid the amount required to operate a project capable of producing a specified quantity of shale oil). In this case, with sufficient competition, firms would bid on an amount equivalent to the negative expected present value of their projected aftertax income. Instead of bidding a bonus to be paid to the Government, they would bid a bonus to be received from the Government. Those bidding the lowest bonuses, up to some aggregate bonus payout from the Government, would receive the awards.

A construction grant would make it possible for otherwise uneconomic projects to have a profitable, positive expected present value of aftertax income. The immediate effect of a grant will be to facilitate capital acquisition because less funds probably will be needed from external sources. * In addition, over the life of the project, there will presumably be lower debt repayment requirements. A construction grant reduces the uncertainty over investment costs but not over operating costs or product prices. Thus, depending on its size, a construction grant may significantly reduce the risk of project failure. Moreover, it may reduce the amount of external financing needed, and because it improves project economics, it enables the firm to borrow. However, it does not create an asset on the firm's balance sheet, and will thus provide no assurance to lenders of a firm's ability to meet its debt repayment obligations. * *

The construction grant is not economically efficient since it affects a firm's perception of its investment costs, creating a bias in favor of more capital-intensive projects. Moreover, once the plant is constructed, output decisions will be based on the market price of oil rather than the strategic value of domestically produced synthetic fuel. Finally, the construction grant will be costly to administer

*A construction grant program should not be confused with a loan program or a program to facilitate financing. To assist financing, the Government should consider a direct-loan or loan-guarantee program.

*'Unless a grant is to be paid at a future date and a firm borrows against it in the short term.

and may result in project delays if not processed expeditiously.

There will be problems in deciding the size of grants without an auction. A firm can refuse the project if the grant is too small, If the grant is too large, on the other hand, the firm would receive excess economic rent* from the project at society's expense. To minimize the cost to the Government, the grant should equal the absolute value of the negative expected economic rent on the project (plus, for a risk-averse firm, any risk premium).**

Second, even if the Government uses an auction to distribute grants, firms will probably collect excess rents at the expense of society. The grant program shares none of the risks of oil shale development. If these risks are as substantial as currently expected, firms may require large risk premiums in their bonuses to ensure against economic loss. Although necessary and efficient from a firm's perspective, the risk premium represents an excessive transfer of income from the public to the private sector. Also, unless competition is high and firms have equal access to technical information, bids will not be driven down to the level of the negative expected economic rent. In this case, firms may strategically bid more than this figure in an attempt to receive higher than the risk-free required rate of return for undertaking the project.

The administrative requirements associated with this incentive could delay implementation of an efficient program for several years. The construction grant is a neutral subsidy; all firms should be able to use it. They may, however, dislike the grant on ideological grounds. Those that are more risk-averse will be at a competitive disadvantage in acquiring grants in an auction (i. e., their requirement for higher risk premiums will reduce the probability of winning a grant).

*Excess economic rent here indicates a situation where the developer has recovered more subsidy than would have been required to under take the project.

**A risk premium is the additional margin of profit required by a firm in order to undertake development.

Construction grants are supported by firms of widely varying size and financial condition. In addition to those with more limited debt capacity, two financially strong companies, Gulf and Standard of Indiana, also support this incentive. Gulf supports only limited grants; its partner in the Rio Blanco development, Standard of Indiana, supports front-end cash construction grants for up to 25 percent of project investment to help offset the heavy initial capital requirements of early projects. (See table 24.)

The effects of grants of 50 and 33 percent of plant cost (estimated to average $1.7 billion including upgrading) were analyzed, assuming that the cost would be incurred over a period of 6 years and that the Government would pay its percentage of each year's cost at the end of the year in which the cost was incurred.

On purely economic grounds, construction grants would be ranked highly by oil shale firms. Compared with the other incentives, the 50-percent grant would offer the greatest increase in expected profit, the greatest decline in risk of loss, and the lowest breakeven price. The 33-percent grant also compares well, ranking second in its effect on profitability, ability to lessen the probability of loss, and breakeven price. For the Government, however, construction grants would be among the most costly incentives.

Expected Profit

In the simulations, (see table 25) the 50-percent construction grant yielded an expected profit of $707 million. When compared with an expected profit of $220 million when no incentive was employed this represents a gain of $487 million, the largest of any incentive tested. The 33-percent grant, although ranking second behind the 50-percent grant, resulted in $321 million in expected profit. Both grant levels would therefore be more than adequate to induce private development of the 50,000-bbl/d oil shale facility.

In assessing the effect of a construction grant on profitability, an analysis was made of its sensitivity to a firm's marginal tax rate and discount rate. An individual firm's marginal tax rate was found to strongly influence the grant's effectiveness: the higher the rate, the lower the value of the incentive to the firm. Because the grant reduces the amount of investment that is depreciated against corporate income tax, the developer has a higher taxable income as a result of this subsidy. In analyzing this incentive, the highest marginal tax rate (46 percent) was used in the calculations; the value of the grants for firms with lower marginal tax rates would therefore be greater than that stated in this report.

It was found that the effect of construction grants on profitability, however, would depend only slightly on the level of the discount rate. The results were calculated using a 12-percent discount rate, * but the expected increase in profit stemming from construction grants changes very little with discount rates of 10 and 15 percent. This is because the subsidy is concentrated in the construction phase, thus is discounted over relatively few years.

Risk

Because the Government shares so large a portion of cost, construction grants have a very pronounced effect on risk reduction. For the representative facility, the probability of loss dropped from 9 percent with no incentive to O percent with both the 50- and 33-percent grants. Thus, these grants rank highest in reducing the risk of loss. In addition, the construction grants result in the greatest reduction in the variation of profit outcomes (as measured by standard deviation) relative to change in expected profit.

Breakeven Price

The 50-percent construction grant also has the lowest breakeven price, $34,00/bbl of premium syncrude, compared with $48.20/bbl when no incentive was offered. The 33-percent grant results in the second lowest breakeven price, $38.70/bbl. Either price would place the shale oil facility in the commercially viable range. Given an initial oil price of $35/bbl, and the expectation that the price will rise over time (at 3 percent per year in real terms), the price of oil at the start of production in 1986 would be $42/bbl. It is more meaningful, however, to compare the breakeven price with a composite price of oil over the production lifetime—$53.00/bbl.* Because the breakeven prices with both the 50- and 33-percent grants are less than this amount, the project would be viable.

Cost to the Government

Construction grants of 50 and 33 percent would be among the most costly to the Government. In the simulations, the gross cost to the Government for the 50-percent grant was $170 million per year for each of the 5 years of construction. The net cost, however, depends on the marginal tax rate of the recipient. Because the grant would reduce the amount of investment subject to depreciation, the Government would recover about one-third of the gross subsidy paid to firms with a 46-percent marginal tax rate, through increased income tax payments. With this tax rate, the net cost to the Government for the 50-percent grant was higher than any other incentive—$494 million** and third highest for the 33-percent grant. However, the construction grants are the most cost-effective, as measured by the ratio of change in expected profit to Government cost. The net cost figures, however, do not include administrative costs, which could be significant.

To guard against cost overloading, the Government would have to establish precise accounting guidelines and be prepared to audit all grant recipients. Furthermore, the grant

*On the basis of studies showing that the real, aftertax return for U.S. business averages from 5 to 10 percent, the 12-percent rate was selected as representative. It reflects the risk involved in oil shale investment compared with that of the average investment.

*The composite price is a constant price, which when substituted for the escalating market price, does not change the profit calculations (see app. A).

**All Government costs are calculated in present value terms using a lo-percent real discount rate. This is the rate adopted by the Office of Management and Budget (OMB) for evaluating Government programs. (See OMB'S Circular A-95.)

application procedure would tend to be time-consuming for both the Government (complex auditing procedures would be required) and the applicant, (a well-documented application would be required). Alternatively, the Government could simply offer to award $400 million ($80 million per year for 5 years) to any company that is willing to build a 50,000-bbl/d plant, the only stipulations being that the plant must be completed and operated.

Low-Interest Loan

The effects of a low-interest loan are similar to those of a debt guarantee. Its primary purpose is to assist firms in financing the large capital outlays required for oil shale projects. Those that otherwise would be unable to raise sufficient capital would benefit most from this incentive.

With a low-interest loan incentive, the Government lends money directly to firms at a lower interest rate than would be provided by private lenders. The money may be obtained from general funds, designated taxes (e.g., the extra-profits tax currently being considered in Congress), or through a Government-financing authority (similar to the Federal National Mortgage Assistance Program).

A low-interest loan and a loan guarantee would have similar effects on project economics. Both would reduce the interest cost of debt; as a result, the firm would have a lower payout obligation and higher cash flow over the life of the project. A low-interest loan program could have a significant effect on project economics. It provides access to capital for firms that otherwise could not borrow in capital markets or that must borrow at very high rates.

Its risk-sharing features are identical to those of the loan-guarantee program. As the direct lender, the Government shares the risks of project failure and default on debt repayment. The equity owners of the development firm remain exposed to the risks of project failure and loss of capital. With the low-interest loan program there is only minor sharing in the risk of investment cost uncertainty and none in the risks of operating cost and product price uncertainty. Because the Government lends directly to the firms, a subsidized interest loan facilitates direct access to capital for financially weaker firms.

The effects on economic efficiency parallel those of a loan guarantee. The reduced interest rate serves as a capital subsidy, thus, it may favor relatively capital-intensive technologies. The primary effect on efficiency is to encourage participation of a greater number of firms in oil shale development projects. If increased competition leads to the testing and development of a wider variety of technologies, future production costs for shale oil may be lowered.

Because the low-interest loan incentive requires discretionary review and approval of loan applications, it will be time-consuming and laborious to administer. Delays in implementing an effective program may be encountered.

The firms that will most benefit from a low-interest loan program will be relatively weak financially with limited access to capital markets. If the Government were to make debt available to all firms at less than market rates (i.e., rather than at the AAA rate), all, independent of financial condition, could presumably benefit from the incentive. Like loan-guarantee incentives, low-interest loan incentives are preferred by companies with limited debt capacity because they need subsidized interest loans to raise project capital.

This type of loan could be structured in a variety of ways. A loan for 70 percent of construction costs was analyzed. It was assumed that loan funds would be made available during the years the construction costs would be incurred (e.g., if construction takes 5 years, funds would be dispersed over the 5-year period at the rate of 70 percent of each year's cost per year. It was further assumed that the developer would begin repayment at the end of the first year of production, that the loan would be issued at an interest rate of 3 percentage points below the prevailing market rate (e.g., 9-percent nominal interest on the loan when the market rate is 12 percent), and that amortization would occur over a 20-year period.

A low-interest Government loan would be a very effective incentive, ranking close behind the 33-percent construction grant and production tax credit in its effect on profitability. It would act to significantly reduce the risk of incurring a loss. However, it might be the most costly to the Government; as such, it could be less cost-effective than other high-ranking incentives.

Expected Profit

The subsidized interest loan resulted in an expected profit of $497 million compared with $220 million with no incentive. This $277 million increase is less than the increases induced by the 50- and 33-percent construction grants but more than the $3/bbl production tax credit. The size of the increase, however, depends on both the marginal tax rate for individual firms and the access those firms have to capital markets. For a firm with a 46-percent marginal tax rate, the 3-percent before-tax difference between the Government's interest rate and a firm's borrowing rate becomes a 1.5-percent aftertax difference, because interest payments are deductible. The aftertax spread would be 2 percent for a firm with a 3-percent marginal tax rate. Hence, the lower the marginal tax rate, the more the loan is worth. In addition, the higher the rate of interest on alternative sources of debt financing, the more the loan is worth. Because different firms may have different borrowing rates, they might value the Government loan higher or lower than the value OTA has computed.

Risk

The low-interest loan does not affect the degree of variation in possible profit outcomes, because it does not reduce the variation in future costs or prices. However, it does significantly reduce the risk of loss; with the loan the probability of earning less than 12-percent return was 0.00, but it was 0.09 when no incentive was offered. Moreover, the loan is effective in reducing the degree of variation in profit relative to expected profit, but to a lesser degree than the construction grants and production tax credit.

Breakeven Price

The low-interest loan resulted in a breakeven price for premium grade synthetic crude from shale oil ($43.40/bbl) that is only slightly higher than the price resulting from the production tax credit ($42.60/bbl). However, it is well below the price prevailing when there is no incentive ($48.20/bbl), and lower than the average expected market price over the production period ($53.00/bbl).

Cost to the Government

The low-interest loan costs the Government more than any other incentive except the 50-percent grant. It also results in the lowest change in profit per dollar cost. The gross outlay for the 70-percent loan is actually larger than that for the 50-percent construction grant because both are computed on the same construction costs. Loan repayments after the completion of the construction phase would also be higher than the increased tax receipts under the 50-percent grant program. However, because the subsequent receipts are discounted more heavily than the initial outlay, the net cost to the Government in present value terms would be almost as great for the 70-percent loan as for the 50-percent grant. Moreover, it actually could be higher than has been calculated, because some firms might default on the loan. *

Purchase Agreement

In a purchase agreement, the Government signs a long-term contract with a prospective

*These conclusions are extremely sensitive to the choice of Government discount rate. If Government cash flows were discounted at a rate of less than 10 percent, the loan would cost less. For example, at a 5-percent real discount rate, the cost to the Government is $2OI million compared with $453 million when the discount rate is 10 percent.

oil shale developer to purchase some quantity of shale oil or hydrotreated syncrude at a contract price (either in nominal or real terms). The Government may set the contract price directly, negotiate it with firms, or invite contract price bids. If the contract price is negotiated or set by competition, the Government can selectively apply the incentive to the most efficient firms by granting the purchase agreement to firms bidding the lowest contract prices. The Government can always control the number of firms using the subsidy by limiting the number of projects and the quantity of shale oil production covered in guaranteed price contracts.

The purchase agreement incentive and the production tax credit subsidize shale oil production by providing (presumably) a higher price to developers than they would receive in the open market. Higher prices will benefit a firm over the life of the project, or until the specified quantity of shale oil has been purchased.

The purchase agreement reduces project risk stemming from the uncertainty over future oil prices. Because the product price is essentially fixed, the Government bears all the risk of price variations. However, this incentive does not share in the risks of project noncompletion or investment and operating cost uncertainties,

It does offer some security to lenders, and may provide a sufficient asset base for firms to borrow against. As a result, the prospects for project financing are improved for firms with limited ability to raise debt. Like the production tax credit, the purchase agreement also has distinct economic efficiency advantages. It does not distort the prices of resource inputs and thus encourages firms to utilize efficiently the Nation's economic resources. In addition, it does not arbitrarily favor any development technologies based on differences in capital intensity or required construction time. Because it works through the product price mechanism, the extent of the subsidy for shale oil is readily apparent, and, in theory, should be set at a level that reflects the social benefit of domestic shale oil production. Finally, when combined with a competitive bid mechanism, the purchase agreement also subsidizes only the most efficient firms.

Despite its advantage for economic efficiency, this incentive imposes significant burdens on administrative efficiency. The Government must determine the amount of shale oil to be subsidized and the contract price, and it must manage a system for allocating the price contracts. If competitive bidding is used to allocate contracts and set contract prices, managing the auction is another major administrative requirement. Moreover, because the mechanisms are less familiar to industry than for such other incentives as the tax credit, they will impose higher costs on firms attempting to use and benefit from them. Although purchase agreements entail a considerable amount of administrative burden, its type and extent are strongly dependent on the particular mechanisms employed.

According to this analysis, all firms except those with very weak financial ability should be able to benefit from purchase agreements. Unlike the tax credit, a firm's ability to use this incentive is not limited by the size of its Federal tax liabilities. To some degree, those that have not yet invested in oil shale development and are strongly averse to the risk of investment cost uncertainty may find this incentive less attractive than the investment tax credit and the loan guarantee.

Expected Profit

In the simulations, a purchase agreement of $55/bbl resulted in an expected profit of $231 million compared with $220 million with no incentive. The $11 million gain in profitability ranks behind gains achieved with all the other incentives tested. The effect on profitability is less than that of the $55/bbl price support, because with the price support a firm benefits when the price exceeds $55/bbl (this occurs in the ninth year of production, assuming a 3-percent annual price increase). The subsidy effect of purchase agreements (and also price supports) is tied to the contract price. At such price, the purchase would cost the Government nothing. However, its subsidy effect is also low. The use of a higher contract price would have substantially increased its incentive impact.

Risk

Because it eliminates all variations in possible future prices, the purchase agreement results in a large reduction (25 percent) in variations in possible profits. However, it does not reduce the probability of loss as much as the price support, because a company cannot benefit from upward variations in price above the purchase agreement price.

Breakeven Price

Because this incentive establishes a minimum price above the breakeven price when no incentive exists, there is no meaningful breakeven price under the price support or the purchase agreement.

Cost to the Government

At no direct cost, the purchase agreement was the least costly incentive for the Government. Government costs are incurred from the first year of production until the market price equals or exceeds the fixed purchase agreement price, If the market price increases over time, the cost to the Government declines, and if the market price exceeds the fixed price, the Government will regain part of its subsidy through low-cost purchases of shale oil. It can also recapture part of the subsidy through the increased taxes that result from a developer's larger taxable income. In analyzing this incentive, a high marginal tax rate for the company was assumed; the cost to the Government would be higher than calculated here if the company had a lower marginal rate.

Price Support

A price support is currently being considered in several proposals before Congress. It is similar to a purchase agreement, except that the Government does not take title to the shale oil; it simply pays the difference between the support price and the prevailing free-market price. If the free-market price exceeds the contract price, the Government pays nothing. The price support, like the purchase agreement and the production tax credit, subsidizes shale oil production since it is presumed to have a probability of being higher than the market price of imported oil.

The effects on project risk and efficiency of the price support are similar to those of the purchase agreement: it reduces the risk of oil price uncertainty, it improves access to debt capital, and it improves project economics. Like the purchase agreement, the price support entails significant administrative costs. However, in general, those associated with price supports are lower than those for purchase agreements.

Expected Profit

In the simulations (see table 25), a $55/bbl price support resulted in an expected profit of $363 million, which is more than enough to induce a profit-maximizing firm to undertake an investment in oil shale. The level of profit presents a gain of $142 million over the case in which no incentive is offered, placing the price support midway in the ranking.

As with most of the other incentives, the expected profit for individual firms using the price support will depend on their marginal tax rates. The price support will be worth less to firms with high marginal tax rates than to those with low marginal tax rates, because the subsidized price increases taxable income.

Expected profit is also very sensitive to a firm's discount rate, because the price support begins only after the start of production and continues for a number of years. The expected profit gain under this incentive varies more with changes in the discount rate than it does with a construction grant. On the other hand, the price support represents a relatively larger sum in the early years of production (assuming increasing oil prices) compared with the constant tax credit. Thus, the $55/bbl price support is somewhat less sensitive to changes in the discount rate than is the $3/bbl production tax credit.

Risk

The price support is effective in reducing risk because it eliminates the possibility of a price for oil below the floor price. By reducing the variation in possible future oil prices, it reduces the total variation in possible profit outcomes. In the simulations, the variation in profit with the price support was reduced by over 20 percent compared with no incentive. Given this reduction and the increased expected profits, the probability of incurring a loss drops from 0.09 with no incentive to 0.01 with the $55/bbl price support. This reduction in risk is only slightly below that for construction grants, the low-interest loan, and the production tax credit. (See table 25.)

Breakeven Price

Because this incentive establishes a minimum price above the breakeven price when no incentive exists, there is no meaningful breakeven price under the price support or the purchase agreement.

Cost to the Government

The price support, which ranks fifth in its net cost to the Government, would be spread over most of the production life of the facility, with a larger share in the early period if the price of oil continues to rise. In the analysis, the net cost figure of $172 million, which accounts for the partial recovery of the gross subsidy through increased income taxes, was calculated using a 46-percent tax rate. The cost of this incentive to the Government would be higher in the event of lower marginal tax rates.

Investment Tax Credit

Several oil shale developers view the investment tax credit as one of the most desirable incentives. These firms have indicated that an additional 10- or 15-percent investment tax credit would be particularly attractive. (See table 24.)

Like the production tax credit, an investment tax credit strongly subsidizes the production of oil shale. Under current tax accounting procedures, it effectively reduces the cost of an investment by the percentage of the tax credit. That is, firms can deduct a specified percentage of their capital costs from their income tax liabilities during the first year in which the project operates. When construction is scheduled over several years, a firm's actual benefit is reduced by discounting because the tax credit is not taken until the project begins operation. The investment tax credit increases net cash flow early in the life of the project when companies often need such a boost. However, depending on the dollar value of the investment tax credit relative to a firm's tax liabilities, it may take several years to fully utilize the tax benefit if other revenues are not available on which to use the tax writeoffs.

By reducing investment costs by a specified percentage formula, the investment tax credit reduces the variance in investment cost, and allows the Government to share in the risk of capital-cost uncertainties. In the early stages of oil shale commercialization, capital-cost uncertainty will be a major source of risk,

As investment costs increase, the share paid by the Government increases in proportion to the percentage rate of the tax credit. Conversely, as investment costs decrease, the Government's share decreases. The investment tax credit does not share in the risks of project noncompletion and price and operating cost uncertainties.

Although an investment tax credit will enhance a project's profitability and return on investment, it cannot overcome the financing problems of firms with limited debt capability. Unlike the production credit, it does not induce lenders to provide the substantial amounts of capital required for oil shale development.

The effect of the investment tax credit on economic efficiency is less desirable than the production tax credit, for several reasons. First, it interferes with a firm's perception of the market prices for the resources used in oil shale development. This incentive subsidizes investment costs only, and so favors the more capital-intensive development technologies. In addition, because the value of the tax benefit decreases as the length of the construction period increases, an investment tax credit incentive favors development technologies with relatively short construction leadtimes.

Because the investment tax credit has been part of the tax structure for several years, it is particularly easy to implement. Analysis has indicated that large, integrated oil companies (i.e., firms with large tax liabilities and strong financial capabilities) will prefer and benefit most. By inference, firms that prefer an investment tax credit to a production tax credit are more averse to the risk associated with investment cost uncertainty than to the risk associated with product price uncertainty.

Expected Profit

In simulating the impact of a simple IO-percentage point increase* in the investment tax credit, it appeared unlikely that it would increase the profitability of oil shale ventures enough to induce their development. In the quantitative analysis, the hypothetical facility had expected profits of $299 million compared with $220 million without an incentive. On the basis of the effect of profitability, the increased investment tax credit ranked near the bottom, above accelerated depreciation and the purchase agreement.

The investment tax credit's effect on profitability (like the production tax credit) is not sensitive to the marginal tax rate unless a firm has excess credits at the time the increased tax credit expires. However, unlike the production tax credit, the investment credit is claimed over a short construction period rather than a long production period. Therefore, its value is relatively more sensitive to a firm's overall tax credit situation. This credit is, however, relatively insensitive to a firm's discount rate because all the tax credit would be claimed early in the life of the project and would thus be discounted over relatively few years.

Risk

The investment tax credit was found to have a slight effect on the risk of loss but virtually no effect on the variability of profit outcomes. With this incentive, the probability of a loss dropped to 0.05, the same level as the increased depletion allowance and accelerated depreciation.

Breakeven Price

At $45.80/bbl, the breakeven price of the investment tax credit was slightly higher than that of the increased depletion allowance ($45.70/bbl), and not significantly less ($2.20) than the breakeven price with no incentive.

Cost to the Government

For this incentive, the cost to the Government ($87 million) was among the lowest, ranking just above accelerated depreciation. Compared with the depletion allowance, however, the cost of the tax credit would be incurred over a shorter period of time.

Accelerated Depreciation

Accelerated depreciation for tax accounting has been discussed by several firms as a possible incentive for encouraging development projects. For example, they have suggested that oil shale investments be deducted from income over a period of 5 years instead of 10 to 15 years, as is now expected. Some firms have even suggested the possibility that the entire oil shale investment could be written off in the first year of project operation.

Accelerated depreciation functions similarly to an investment tax credit. It provides a modest subsidy for development. However, in

*The existing investment tax credit has an additional IO-percent tax credit for energy investment, However, this credit was ignored in the calculations because it was due to expire in 1982.

comparison with an investment tax credit, accelerated depreciation will have a weaker, only moderate subsidy effect, which is limited by the firm's marginal income tax rate and the interaction of depreciation with depletion in tax computation procedures.

Shortening the period over which investment costs may be deducted from pretax income increases the present value of the tax deductions and, thus, will lead to a higher return on investment for a project. In addition, accelerated depreciation would improve cash flow in the early years of a project's operation when firms are often short of cash. In effect, the Government pays an increased share of the investment cost through reductions in income tax liability. The share paid is the present value of depreciation deductions multiplied by the firm's Federal income tax rate, which thereby sets a ceiling on the subsidy effect of this incentive. The maximum benefit would be obtained with an instantaneous writeoff; in this case, the share paid by the Government would be equal to 0.46 multiplied by the cost of the investment (assuming 46 percent of the firm's corporate income tax rate).

However, the subsidy effect of accelerated depreciation could be limited by the interaction of depreciation and percentage depletion in computing Federal income tax liability. Percentage depletion is a deduction from taxable income that is determined as a percentage of gross production revenue in any year. However, the maximum deduction for percentage depletion allowed in any year is 50 percent of net income after subtracting all other deductibles allowed by the Internal Revenue Code. Such deductibles include depreciation. Thus, increasing the depreciation allowance in any year would reduce the income ceiling on the depletion allowance and could reduce the deduction allowed for percentage depletion. In this case, the benefit to a firm from accelerated depreciation would be somewhat offset by the reduction in the tax benefits of percentage depletion,

Through accelerated depreciation, the Government shares in the risk stemming from the uncertainty of investment cost. In effect, it pays a percentage share of the investment costs of a project, thus reducing their variation. It has no effect on the risks stemming from the possibility of project failure and the uncertainty of production cost and price,

Accelerated depreciation will improve project economics but, by itself, is not sufficient to facilitate a firm's access to debt markets. It does not provide an asset against which firms may borrow.

Accelerated depreciation has a negative effect on economic efficiency. * It interferes with the perceived prices of the resource consumed in oil shale development. Because it functions as a capital subsidy, it will favor the more capital-intensive technologies. It will not affect the production signal provided by product price. Moreover, like the investment tax credit, accelerated depreciation does not function through an easily observable mechanism (e. g., product price). Therefore, it will be relatively difficult for society to ascertain the magnitude of the premium it is paying to develop domestic oil shale resources.

Depreciation, which is familiar in tax accounting, would probably entail a minimal administrative burden to implement.

Large, integrated firms with strong financial positions will benefit most from this incentive. Their pretax income and tax liabilities from other business activities are sufficiently high that the accelerated depreciation writeoffs can be taken as they become available. In addition, unless the accelerated depreciation is made retroactive, firms that have not yet invested in oil shale development will have a somewhat stronger preference for this incentive than firms that have made investments with a longer depreciation schedule.

'This assumes that the existing depreciation period is efficient. In actuality, depreciation probably inefficiently biases against capital-intensive projects. Shortening the depreciation period reduces some of this bias and hence promotes efficiency.

Expected Profits

In the simulations, the accelerated depreciation schedule induced an increase in expected profit of $76 million, which was the second lowest figure for any incentive tested.

The effect of accelerated depreciation on profitability depends greatly on the tax situation of a firm: it will benefit firms with higher marginal tax rates more than it will benefit those with lower rates. This difference arises for two reasons. First, the amount of tax savings for a given amount of depreciation is directly proportional to a firm's tax rate. Second, a firm with a high marginal tax rate and with other income-producing investments will be able to write off the depreciation against other income, whereas a firm with a low tax rate will be likely to have excess deductions. In the latter case, the increased depreciation deductions must be carried forward and are thus worth less, through discounting, than they would be if they could immediately offset taxable income.

The value of this incentive is also affected by the discount rate. The effect is slight, however, because both the tax writeoff and its timing are small. A 3-percentage point increase in the discount rate produced only a lo-percent reduction in the change in expected profits.

Risk

Accelerated depreciation was found to have little effect on the risk of oil shale investments. In the simulations, the probability of incurring a loss did not drop significantly nor did the absolute variation in possible profit outcomes. Relative to change in expected profits, the variation in profit was next to the lowest, ranking above the purchase agreement.

Breakeven Price

By analysis, the breakeven price with the 5-year depreciation incentive was found to be $46.00/bbl compared with $48.20/bbl for the 12-year depreciation. This reduction in breakeven price was the smallest of any incentive tested.

Cost to the Government

Of the incentives tested, accelerated depreciation is one of the least costly to the Government and one of the most cost-effective. In the simulations, the net cost to the Government was $79 million, and the ratio of change in expected profit to the Government was 0.96. Moreover, because the incentive is granted through the existing tax system, the cost of its administration would be negligible. (See table 25.)

Increased Depletion Allowance

An increased percentage depletion allowance has been discussed as a possible incentive for encouraging oil shale development. Firms have suggested that the percentage depletion allowance be increased to 25 or 27 percent.

The primary effect of an increased percentage depletion allowance would be to subsidize the economics of oil shale development. Specifically, increasing the depletion allowance will increase the share of production revenues that are shielded from the Federal corporate income tax. The depletion allowance, like a product-price increase, will improve a firm's cash flow throughout the producing life of a project. As a result, a firm's return on investment for a project is improved.

The depletion allowance might be assumed to be as effective an incentive as the production tax credit because both function through the price mechanism. However, it has several undesirable characteristics as a subsidy. The presumptions underlying its use as an incentive are that oil shale development is uneconomic and that the increasing (effective) product price is the appropriate vehicle for its subsidization.

To be an efficient subsidy through the price mechanism, the value of the price subsidy should decrease as the product price increases (i. e., as the need for the subsidy decreases). However, the percentage depletion allowance has the reverse effect. As the product price increases, the value of the price subsidy also increases. Conversely, as the product price decreases and the need for the subsidy increases, the value of the subsidy actually decreases. This effect will make it impossible to maintain the subsidy at a desired level.

In addition to its undesirable subsidy effects, the percentage depletion allowance has poor risk-sharing characteristics. In fact, it increases the risk associated with the uncertainty about future shale oil prices. Because the value of the price subsidy increases with the product price, this incentive magnifies the effects on a firm of changes in the product price. The variance of aftertax income increases as the percentage depletion allowance is increased. This incentive does not share in the risks either of project failure or of the uncertainties of investment and operating cost. The depletion allowance will improve project economics but will not significantly influence a firm's ability to raise debt.

The effect of the percentage depletion allowance on economic efficiency is similar to but more adverse than the production tax credit. It does not affect the prices of resource inputs. Consequently, resources should be combined in an economically efficient manner and a firm's preference for specific oil shale development technologies should not be influenced. However, in effect, it alters the price perceived by a firm and thus will influence its production and investment decisions. Moreover, the contrary manner in which the subsidy effect increases as product price increases will make it difficult for the Government to use this incentive to promote efficient decisions that reflect the social benefits of shale oil production.

Like accelerated depreciation, percentage depletion is a familiar component of the U.S. tax code, and would thus be very easy to apply. The firms that will benefit most from an increased depletion allowance will be those having large before-tax income and large tax liabilities. Moreover, by inference, firms that prefer an increased depletion allowance are relatively unconcerned about risk of future decreases in product price. Rather, they are apparently betting in favor of continued long-term increases in the price of imported oil. No firm seriously advocates this incentive. (See table 24.)

In analyzing this incentive, an increase in the depletion allowance from the current 15 to 27 percent was assumed. Such an increase would be a significantly less effective incentive than the construction grants, the production tax credit, the low-interest loan, the price support, or the purchase agreement. Compared with these other incentives, the increased depletion allowance would result in a much smaller gain in expected profits and only a slight reduction in the risk of incurring a loss.

Expected Profit

The increased depletion allowance resulted in a comparatively modest gain in expected profit—$140 million—compared with no incentive. Because firms cannot claim depletion deductions in excess of 50 percent of taxable income, increasing the depletion allowance above 27 percent does not result in significant additional expected profit.

For firms with lower marginal tax rates, the gain in expected profit would be even smaller. In the simulations, for example, the $140 million gain in profitability calculated using a 46-percent tax rate would be reduced to only $70 million if the tax rate were 23 percent. (See table 26.)

The effect of an increased depletion allowance on profitability is also more sensitive to the discount rate than any other incentive tested. This sensitivity stems from the increase in the incentive's value that accompanies the increase in the real price of oil (and hence revenues). Thus, a higher value in later years is more sensitive to discounting than a value that remains constant over time (as the production tax credit does, for example).

Risk

Although a higher depletion allowance actually increases the variation in possible profits, the gain in expected profits results in a small reduction in the probability of loss. In the simulation the 27-percent depletion allowance reduced the probability of loss to 0.05, compared with 0.09 when no incentive was employed. The increase in the variability of profit outcome occurs because profits are more sensitive to changes in future prices with the higher depletion allowance.

Breakeven Price

Although the increased depletion allowance will result in a reduced breakeven price, this reduction is likely to be small. In the simulations, the breakeven price fell from $48.20 to $45.70/bbl. (See table 25.)

Cost to the Government

The cost of this incentive to the Government is commensurate with its effect on expected profit. In the analysis, the increased depletion allowance cost $197 million, which makes it the fifth most costly incentive. Moreover, it is not a cost-effective option since it results in the second lowest ratio of change in expected profit to Government cost.

Loan Guarantee

Under a loan-guarantee incentive, which has been frequently discussed in Congress and by oil shale developers, the Government guarantees to lenders to repay a specified portion (e.g., 50 to 70 percent] of the project debt if a firm defaults on its debt payments because of the economic failure of its oil shale project. A loan guarantee would be administered selectively by a Government agency without charge or for a fee. Under a fee arrangement, a firm effectively buys an insurance contract to guarantee debt repayment,

A loan guarantee is primarily designed to facilitate project financing and, as a result, has only a limited subsidy effect on the economics of oil shale development. Indeed, the only effect on project economics is to reduce the interest rate on debt for firms with low bond ratings. Thus, over the life of a project, a firm's debt service obligation will be somewhat reduced. A loan guarantee will be of little or no value in improving project economics for firms with strong balance sheets that can borrow at low rates.

This type of incentive requires the Government to share directly in the risks both of project failure and of default by a firm on its debt obligations. However, as long as a firm's equity contribution to total project investment remains at a reasonable level (e.g., 40 percent or more), a loan guarantee does not unduly shield a firm from economic loss (i.e., the incentive does not introduce moral hazard). * In the event of default, the loan guarantee does not protect equity owners against loss. As a result, it encourages management to operate in an economically efficient manner, and provides only weak protection from the risk of investment cost uncertainty—but only if it is for a percentage share of the capital required for the project and if the firm can borrow at a lower interest rate than would otherwise be possible. A loan guarantee does not share in the risks of operating cost and product-price uncertain y.

Of all the incentives that provide for private lending, it has the strongest effect in improving the ability of firms with limited debt capability to borrow in capital markets. By guaranteeing the fulfillment of a specified portion of a firm's obligations, the loan-guarantee program provides an asset that financially weaker firms may borrow against.

Given its limited effects on project economics, a loan guarantee has relatively minor effects on efficiency. It acts as a capital subsidy and so may favor more capital-intensive technologies. It does, however, improve competition in oil shale development by removing a major barrier to entry for less well-fi-

*Moral hazard would exist if the guarantee was constructed as to eliminate so much corporate risk that project failure is encouraged.

nanced firms. Enhancement of competition may lead to testing a broader set of technologies, and in the long run may result in higher overall efficiency by reducing production costs.

This incentive will present certain administrative problems, even though the Government has previously used loan-guarantee programs. A firm's application must be selectively reviewed and approved, thus increasing the potential for delay.

The loan-guarantee incentive benefits smaller companies with an insufficient asset base to back the major debt requirements for undertaking an oil shale development project (i.e., companies with a limited capability to raise debt that would otherwise have to borrow at higher interest rates or be excluded from oil shale development). In addition, larger companies with a large asset base but also large debt (i. e., a high debt/asset ratio) may also need guarantees to embark on an oil shale project. With the increasing debt/equity ratios evident in the petroleum industry, a growing number of firms fit this description. Those with a strong balance sheet and large asset base will not benefit from a loan-guarantee program, and for competitive reasons may not prefer its implementation.

Loan guarantees tend to be preferred by firms that have limited debt capacity. Superior Oil backs them in principle, believing that they will help some companies obtain financing to get their plants started. The Oil Shale Corp. (Tosco) reported that it would need them to obtain financial backing, and SOHIO Natural Resources, a subsidiary enterprise with limited debt capability, claims it could also take advantage of them. Occidental, a considerably larger firm, advocates any and all types of loans or loan guarantees, especially nonrecourse loans. As would be expected, the largest and financially strongest companies find loan guarantees less desirable. (See table 24.)

Government Participation

Government participation has been discussed as part of several bills being considered in Congress. Although it has certain fundamental advantages if the primary purpose of an oil shale incentive program is to share risk, it would meet strong resistance on ideological grounds, and would be extremely difficult to administer. Moreover, it may lead to inefficiency in oil shale development and production activities.

A Government participation program is based on the assumption that oil shale development is economically sound but has very high risks. Because of these risks, private firms are assumed to be reluctant to undertake projects, or willing to undertake them only with the expectation of high profits on their investment to cover their risks. Government participation would provide a mechanism for it to share risks with private firms thus encouraging them to commit capital to oil shale projects.

In such a program, the Government would provide a specified share of equity. From that point on, it would simply be an equity partner in the project and would share proportionately in any project losses or profits. Depending on the terms of its agreement, the Government could either be a silent partner or participate in management decisions. The partnership could be managed through an existing agency or a separate, newly formed administrative unit (e.g., the proposed Energy Security Corporation).

Because Government participation is simply a joint venture arrangement between the Government and private firms, this incentive would not provide any significant subsidy to oil shale development. It would, however, have the strongest effect of all the incentives on the sharing of risk between public and private sectors. In this program, the Government would share in the risks associated with all project uncertainties in proportion to its percentage ownership in a project. When the project showed a loss, the Government would lose; when it showed a profit, the Government would win. Government participation would reduce a firm's exposure to economic loss. At the same time, it would decrease the potential gains for a firm. That is, the variance in a firm's expected present value of aftertax income would be proportionately reduced by the multiple $(1 - SG)^2$, where SG equals the share of Government ownership.

The extent to which Government participation would assist a firm in raising debt will depend on the terms of its involvement in a project. If the Government does not agree to guarantee a firm's project debt, its participation would have little effect on the firm's ability to borrow. Debt-financing support would still come from the firm's own asset structure. Alternatively, if the Government provided a share of project debt or guaranteed a share of project debt, a firm's debt requirements would be reduced, and loans could be more easily acquired.

A Government participation program would have essentially neutral effects on the economic efficiency of private sector investment and operating decisions. By simply creating a partnership or joint venture, the incentive neither changes cost or prices, nor provides a project subsidy. * The primary effect of this incentive on economic efficiency would be to reduce the effects of private sector risk aversion. However, economic efficiency may decrease if the Government decides to operate as an active partner in oil shale development projects. Efficiency would be reduced if Government participation, as a result of inexperience or bureaucratic interference, contributed to inefficient managerial decisions.

A Government participation program would entail the greatest administrative burden of all incentives. A new Government bureaucracy would probably have to be created to manage the program, with the likelihood of lengthy delays in getting the program to operate effectively.

OTA's analysis indicates that Government participation would most benefit firms that are relatively risk-averse, thus unable to finance an oil shale development project alone. However, because private firms may join together in partnerships, there may be no incentive for them to enter a joint venture with the Government as an active partner. If the Government adopted a silent-partner role, however, a firm could take full managerial responsibility for a project, while still receiving the risk-sharing and financial benefits of the joint venture. Such an arrangement is not usually possible with any other private partner.

All firms except one oppose the Government participation incentive, primarily because of their fears of bureaucratic inefficiencies, of support of one technology to the exclusion of another, and of administrative problems. The only advocate, SOHIO, has sought $15 million in Government appropriations to help fund its already approved full-sized module program.

The Government could also contract for the construction of several modular plants it would then operate, either alone or through contracts. It could thus conduct operations to obtain accurate information about technical feasibility, project economics, and the relative merits of different processes. This would be of assistance in evaluating its future policies toward oil shale, in disseminating technical information, and in improving its understanding of the value of its oil shale resources. After enough information had been obtained, the facility could be scrapped or sold to a private operator. This policy would provide the Government with information and experience. However, the cost would be much higher than that of incentives to private developers.

Considering that the technologies to be tested are proprietary, it is by no means clear that the Government would have the legal

*In theory, a Government participation program would be combined with a block grant program to achieve a highly effective subsidy and risk-sharing incentive program.

right to publish all of the information. In addition, its experience in designing, financing, managing, and obtaining permits for an oil shale plant may not resemble that of private industry. Thus, the information acquired may be of little use to subsequent private developers.

Most of the information secured through Government ownership could be made available as a condition of granting financial incentives to private firms. Furthermore, this kind of Government intervention is likely to discourage private developers from undertaking their own modular development and R&D programs. Government programs of this kind tend to reduce the benefits that a particular firm could obtain from R&D or modular testing. Finally, the information argument tends to disregard the fact that patented and licensed technologies make definite provision for the dissemination of technical information on both gratis and fee terms to possible users of a process.

Government Ownership Versus Incentives for Private Development

Several factors favor incentives for private development. One is the amount and timing of Government financial support. With Government ownership, Treasury funds would be used to supply front-end money during the construction period. This would involve very large initial outlays. With private ownership, incentives such as loan guarantees, purchase agreements, and production tax credits would reduce and delay budget outlays much more than would be possible with Government ownership. Furthermore, Government expenditures would be spread over the life of the project. Only the failure of a project insured by a debt guarantee would obligate the Government for more than a small fraction of plant cost. As noted previously, fee-based guarantees would reduce this risk.

Another factor favoring private development is that limited incentives would encourage more efficient operation by leaving managerial and cost risk intact. Cost-plus contracting for a Government-owned facility could not be expected to encourage efficiency. Incentives must be limited, however, because management efficiency would decline under high levels of Government subsidy.

A final factor is that private ownership and operation would develop industrial experience in designing, licensing, financing, building, and running an oil shale plant. Government ownership may not realistically simulate industrial experience. The regulatory, financing, litigation, and managerial experiences encountered by Government are usually much different from those of industry.

Constructing an oil shale plant requires committing major physical and financial resources that would become unavailable for other purposes. Under the private option, funding would be diverted from alternative private investments and consumption. The Government option would, in the absence of higher taxes or funding through revenue bonds, either raise the Federal deficit or withdraw funds from other programs.

Which Incentives Are Most Efficient and Effective?

As the above discussion of alternative financial incentives indicates, there is no single “best” subsidy. Firms in different circumstances will tend to require different kinds of incentives to avert the risks that prevent them from undertaking commercial operations. In general, all incentive programs must be properly administered in order to be effective, This is particularly true of nontax subsidies such as low-interest loans, debt guarantees, price supports, and purchase agreements. These entail much greater administrative involvement than do tax credits, accelerated depreciation, or increased depletion allowances. The absence of close supervision of nontax incentives can lead to oversubsidizing developers. On the other hand, the creation of bureaucratic mechanisms that are extremely time-consuming and complicated, or which make the acquisition of the subsidy or its level dependent on future events that the developer cannot foresee, will radically reduce the subsidy effect of the incentives.

OTA has concluded that production tax credits, purchase agreements, and price supports are the most viable subsidy mechanisms to employ if the Government decides it is necessary to provide financial incentives. The subsidy effect of the purchase agreement and price support incentives are relatively low for the contract price ($55/bbl), which was computer simulated in the present analysis. This should not detract from the qualitative merits of these incentives. Furthermore, this analysis indicates that either loan guarantees or low-interest loans will be necessary to ensure significant participation by smaller or even moderately sized firms. The high cost of providing low-interest loans suggests that debt guarantees would be the best mechanism through which to ensure this participation.

Are Financial Incentives Needed?

The rationale for providing financial incentives is that hastening the commercialization of oil shale technologies, which although not immediately viable would probably be capable of commercialization at a later date, serves the long-run economic and national interests of the United States, The assumptions underlying this argument are that capital requirements, remaining technical uncertainties, risk of cost overruns, unstable regulatory environments, and uncertainties about present or future profitable marketability indicate to developers that their capital would be more profitably employed in alternative investments. An incentive or subsidy alters the economics of commercial production by attempting to either sufficiently reduce the risk or raise the profitability to encourage development.

Whether and to what extent oil shale development will require subsidization depends on the present and anticipated future relationship between oil prices and the cost of producing shale oil. Expectations concerning these future trends involve a consideration of such factors as: the developer's confidence in the accuracy of shale oil plant cost estimates, world petroleum demand, OPEC cartel pricing decisions, the political stability of foreign oil supply, and the rate of profit a company requires to justify its investment relative to alternatives.

Assuming that developers have some confidence in their present estimates of plant costs, and that these estimates contain contingencies for regulatory delay and environmental litigation, then the primary consideration becomes the ability to market at an acceptable rate of return. Developers base their evaluation of marketing potential on the required rate of return and the feasibility of obtaining this return given the price of competing OPEC crude. Until very recently, it was accepted that the commercialization of shale oil would require some form of subsidy.

In narrow economic terms it is no longer clear that shale oil requires subsidy to compete profitably with conventional petroleum. Price hikes during the end of 1979 and the beginning of 1980 have increased average posted spot prices for foreign and domestic crudes by more than 30 percent. Wyoming Sweet and the best grades of North African crude now have posted prices of between $34 and $38/bbl. The spot-market prices for these oils are between $40 and $50/bbl.

If it is assumed that developers require no more than a 12-percent real return on their investment, and that current capital and operating cost estimates are reliable, then shale oil could probably be produced and marketed profitably without subsidy. Predicted decreases in next year's OPEC exports (3 million bbl/d) along with the expectation of continued real price increases of at least 3 percent per year, reinforce the belief that the market outlook for shale oil will continue to improve in the future. However, ruling out the need for financial incentives would be unwise for several reasons.

First, the present competitiveness of shale oil assumes realistic capital and operating cost estimates. For the reasons discussed earlier in this chapter, this is still a risky assumption, and construction and operating costs are still escalating. Since a commercial or modular facility has never been constructed or operated, scaling-up the technology will almost certainly add hitherto unforeseen costs as technical problems—even minor ones—are encountered. If it takes place in the context of commercializing or deploying a large number of synthetic fuel plants, the shortage of already scarce equipment such as valves, compressors, and heat exchangers can be expected to further inflate construction costs. World oil price increases in excess of the 3- or 4-percent real annual growth assumed by developers would push construction costs up still further.

Second, the present competitiveness of shale oil assumes that developers are willing and able to accept an anticipated real discount rate (i.e., rate of profit) of 10 or 12 percent on an inherently risky investment. Given the nature of the risk, it is questionable whether developers would be willing to undertake the investment at this rate.

Finally, shale oil's emerging competitiveness is related to recent oil price increases. If these increases contribute to recession in the industrialized West, petroleum demand can be expected to decline. This could reduce prices in real terms, thus reducing the competitiveness of shale oil. In the longer term, however, it should move to parity with conventional crude as a result of dwindling oil reserves. However, shorter term price declines could take place as they did during the years immediately following the oil embargo of 1973 to 1974.

In the consideration of appropriate incentives, this relative change in the competitiveness of shale oil implies that emphasis should be placed on the desirability of incentives that help with financing, while reducing the risk of extreme OPEC selling price reductions in real terms. Debt guarantees, price supports, and purchase agreements are most likely to provide such assistance.

Economic and Budgetary Impacts

The economic and budgetary impacts of oil shale development will depend on the production levels and speed with which they are met. Low production levels are unlikely to have significant effects on Government spending, on the national rate of inflation, on the level of national employment, or on the cost and availability of capital. To examine these impacts, four growth-related production scenarios were prepared that distinguish shale oil development by both the anticipated level of production and the required degree of Federal involvement. The rationales, the technical descriptions of the envisioned facilities, and the analytic assumptions of these scenarios are discussed in detail in chapter 3. Briefly, the scenarios are:

Scenario	Production target in bbl/d of oil by 1990
1	100,000
2	200,000
3	400,000
4	1,000,000

Industry Costs

A standard commercial oil shale facility is conventionally described as one that would produce 50,000 bbl/d, with an on-stream operating factor of 90 percent, or 329 days per year. Such a facility would actually consist of a series of integrated modular retorts (normally five or six) each with a capacity of between 8,000 and 12,000 bbl/d. No single plant is likely to produce exactly 50,000 bbl/d. At present, the plans of the Colony operators call for a commercial facility with a 45,000-bbl/d capacity, tract C-b is projected to produce 57,000 bbl/d, a 76,000-bbl/d plant is projected for tract C-a, Union Oil's ultimate intention is to build a facility with a capacity in excess of 75,000 bbl/d, and Superior and Geokinetics expect to operate commercially profitable plants with small production capacities—11,500 bbl/d and 2,000 bbl/d, respectively.

Determining the most efficient and cost-effective size for a commercial plant depends on the amount, quality, and accessibility of the shale resource on the tract, the method of mining, the type of retorting technology, and a variety of other factors that affect the cost of shale extraction, transportation, waste disposal, and refining.

Current capital cost estimates for a 50,000-bbl/d commercial-sized oil shale plant range between $1.4 billion and $1.7 billion. In general, these plants are expected to represent an approximately 20-percent economy of scale in comparison with smaller (e.g., 9,000 to 12,000 bbl/d) modular plants. A very large commercial facility of 100,000 bbl/d might represent a 10- to 15-percent economy of scale relative to a 50,000-bbl/d operation. Whether and to what extent these economies would actually be obtained would depend on the particular properties of the development site, the mining techniques used, the technology adopted, and how efficiently the projects in question were managed.

The estimated costs of industries of different sizes are presented below. These estimates assume a 30:70 ratio of debt to equity. They include the cost of hydrotreating and upgrading to premium crude quality and minor transportation costs. They do not include the cost of major pipeline construction or unit train costs for transportation out of Uinta or Piceance Basins. Estimates are in third-quarter 1979 dollars and assume a 5-year construction period for each plant.

In billions of dollars	Scenario 1 100,000 bbl/d	Scenario 2 200,000 bbl/d	Scenario 3 400,000 bbl/d	Scenario 4 1,000,000 bbl/d
Loans, ... , .,	0.9-I .35	1.8-2,6	3.6- 4.2	9.0-13.5
Equity . . . ., .	2.1-3.15	4.2-5.9	8,4- 9.8	21.0-31.5
Total ... , .	3.0-4.5	6.0-8.5	12.0-14.0	30.0-45.0
Maximum annual. , . . .	0.6-0,9	1.2-1.7	2.4-2.8	6.0-9.0

Given current estimates, an industry of 1 million bbl/d would cost roughly $30 billion in third-quarter 1979 dollars. But these estimates are unlikely to be completely accurate. Real cost escalations of 10 to 20 percent would not be unexpected under the best of circumstances. More importantly, if 1 million bbl/d are deployed over a lo-year period, capital cost increases for plant construction are inevitable. Under such circumstances, the demand for skilled labor, for pollution control equipment, for valves, for mining equipment, for compressors, for heat exchangers, and for other needed equipment will completely outstrip supply. The consequences would be large price increases for these goods and services as well as construction delays. Hyperinflation of the costs of required goods and services, equipment shortages, and consequent construction delays could easily inflate total capital costs for facilities by 30 to 50 percent in real terms. Therefore, the costs of this scenario could easily reach $45 billion.

Cost to the Government

Each of the scenarios decribed above assumes a different extent of Federal involvement in the industrialization of oil shale. The scenarios differ from each other in the amount of the target production and the degree of governmental cost and financial exposure. The cost to the Treasury is, in turn, determined by the type and magnitude of the incentives that are provided. Those that have been evaluated in this assessment vary substantially in the amount and kind of risk that they avert for the developer. They also vary with respect to their overall impact on project economics and potential company profits.

In general, the incentives considered entail costs to the Government that are directly related to their impact on a firm's expected profits. (See tables 25 and 26.) That is, sub sidy costs to the Treasury are closely correlated with their influence on overall project economics. However, the relation between the effect of incentives on a firm's profits and the cost of the incentives to the Government is not exactly linear. Some subsidies clearly provide more financial encouragement with less governmental cost and exposure than others. The real cost to the Government is determined by: 1) the gross cost of the subsidy, 2) the amount of increased tax payments due to additional production, 3) the Government's assumed discount rate (what it is assumed could be gotten if the capital were employed elsewhere), 4) the timing of the Government's payment of the incentive, and 5) the timing of a developer tax or other payback to the Government.

Calculating the cost of incentives to the Government is complicated by the difficulty in determining the first three of these factors. For example, the gross cost of the subsidy (i.e., the size of the offered subsidy) is hard to predict for several of the incentives. The number of production tax credits that might be taken by developers is not entirely predictable, nor is the extent of the financial obligation that the Government might incur under debt insurance or guarantee programs. The number of takers for price supports could vary substantially depending on how they were constructed, on the support price level, and on future shale oil market conditions.

The amount of increased tax payment that particular incentives might generate is also difficult to predict. This is because the effective tax rate that firms pay on production varies according to the circumstances of the corporation in question. The range is potentially from O to 46 percent on Federal taxes.

Finally, the calculation of these costs assumes that the Government's discount rate is known, and that the tax generation ability of alternative Government uses of the moneys is also known. Since there is considerable disagreement among economists over the assumption of what the Government discount rate should be, some uncertainty is introduced into the calculation. These calculations assume a Government discount rate of 10 percent, which is the rate suggested by OMB.

Given these difficulties, the reported costs to the Government of providing the incentives should be viewed as illustrative of the probable average cost of providing the incentive to a number of developers. It should also be remembered that these estimates do not include the administrative cost of overseeing the incentive. Several percent could be added to the cost of the incentive, in the cases of debt guarantees, purchase agreements, block grants, and low-interest loans. The costs to the Government reported in this chapter would apply only to first-generation facilities. Subsequent plants would probably require less governmental involvement and thus lower governmental costs. If the incentives included fade-out provisions as oil prices rose in real terms and shale oil became more competitive, then the Government's costs would also fall substantially for later plants—if the price of world oil continues to rise faster than the cost of building and operating shale oil facilities.

In this chapter, the cost to the Government of providing an incentive is the gross subsidy to the firm less increased tax payments to the Government. This cost was calculated in present value terms. The net cost for each year (i.e., the subsidy less tax revenues) was discounted at the Government's discount rate (i.e., 10 percent). The resulting present value calculations were summed for all years. The nature of the Government cost calculations is described in greater detail in appendix A.

Scenario 1: 100,000 bbl/d by 1990.—OTA's analysis indicates that the production of 100,000 bbl/d by 1990 will probably take place without further subsidy beyond the general purpose tax credits that are currently available to any industrial or energy developer. Consequently, this scenario would not require any additional cost to the Government.

Scenario 2: 200,000 bbl/d by 1990.—The cost to the Government of subsidizing the 200,000 bbl/d envisioned in this scenario would depend, in part, on which incentives are used to stimulate production. As is shown in table 25, the estimated cost to the Government of subsidizing a 50,000-bbl/d plant will depend on the incentives chosen. If the Government chose to provide only one of the incentives considered in this chapter, then its costs would vary between approximately $0 and $494 million in 1979 dollars. However, this range should be adjusted in several ways. First, the construction grant subsidies are so costly and politically unpopular that they should probably be dropped from consideration. Second, although the purchase agreement is a powerful incentive in theory, its impact when set at $55/bbl over the life of the project is too low to have a significant influence on project economics. Consequently, it should also be dropped from consideration.

Each of the remaining subsidies would yield substantial profits if a 12-percent discount rate is assumed. Although all but the low-interest loan will still yield a relatively small loss if a 15-percent discount rate is assumed, this is offset by the fact that the present calculations assumed a l-year construction delay. The cost of this delay is $117 million. If such a delay does not take place, then all of the incentives except the purchase agreement will provide a small profit (or small loss) in addition to the 15-percent discount rate (return on investment).

Thus, the cost of spurring the construction of a 50,000-bbl/d plant with the use of a single subsidy would be between approximately $100 million and $400 million over the life of the project. Therefore, the cost to the Government of stimulating the production of 200,000 bbl/d would be between $400 million and $1.6 billion.

If it were certain that any of the incentives included in these ranges would induce the desired level of production, the least costly subsidy would be the best choice from the Government's perspective. Unfortunately, this is not necessarily the case. As discussed previously the particular corporate and financial circumstances of individual developers vary widely with respect to the specific risks that they need or wish to avert. Therefore, their incentive needs may be quite different. Some firms may find it difficult to use tax credits. Others may be too small or weak financially to take advantage of price supports or purchase agreements. Instead, they require some kind of financing subsidy such as a low-interest loan or debt guarantee. Some form of choice among possible incentives is probably necessary in view of these differences.

If the Government provided a choice among possible incentives, then the cost of financing this scenario would probably be between $1.2 billion and $1.4 billion in 1979 dollars.

Scenario 3: 400,000 bbl/d by 1990.—0n the basis of the same assumptions that were used in the second scenario, the cost to the Government of providing a single incentive would be between $800 million and $3.2 billion in 1979 dollars. If developers were given their choice among the incentives, then the cost to the Government to stimulate this level of production would be between $2.8 billion and $3.2 billion in 1979 dollars.

Scenario 4: 1 million bbl/d by 1990.—The costs to the Government discussed below assume that almost all of this production would take place with incentives to private industry rather than through direct Government ownership. However, since the list of incentives being considered includes both a 33- and 50-percent construction grant, the following analysis captures the financial consequences of Government participation. It also assumes that an effort to deploy the industry by 1990 would put enormous strain on U.S. manufacturing capacity (e.g., valves, heat exchangers, pressure vessels, and mining equipment), or architectural-engineering schedules, and on the reservoir of skilled workers. This would delay construction timetables and produce sizable cost overruns. The precise amount of these overruns cannot be predicted.

Conversations with representatives of industry and major construction firms, plus an examination of the available literature, suggest that such cost escalations could easily reach or exceed 50 percent of the original estimates. The calculations for the total capital cost of this scenario include this assumption. It is difficult to predict the effect that such overall cost increases would have on the cost of Government subsidies, since a large part of the increases would be absorbed by the developers, Increases in the total capital costs of the target production would not translate directly into higher governmental costs, but would more likely reduce overall production because of project failures. How much the Government's costs escalated would be sensitive to the particular incentives used. They would also be affected by the degree to which hyperinflation of overall plant costs and resulting project failures reduced tax receipts.

In order to stimulate sufficient developer commitment to stand a chance of meeting the production target, firms would have to be allowed to choose the incentive that benefited them most. In which case, the total direct cost to Government would probably be between $6 billion and $7 billion. However, it is likely that project failures and construction delays would prevent the production target from being met. Consequently, the above estimate of cost to the Government would be more likely to represent a production in 1990 of 500,000 to 750,000 bbl/d rather than the full 1 million bbl/d.

It should be noted that the above calculations do not include necessary administrative costs nor do they capture all of the costs of additional refineries, piping, and transportation facilities that would be required for the third and particularly the fourth scenarios. The estimates are in present value terms and do not represent, except for the block grants, payment by the Government of a single lump sum. All the other incentives would allow phased expenditures over a number of years, thus, limiting the Government's financial obligations during any one year. Most importantly, the calculations use OMB's lo-percent discount rate, and assume that the gross amount of the subsidies would be used in some equally productive manner if it was not spent on oil shale. Assuming alternatively that these moneys were used less productively, then the real cost to the Government of the subsidies would fall substantially. For instance. the net cost to the Government of providing the low-interest loan would be $453 million if a Government discount rate of 10 percent is assumed. The cost would be $201 million if a 5-percent discount rate is assumed.

Capital Market Impacts and Financial Feasibility

The capital outlays needed to develop a sizable shale oil production capacity are immense, e.g., $30 billion to $45 billion for just a l-million-bbl/d capacity, This has led many to question the financial feasibility of private sector development and to argue that Government financial guarantees and/or direct Government participation are mandatory if there is to be significant shale oil production capacity by 1990 or even by 2000. Still others have asserted that even if the Government ensures the necessary financing, its achievement would mean severe distortions of the capital markets, namely: 1) a significant increase in capital costs (interest rates and required return on equity), which would reduce other business investment and 2) distortions in particular economic segments such as housing, due to high interest rates and the "crowding out" of mortgage financing. Yet proponents of shale oil development argue that there are significant long-run benefits to be gained.

These include capital market benefits in terms of balance of payments, of inflation, and of strength of the U.S. dollar.

Concerns

There is a clear need to address systematically the financial and economic issues of shale oil financing. Thus, it is necessary to consider: 1) the level of required financing associated with alternative rates of shale oil development, 2) the financial feasibility, 3) the capital market impact in aggregate and on particular capital market segments, 4) financial aspects of Government policy alternatives, and 5) the impact of shale oil on the balance of payments, on inflation, on the strength of the U.S. dollar, and on tax revenues.

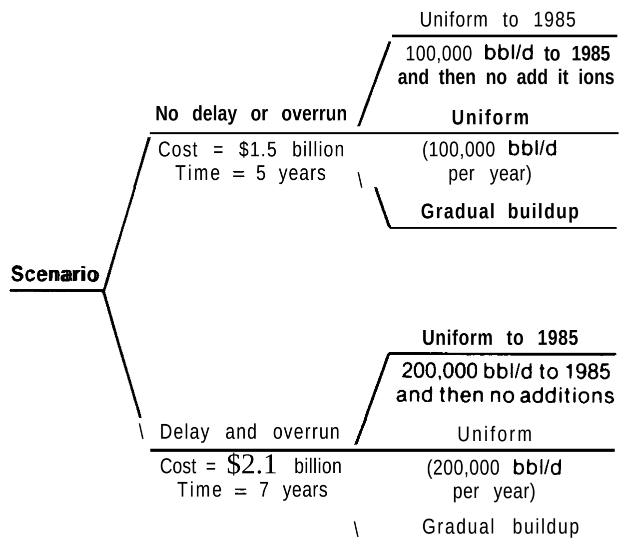
Scenario Framework

The development envisioned in either scenario 1 or 2 would not entail significant capital outlays, Thus these scenarios do not involve issues of financial feasibility and capital market distortions. Financial-economic considerations would, however, cause variations to scenario 3 (pioneer commercial industry) and scenario 4 (aggressive develop ment). Two concerns within each scenario are: the effects of delays and cost overruns and variations in the timing of development.

Delays and cost overruns.—In the absence of delays and cost overruns, it was assumed that the prototypical plant would take 5 years to build and cost $1.5 billion in 1979 dollars (the upper end of current estimates for room-and-pillar mining with surface retorting). To assess the effect of delays and cost overruns, an adverse variation was considered to be a 2-year delay and a $600 million overrun.

Alternative plant initiation schedules.—There are several ways to reach a target level for a given production capacity by 1990. One is to initiate the necessary capacity at a uniform rate, and stop adding capacity in 1985 to reflect the 5 years from initiation to completion. Another is to add plants at a uniform rate, for example, 100,000-bbl/d capacity (two prototypical plants) per year in scenario 3 and 200,000bbl/d (four prototypical plants) in scenario 4. Third and more realistic is to gradually build up the development rate from current levels to a target level of capacity additions. For each scenario, figure 52 shows the combinations of delay-overrun variations and capacity addition variations.

Figure 52.—A Summary of Variations in Each Scenario



Peak Financing Requirement

While the total capital outlay to put a shale oil industry in place may suggest financial infeasibility and the possibility of severe distortions in the capital markets, it is critical to recognize that the total is spread over a number of years. Moreover, once there is significant capacity in place, much of the cash generation is available to finance further growth, so that even a growing capacity becomes “self-financing” at some point.

The key issue of aggregate financial feasibility and capital market impact is the peak annual financing requirement. The annual financing requirements for various scenario variations* are plotted in figure 53. The peak financing requirements are summarized in table 27.

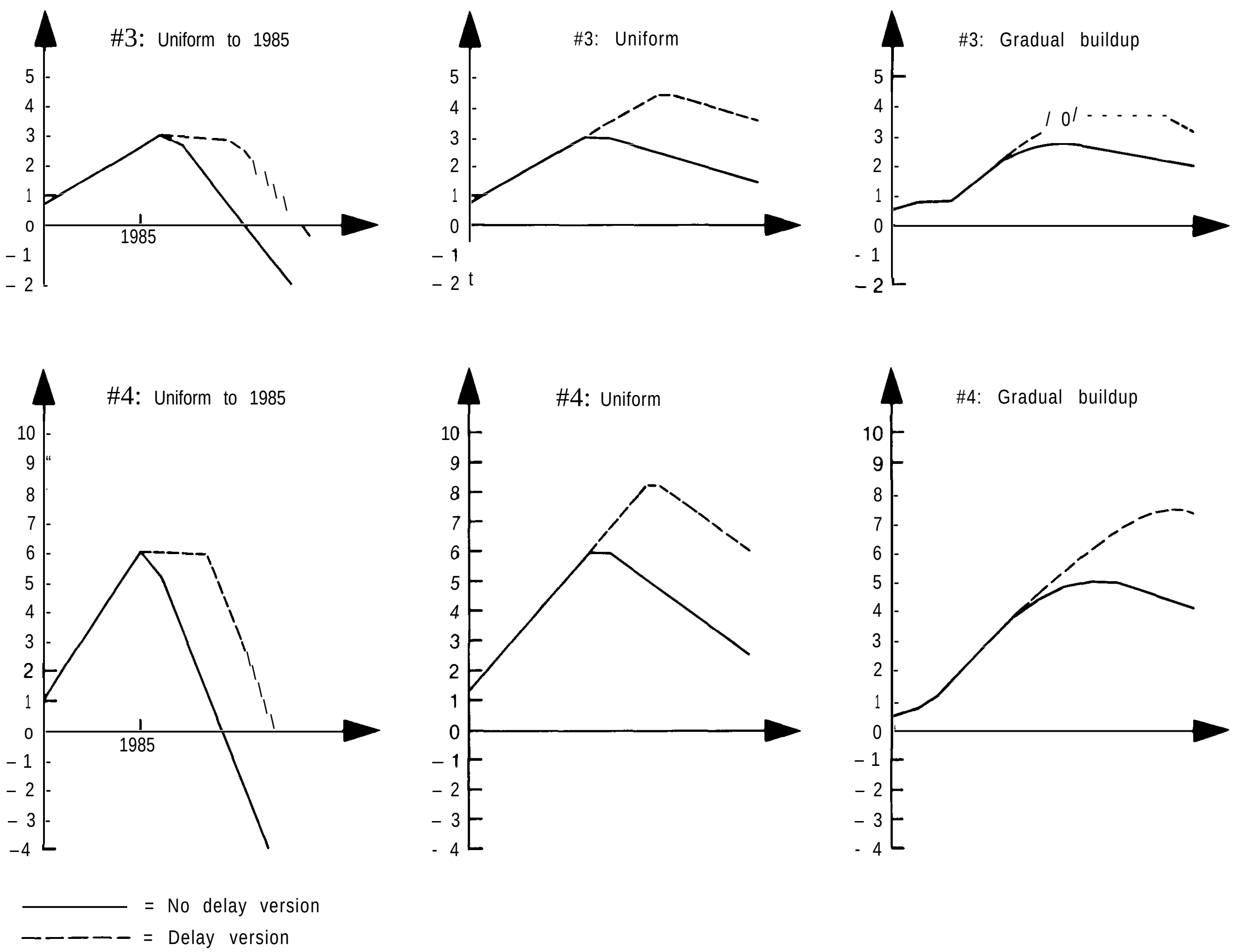
Scenario 3.—The peak annual financing requirement would be no more than $3 billion (1980 dollars) for a uniform addition of 100,000-bbl/d capacity per year with no delays and overruns. It would be no more than $4.2 billion for the delay-overrun variation.

Scenario 4.—The peak annual financing requirement would be no more than $6.0 billion for a uniform addition of 200,000-bbl/d capacity per year with no delays and overruns. It would be no more than $8.4 billion for the delay-overrun variation.

The use of the phrase "no more than" in the paragraph above reflects the fact that very conservative assumptions about cost and cash flow were used in each scenario in order to make certain that peak financing requirements are not understated.

*For more details on the scenario variations, the cost and revenue assumptions, the simulation methodology, and a detailed case-by-case development of the cash flows, see Bernell K. Stone, *Shale Oil Financing: An Assessment of Financing Requirements, Capital Market Impact, Financial Feasibility and Financial Aspects of Policy Alternatives.*

Figure 53.—Year-by-Year Financing in Billions for Various Scenarios



SOURCE Office of Technology Assessment

Table 27.–Peak Financing for Each Scenario (billions of dollars)

Version	No delay or overrun	Delay and overrun
Scenario 3		
Uniform to 1985	$3.00	$3.00
Uniform.	3.00	4.20
Gradual buildup . .	2.40	3.90
Scenario 4		
Uniform to 1985 .., ., .	6.00	6.00
Uniform.	6.00	8.40
Gradual buildup	4,95	735

SOURCE Off Ice of Technology Assessment

Aggregate Financial Feasibility

There is no significant problem of aggregate financial feasibility. Assuming that the current rate of domestic business capital investment grows at a conservative rate of 4 percent into the mid-1980's at the time of the peak financing requirement, the $6 billion would be less than 3 percent of total domestic business investment and the $8.4 billion would be less than 4 percent. *

While a figure of $6 billion to $8 billion sounds like a large annual outlay, 3 to 4 percent of net domestic business investment should cause no significant financial distortions in terms of interest rate shifts or capital market flows. This amount is well within the normal year-to-year fluctuation in domestic business investment, and a small fraction of year-to-year shifts in net domestic savings. Likewise, it is within normal shifts in capital flows from abroad. In fact, the international capital markets are now recycling many times this amount of petrodollars. Finally, it is a small fraction of the total annual mortgage financing market, where mortgage refinancing intermediaries annually recycle tens of billions. Moreover, the experience of the past 3 years has shown that thrift institutions can compete for funds at times of high interest rates when rate ceilings are lifted. Hence, this level of financing should cause no significant distortion of the housing industry.

The capital flows are well within the financial capacity of the major petroleum companies. For instance, EXXON has announced a $6.5 billion capital investment plan for 1980. A survey of the 1979 annual reports of the 18 major integrated oil companies indicates capital investment programs exceeding $50 billion per year. Moreover, cases such as the SOHIO financing of its Prudhoe Bay development, and its share of the Alaskan pipeline, indicate an ability for private enterprises with limited financial capacity to put together creative financing packages without Government assistance, when there are promising investment opportunities.

Hence, not only is there no aggregate problem of capital market capacity or distortion, but there is also no significant problem of capacity or feasibility for the private sector to provide financing as long as shale oil is a profitable investment.

A Caveat

The analysis above has looked at an aggressive development scenario in a clearly worst case for financial requirements and found no significant problem. However, it has ignored other possible sources of significant additional financing. Were shale oil financing to be only one of several Government-supported projects, each with comparable peak financing requirements in the mid-to-late

*The annual rate of business expenditures for new plant and equipment in 1979 is $174 billion ($180 billion seasonally adjusted annual rate in the fourth quarter). Hence, by the time of peak financing in the mid-1980's, business expenditures for new plant and equipment should be well over $225 billion with 4-percent annual growth, 1980's, then there is a potential problem in the sense of crowding out other domestic investment, distorting particular markets such as housing, or significantly increasing interest rates necessary to induce domestic saving and/or investment capital from abroad. While consideration of financing induced by other Government programs is beyond the scope of this report, this possibility must clearly be recognized, and an overall financial impact assessment made.

Finance Mix

Thus far the analysis has focused on the total peak financing and secondary financial effects. In general, the capital markets are very efficient at shifting funds between capital market segments. Therefore, the major macro impact depends on the amount of overall financing regardless of the particular mix. Nevertheless, there are mix issues, especially capacity to provide new equity and ability to support debt without guarantees.

The investment tax credit implies that the Federal Government automatically provides up to 20 percent of the total investment. * A scenario of further Government support of development cost beyond the investment tax credit could be an additional 20 percent for a total Government share of 40 percent. These two cases are summarized in table 28 assuming the remainder is 50-percent debt and 50-percent equity. The actual share of debt in the total financing is less, namely 40 percent and 30 percent respectively.

Table 28 shows strikingly that there should be no financing problem for the major oil companies. Both current earnings and retained earnings (earnings after dividends) are many times this amount for the 18 largest companies.

Debt capacity of the major oil companies is also more than adequate. Even if peak needs were to persist for 10 years ($32 billion), the current debt capacity would tolerate such amounts in terms of debt-equity ratios and interest coverage. Hence, for the overall energy industry, there is no significant problem of providing either debt or equity, assuming that the equity is primarily from retained earnings.

*The use of 20 percent here assumes that the extra IO-percent investment tax credit continues. Otherwise, this figure will drop to 10 percent.

Table 28.–Finance Mix

	Current Investment tax credit only		Government sharing of construction costs 20%	
	Percent	$ billions	Percent	$ billions
Government	20	1 6	40	3 2
Private debt	40	3 2	30	2 4
Private equity	40	3.2	30	2 4
Total	100	8 0	100	8 0

SOURCE Off Ice of Technology Assessment

Smaller Companies and New Equity

For smaller companies, the financing burdens can be formidable. Likewise, the magnitude of equity financing for a single commercial facility is onerous. The new equity market is not likely to provide significant venture capital for new enterprises or small companies in this area. Without Government assistance, a small company can participate only via joint ventures. However, this limitation is not unique to shale oil. Small companies cannot generally undertake billion dollar capital investments in any industry. Moreover, such companies generally lack the managerial and technical resources to undertake such ventures successfully. While financing is an obstacle for small companies, it is probably not as severe as building the organization to manage such a project.

Significant contributions to establishing a large shale oil industry should not be expected from small companies. Both technical and managerial talent and financial resources for major development reside in the large energy companies.

Secondary Financial Impacts and Benefits

In addition to the peak capital requirements and the direct impact on the capital markets, there are also a variety of secondary financial effects—balance of payments, strength of the U.S. dollar, inflation, and tax revenue (net effect on the Federal budget).

Balance of Payments and Strength of U.S. Dollar

Shale oil development has two balance-of-payment effects—the direct effect of its production and the indirect effect from its influence on the world oil price.

Direct effect.—Producing shale oil will reduce the need for imports. There should be a one-for-one substitution of shale oil for imported oil. At a $30/bbl current-dollar price for imported oil in the mid- to late 1980's, the shift in balance of payments is $5.5 billion (scenario 3 with no delay) to $7 billion (scenario 4 with delay) in 1990. It would rise to $15.5 billion (scenario 3 with no delay) to $27.0 billion (scenario 4 with delay) in 2000. These effects are summarized in table 29.

Indirect effect.—The indirect effect arises from price pressure exerted by domestic shale oil production on the price of world oil.

Table 29.–The Current Dollar Improvement in the Annual U.S. Balance-of-Payments Position Associated With Alternative Development Rate Scenarios

	Representative years		
Improved source	1990	1995	2000
Scenario 3 with no delay or cost overrun and annual capacity additions at the rate of 100,000 bbl/d			
Direct substitution (billions)[a], ..., ., .,	$5.5	$10.5	$15.5
Scenario 4 with 2-year delay and a $600 million cost overrun and uniform annual capacity additions at the rate of 200,000 bbl/d			
Direct substitution (billions)[b], ., ., ., ., .,	7,0	17.0	27.0

[a]This assumes the current dollar price of world 011 is $30/bblin each year and corresponds to start-of-year capacity of O 5 million in 1990, 1 million in 1995, and 1 5 million in 2000 plus 50 000-bbl/d average production from phase-in of 100,000 -bbl/d capacity in each year
[b]This assumes the current dollar price of world 011 is $30/bbl in each year and corresponds to start-of-year lull production capacity of O 6. 1 6. and 26 million bbl/d respectively for 1990 1995, and 2000 plus 100000 bbl/d average production from phase-in of 200 000-bbl/d capacity in each year

SOURCE Office of Technology Assessment

For every dollar reduction in the price of world oil (at current import levels of approximately 3 billion bbl/yr), there is a $3 billion improvement in the balance of payments.

Taxes

The direct effect of any shale oil incentives can be either a reduction in taxes and/or Government payments to shale oil producers. Hence, the direct effect of incentives is to increase the Government deficit. To the extent that there is a net increase in economic activity, there are countervailing tax revenue benefits. These include: 1) the taxes paid by shale oil producers, 2) the taxes paid by suppliers to the shale oil companies, 3) the taxes paid by workers for shale oil companies, and 4) the taxes paid by workers for shale oil suppliers.

It is very difficult to assess the impact of shale oil financing on Federal tax revenue. One of the primary variables is the extent to which shale oil production and related economic activity is incremental (net new domestic production) or substitutes for other economic activity.

Estimates of the incremental Federal tax revenue are summarized in table 30. Two cases are considered—loo-percent incremental domestic production and a more plausible 50-percent incremental production. The effect is modest in 1990 due to the assumption of no taxes by the shale oil producers. However, by 2000 it rises to several billion. These figures exclude secondary activity such as incremental tax revenues due to servicing the employees and suppliers. They also do not reflect any benefits of higher employment in reducing unemployment compensation and welfare payments.

Any reduction in the Government deficit will be a long-run benefit to the capital markets to the extent that it reduces deficit financing and the associated "crowding out" of private sector financing by Government debt.

Table 30.–A Summary of Estimates of the Improvement in Federal Tax Revenue Attributable to Shale Oil Production From the Taxes Paid by Shale Oil Companies, Their Employees, Their Suppliers, and Their Suppliers' Employees

	Representative years		
	1990	1995	2000
Scenario 3–uniform 100,000-bbl/d capacity growth and no delay			
Value of annual production (billions)	$5,50	$1050	$1550
Proportion of annual production paid in taxes	15	.20	25
Net tax Improvement. 100% new activity (billions)	83	2,10	388
Net tax Improvement 50% new activity (billions)	41	1.05	1,94
Scenario 4–uniform 200,000-bbl/d capacity growth and delay			
Value of annual production (billions)	700	1700	2700
Proportion of annual production paid in taxes.	15	.20	,25
Net tax Improvement 100% new activity (billions)	1.05	3 4 0	6 7 5
Net tax Improvement. 50% new activity (billions)	.53	1 70	3.38

Notes on the lax proportions

1 The proportions used here (15 20 and 25) are developed In detail m Bernell K Stone *Shale 01l Financing An Assessment of Financing Requirements Capital Market Impact Finan-c/a/ Feasibility and Financial Aspects of Policy Alternatives* They assume a 20 percent before-tax rate of return for the companies 20 percent direct labor expense 50 percent supplier ex pense and 10-percent other Supplier direct labor payments are assumed to be 50 percent of supplier revenue

2 The corporate and personal tax rates used were 50 and 25 percent respectively

3 The proportions assume no corporate taxes from shale 011 producers in 1990 (due to acceler ated depredation and investment lax credits) a 25 percent effective rate in 1995 and a full 50-percent rate in 2000

SOURCE Off Ice of Technology Assessment

Capital Costs: Secondary Effects

The direct effect of more capital investment is to raise capital costs. It has already been noted that this should be minor since the peak capital outlays are small as a proportion of total business investment, and would require only a modest change in saving. The various secondary financial effects (balance of payments, Government deficit, inflation) also impact capital market rates. The long-run effect of improved balance of payments, reduced inflation, and reduced deficits will be to reduce capital market rates—both interest rates and required equity returns necessary for any given level of savings. The long-run reduction should be several percentage points. Moreover, while the short-run impact of higher inflation would be adverse, the fact that capital markets are "anticipatory" (i.e., future looking) means that current rates will reflect not just current inflation but also the future improvement in inflation, balance of payments, and the budget deficit. Thus, the long-run improvements could outweigh both the short-run effect of inflation and the increased financing need. Consequently, the overall effect of shale oil on capital market rates is at worst a minor short-run increase and a clear long-run decrease.

Financial Aspects of Policy Alternatives

Impact on Peak Financing

From the viewpoint of aggregate impact, the most important Government action is that which prevents or at least minimizes delays (i.e., by removing environmental delays and licensing delays once a plant is started), thus, cost over-runs.

Impact on Private Sector Share of Peak Financing

Government subsidies in the construction and very early production stages reduce the private sector share of peak financing but not the overall impact. This is because the Government must raise its share via some combination of Government borrowing or more taxes, either of which reduces funds available for private sector financing.

General Impact of Subsidies

The overall effect of subsidies and/or risk reduction is to make investment more attractive and ensure more rapid development than would otherwise take place. Subsidies also make possible more rapid private-sector development once a basic industry is in place, i.e., beyond the 1990 period.

Government willingness to subsidize, especially via production subsidies and minimum price guarantees, sends an important message to savers and the world capital markets—namely that there will be a significant

U.S. shale oil industry with decreasing reliance on foreign oil. Hence it should reduce inflationary expectations, induce savings, induce investment from abroad, and strengthen the U.S. dollar. These policies could, therefore, have an immediate and significant beneficial effect on the domestic capital markets via their impact on future expectations.

Summary

There is no significant problem in providing peak financing requirements even for rapid shale oil development in terms of capacity of the capital markets, increases in capital costs, or reallocations from other industrial-financial sectors of the economy. Major energy companies have the capacity to provide any reasonable mix of debt and equity via retained earnings.

Long-run secondary effects on balance of payments, strength of the U.S. dollar, inflation, and the budget deficit are all favorable. The overall impact on capital markets should also be favorable, especially given that current rates will reflect future expectations about inflation and the balance of payments.

Effect on Inflation and Employment

Oil shale programs will undoubtedly be a part of a larger synthetic fuels policy. All of the legislation before Congress is concerned with the development of a synthetic fuels industry as such. The development of oil shale, were it to take place, would do so in the context of some particular array of policies concerned with such issues as conservation, oil import reduction, coal conversion, and/or increased solar power usage. Furthermore, shale oil development, like any other long-term financial commitment, will interact with Government policy and economic trends in numerous areas such as monetary policy, fiscal policy, tax policy (the windfall profits tax is particularly relevant), the characteristics of the balance of payments, and overall capital availability. To evaluate how prices and employment will be affected by oil shale development, it would be necessary to examine these effects for all of the major synthetic fuels proposals before Congress, and attempt to assess the course of the U.S. economy over the next 10 years. This task is outside the scope of this report. However, the Congressional Budget Office in its September 7, 1979 report to the Senate Budget Committee has attempted to make such an analysis.

The impacts on prices and employment nationwide of the deployment of the first scenario (100,000 bbl/d) would be insignificant. Even the realization of the second scenario (200,000 bbl/d), would have negligible effects on national inflation and employment. However, the inflationary effects of this production on the cost of the machinery and equipment necessary to the industry might be small, although discernible and could be significant, particularly on the price of labor, land, and rents, in the immediate geographical areas of development.

Even the third scenario (400,000 bbl/d) would not have an appreciable effect on national inflation rates or employment levels, It would substantially affect local prices, have an enormous positive impact on local employment, and a definable one on regional employment. Depending on the phasing of the influx of workers, the local expenditures by the developer, and the approach taken in dealing with socioeconomic impacts, the inflationary effect on land, labor, rent, and goods could be very large, particularly on land and rents. (See ch. 10.)

The prices for the machinery and equipment used for constructing the facilities would escalate sharply. It has been estimated that the construction of an industry with a 400,000-bbl/d capacity would use between 10 and 20 percent of the current U.S. manufacturing capacity for valves, pressure vessels, heat exchangers, and certain kinds of mining equipment.[6] This would clearly be inflationary for these industries. The extent would depend on the rapidity with which the industries could respond to the increased demand, how much in advance of need the equipment orders were placed, and the availability of foreign substitutes.

It is likely that the fourth scenario (1 million bbl/d by 1990) will affect the national economy somewhat differently from 1980 through 1985 than it will from 1986 through 1990. The short-run direct effect of shale oil development will be to use resources with no offsetting production. Hence, it would be clearly inflationary, although the direct inflationary impact might be offset somewhat by price pressure on world oil.

The long-run effect will be to reduce inflation because of the substitution of domestic production for imports, the pressure on the world price of oil, the improvement in the balance of payments, and the favorable impact on the Federal budget. Moreover, because capital markets set current rates on the expectation of future events, the anticipation of reduced inflation can lower current capital costs.

Simultaneously, however, this oil shale program could also exert inflationary pressure on general prices over the longer term starting in the early to middle 1980's because the high demand created by the level of investment would probably create temporary bottlenecks in various sectors of the economy, and shortages of materials and skilled labor. The net effect will tend to push up the prices of the essential elements of production.

Assuming that all other factors remain the same, the tendency will be for the inflation rate to fall by 0.05 to 0.1 percent and for the level of unemployment to rise by 0.025 to 0.05 percent during the earlier period of development. During the latter half of the decade, however, employment in the industry will grow sufficiently to very slightly reduce the national rate of unemployment (i.e., 0.015 to 0.025 percent). During this time, the tendency will be for increasingly rapid investment to exert only a small influence on the rate of inflation. It is unlikely that this impact would exceed 0.1 percent. These figures should be regarded as tendencies representing the direction of the impact—if nothing changes. Given the high probability that all things will not remain the same, these estimates should be viewed with extreme caution. One fact is, however, quite clear: oil shale development by itself will have a very small impact either on national rates of inflation or on employment.

Although the national impacts would be quite small, the local, regional, and sectoral effects would be much more substantial. Development of the magnitude envisioned in this scenario would bring many operating, professional, and construction employees into the area. This will unquestionably have an extraordinary impact on local prices, rents, and land costs, as well as on local employment. These issues are discussed in detail in chapter 10.

Construction Industry and Equipment Capacity

Current construction equipment capacity will severely hamper the ability to achieve oil shale production at the level assumed in the fourth scenario. It is apparent that limitations will be encountered in the following areas:

- the capacity of design and construction firms;
- the availability of various kinds of long leadtime equipment such as pressure vessels, valves, compressors, pumps, heat exchangers, heavy mining equipment, and alloy components;
- the capacity to move equipment to remote construction sites, and to transport shale oil by rail and pipeline to markets or refineries; and

- the availability of sufficient numbers of an adequately trained labor force to meet construction schedules.

Meeting the production targets will necessitate substantial improvements in each area. Such an expansion of capacity will require a national commitment to divert resources from other areas and uses, will create bottlenecks in other parts of the economy, and will lead to rapid inflation of costs in the relevant mining, construction, and equipment industries. In order to achieve this production goal the following annual manpower and equipment needs would have to be met.

In these projections it is assumed that approximately 20 commercial facilities having an average capacity of 50,000 bbl/d will be constructed. Most would not reach the design stage until at least 1982. Their construction is unlikely to be started until between 1983 and 1984; and will not be completed until between 1989 and 1990. Consequently, many of the projects will be designed and constructed simultaneously, thus, severely taxing the capacity of equipment suppliers and construction firms.

These projects because of their size, complexity, and the vast array of skills and expertise they require, will necessarily need to be contracted to a limited number of large architectural-engineering firms. Only a few design and construction firms have the managerial, technical, and economic experience to construct such plants. An examination of the existing capacity of such firms by Engineering News Record on April 12, 1979, indicates that of the construction firms involved in building manufacturing process facilities, only 21 contracted in 1978 for work having a total dollar value near the level of expenditure required to construct a small commercial oil shale plant—$400 million per year.[7] It can, therefore, be concluded that no more than 21 firms have the current capacity for such work. Many of these are already booked years in advance. However, workloads between now and 1985 will probably increase the number of firms that are able to undertake projects of this magnitude. There is also the possibility that by combining together, smaller firms will be able to undertake such projects.

In 1978, the construction industry contracted for $27.2 billion worth of new work, only $21.6 billion of which was industrial work. Thus, the annual construction costs of the oil shale plants that would have to be built between 1983 and 1990 to reach the million-barrel-per-day target represents 35 percent of the workload in 1978.

In particular, shortages of skilled labor can be expected during efforts to deploy an industry of this size. In 1978, there were approximately 45,000 workers in the United States having the necessary technical and professional skills (e. g., draftsmen, engineers, managers, and scientists). From 1983 to 1990, shale oil plants producing 1 million bbl/d would require 11,000 to 18,000 professional employees, which is more than 36 percent above process industry requirements in 1978. At this time, the United States has a total construction work force of around 4.5 million. During each year between 1983 and 1990, constructing the plants would require an additional 130,000 workers. The need for such a large labor force would act to hamper the deployment of an industry of this size, and would substantially inflate labor costs.

Chapter 6 References

[1]This discussion is indebted to that presented by Robert Merrow, Constraints on *the* Commercialization *of Oil Shale*, RAND Corp., 1977,

[2]This discussion in this section draws on material presented by Robert Merrow, Constraints on the Commercialization *of Oil Shale*, RAND Corp., 1977, and Synthetic *Fuels:* A Report Prepared *for* the Budget Committee *of* the U.S. Senate, 1979.

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[7]''A Fluor Perspective on Synthetic Liquids, " Fluor Corp., 1979.