

CONSTRAINTS ON THE COMMERCIALIZATION OF OIL SHALE

PREPARED FOR THE DEPARTMENT OF ENERGY

EDWARD W. MERROW

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PREFACE

Beyond supporting research, development, and demonstration projects, government energy policy is directed toward introducing new energy technologies into commercial use. Considerable policy attention has been focused on the commercialization of energy process plants that produce substitutes for imported petroleum and natural gas. These include the production of crude oil from oil shale and gas from coal or biomass. Commercialization refers to the adoption of a technology for general use by the private sector after most questions of technical feasibility have been resolved.

This report discusses the principal economic and institutional problems surrounding the commercialization of surface oil shale technologies. The study was conducted for the Department of Energy and its predecessor, the Energy Research and Development Administration, as part of an overall Rand program of research and policy analysis. A companion report by William F. Hederman, Jr., *Prospects for the Commercialization of High-Btu Coal Gasification*, R-2294-DOE, April 1978, addresses similar economic and institutional issues arising in the commercialization of synthetic natural gas from coal.

SUMMARY

This report examines the problems and prospects for the commercialization of oil shale from surface retorting. Commercialization refers here to the process of private sector adoption of a technology for general use after most of the technological uncertainties have been resolved. The report addresses three primary questions:

- o What economic and institutional constraints are currently delaying the introduction of surface retorting plants by the private sector?
- o What kinds of government policies or actions might remove or mitigate constraints on commercialization?
- o In light of the constraints and the feasibility of actions to mitigate them, what would be realistic goals and schedules for commercialization?

Three categories of constraints and uncertainties can be identified: technical constraints relating to the performance characteristics of the technology; economic constraints on the ability of the technology to yield an acceptable rate of return to investors; and institutional constraints that arise from the organizational and political context in which commercialization takes place. Because surface retorting involves relatively well understood technologies, this study deals almost exclusively with economic and institutional constraints.

In early 1974, when OPEC tripled oil prices, it appeared that the longstanding cost barrier to oil shale commercialization had been removed. It was then estimated that oil from shale would have to be priced at only \$8.00 per barrel to earn a 15 percent rate of return to investors, well below the OPEC price. By the end of 1974, however, some revised industry estimates exceeded \$19.00 per barrel to earn the

same rate of return. Capital cost estimates made since the end of 1974 by industry have been about four and one-half times the estimates made in 1971.

Four factors are responsible for the increases in capital cost estimates: (1) increases in the general price level that account for about 12 percent of the total increase, (2) increases in the costs of capital construction throughout the economy, over and above general inflation, that account for an additional 6 percent of the total increase, (3) costs of environmental protection, which can account for between 8 and 20 percent, and (4) a large residual, much of which can be attributed to better knowledge of costs as a result of more complete plant design. The serious underestimation of costs based upon plant designs prior to the completion of a final design for actual plant construction poses important difficulties both for government energy planners and corporate investors. The federal government has had to scale down its plans that called for a major contribution to energy supplies from oil shale, and oil companies have lost substantial sums of money.

The underestimation of capital costs for first-of-a-kind energy plants appears to be commonplace, notable examples being the experience with plants for high-BTU gasification of coal, coal liquefaction, and nuclear power. In the future the problem might be eased through such measures as government cost-sharing of definitive plant designs to provide more confident cost estimates on a timely basis, and developing a data base on cost experience with industrial first-of-a-kind plants in the chemical processing and electricity generation industries. Such a data base would permit a more quantitative analysis of the factors that have driven estimates upward between preliminary design and first-of-a-kind plant construction.

At present, the cost of shale oil is the principal barrier to the commercialization of surface retorting processes. Potential developers now estimate that cost at about 50 percent above the current world oil price. The time when shale oil will become cost-competitive obviously depends on the relative changes in world oil and shale oil prices. Major factors that will affect the shale oil price in the future include the accuracy of current capital cost estimates, changes in real

capital and operating costs (including those arising from possible bottlenecks in construction), additional environmental, tax, or other governmentally imposed costs, and technical advances and learning effects.

Currently, shale oil from surface retorting is estimated to cost \$20 to \$26 per barrel (in 1977 dollars) to maintain a 15 percent discounted cash flow rate of return on an all-equity basis. Shale oil costs, however, are sensitive to a number of assumptions: capital costs, interest rate on debt, plant availability, state and local taxation, and environmental policies. Uncertainties surrounding these factors mean that costs could go even higher than the range of current estimates. Assuming that shale oil costs will in fact remain in the \$20 to \$26 per barrel range, and assuming a 2 percent per annum real increase in world oil prices, shale oil from surface retorting would become competitive between 1995 and 2008. However, capital costs of large plant construction and operating costs for chemical and refinery plants have outpaced inflation over the past decade. A continuation of these trends would dim the prospects for competitive shale oil in this century. At today's low and high estimates of \$20 and \$26 per barrel of shale oil, a 4 percent and a 5.5 percent per annum real increase in world oil prices would be necessary to achieve competitiveness by 1995 if past increases in capital and operating costs are extrapolated into the future.

Bottlenecks in the supply of components and engineering services for plant construction could also affect shale oil costs during commercialization. Bottlenecks would lead to sharply increased costs or major delays, or both, for plants under construction. The potential for bottlenecks in oil shale cannot be isolated from other economic factors in general and other energy plant construction in particular. Architect-engineering services appear to represent the most serious potential for bottlenecks if, as a result of very sharp increases in world oil prices or a government subsidy program to deploy oil shale and other synthetic fuel technologies, a rapid buildup to more than a million barrels per day over 10 to 12 years took place. Architect-engineering services are subject to bottlenecks because only 6 or 8 firms have the wide range of skills necessary for oil shale plant

design and construction, and lead times of 5 to 8 years are necessary to expand supply in certain critical areas.

Decreased costs through learning have been sometimes cited as offsetting future increases in capital and operating costs. If a learning factor of 10 percent were assumed for shale plant construction, meaning that costs would decline 10 percent with each doubling of the cumulative number of plants, then the cost of the sixteenth plant would be only about two-thirds that of the first, assuming other factors remain constant. Unfortunately, for several reasons, such significant gains from learning are highly unlikely for surface retorting plants: (1) A considerable portion of shale oil capital costs are either not considered reducible through learning or occur in well-established technologies that have already attained most of their learning gains; (2) because oil shale plants will be site-specific to some extent, it will be difficult to duplicate experience that is critical to learning; and (3) changes in environmental and safety rules may force plant redesign and disrupt learning. As a result, a learning factor of 2 to 3 percent is probably as much as can be hoped for.

Commercialization is also constrained by institutional problems. The most serious of these appears to be the availability of water. Water allocations in the semiarid shale region are subject to a variety of laws, compacts, and restrictions governing the Upper Colorado River and are subject to intense political pressure. Surface retorting plants would probably encounter difficulty in obtaining water at an industry size of one million barrels per day. This problem would become progressively more severe as the industry approached two million barrels of daily capacity, especially if the industry buildup were rapid. Other important institutional constraints include uncertainty over future environmental regulations, legal challenges to oil shale production from environmentalists and others, and a currently unfavorable climate for investment in oil shale by oil companies due to uncertainty about the effects of the proposed crude oil equalization tax and the continuing possibility of divestiture legislation.

At the present time, a government commercialization effort for oil shale surface retorting would not be likely to result in a viable

industry in this century. Alternative oil shale technologies such as modified *in situ* processes offer prospects of lower shale oil costs, but are less well developed. Data on modified *in situ* processes are not abundant enough as yet to permit serious estimates of commercial-scale costs. Consequently, government decisions regarding the commercialization of modified *in situ* technologies should await the completion of further technical tests and an independent definitive plant design.

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All errors remaining are the responsibility of the author.

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Chapter 1
INTRODUCTION

Since the Arab oil embargo and subsequent "energy crisis" of 1973-74, the federal government has been more active in promoting the development of new energy technologies. It has increased its funding of energy R&D, and has been contemplating major programs to accelerate the commercialization of nonnuclear technologies.* Between 1974 and 1976 there was active discussion within the federal government and industry of whether and how the government might promote the early establishment of industries to produce substitutes for petroleum and natural gas. Two major task forces addressed the issues, and two legislative proposals calling for large subsidy programs were submitted to Congress.† Congress did not enact legislation to accelerate the use of oil shale and other synthetic fuels, however; meanwhile, the United States has grown increasingly dependent on foreign supplies of oil, and estimates of world supplies of petroleum and natural gas are fraught with uncertainty. If another oil embargo occurs or if world oil prices begin to climb rapidly because world production peaks sooner than expected, the perceived need to speed the introduction of domestic substitutes could quickly return. We would define a rapidly accelerated buildup to be the production of 3.5 to 4 quadrillion BTU (quads) per year over a 12 to 15 year period, or about two million barrels per day.

This report analyzes the commercialization prospects for one such technology: surface retorting of oil shale. The analysis is one component of Rand's study of constraints on the commercialization of energy process plants that produce substitutes for imported petroleum and natural gas. Energy process plants--oil shale, coal gasification, coal

*The government's involvement in nuclear power technologies dates back more than 20 years. The Power Reactor Demonstration Program was the first major commercialization program undertaken by the federal government.

†The Project Independence Task Force and the Interagency Task Force on Synthetic Fuels Commercialization.

liquefaction, and liquid and gaseous fuels from waste and biomass--share a number of characteristics that are important for commercialization planning:

- o These plants use abundant resources, such as coal or oil shale, or potentially abundant resources, such as biomass. They could, therefore, become large and long-term sources of substitutes for the scarcer petroleum and natural gas reserves.
- o All are more capital-intensive than conventional oil and gas sources.
- o Most of the process plant technologies are expected to achieve minimum cost per unit output at large plant size, which, combined with capital intensiveness, means that very large capital plant outlays are necessary.
- o For the most part, until 1974, the private sector developed energy process plant technologies with minimal government support. This is in sharp contrast to nuclear power development, in which the government has acquired most of its experience in aiding the commercialization of energy supply technologies.
- o Finally, the energy process plant technologies entail long commercialization planning horizons. Construction of a single plant takes four years or more, and the orderly buildup of a sizable industry would take many more years.

The principal questions addressed in this report are:

1. What economic and institutional constraints could delay or prevent the commercialization of oil shale?
2. In light of the constraints and of the feasibility of actions to mitigate them, what would be realistic goals and schedules for commercialization of oil shale plants?
3. What are the lessons from previous government attempts to advance the commercialization of the technologies, and in what areas is the current knowledge base insufficient to assess commercialization issues?

Issues of *why* the government should become involved in commercialization are important but are not the subject of this report. Government involvement in commercialization may be justifiable when the private sector declines to undertake, or withdraws from, an enterprise that answers a pressing social need or otherwise promises important social benefits. The penalty of inaction by both sides may take the form of forgone social benefits, such as the value to national security of assured domestic supplies of oil, or the form of costs (externalities) imposed on society, such as damage to the environment. The private sector occasionally fails to promote the socially optimal use of a technology because the government is already intervening in a way that discourages use of the technology (for example, through price regulations).

Market failure is only a necessary, not a sufficient, reason for government involvement. Only if the benefits of government involvement exceed the costs, appropriately discounted, is government action justified. The relevant choices are not between efficient markets and inefficient government, or between efficient government and inefficient markets, but between inefficient government and inefficient markets. The key is to know which one will be less inefficient in a particular situation.

DEVELOPMENT, COMMERCIALIZATION, AND DEPLOYMENT

In this study, commercialization refers to the process of the private sector adopting a technology for general use after most uncertainties surrounding technical feasibility have been resolved. Commercialization may take many years, or only a few, depending on relative economic advantage and constraints on the use of the technology. In the United States the private sector undertakes most commercialization of new technology without direct government involvement, although the level of government activity in aiding commercialization has expanded greatly in the past ten years, especially through the use of demonstration projects.* We are most interested in the initial period of commercialization--roughly, from the time that the results of development

* See W. S. Baer, L. L. Johnson, and E. W. Merrow, *Analysis of Federally Funded Demonstration Projects: Final Report*, The Rand Corporation, R-1926-DOC, April 1976.

activities are known to the time that the continued expansion of use of a technology is self-sustaining in the private sector. In particular we are concerned with how the government might facilitate or accelerate the initial phases of commercialization.

It is important for our purposes to distinguish between development and commercialization and between commercialization and deployment. Development activities focus principally on the resolution of technical and, to a lesser extent, economic uncertainties surrounding the use of a process. Commercialization activities are directed at promoting the immediate use of a process by the private sector, and address principally nontechnical uncertainties or economic and institutional constraints on the use of a technology by the private sector.

A government commercialization program should also be distinguished from a government-sponsored deployment effort. Underlying a commercialization effort, on the one hand, is an assumption that any constraints on the use of the technology by the private sector are temporary, and that the commercialization effort will hasten overcoming those constraints and thereby accelerate the introduction of a technology that would have been introduced in the long run by the private sector without government assistance. A deployment effort, on the other hand, requires no such assumption, because it is usually a response to a major crisis. During World War II, for example, the federal government subsidized the deployment of synthetic rubber plants as part of the war effort. It was merely serendipitous that the synthetic rubber processes subsequently became competitive with natural rubber and commercialization occurred.

Both deployment programs and commercialization efforts for energy process plants have been suggested as strategies for increasing U.S. domestic energy production to counter the political and economic leverage of the OPEC cartel. Although both approaches have the same goal--augmentation of energy supplies--they imply very different relationships between the government and the private sector. A deployment effort can be planned and paced largely by the government. It is in many respects a "closed system" similar to weapon system acquisition by the Department of Defense. The role of the private sector may be limited to the

construction and perhaps operation of the plants. Decisions to adopt are made by the government.* Commercialization, by contrast, requires a close interface between government and potential purchasers of the technology in the private sector.

CONSTRAINTS ON COMMERCIALIZATION

Successful commercialization of a technology ultimately depends upon only one factor: profitability. No matter how actively the government promotes a technology's introduction, commercialization will not occur if industry cannot obtain a positive return on its investment comparable to what other investment opportunities may offer. In contemplating the prospects for successful commercialization, both government and industry may need to consider a large number of factors that may affect profitability. These factors fall into three interrelated categories: technical, economic, and institutional. Within each category, problems and uncertainties may arise that jeopardize commercialization by reducing profitability or increasing risk, or both. These problems are "constraints."

Technical constraints and uncertainties frequently center on the performance of a process with scale-up from pilot or demonstration plants. A technical barrier looms if an advance in the technological state of the art is necessary to meet system performance goals; for example, scale-up may demand that a component perform beyond the capabilities of available equipment. The seriousness of such barriers would depend on the completeness of the development effort, and the extent to which the technology involves novel elements.

Economic constraints and uncertainties vary substantially between technologies that produce a substitute for an old product and those that produce largely new products.

In the former case, economic uncertainties and constraints center

* Government deployment programs eliminate the need for private sector investment decisions, but do not necessarily avoid institutional constraints. Environmentalists, for example, could be expected to resist a government deployment effort for synthetic fuels plants as vigorously as they would resist commercialization by the private sector.

on cost. In unregulated markets, an economic barrier arises if the output of the new technology cannot be sold at the prevailing price and yield an acceptable rate of return to investors.* Cost uncertainty may stem from residual uncertainty in the technical dimension or from uncertainty about the cost effects of accommodating institutional constraints. As we will discuss in the case of oil shale, however, cost uncertainty can also exist independently of the other dimensions.

In the case of a new product, economic constraints and uncertainties are more complex because consumer response to the product at different prices may be unknown, consumer resistance to the product may have to be overcome, and new markets may have to be established.

Institutional constraints and uncertainties arise from the organizational and political context of commercialization. The institutional milieu will always be influential, as either a help or a hindrance. The extent to which it constitutes a constraint will depend largely on the extent to which commercialization entails a conflict of values and interests among those involved in and affected by the new technology.

For commercialization to occur, a technology must remain within constraint ceilings in all three areas, or the technology must be changed to accommodate the constraints. Recognition that the three types of constraints are highly interdependent is not only obvious, but crucial, for understanding commercialization. Constraints in one area can often be traded off with those in another. Technical constraints can often be mitigated by relaxing performance goals, but generally at the price of less favorable economics than estimated with higher performance goals. Costs may be reduced by relaxing institutional constraints, such as environmental goals. And of course, environmental regulations are frequently met by changes in the technology.†

* In regulated markets such as natural gas, decisions of regulatory commissions substitute for the forces of the market. Nonetheless, a regulatory decision to allow a new technology to be used is generally affected by its relative costs.

† Tradeoffs also may be made within the types of constraints. An obvious example would be tradeoffs between capital costs and operating costs.

The chances for successful commercialization are determined by the amount of latitude in which the technology can be adapted to cope with technical, economic, and institutional constraints without encountering barriers. If, for example, the relative economic advantage of a technology is very large, then extensive accommodations to environmental goals can be made before an economic barrier is reached. If the technical performance requirements of the system are low, relative to the existing state of the art, there may be room for reducing economic or institutional constraints through improved technical performance goals. But if performance goals are high, the costs are close to or above competitive selling prices, and institutional barriers are being pressed, then the technology is a poor candidate for successful commercialization unless the ceilings on the constraints can be raised. The usual response of the private sector in such situations is to postpone commercialization pending technological improvements, increases in market prices for the products, or improvements in the institutional climate. It is the dilemma and challenge of government commercialization planners that the technologies they consider are usually poor candidates for immediate commercialization; otherwise, the private sector would be vigorously pressing forward on its own. By our previous definition, a technology meriting government support is one that may ultimately be commercialized by private efforts, but on too slow a schedule to suit social needs. In that case, the only recourse for government commercialization planners is to attempt to relax constraints by changing the points at which barriers are encountered: technical barriers, by R&D; economic barriers, by some form of subsidy; and institutional barriers, by a variety of actions, such as changes in administrative rules and regulations, legislation, and political persuasion. To know which actions (if any) to take, the planner must know the point at which barriers are reached for a technology, what factors determine them, and the extent to which lifting the ceiling on one type of constraint will affect the levels of others.

CONSTRAINTS ON THE COMMERCIALIZATION OF OIL SHALE

Shale oil is derived from fossil organic matter--kerogen--trapped in marlstone rock. The world's richest deposits are found in the

Piceance and Uintah basins of Colorado, Wyoming, and Utah. When treated with heat, the kerogen is released and can be upgraded into a high-quality refinery feedstock to substitute for conventional petroleum. Western U.S. oil shale reserves are immense: Over 1.8 trillion barrels (over 15 gallons per ton) are in place, of which about one-third is considered recoverable. As shown in Table 1.1, the 243 billion barrels of high grade shale compares favorably with the Middle East petroleum reserves, and dwarfs the Alaskan North Slope reserve.

Table 1.1

KNOWN RESERVES IN THE UNITED STATES AND MIDDLE EAST
(In billion barrels)

Western U.S. oil shale ^a	243
Petroleum ^b	
Middle East	268
North Slope	9
Continental U.S.	33

^aMost accessible reserves will yield 25 gallons or more per ton.

^bRecoverable at current prices.

Oil shale is second only to coal as a U.S. fossil fuel reserve, and is by far the nation's largest reserve of liquid fuels. Shale oil, if produced, might be expected to directly replace imported petroleum-- a major goal of current U.S. energy policy.

There are three basic types of technologies for the extraction (retorting) of kerogen from shale: *in situ* (in place) retorting, which requires no mining; modified *in situ* retorting, which requires partial mining; and surface retorting, which requires complete mining and transport of the shale to a processing facility. (See App. A for more details.) All three have been known theoretically for many years, and varying levels of R&D have been performed on all three for at least 25 years, but they have reached different levels of technological maturity.

The technological feasibility of *in situ* retorting for deep reserves is still in doubt. *In situ* methods are in early development,

and by most estimates are at least 15 or more years away from availability for commercial use. *In situ* research has been funded and conducted largely by the federal government through the Bureau of Mines and the national laboratories,* but some has been conducted by oil firms. Until recently, the principal oil firm conducting *in situ* research was Shell Oil.

Modified *in situ* technology development has received only a low level of government funding; it has been pursued more vigorously by the private sector, primarily Occidental Petroleum Corporation. Occidental's process, on which a number of patents have been obtained, has proceeded through the pilot stage and is currently being tested at near commercial scale.†

The most mature technology for shale oil recovery is the surface process. Since World War II, the federal government and private firms have piloted at least six types of surface retorting technologies. They differ primarily in their methods of heating the shale to pyrolysis temperatures, about 900° F. (See App. A for details.) Although none of them have been scaled up to commercial size even as a module, industry and government are confident, owing to extensive experience and the basic simplicity of the technology, that scale-up will encounter

*The Laramie, Wyoming, facility of the Bureau of Mines, now part of DOE, has conducted *in situ* research for shale since 1963, with current budget outlays of \$1.3 million. Lawrence Livermore Laboratory (LLL) began researching the feasibility of using nuclear explosives for *in situ* fracturing in the early 1960s. Modified *in situ* research has been conducted at LLL since 1973, with current budget outlays of \$2.5 million. In addition, the Office of Coal Research, also now part of DOE, has conducted an extensive program of *in situ* work for coal that has partially benefited the *in situ* shale program.

†Although Occidental is clearly pursuing development, it is difficult to assess the state of the art for Occidental's modified *in situ* process in the absence of independent data. The large retort ignited in fall 1976 was less successful than hoped, although Occidental appears not to be disturbed about it. Public announcements of when Occidental will have a commercial facility in operation are also unclear. It has simultaneously been suggested that it could be as soon as 1981 or as late as 1985. Rio Blanco, a consortium of Standard of Indiana and Gulf Oil, has recently announced plans to employ its own modified *in situ* process for oil shale tract C-a in Colorado.

no serious technical difficulties. Other aspects of the extraction-to-finished-product process are: mining, spent-shale disposal, and upgrading (partial refining). Because these aspects involve no new technology, this report discusses the problems of surface shale technology commercialization. Where issues and conclusions are applicable to pure or modified *in situ* development, that will be explicitly noted.

A surface shale oil production complex entails a series of large-scale operations. First, using neither underground or open pit mining, over 65,000 tons per day of oil shale must be mined to feed a 50,000 barrel per day production facility. The mined shale is conveyed to a nearby plant where the rock is crushed to a size appropriate for the particular retorting technique employed. A 50,000 barrel per day facility employs 10 to 12 retorts (heating vessels) in parallel. The retort products are raw shale oil, gas (usually of low heat content), and spent shale amounting to 85 percent of the input shale by weight and over 100 percent by volume. The raw shale oil is either sent to an on-site upgrading plant where sulphur, nitrogen, and other impurities are removed, or is treated with chemicals that make it possible to pipeline the raw shale oil to an upgrading plant and refinery near market points in the Midwest or on the West Coast. Upgraded shale oil ("syncrude") would be pipelined to refineries without additional treatment. Shale syncrude is a high-quality substitute for conventional petroleum crude and can be refined with conventional techniques. The large quantities of spent shale must be either landfilled or partially returned to the mine. (Complete return is impossible because of expanded volume. Back-filling the mines is also more costly than landfill.) By-products from upgrading are elemental sulfur (about 160 tons per day), ammonia (about 135 tons per day), and coke (about 660 tons per day). A 50,000 barrel per day facility employing underground mining would consume between 6000 and 9000 acre-feet of water per year with no return flow.

Although this report focuses on economic and institutional constraints and uncertainties, their relationship with technical constraints is discussed at a number of points. There are two reasons for this: (1) Surface oil shale technologies are considered well known (only

minimal uncertainties are thought to remain), and (2) surface technologies offer little scope for modifications to reduce either economic or institutional constraints. With surface technologies there is no way to avoid a very large mining effort, a very large plant, and disposal of very large quantities of spent shale. Although some possible improvements in surface technologies are now in the development stage,^{*} available technology offers little promise of markedly improved performance. Despite more than thirty years of development, surface shale technologies today are not markedly superior in expected performance characteristics to those of a generation ago. The fact that surface shale technologies are costly and unlikely to become cheaper reduces the scope for tradeoffs between technical and economic and institutional constraints, and thereby reduces their prospects as candidates for commercialization. It also increases the salience of economic and institutional constraints.

In preparing this case study of the prospects for surface oil shale commercialization, we reviewed the extensive literature on oil shale going back to 1950; and we interviewed government officials involved in oil shale development at the federal, state, and local levels, representatives of major oil shale developers, members of architect-engineering firms with oil shale development experience, and members of citizens groups in Colorado and Utah concerned with oil shale development in the Piceance and Uintah basins.

Chapters 2 and 3 explore economic constraints. Chapter 2 examines why economic constraints continue to preclude the commercialization of oil shale despite the rapid increases in world oil prices since 1973. In particular, it examines the factors that have contributed to the very large increases in the estimates for capital costs of surface shale facilities, and discusses the implications of our findings for how estimates might be improved for process plant technologies in the future.

^{*}The hydroretorting process being developed by the Institute for Gas Technology may advance the state of the art in surface retorting. The economics of hydroretorting are unknown and its commercial availability is a number of years away. F. C. Schora, et al., "16T/A.G.A. Oil Shale Process for Oil and/or Gas Production," *Hydrocarbon Processing*, April 1977..

Chapter 3 explores the question of when or if surface oil shale will become competitive with world oil by examining the critical assumptions that underlie projections of relative price changes, and by assessing the escalation in capital and operating costs, learning assumptions, and potential bottlenecks in construction.

Chapter 4 discusses potential institutional constraints on the commercialization of oil shale that might arise in both the private and public sectors. Included are possible imperfections in private investment decisions, problems raised by interjurisdictional disputes, water allocation, and environmental policies.

Chapter 5 summarizes some of the implications of this examination of oil shale for the commercialization of energy process plants, and suggests how the framework from this analysis might be applied to other technologies.

Chapter 2

OIL SHALE ECONOMICS, PAST AND PRESENT

For oil shale production to be commercially competitive, it must sell at a price that allows at least a "normal" rate of return to investors and is no greater than the market price for a premium quality refinery feedstock.* Figure 2.1 shows the relationship over time among world and United States domestic oil prices, Saudi light crude prices, and the estimated prices for upgraded shale oil that would be required to yield a 15-percent discounted cash flow (DCF) rate of return on investment (ROI), assuming 100 percent equity financing of the project[†] (all in 1977 dollars).

Estimates of oil shale plant costs have been made by government and industry firms since 1950. Estimates have been updated and designs refined during periods when commercial interest in oil shale was high. These studies, reported in App. B, have been used for both industry planning and government information.

As is obvious from Fig. 2.1, the estimated ceiling price required for shale oil has always exceeded world and domestic oil prices. In

*Upgraded shale oil ("syncrude"), because it is essentially sulfur- and nitrogen-free, should bring a price slightly above Saudi Arabian light crude--the benchmark against which world oil prices for different grades are computed. Syncrude can be processed at existing refineries.

[†]Posted prices of Saudi Arabian light crude Freight on Entry (F.O.E.) are used as the benchmark of world oil prices. Until 1973, shale oil had to compete with the prices of U.S.-produced crude, which were kept above the world oil price by import quotas on foreign oil. The 15-percent DCF on 100-percent equity was used as a basis against which to normalize the cost projections of a large number of studies. The 15-percent figure was chosen because (1) it was the most often used rate, and (2) it is widely considered a necessary rate of return by the oil shale developers. A 15-percent rate of return is considerably higher than that which would be required for routine, low-risk business ventures. Given the high risk entailed in oil shale development, at least in the initial period, 15 percent has generally been the minimum return on equity capital felt to be necessary by potential oil shale developers. A 10-percent rate of return target would significantly lower the selling price necessary to balance cash flow, but not enough to compete with current prices for world oil. See App. B.

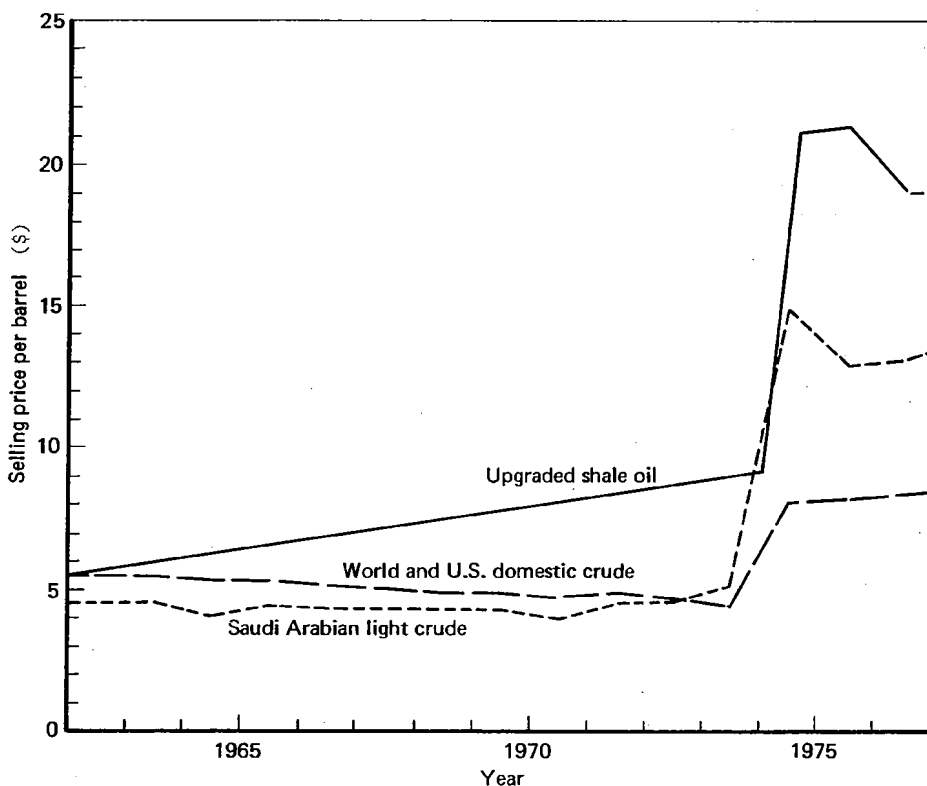


Fig. 2.1—Prices of world and U.S. domestic crude oil, Saudi Arabian light crude, and required selling prices of upgraded shale oil for 15% ROI (in constant \$ 1977)

only one study,^{*} published in 1963, did anyone project required shale oil selling prices to be less than domestic crude prices. However, during the mid- to late-1950s the Union Oil Company was actively involved in a project that was moving toward the first commercial shale facility. Union was very short of conventional crude supplies and felt that shale would, on balance, be profitable from an overall corporate viewpoint. Union terminated its effort when it was able to obtain petroleum crude supplies in 1958.

Oil shale R&D by oil companies, development firms, and construction firms continued, however, primarily through consortium arrangements.

^{*} Henry Steel, "The Prospects for the Development of a Shale Oil Industry," *Western Economic Journal*, Fall 1963.

The next serious attempt to launch a commercial project did not occur until the steep climb in world oil prices began in 1973. This project was an outgrowth of the Colony Development Operation begun in 1964. Colony began to move quickly toward developing its private land holdings in Colorado's Parachute Creek. Given that the required selling price for shale had not been estimated at more than double the world oil price since before 1962, the tripling of world oil prices (in constant dollar terms) from 1972 through 1973 led Colony, among others, to believe that oil shale's time had finally arrived. However, by the time that the definitive engineering design for the Colony facility had been completed, the estimated project cost had risen from an initial estimate of \$255 million capital cost in 1972 to \$960 million in September 1975. The required selling price for a 15-percent DCF rose from \$6.60 to about \$21.70/bbl.*

Shale oil, therefore, has never been competitive with conventional crude oil supplies. It is noteworthy, however, that considerable R&D efforts by a number of private firms have continued throughout the past 20 years.† In addition, oil shale commercialization nearly became a reality at least twice in the past two decades: in 1957-58 and again in 1973-74. We can see that whenever estimated shale costs have approximated either domestic or imported oil prices, commercialization plans have taken shape, and taken shape rather quickly. The private sector not only has been intimately involved in R&D for surface shale processes, but has been ready to move toward commercial deployment whenever economic conditions have appeared to justify it.‡ These

* Estimates do not provide for lease costs, transportation, and R&D cost recovery. Estimates of R&D cost are not available.

† Despite the long history of R&D on surface retorting processes, it is striking that little technological advance appears to have taken place. All of the surface shale retorting processes currently being considered have been around in basic design for at least 20 years. Although each process has undergone refinements, no conceptually different retorting processes have been seriously researched in this period.

‡ Although oil companies appear to have been ready to go forward with commercialization in the past, one cannot automatically assume they will in the future. Environmental and other institutional constraints, discussed in Chap. 4, are more serious potential impediments to commercialization today than in the past.

efforts were completely independent of any government subsidy or other encouragement.

Figure 2.2 plots the change in estimates for the capital costs of surface oil shale facilities from 1971 to 1977 as multiples of the 1971 estimate.* The most obvious and striking feature of Fig. 2.2 is the very rapid increase in the estimated capital cost of building a shale plant that occurred between mid-1973 and early 1975. Estimates escalated from about 1.35 times the 1971 level in 1973 to about 4.4 times that level in 1975. If the estimated costs of building and operating an oil shale facility had stayed on the 1962-1972 trend line, oil shale prices would have been considerably below those for the OPEC oil with which it would compete.

Several hypotheses have been advanced to explain the increase in cost estimates. One such hypothesis is that oil shale development companies exaggerated the cost of shale oil in order to increase government subsidies. This possibility, mentioned in the press, seems to be based on little more than the fact that the estimated costs went up at the same time that possible subsidies for an oil shale industry were discussed. We have been able to find no supporting evidence for this view. Rather, we believe that the increases in estimated required selling prices result from four principal factors:

- o Increases in the general price level;
- o Economy-wide increases in the real costs of capital plants;
- o Tighter environmental regulations for shale development; and

* 1971 will be used as the base period from which to measure increases in cost estimates because several initial estimates were completed in that year, not only for oil shale but for several other energy process plant technologies with which the study as a whole is concerned. In preparing Fig. 2.2, costs were normalized to capital costs per barrel of daily capacity. Plant sizes were nominal, 50,000 or 100,000 barrels per day. All formal cost estimates available to us are included. Not included are costs reported in newspapers, journal articles, or testimony for which backup material was unavailable. Appendix B presents the data from which this and the preceding figure were developed. Note that Fig. 2.2 is expressed in then-current rather than constant dollars.

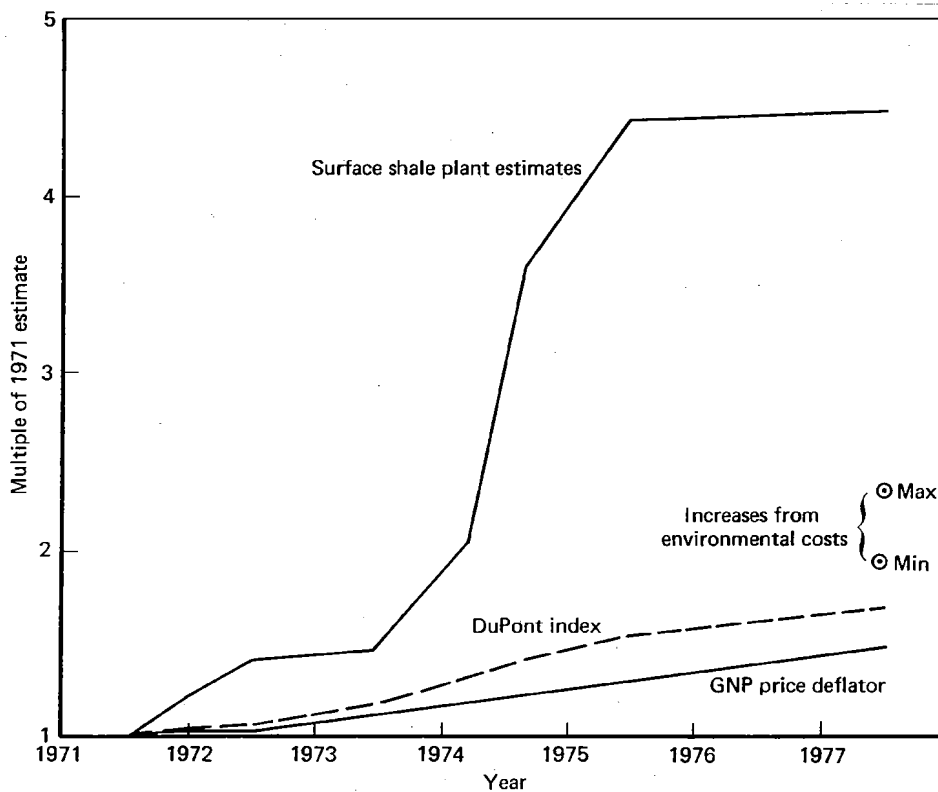


Fig. 2.2— Escalation in capital cost estimates since 1971

- o A large residual, much of which can be attributed to better knowledge of what the costs of a commercial shale facility would be, due to more complete design.

INCREASES IN THE GENERAL PRICE LEVEL

There is a widespread notion among oil shale developers that inflation was the primary culprit in the progressively discouraging economics of oil shale in the period after 1972. Although the evidence discussed below clearly suggests that this argument is mistaken, it is easy to understand how the perception arose when one recalls that the period from 1973-75 was one of very high general inflation. To oil shale developers, facing current rather than adjusted prices, the effects of general dollar inflation would appear very large indeed. In

addition, of course, one of the by-products of inflation in the general economy is to increase nominal interest rates, a fact to which large capital construction efforts are very sensitive. Included in Fig. 2.2 is the implicit GNP price deflator between 1971 and 1977, which measures changes in the general price level. As is evident, such changes account for only about 12 percent of the escalation in cost estimates over this period.

General inflation in itself is not important for commercialization efforts except insofar as it affects the perceptions of industry. Much more important are the *relative* price changes discussed below and in the next chapter.

CAPITAL PLANT COST ESCALATION

In the past decade increases in construction costs for refineries and chemical processing facilities have outpaced inflation by about 2 percent per annum.* During the late 1960s and the first years of the 1970s, the principal driving force in construction-cost inflation was large increases in the costs of construction labor; after 1972, it was rapid increases in the cost of components and materials.† The strongest inflationary surge in chemical plant costs took place in 1973-74, coincident with the very large increases in the estimated costs of shale facilities. But while there was a 12 percent real dollar increase in the DuPont Chemical Process Plant Construction Index in 1974, the estimated capital costs of an oil shale facility rose 54 percent between March and August alone.‡ As can be seen in Fig. 2.2, the real increases in chemical process plant costs (adjusted for inflation) account for only 6 percent of the increase in estimated shale plant costs between 1971 and 1977.** (The implications of the rapid price run-up in 1973-74,

* Based on Nelson Refinery Index and DuPont Chemical Plant Index.

† Edmund Faltenmayer, "Hyperinflation in Plant Construction," *Fortune*, November 1975.

‡ Colony estimates for capital costs of a 50,000 barrel per calendar day (BCD) facility using TOSCO II retorting and including upgrading.

** The DuPont Index was chosen as the best surrogate for how shale plant costs would have changed if an industry had been in place in the

caused by bottlenecks in equipment supply and inflation in materials prices will be discussed in the Chap. 3 under the heading "Bottlenecks and Shortages.") A real increase in chemical process plant costs of 2 percent per year over a long period of time would be of serious concern to government and industry commercialization planners if it is believed that such increases will continue for energy process plants in the future. But this factor, even allowing for substantial measurement error in the DuPont Index, accounts for only a very small portion of the total increases in estimates.

INCREASES IN COST ESTIMATES ATTRIBUTABLE TO ENVIRONMENTAL PROTECTION

As suggested in Chap. 1, institutional constraints frequently trade off with cost. Such tradeoffs are clear in the case of environmental regulations, and have had appreciable effects on the estimated capital cost of oil shale.

Until 1967 no national air quality standards of any consequence had been passed. Even the Air Quality Act of 1967 (P.L. 90-148) went essentially unenforced.* Starting with the National Environmental Policy Act of 1969, and continuing with the 1970 Clean Air Amendments, the 1972 Water Pollution Control Act Amendments, and the granting of substantial enforcement power to the Environmental Protection Agency, changes in the stringency of environmental protection measures amounted

past. Engineering firms interviewed consider the DuPont Index as good as or better than any other published index. No index is fully adequate for estimating changes in shale facility costs because shale facilities entail a combination of solids, liquids, and gas processes not fully captured in either refinery or chemical process plant indices. There was consensus among engineering firms that all of the indices for chemical and refinery plant construction costs tend to understate the size of the increase in the 1974-75 period. This lack of sensitivity to year-to-year price changes can be ascribed to using list prices for components rather than prices actually paid. While delivered prices for many components and materials were somewhat below list prices--the period before 1973--delivered prices were generally considerably above list prices in 1973-74. Because of faster and more accurate reporting for labor cost changes, the indices are generally more accurate during periods when labor rather than equipment and materials prices are changing.

* Allen V. Kneese and Charles L. Schultze, *Pollution, Prices, and Public Policy*, The Brookings Institution, 1975, p. 49.

to a revolution. Beyond question, these changes, which are reflected in state legislation as well, have been and will be very costly to industry. It is difficult, however, to establish exactly what it costs a particular industry to meet environmental regulations. The costs to industry generally (excluding the automotive industry) of meeting air and interim water quality standards have been estimated at about \$82 billion for the "best practicable treatment" standard and \$116 billion for the "best available technology" standard between 1975 and 1985, in 1975 dollars.

The costs of environmental protection in oil shale development devolve to a number of organizations: to the federal government in the form of environmental R&D costs, EPA standard setting and enforcement costs, the costs of environmental impact statement preparation by ERDA and the Department of Interior on federal leases; to state government for monitoring and enforcement; and to developers. In this section we are concerned with the direct and indirect costs of environmental protection that fall on developers of oil shale. In particular, we have attempted to assess the impact of environmental costs on capital cost estimates for shale facilities, and the nature and effect of indirect costs of environmental protection.

To estimate the cost to developers, we have surveyed the firms that have been most involved in oil shale development to date, and have examined available data on the costs of environmental equipment used in shale facilities. Until 1974 estimated environmental costs were minimal because the estimates had not kept pace with changes in environmental standards.

Estimates of the direct capital costs of pollution control among those surveyed ranged from a low of 6.5 percent to a high of 15 percent of total capital costs.* Almost all of the environmental costs had to do with retorting (removal of particulates, hydrocarbons, and H₂S from the gas train) and shale handling (dust control in screening and spent shale disposal). If we assume a value of zero for such environmental

*Data from noncommercial scale plant estimates are not included. We could not verify the reported environmental costs directly. The estimates reported bracket the independent estimates of Kneese and Schultze, *ibid.*, for the oil industry.

costs in 1971 estimates, then between 8 percent and 20 percent of the increases in estimated capital cost between 1971 and the present can be attributed to environmental factors.

All developers emphasized the difficulty of estimating even direct environmental costs, partly because they have no actual experience with the construction and operation of a commercial-scale facility, and partly because the developers have not systematically tried to separate environmental costs in their estimating or accounting.*

Although direct costs of environmental protection have been included in estimates since 1974, indirect costs stemming from environmental regulations have not. Such costs include:

- o Changes in siting,
- o Increased transportation costs incurred to avoid prerefining in the immediate area,
- o False starts,
- o Changes in mining plans,
- o Disruption of construction schedules, and
- o Less reliable plant operation.

Disruption of construction schedules can be particularly damaging to plant costs depending upon when in the construction process a delay takes place. Delays in obtaining initial permits to begin construction usually cause only a modest increase in costs. Delays late in the construction process (as might result from an injunction sought for environmental reasons) can have a devastating effect on plant economics, both because of losses in interest or return on investment during construction and because of losses in labor productivity, as workers must either be retained idly or dismissed and replaced at a later date. Because of the addition of environmental equipment, plant reliability will tend to decline if the plant must be shut down when environmental

*To our knowledge there has been no systematic attempt to index the cost of pollution control equipment. We also failed to uncover any analyses of the added costs of pollution control for the chemical process or refining industries.

equipment fails. Even a slight impact on plant service factors is significant; a 5 percent decrease increases the required selling price about 7 percent to maintain the same return on investment.

From the developers' viewpoint, uncertainty is the greatest problem stemming from environmental concerns and other institutional constraints. Even within existing regulations there is substantial uncertainty over how the laws will be interpreted, administered, and enforced. Added to that must be uncertainties about future regulations and how plants already built or under construction would be treated under new, more stringent, legislation.

Rather than attempt to estimate indirect costs of environmental regulations, developers have increased their estimates of the uncertainty surrounding the accuracy of current estimates, usually in an informal way.

To summarize, environmental regulations have significantly increased the estimated direct capital costs of a shale facility and the uncertainty facing developers. Nonetheless, environmental costs that have entered cost estimates since 1971 can account for no more than one-fifth of the total escalation in estimated shale plant costs between 1971 and the present. To explain the bulk of that escalation, one must look to the way the estimates themselves have been made.

BETTER KNOWLEDGE OF COSTS

The residual after general inflation, capital plant escalation, and environmental factors are taken into account is roughly 70 percent of the increase in capital cost estimates for oil shale plants since 1971.* When we consider that the largest increases in estimates have taken place when the engineering estimates became more complete, and

*This should be interpreted as only an approximation. Both the capital cost escalation measured by the DuPont Index and our estimates for the amount of increase attributable to environmental factors may be subject to some error. We would note, however, that even if the top estimate of environmental costs is taken, and the constant dollar increase in chemical process plants is three times that estimated by the DuPont Index, fully 50 percent of the increase in shale plant capital costs remains unexplained.

on the basis of discussions with architect-engineering firms (A-Es) and potential purchasers of oil shale plants, and in light of evidence from other technologies, we believe that the great bulk of the residual can be attributed to better knowledge of costs that accompanies more complete engineering design.

Cost Estimates for New Processes

Estimating the cost of a process that is new at commercial scale ordinarily is an iterative process of preparing a series of designs, each going into greater detail and each estimating costs on the basis of the improved information. As each design and cost estimate is completed, the potential plant purchaser has an opportunity to reevaluate the technical and economic feasibility of the proposed project. There are four kinds of engineering design estimates that represent different stages of the design process. In some cases all four may be carried out by a single architect-engineering firm in the course of a design project that carries from process development through the construction of a commercial plant. In other cases, the designs may be conducted by different A-Es and be spread out over many years. The four stages of design are discussed below.

Initial estimates, sometimes called "back of the envelope" designs, are based on little engineering work. They are generally made when a technology is in the early stages of development and provide only a rough guide to costs. Initial estimates usually cost about \$10,000 or less, and are often offered gratis to potential plant purchasers by process developers.

The *preliminary design estimate* is the first serious attempt to design and estimate the costs of a process. For preliminary estimates the overall scope of the plant is defined, and subsystem flow diagrams are prepared. Preliminary designs are often called "black box" designs because what goes "inside" the subsystems is not defined. Process flow sheets, piping and instrumentation diagrams, and the purchase specifications for components are not included. Although many of the materials and components of a subsystem will be known--so many pumps, compressors, steel requirements, etc.--neither the specifications for the components

nor precisely how they will be integrated are defined. The results of the preliminary design signal the first important decision point for a plant purchaser, because engineering costs increase rapidly as one moves to the next stages of design. A-Es and potential plant purchasers say that final plant costs can be expected to fall within about 30 to 40 percent of the preliminary design estimate, assuming an immediate start of construction.*

The usual next step is a *detailed design* or control estimate. This involves completing process flow sheets, all plant diagrams, and purchase specifications for materials and components of the plant. Meanwhile, interchange is usually extensive between the A-E and the potential plant purchaser, because the contours of an operating plant are taking shape. When the detailed design is complete, the final plant costs are expected to be within 20 to 25 percent if construction starts immediately.

The *definitive design* is the last step preparatory to plant construction. Bids on equipment and materials are received, precise manpower requirements and costs are defined, and the construction schedule is worked out in detail. A definitive design is usually undertaken only if plant construction is expected to follow directly. By the time the design is complete, uncertainty is much reduced and actual costs are generally expected to be within plus or minus 10 percent of the estimate. For technologies involving large scale-up, such as oil shale, the upper end of the uncertainty range is often extended to about 20 percent. By the time the definitive design and estimate is complete, the engineering cost to the plant purchaser will be about \$15 to 30 million for a major first-of-a-kind facility, not including the costs of the plant purchaser's own personnel. For well-established process plant technologies, the preliminary and detailed designs can often be dispensed with unless the site offers novel elements in the design,

*The final plant costs in this case include only those portions of the plant that are the responsibility of the A-E. It does not include all capital cost items. For example, the capital costs of reserve acquisition, start-up, and working capital are often not included. Estimating these costs is generally the responsibility of the plant purchaser.

because actual costs of previously constructed plants provide a basis for cost estimation.

For a new process, the kind of design is only one element in arriving at confident cost estimates. The other element is the quality of the technical data base from which the design is made, which in turn depends on the completeness of technical development. Technical development for new technologies usually proceeds from laboratory or bench-scale tests of basic concepts, to a process development unit that is generally a small continuous process model, to a pilot "mini-plant" in the field that allows testing of materials and process configuration. Occasionally, industry will construct a semiworks or demonstration plant that tests at least some aspects of the technology at the same scale as would be found in a commercial facility.* Each stage in the process should provide progressively better technical information upon which to base a design for a commercial scale plant.

Figure 2.3 illustrates the relationship between the type of design and the development stage for the reduction of uncertainty about cost. Just as an initial estimate, regardless of the stage of development, provides very little confidence in cost estimates for first-of-a-kind plants, even a very complete design--that is, whether detailed or definitive--will provide little confidence if the technical data are based on a bench-scale unit. As one moves along *both* dimensions, confidence in the cost estimates improves. The process is *supposed* to work so that, as progressively more complete estimates based upon better technical data are prepared, the range of uncertainty narrows.† Except

*In oil shale, developers generally agree that a demonstration would not provide enough information about the technology or cost to justify the expenditure. Exactly what constitutes a demonstration as opposed to a large pilot or pioneer commercial plant is, of course, unclear. For oil shale the most frequently mentioned demonstration plan was for a commercial scale module producing 7 to 10 thousand barrels per day. The usefulness of such a demonstration would be to show environmental acceptability rather than to gain knowledge of costs.

†The uncertainty ranges in Fig. 2.3 should be interpreted as rough "rules of thumb" only. Different plant designers may use different ranges depending on the type of plant being designed and the proclivities of the particular firm.

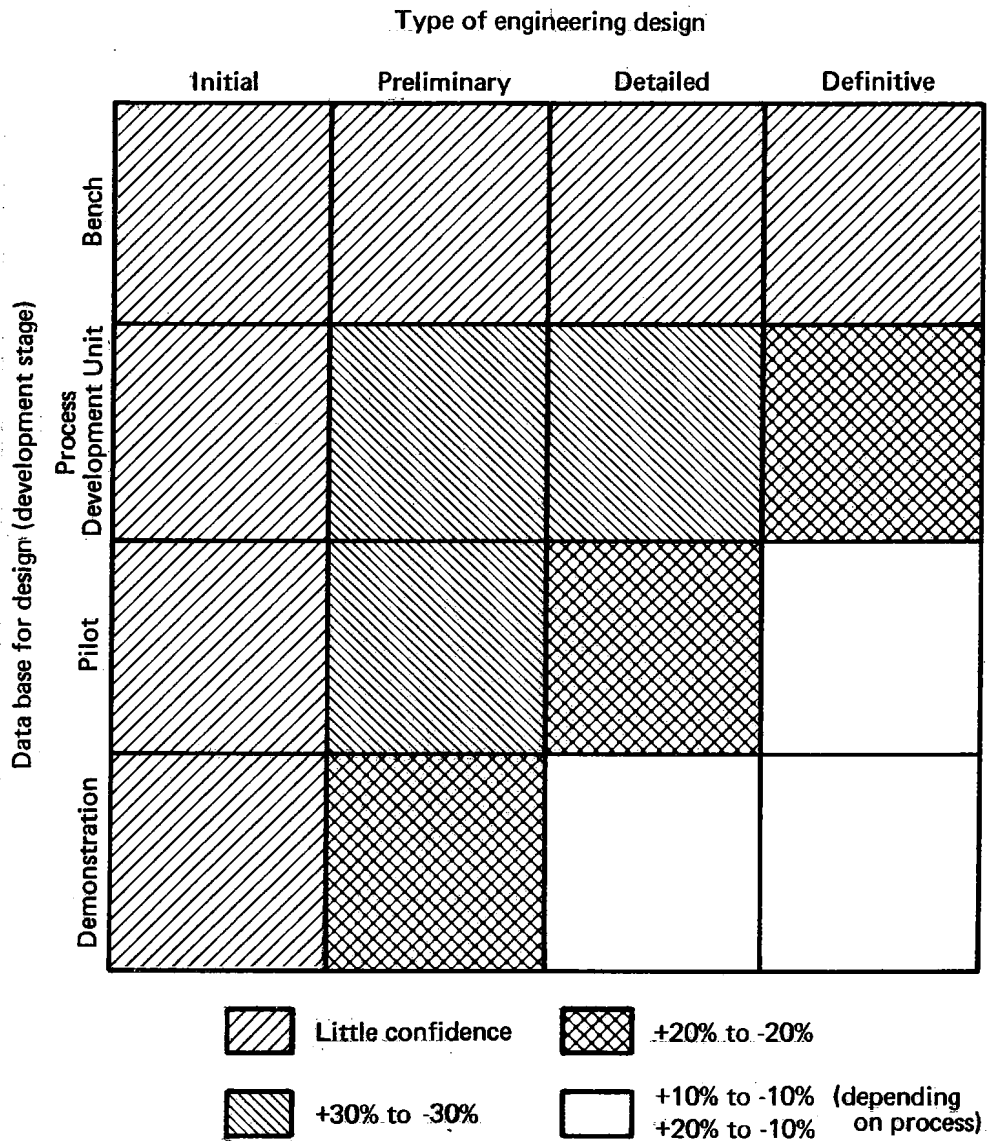


Fig. 2.3—Effect of development stage and type of estimate on cost uncertainty

for the effects of increases in the costs of labor and materials, the cost estimates from the definitive design should lie within the range of uncertainty of the preliminary design estimate. Plant purchasers clearly hold these expectations, and corporate planning proceeds on that basis. That potential plant purchasers and A-Es held such expectations about the cost-estimating process is illustrated by the fact that both potential plant purchasers and A-Es were amazed (and dismayed) by the data reported in Table 2.1. Between the preliminary estimate in November 1973 and the definitive design less than 10 months later, the estimated cost rose 75 percent. The preliminary design estimate was about double the initial estimate prepared for Colony in 1972.* Members of the Colony consortium were not the only ones to be surprised at the results of the first definitive design for an oil shale plant; the rest of the industry, and government engineers and planners, were equally surprised. The results of the Colony definitive design were subsequently replicated by other potential purchasers of surface oil shale plants.

This period 1974-1975 was a critical time in the planning of oil shale commercialization, not only for the private sector but also for government planners. Two high-level task forces were trying to formulate programs to accelerate the commercialization of oil shale and other synthetic fuels technologies. But the results of the first definitive engineering design were not quickly adopted by federal oil shale planners.

The results of the Colony definitive design were made available in August 1974, showing capital costs[†] of about \$770 million for a 50,000 barrel per day facility, resulting in a required selling price of about \$19.00 to maintain a 15 percent DCF return. Later that year and *after discussions with the Colony estimators, the government was still using estimates of \$280 million for capital costs, yielding a selling price of \$8.35 to maintain a 15 percent DCF, about \$2.65 below the OPEC crude*

* J. A. Whitcombe, "Oil Shale Development: Status and Prospects," *Journal of Petroleum Technology*, January 1976, p. 18.

† Not included are reserve costs, transportation costs, and recovery of R&D costs.

Table 2.1

COST ESTIMATES FOR COLONY SHALE OIL PROJECT

Type of Estimate	Date of Estimate	Estimated Construction Cost ^a (\$ million)	Percent Increase Over Preceding Estimate
Preliminary design	November 1973	\$406	---
Detailed design ("control estimate")	March 1974	554	36%
Definitive design estimate	August 1974 ^b	710	28%

SOURCE: Mr. David M. Crowley, Director of the Synthetic Crude and Minerals Division, Atlantic Richfield Company. (ARCO was the operator of the Colony Shale Project.)

^aThese costs include only the capital construction costs for the mine and other on-site facilities that were the A-E's responsibility. Not included in the estimates are the following items: acquisition of reserves, community planning and development, spare parts, land acquisition, environmental analysis, mining and semiworks tests, project management staff, mining predevelopment, mobile equipment, ceramics, chemicals and catalysts, prepaid licenses, employee recruitment and training, accrued interest, interest during construction, start-up, working capital, contingency for nonplant facilities, miscellaneous and other expenditures.

^bBased on a field start of October 1974.

price of F.O.E.* Fifteen months later, government commercialization incentive proposals were based on a required selling price of \$12.10

*Project Independence Task Force Report *Potential Future Role of Oil Shale: Prospects and Constraints*, U.S. Department of the Interior, November 1974. The data for the Task Force were supplied by the Process Evaluation Group of the U.S. Bureau of Mines, Morgantown, West Virginia. Results of the Colony estimates had been made available to that group before the publication of either the Task Force Report or the Process Evaluation Group's *Economic Analysis of Oil Shale Operations Featuring Gas Combustion*, Technical Progress Report 81, September 1974. Although TPR 81 is based on the gas combustion retort and Colony's estimates on TOSCO II (see App. A), this cannot account for the difference in estimates.

to maintain a 15 percent DCF, only slightly above the OPEC price.* In the meantime the Colony estimates had been revised (in the light of more information and to account for inflation) to capital costs of \$829 million and a selling price of \$21.70 for 15 percent DCF.† It is im-portant to emphasize that this was not a case of information being withheld from government, but a problem of the best available information not being used by government. Government planners chose to rely upon cost estimates produced by the government rather than the private sector.

Sources of Error in Early Estimates

Error in initial estimates is not surprising; such estimates are often made casually, and rarely include the full scope of the plant. Error in initial estimates is somewhat less important than error in preliminary or detailed estimates because initial estimates are seldom used as more than a crude guide for corporate or government planning. There are several sources of potential error in preliminary design estimates.

Preliminary designs are generally not site-specific, but are prepared on the basis of a conception of a "typical" site. The problems associated with *any* particular site will often be much more obvious and severe than those associated with the "typical" site. For oil shale, for example, the cost of road construction and product transport facilities often considerably exceeds original estimates. When detailed shale mine plans have been completed in the past, each developer has found that the geology of the particular tract called for unexpected

* Report of the Synfuels Interagency Task Force, *Synthetic Fuels Commercialization Program: Technology and Recommended Incentives*, Vol. III, November 1975, pp. IV-E-10-11.

† Again this figure excludes reserve costs, transportation and R&D. In addition to ARCO and Whitcombe, op. cit., Colony cost data are from J. A. Whitcombe, R. G. Vawter, and J. F. Nutter, "Shale Oil Production Costs and the Need for Incentives for Pioneer Plant Construction," paper prepared for American Chemical Society, Division of Industrial and Engineering Chemistry, Symposium on the Commercialization of Synthetic Fuels, February 1-3, 1976, Colorado Springs; and discussions with representatives of TOSCO (a member of the Colony consortium), and C. F. Braun Company (the A-E for the Colony project).

unexpected expenses, and in one case, the form of mining had to be changed completely.*

The ease or difficulty of plant construction cannot be accurately measured from a preliminary design. Ultimate capital costs are very sensitive to manpower and construction time requirements and when in the construction process capital outlays must be made. Preliminary designs for oil shale facilities have called for a construction time of 3.5 to 4 years. Construction times based on definitive designs (and not including any allowance for regulatory or other delays) are estimated at 4.5 to 5 years. Adding a year to construction times for an oil shale plant increases capital cost about 8 to 10 percent.†

A preliminary design will almost always exclude some factors that contribute to cost, perhaps because they are simply not recognized, or because they simply cannot be estimated in the absence of a specific choice of site.

It is important to note that there is a systematic downward bias in preliminary estimates rather than a dispersion. This is illustrated by Fig. 2.4, which presents the point estimates for capital costs made between 1971 and the present. The square represents the Colony detailed design (control) estimate, and the triangles the definitive design estimates. Although there is some variance in the preliminary estimates, none of them approach the definitive-design-estimated capital cost.

We conjecture that the downward bias in the preliminary estimates derives from the manner in which the multitude of uncertainties are treated. Confronted with uncertainties, the estimator tends to take an optimistic view of the ultimate cost when uncertainties are resolved. And, of course, for those cost factors that cannot be recognized until

* The owners of C-a (Colorado tract A of the Department of Interior's Prototype Oil Shale Leasing Program) abandoned surface mining plans for environmental and economic reasons. Owners of C-b discovered that the tract could not be mined using the room and pillar method as planned because of unexpected geological problems.

† Assuming that the temporal distribution of investment is shifted back 12 months.

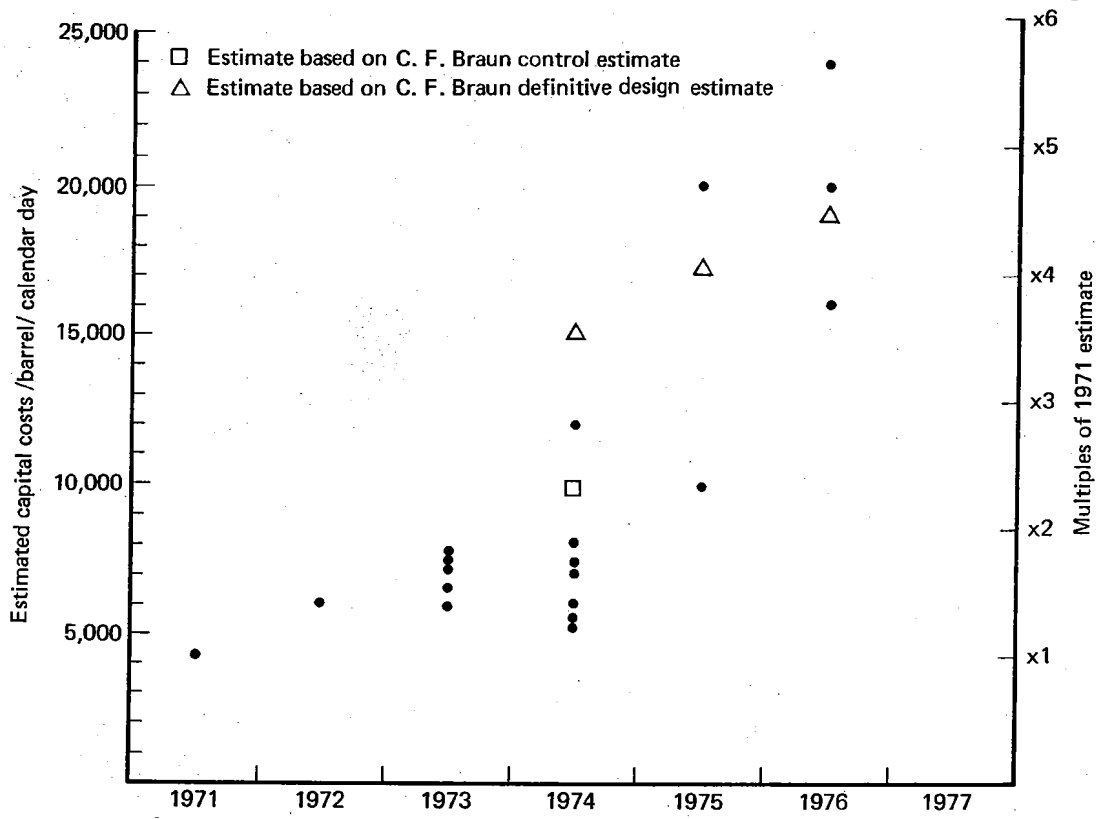


Fig. 2.4—Surface shale oil plant construction costs and cost escalation since 1971 (in constant \$ 1977)

a detailed or definitive design is prepared, even the method of treating uncertainty is irrelevant.*

As is evident in the case of oil shale, even detailed designs in which the basic "blueprint" for the plant is complete can be subject to significant underestimation. We believe that this can be attributed not only to the fact that construction schedules and equipment and materials prices are not quoted until the definitive design is completed, but to the fact that until the detailed design is complete the costs falling outside the responsibility of the A-E are not included systematically. (See Table 2.1, footnote (a), for a list of capital cost items sometimes omitted from A-Es' estimates.)

Another possible source of error in oil shale cost estimation is the fact that an oil shale facility demands an extraordinary range of skills on the part of any A-E firm. Although no one portion of the facility, e.g., mining, retorting, refining, may be particularly complex, the facility in its entirety is extremely challenging to an A-E.

Estimation Error in Other Technologies

The problem of errors in cost estimates for new technologies is by no means confined to surface oil shale facilities. The cost estimates for other synthetic fuels such as coal liquefaction and gasification have shown similar patterns. For example, 40 percent of the \$290 million increase between 1973 and 1975 in the cost estimate for the Western Gasification Company Lurgi high-BTU plant has been attributed to the effects of definitive engineering.† Capital cost estimates for

* Although this problem did not emerge in oil shale, preliminary designs may not expose areas in which advances in the state of the art will be necessary. This may not mean that major breakthroughs in technology are necessary, but simply that, for example, the plant requires components that are not commercially available. The first electricity generating nuclear reactor, for example, required a low-pressure turbine that was not then in manufacture. Although this one component represented a step *back* in the state of turbine technology, it was responsible for an appreciable part of the cost overrun for the Shippingport reactor. L. L. Johnson, E. W. Merrow, W. S. Baer, and A. J. Alexander, *Developing Breeder Reactor Technology*, The Rand Corporation, R-2069-NSF, November 1976.

† Henry Linden, "Is the Synthetic Fuels Option Still Credible," *Energy Systems and Policy*, Vol. 1, No. 4, 1976, App. B.

syncrude from Canadian tar sands increased by more than 100 percent between January 1974 and February 1975, much more than could conceivably be attributed to capital plant cost escalation and inflation.*

Similar problems have occurred in successive light water reactor (LWR) designs. In the case of LWRs, data are not available that would enable one to compare preliminary and definitive designs of new reactor types (or redesigns of existing reactor types that have occurred since initial commercialization). A strong inference that preliminary design estimates have been low can be made, however, from the fact that *actual* plant costs exceeded design estimates numerous times.

The area of technology development in which the most systematic evidence and analysis of growth in estimates has been accumulated is that of weapon systems acquired by the Department of Defense. The growth in the costs of 15 weapon systems completed in the 1960s, from the time at which DOD approved the cost, delivery schedule, and performance requirements of the systems until delivery was actually made, averaged 40 percent after adjustments for inflation and changes in programs.[†] In addition, delivery schedules slipped an average of 15 months, and although the ratio of estimated to actual performance averaged 1.0, some systems performed much less well than originally promised.[‡]

Implications for Policy and Analysis

The underestimation of costs is a serious problem for government. The ability to plan for commercialization of a technology, and therefore for future energy supplies, is hampered significantly if costs cannot be predicted with any accuracy until commercialization is about to commence. It is an equally difficult problem for industry; it is highly unlikely that oil companies would have bid over \$400 million for

* Ibid., App. A.

† Robert Perry, Giles K. Smith, Alvin J. Harman, and Susan Henrichsen, *System Acquisition Strategies*, The Rand Corporation, R-733-PR/ARPA, 1971, pp. 5-9.

‡ The range of actual to estimated performance in the sample was from about 0.35 to 2.1. If these systems were produced for the private sector, schedule slippages and less than estimated performance would translate into higher costs per unit output.

the Prototype Oil Shale Leasing tracts, or advanced many millions in development efforts, if they had known the cost estimates associated with the definitive design.

At least two steps have been or might be taken to ameliorate the problem for government planners. DOE's Fossil Energy Program Planning and Analysis Office is attempting to improve the comparability of early estimates by applying a consistent methodology to all estimates.* An example of this approach to provide an improved basis for comparing alternative technologies is the analysis of coal *gasification* costs being performed for DOE by C. F. Braun and Company.† The approach employed by Braun is to create a set of common assumptions upon which to systematically compare the costs of alternative technologies for high-BTU gasification. This approach would be most useful for comparing technologies at similar stages of development and for which similar designs had been completed in order to obtain an ordinal ranking of which technologies appeared more economic.

But such an approach cannot effectively address the problem of increases in estimates discussed in this section. If, for example, a set of common assumptions had been established and applied to surface oil shale technologies in 1972, an estimator might have concluded that process "X" appeared preferable to "Y" and "Z," but probably would also have concluded that *all three processes* would produce upgraded shale oil at less than \$8.00 per barrel for a 15 percent DCF return.

A second approach that the government might take to improve its information base for planning commercialization efforts would be to promote the timely performance of a definitive engineering design for a new process through cost-sharing of the design with industry. Industry does not usually contract for a definitive design until it has decided to proceed directly with construction. In some cases, such as

* Martin Adams, Cyril Draffin, and Chris Knudson, *Economic Evaluation by ERDA of Alternative Fossil Energy Technologies*, paper prepared for American Chemical Society Symposium on Comparative Economics for Synfuel Processing, April 1976.

† Roger Detman, *Factored Estimates for Western Coal Commercial Concepts: Interim Report*, FE-2240-5, Government Printing Office, October 1976.

oil shale and high-BTU coal gasification, that decision will wait for many years until the technology has been sufficiently developed so that a definitive design will yield confident cost estimates. By sharing the costs of a definitive design--perhaps totaling \$15 million or more for a large plant--the government should be able to obtain fairly reliable estimates upon which to base commercialization or deployment programs.*

This alternative is distinctly limited, however. A definitive design cannot yield accurate estimates until the development process is essentially complete. In most cases, the government will need reasonably reliable estimates during development rather than afterward.

An alternative approach that offers some prospect of improving the ability of government and industry to predict cost increases that might be expected for a technology is suggested by analyses of escalation in estimates for weapon systems. Over the past fifteen years or so, an extensive data base has been collected on cost-escalation experience for weapon systems acquired by the DOD and Western European nations.† This has enabled cost growth (i.e., increases in the costs of systems from early estimates to actual production) to be *statistically related* to factors such as the performance characteristics sought (e.g., speed and payload for aircraft), physical characteristics (such as weight), measures of the advance in the technological state of the art implied

* An effort similar to this was undertaken for the preparation of designs for the Prototype Large Breeder Reactor under a cost-sharing arrangement between ERDA and the Electric Power Research Institute. In this case, however, no potential plant purchaser was directly involved in the effort.

† Most of this work has been performed at The Rand Corporation under the sponsorship of the Air Force and the Department of Defense. In addition to Perry, et al., op. cit., relevant Rand reports include: Alvin J. Harman, assisted by Susan Henrichsen, *A Methodology for Cost Factor Comparison and Prediction*, RM-6269-ARPA, August 1970; J. R. Nelson and F. S. Timson, *Relating Technology to Acquisition Costs*, R-1288-PR, March 1974; R. L. Perry, D. DiSalvo, G. R. Hall, A. J. Harman, G. S. Levenson, G. K. Smith, and J. P. Stucker, *System Acquisition Experience*, RM-6072-PR, November 1969; and Robert Summers, *Cost Estimates as Predictors of Actual Weapons Costs: A Study of Major Hardware Articles*, RM-3061-PR, March 1965.

by the system, and program characteristics (such as duration of the development program). This has enabled the DOD to be aware that if, for example, the system they want calls for major advances in the state of the art or requires a long program period, they should adjust their expectations of final cost upward from early estimates. These statistically based estimates can complement engineering estimates and indicate where underestimation of costs is most likely to occur for a particular kind of system.

A similar data base for energy technologies (e.g., for process plants and electricity generation technologies) would promote more realistic cost estimates for technologies at the process development unit and pilot plant stages. Of course, the factors that lead to underestimation in process plant technologies will probably differ from those in weapon systems. For example, it might be discovered that scale-up, process complexity, or measures of the difficulty of construction are the primary predictors of process plant costs, rather than advances sought in the state of the art. Exactly what factors contribute most to cost growth cannot be determined a priori. At least one large purchaser of chemical process plants is attempting to use its own cost experience to adjust initial estimates, but at present no industry-wide data base exists for either process plants or electricity generation. Such a data base and the accompanying methodology and analysis might prove useful to both government and industry in improving commercialization planning. The development of a data base would complement rather than substitute for engineering designs, and might provide a basis upon which to decide when engineering designs are seriously underestimating costs.

SUMMARY

This chapter has explored the factors that led to rapid increases in the estimated capital cost of shale facilities, which in turn have raised the estimated required selling for shale oil above levels competitive with world oil prices. The result is a barrier to commercialization for the present.

The most important factor in the increased estimates appears to be

improved understanding of costs resulting from definitive engineering designs. This conclusion differs from the perceptions of industry, which lays most of the blame on inflation and capital plant cost escalation.

The most promising avenue to obtaining more accurate early cost estimates is the development of a data base on changes in estimates that similar chemical process plants have computed in commercial operation. The subsequent analysis could enable cost estimates for early energy process plants to be adjusted empirically in the future.

Although escalation in the costs of process plant construction and costs associated with environmental protection can explain only about 25 percent of the increase in cost estimates between 1971 and 1977, these factors have important implications for when (or if) surface oil shale plant technologies will become competitive in the future--the subject of the next chapter.

Chapter 3

FUTURE PROJECTIONS OF OIL SHALE ECONOMICS

Potential developers currently estimate the cost of shale oil from surface retorting processes at about 50 percent above the current world oil price. The questions addressed in this chapter are:

- o What factors will determine whether shale oil will become cost-competitive over the next ten to fifteen years?
- o What would be the probable effect on shale oil cost trends if government policy changed and a deployment of shale plants were begun through subsidy?

Ultimately, the competitiveness of shale oil without government subsidy depends on only two factors: the delivered costs of shale oil, and world oil prices. Because we have not made an independent assessment of projections for world oil prices, different rates of change in those prices are presented here only for illustration. For that purpose we have chosen a rate of real increase of 2 percent per year (although world oil prices have not increased in real terms since the initial round of OPEC increases in 1974). Predictions of world oil prices vary widely from one model or study to another. They may not increase in the continuous manner depicted in Figs. 3.1 and 3.2, but be subject to sharp discontinuities.

We have assessed the following factors that could affect future shale oil production costs:

- o The range of uncertainty in current estimates of capital costs;
- o Future trends in capital and operating costs;
- o Capital cost reduction from learning effects; and
- o The possibility of bottlenecks in construction.

The first two factors affect the likelihood of private sector development without government support, as well as the cost of a subsidy effort.

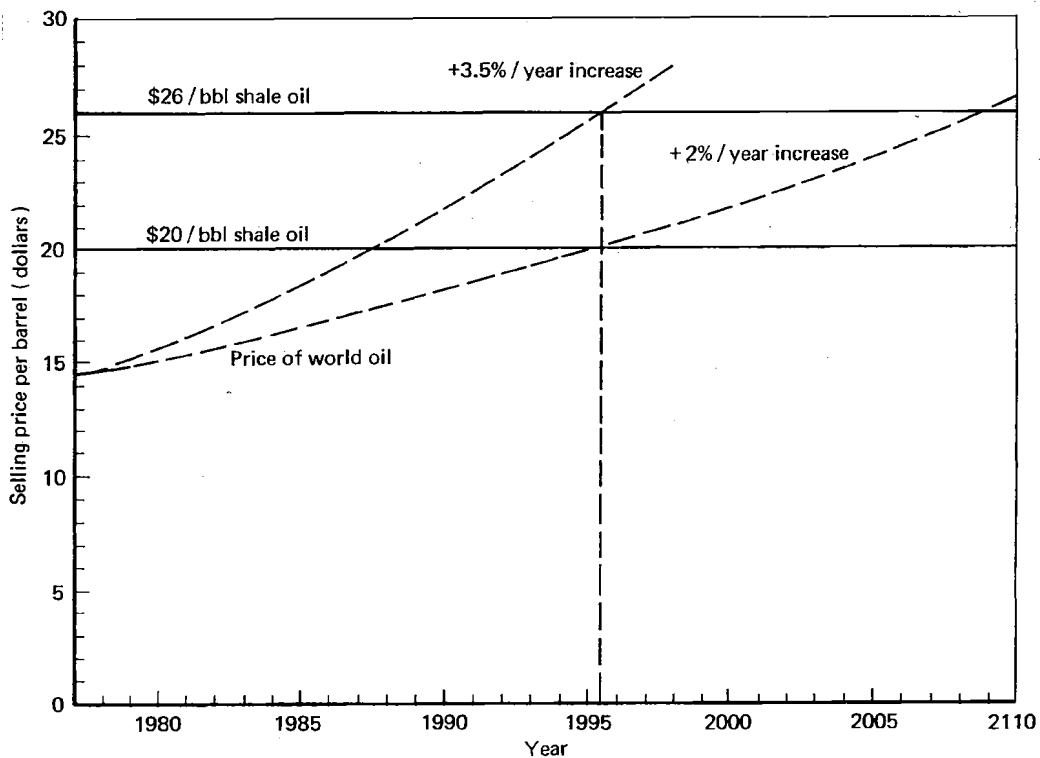


Fig. 3.1— Effect of uncertainty in current estimates on expectations (1977 \$)

In light of the probable trends in those factors, the last two factors are most relevant to a government subsidy effort for shale plant construction.

UNCERTAINTY IN CURRENT ESTIMATES

In late 1976, ERDA's Fossil Energy Division estimated the price range for surface shale oil at \$16 to \$25 per barrel (15 percent return on 100 percent equity).^{*} Even the most optimistic developers now consider the \$16 figure too low. The current range is \$20 to \$26 per barrel with \$22 as the mode. Even this range is subject to some uncertainty (especially at the high end) because selling prices are highly sensitive

^{*}Prepared statement of Dr. Philip C. White, Hearings Before the Subcommittee on Minerals, Materials, and Fuels of the Senate Committee on Interior and Insular Affairs, November 30, 1976, p. 7.

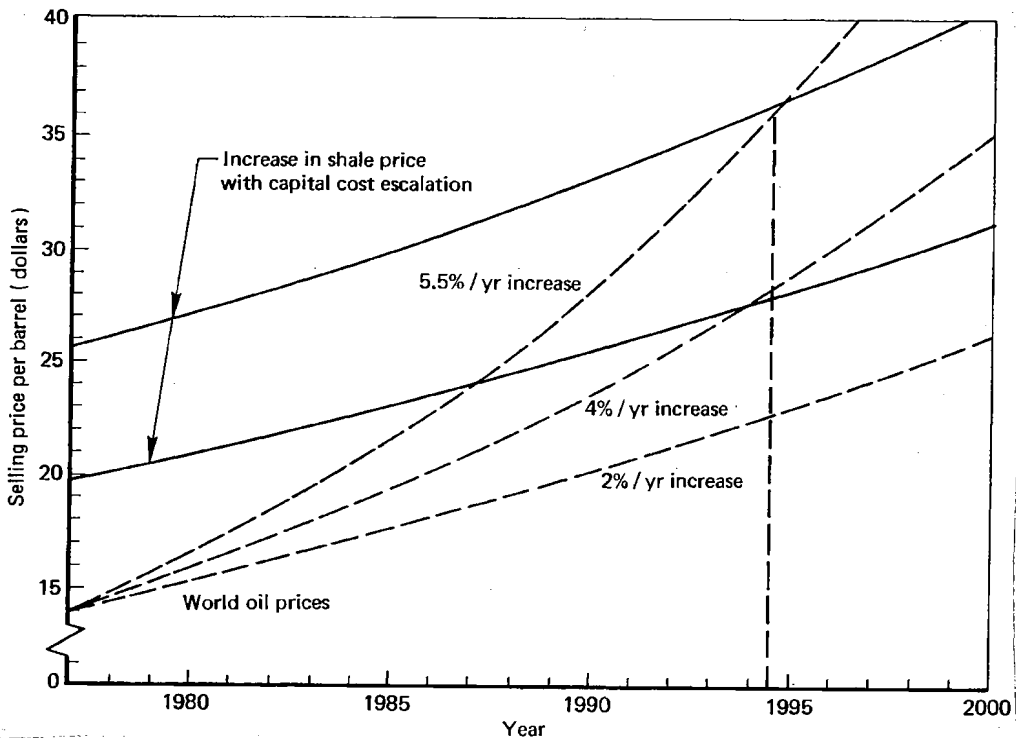


Fig. 3.2— Effect of continued capital cost escalation on expectations (1977 \$)

to a number of assumptions. An error of 10 percent in estimating capital costs—a modest error for a first-of-a-kind facility—would affect the required selling price more than \$1 per barrel to maintain the same rate of return. A one-year extension of the construction or start-up period, perhaps as a result of regulatory or legal delays, would add a similar amount. Each 1 percent decrement from the 90 percent service factor assumed in plant designs would add about 25¢ per barrel to the required selling price, and 90 percent is the service factor assumed for *mature-technology* chemical process plants.* (The service factor is the ratio of actual to rated output over time.) The profitability of shale plants is also sensitive to assumptions about taxation by all levels

*These calculations are based on the cost model developed by C. F. Braun and Co. for industry-financed coal gasification plants appropriately modified for oil shale. See Roger Detman, op. cit., pp. 33-36.

of government. For example, elimination of the depletion allowance for shale would add about \$2.50 to the required selling price per barrel.

These uncertainties would make oil shale a highly risky investment even if current estimates were in the competitive world oil price range. This uncertainty is reflected in the insistence of almost all potential developers that a 15 percent return represents a firm target, even though 10 to 12 percent is more representative of oil company rates of return in the past fifteen years. The risk is compounded by the susceptibility of oil shale facilities to economies of scale. A production rate of 50,000 barrels per calendar day is generally considered the minimum economic scale, and facilities with twice that production rate are believed about optimal, although no thorough economic analysis of the feasibility of smaller plants--20,000 to 30,000 barrels per day--has been performed.*

As illustrated in Fig. 3.1, the actual cost of the first commercial plants may have a strong impact on expectations of when and if oil shale will become competitive with world oil. Assuming a price of \$20 per barrel oil shale, a 2 percent per year increase in the real price of world oil will bring competitiveness in 1995, *ceteris paribus*. Assuming \$26 per barrel, the date becomes 2008 unless we assume higher world prices; at the same \$26 figure, a real price increase of 3.5 percent per year would be necessary to make shale oil competitive by 1995.

FUTURE TRENDS IN CAPITAL AND OPERATING COSTS

Figure 3.1 assumes that the costs of shale production remain constant within a range of uncertainty associated with moving from

* A related aspect of economies of scale is a possible inverse relationship between plant size and capacity or service factors. It is believed that such an inverse relationship may exist for utility plants above 400 MWe, both fossil and nuclear. To our knowledge data do not now exist that would suggest whether or not a similar inverse relationship exists for chemical process and refinery plants. Given the great sensitivity of the required selling price of shale oil to plant service factors, this area needs empirical research. See *Report on Improving the Productivity of Electrical Powerplants*, FEA, PB-242473, March 1975, and *Power Plant Performance: Nuclear and Coal Capacity Factors and Economics*, Council on Economic Priorities, New York, 1976.

definitive plant designs to actual plant construction and operation. As pointed out in Chap. 2, however, capital and operating costs for chemical process plants and refineries have not remained constant in real terms for the past decade. Since 1965 the real increase in the DuPont Index of all chemical process plant costs has averaged 2 percent per year.

Figure 3.2 illustrates what would happen to our expectations of when shale would become competitive if the trends in capital and operating costs since 1965 are projected into the future. It is evident that the prospects for oil shale commercialization by the private sector in this century would be even dimmer if these trends in capital and operating costs continued. To make shale oil competitive by 1995, real price increases for world oil averaging 4 percent to 5.5 percent per year would be required.*

We are not *predicting* that increases in capital and operating costs for chemical process plants will continue to escalate as they have in the past. Rather, we stress that it is the relative changes in world oil and oil shale costs that will determine when shale oil becomes competitive, and that *both* world oil and shale oil costs may be subject to upward pressures. Should trends in capital and operating cost continue, they have implications far beyond oil shale; commercialization prospects for all capital intensive energy process plants would dim substantially.

In addition to general trends in process plant costs, factors particular to oil shale plant costs subsequent to deployment must be considered. Chief among these are learning curves and potential bottlenecks in plant construction, which will be discussed next in conjunction with the possible effects of changes in environmental regulations after deployment has begun.

*Of the ETA, Nordhaus, and SRI models, only the ETA model, under an assumption of high growth in GNP, forecasts the wellhead oil price increasing as fast as 4 percent per year between 1975 and 2000. We would assume that very large price increases for energy would have the effect of slowing economic growth, which in turn would slow the growth in energy demand. Of course, if world oil supplies peaked sharply around 1985, then large price increases thereafter would be likely.

LEARNING CURVES FOR OIL SHALE

A learning curve is a hypothesized inverse relationship between the cumulative number of units of an item produced and the cost per unit produced. The existence of unit-cost decreases attributable to learning has been empirically established for a wide variety of products including automobiles, refined petroleum, synthetic fibers, electronics, and airframes. (Learning curves were first recognized for airframes, which have been subjected to the most thorough empirical research.) In fact, some have argued that the phenomenon is virtually universal in manufacturing.* It is therefore not surprising that it has found its way into cost projections for new energy technologies. This section reviews the assumptions underlying the learning curve and inquires into its proper application to oil shale. The discussion will be extended to other new energy technologies in which concept has been applied. To anticipate our conclusions, we find that the learning curve has been sometimes misapplied to oil shale cost estimates and that cost reductions from learning have often been overestimated.

It is important to distinguish learning from either technological innovation or economies of scale, either of which can also reduce costs over time. For example, catalytic cracking and centrifugal compressors were technological innovations whose costs at the outset were lower than those of the technologies they replaced; and following a learning period, the costs decreased still further. In some cases the line demarcating technological advance from learning is much less clear. For example, extensive design changes resulting from experience with a prior plant might be placed in either category. In general, incremental cost decreases over time are attributed to learning, while breaks in a downward sloping cost curve are attributable to other things.

Economies of scale reduce average cost as the rate of output increases. This phenomenon is conceptually distinct from cost reductions through learning, although a learning process is often associated with ascertaining the optimal production rate after a technology is introduced.

* Winfred B. Hirschmann, "Profit from the Learning Curve," *Harvard Business Review*, January-February 1964.

Economies of scale may also result from the introduction of a new piece of hardware; for example, the introduction of centrifugal compressors more than doubled the optimal size of ammonia plants.*

Factors Underlying Learning

Learning derives from a number of factors that show up in increased worker productivity. In aircraft production, improved managerial organization and supervision contribute significantly to learning. Worker productivity also improves with the repetition of a task, which makes labor force stability an important factor in learning.†

It is important to distinguish capital-intensive from labor-intensive processes with respect to learning. For labor-intensive processes such as airframe production, most gains from learning appear during production. For capital-intensive processes such as shale, coal gasification, and nuclear reactors, large learning gains can accrue only in construction (i.e., capital) costs. Even a very steep learning curve for operating costs would have but a minor effect on product costs for these technologies.‡ Significant cost decreases may also result when learning promotes higher service factors, i.e., more intensive use of the plant. Given that high service factors are already assumed for oil shale plants, however, this kind of learning would probably do no more than cause costs to decline toward original estimates--not below anticipated costs.

* D. E. Chalkey, "Technological Advances--Help or Hindrance?" paper presented to Heavy Organic Chemical Group of the SCI, January 18, 1972.

† David L. Bodde, Energy Systems Group, TRW, "Riding the Experience Curve," *Technology Review*, March/April 1976.

‡ It is not unusual for operating costs to exceed estimates initially but then come down as the engineering is debugged and operating routines are set. Because operating cost estimates are made for normal operation, with a special allowance for start-up in most cases, benefits from learning for operating costs cannot be expected. The operating history of light water reactors suggests that learning does not automatically occur in operating costs. One of the factors cited for the disappointing operating record of LWRs has been a lack of proper training of operating crews and high turnover rates for operating personnel. *Report on Improving Productivity of Electric Powerplants*, FEA, 1975, p. 35.

Much more is known about learning curves for labor-intensive than for capital-intensive processes because most of the original applications of learning theory were to labor-intensive processes; but what evidence there is suggests that learning is less pronounced for capital-intensive technologies.*

Learning-cost decreases can occur for capital plant construction in two principal ways: the learning embodied in construction labor and management, and improvements in process engineering. To obtain most of the potential learning embodied in construction labor and management requires that several conditions be met. There must be substantial continuity for construction labor and supervision between plants. The plants must be substantially the same.† Finally, there needs to be temporal continuity and feedback between one plant design and the next.

Belief in the importance of these factors is illustrated by Duke Power's approach to the construction of LWRs. Duke Power has maintained continuity for construction labor and supervision by hiring its own construction force and maintaining a very large design and construction engineering staff. The company also has attempted to build identical reactors to the maximum extent possible and maintain a steady workload over time. Duke believes that substantial capital cost savings will result.‡

Shape of the Learning Curve

Starting with T. P. Wright's** pioneering work for airframes, the most common assumption about the shape of the learning curve has been

* Nicholas Baloff, "Startups in Machine Intensive Production Systems," *Journal of Industrial Engineering*, January 1966; Hirschmann, op. cit.

† Losses of learning due to design changes have been observed for airframes. See Paul Meyer James, "Derivation and Application of Unit Cost Expressions Perturbed by Design Changes," *Naval Research Logistics Quarterly*, Vol. 15, No. 3, September 1968; and Nelson and Timson, op. cit.

‡ Interview with Warren Owen, Vice-President for Design Engineering, Duke Power Co. Because Duke Power has completed only 3 of its 16 plant programs, it is not yet possible to determine if its expectations will be met.

** T. P. Wright, "Factors Affecting the Cost of Airframes," *Journal of the Aeronautical Sciences*, February 1936.

log-linearity; that is, for each doubling of production, unit cost will decline by a constant percentage, as depicted in Fig. 3.3. Algebraically, the cost of the nth unit (C_n) can be expressed as:

$$C_n = C_0(1 - \alpha)^x,$$

where C_0 is the cost of the first unit, α is the learning factor, and x is equal to $\log_2 n$ or $\log n / \log 2$, where n is the number of the unit being estimated. In the past decade, however, more and more evidence has accumulated suggesting that, rather than log-linear, many learning curves show an S-shape.* An S-shaped curve, which A-Es have suggested to us as being more probable for shale than is log-linearity, means that learning will be negative or very gradual in the beginning phases of industry build-up of a new technology and accelerate later.† Unfortunately, no empirical basis has been developed that would enable us to predict the inflection points for the S-shaped learning curve for a new technology. Nonetheless, if the S-shape is assumed, it does have implications for government commercialization efforts, which will be discussed below.

In attempting to use the learning curve in cost projections for a new technology, one must also consider the likelihood of either breaks in production or major design changes. As Gates and Scarpa have pointed out, "Whenever the routine-acquiring process is delayed for even a short

*See for example, Vincent Colasuonno, *An Analysis of Progress Curve Conceptual Advances and Progress Curve Uses Since 1966*, U.S. Air Force, 1967, available through NTIS; Nicholas Balott, "Extension of the Learning Curve--Some Empirical Results," *Operations Research Quarterly*, Vol. 22, No. 4, December 1971; D. M. Nathanson, "Forecasting Petrochemical Prices," *Chemical Engineering Progress*, November 1972; Richard J. Alden, "Learning Curves: An Example," *IE*, December 1974.

†One cost estimator for an A-E firm suggested that the costs of the second and perhaps third commercial scale oil shale plants would actually be greater than for the initial plant. His reasoning was that the first plant would be built with less redundancy and with lower-grade materials than would ultimately prove necessary for optimal reliability. He suggested that this phenomenon was not unusual for first-of-a-kind plants.

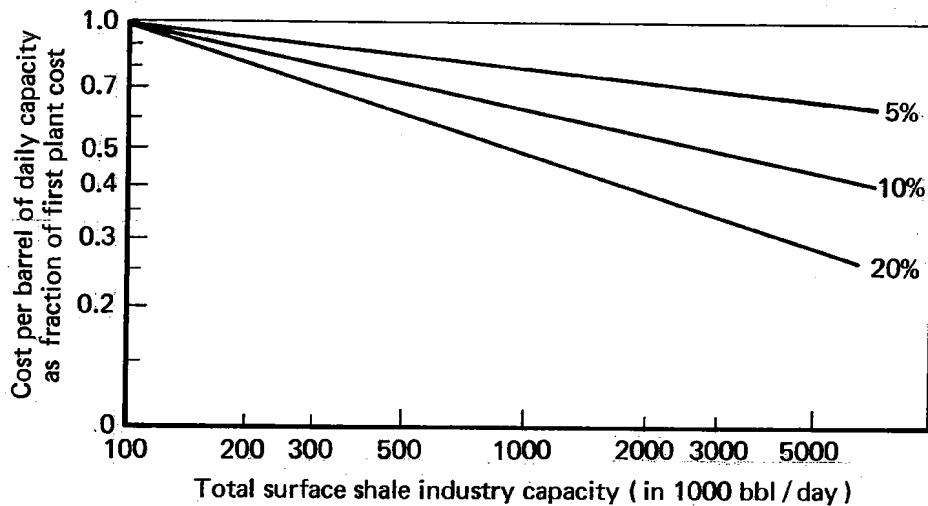


Fig. 3.3 — Illustrative learning curves for oil shale

time, some of the experience curve effect is lost, although upon resumption of the activity, the routine acquiring process resumes at the same decremental rate."^{*} Gates and Scarpa also find that although learning resumes after a break in production, the loss entailed in the break is never completely regained. Similarly, design changes can materially lessen the amount of learning that can be expected for a technology.[†] If repeated design changes are anticipated, learning advantages may not occur at all.

Firm-Specific vs. Industry-Wide Learning

In attempting to predict how learning will affect the costs of production from a new technology, it is necessary to distinguish between learning advantages that are captured by an individual firm and those

^{*} Marvin Gates and Amerigo Scarpa, "Learning and Experience Curves," *Journal of the Construction Division, Proceedings of the American Society of Civil Engineers*, March 1972, pp. 79-101.

[†] James, op. cit.; and idem, "Analysis of the Turbulent Regime of the Progress Curve When New Learning Additions Have Variable Slopes," *Naval Research Logistics Quarterly*, Vol. 15, No. 4, December 1968.

that accrue to the industry as a whole. Firm-specific learning may take the form of patents, proprietary information, and "know-how" specific to individual members of a firm. The advantages of industry-wide learning, on the other hand, accrue to all present and future members of the industry.

Learning depends heavily on the organizational and institutional set-up for development. For example, when government is involved in developing and demonstrating a technology, more information usually becomes available to the industry than when the private sector alone develops the technology. The availability of information also depends on whether learning accrues primarily to plant designers and constructors instead of plant purchasers. Much of what A-Es sell is learning they have acquired in designing and constructing previous plants.* Plant purchasers who have acquired learning have little or no incentive to share it if it gives them a cost advantage over competitors. Other factors that affect the diffusion of learning are the amount of interaction within the industry and fears of antitrust action.†

The implications of firm-specific and industry-wide learning for incentives to develop a technology are completely different.† If there is substantial firm-specific learning, then there are distinct advantages to being the first firm in an industry to deploy a new technology--the advantage of "being in on the ground floor." If, on the other hand,

* A recent analysis of LWR costs suggests that some learning may have occurred for LWRs, all of which is specific to particular A-E firms. LWR costs have been perturbed by so many factors that a modest learning factor has but a marginal impact on costs. William E. Mooz, *Cost Analysis of Light Water Reactor Power Plants*, The Rand Corporation, R-2304-DOE, June 1978.

† The 1975 FEA Report, op. cit., cites the fear of antitrust as one of the reasons that learning has been slow to take place for LWRs. For a similar conclusion, but in the shipbuilding industry, see John W. Wirt, "Shipbuilding Research, Development, and Demonstration Program" in W. S. Baer, et al., *Analysis of Federally Funded Demonstration Projects: Supporting Case Studies*, The Rand Corporation, R-1927-DOC, April 1976.

† For the different implications of whether learning is appropriate to a firm or not, compare Sherwin Rosen, "Learning by Experience as Joint Production," *Quarterly Journal of Economics*, Vol. 86, August 1972, with Kenneth Arrow, "The Economic Implications of Learning by Doing," *Review of Economic Studies*, Vol. 29, No. 3, June 1962.

there is a preponderance of *industry-wide* learning, every firm in the industry will have an incentive to be *second* if not later in line. This type of public-good problem is typically used as a rationale for government aid in absorbing "first-of-a-kind costs" by demonstrating or otherwise subsidizing commercial introduction of a technology, including new energy technologies.

Note that the government's very involvement in developing a technology may further compel it to subsidize commercial introduction, because most of the accrued learning is available to all firms. By converting what might have been an appropriable (private) good into a nonappropriable (public) good, the government removes a firm's incentive to be first. In some cases, of course, this may be good public policy.

Learning in Oil Shale

A number of studies have included an assumption of learning in projecting oil shale costs from surface technologies.* Learning factors of 5 to 10 percent have been most commonly assumed, meaning that oil shale plant costs will decline 5 percent or 10 percent with each doubling of industry capacity. As depicted in Fig. 3.4, a 10 percent learning factor can dramatically affect one's expectations about when or if crude from shale will become competitive with conventional petroleum. As can be seen from Table 3.1, the sixteenth oil shale plant would cost only two-thirds as much as the first if a 90 percent learning curve (10 percent learning factor) were assumed. The learning curve could vitally affect expectations of the costs of a government subsidy program to deploy an oil shale industry.

In this section, we compare what is known about surface technology and the likely circumstances of its deployment with the criteria for applying a learning curve to capital-intensive technologies.

1. Learning is less pronounced for capital-intensive than for labor-intensive technologies. A 10 percent learning factor is often applied to capital-intensive technologies although

* See, for example, Project Independence Task Force, *Report on Oil Shale*; National Petroleum Council, *U.S. Energy Outlook, 1972*; Resources for the Future, unpublished paper.

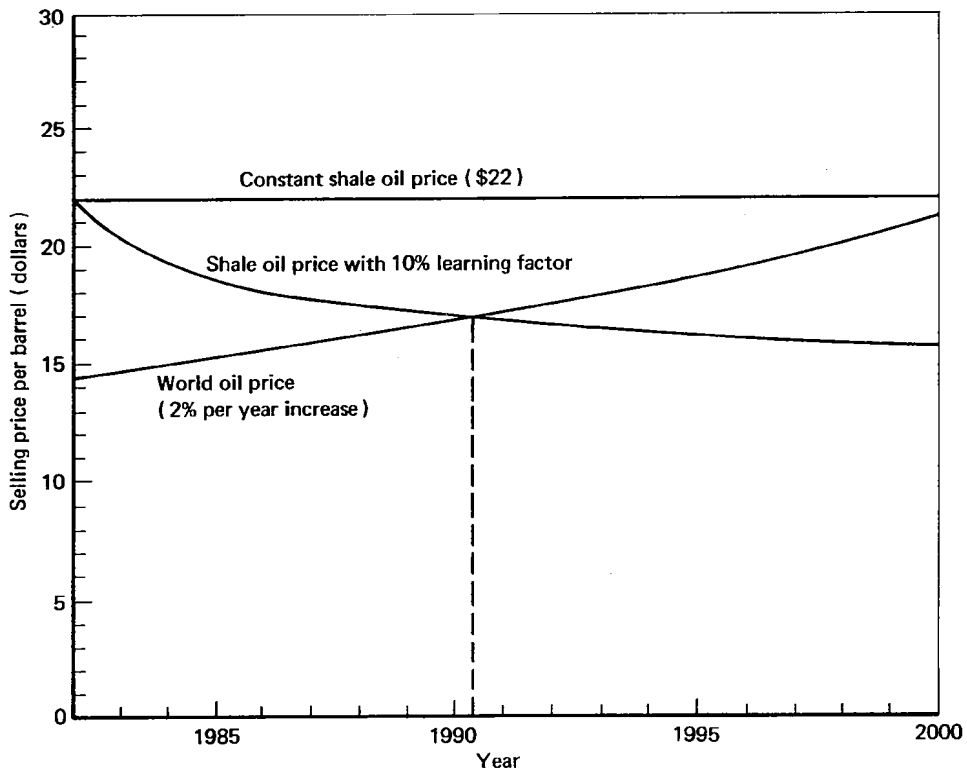


Fig. 3.4— Effect of learning assumption on required selling price (1977 \$)

Table 3.1

EFFECT OF LEARNING ON CAPITAL COSTS OF LAST PLANT FOR DIFFERENT LEARNING CURVE ASSUMPTIONS

Cumulative Number of Plants	Cost of Last Plant as a Proportion of the First	
	95% Learning Curve	90% Learning Curve
1	1.0	1.0
2	0.95	0.90
4	0.90	0.81
8	0.86	0.73
16	0.81	0.66
32	0.77	0.59

the empirical basis for this number is quite weak. One might use 10 percent as one's *most optimistic* figure if other aspects of the technology's deployment discussed below are favorable to learning.

2. Cost decreases from learning are pronounced in the early period of the technology's use. As can be seen in Table 3.2, 17 percent of the capital costs of a shale facility are accounted for by upgrading and by-product recovery, well-known technologies that have already been subject to substantial learning.* Mining is another well-known technology, but one for which learning has never been established.† Indeed, among total capital costs, only retorting, making up about 25 percent of investment, is a "new technology"--and this only in the sense of being new at commercial scale. Figure 3.5 illustrates the difference between assuming 90 percent for total investment and 90 percent on 25 percent of investment, which is equivalent to a 2.5% learning factor.

Table 3.2

CAPITAL COSTS FOR SURFACE SHALE FACILITIES

Retorting	25%
Mining	10%
Upgrading	11%
By-product recovery	6%
Utilities and general facilities	17%
Reserve costs	14%
Other	17%

SOURCE: Colony Development Corp., 1977.

* D. M. Nathanson, "Forecasting Petrochemical Prices," *Chemical Engineering Progress*, Vol. 68, No. 11, November 1972.

† Mining probably does show some learning with respect to operating costs. After a mine is opened and progressively more is known about the geology of the area, some cost-saving improvements may take place. One must also caution that capital and operating costs for shale mining could easily exceed expectations. Operating costs and deferred capital investment for mining could even increase during production in the

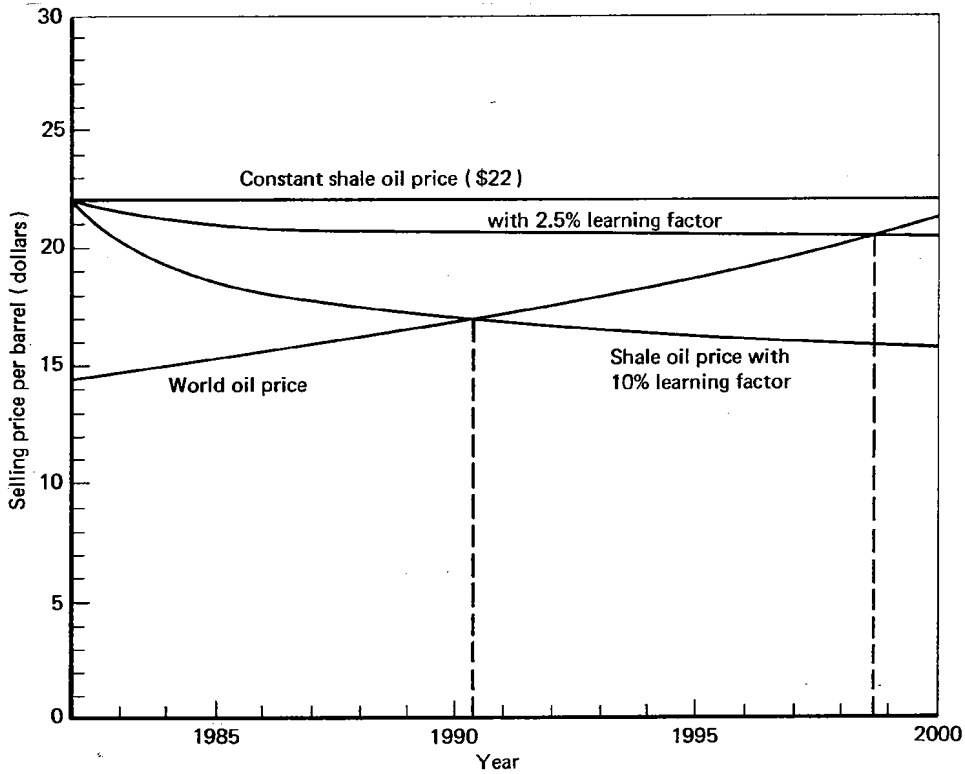


Fig. 3.5 — Effect on required selling price of 10% learning factor for 25% of capital investment (1977 \$)

3. Maintaining stability in construction labor, especially skilled labor, may be very difficult if oil shale plant deployment begins in the near future. The oil shale region is already critically short of both skilled construction and mining labor. In the immediate area, oil shale will have to compete for labor with expansion of conventional coal mining and possibly coal gasification. Even without oil shale development there are reports that "raiding" of skilled labor is going on.

absence of inflationary pressure. The extent to which mining is an inexact science is supported by the fact that the C-b tract, which brought the second highest bonus bid, has turned out to be unminable by conventional room and pillar techniques, much to the surprise and chagrin of the original developers.

4. The most vital requisite for learning is the ability to duplicate experience. For five reasons, that duplication may prove very difficult in oil shale.

Obstacles To Learning Through Duplication of Experience

First, there are at least six potential surface retorting technologies. At least two and as many as five of them would be used if government subsidies were made available for oil shale. Each will be on its own learning curve--and recall that more learning can be hoped for in retorting than in any other part of the capital investment. Consequently, lesser amounts of learning will accumulate for an array of technologies instead of a large body of knowledge about one technology.

Second, oil shale plants will to some extent be site-specific. The grade of the shale, water availability, underground water problems, associated minerals, proximity of plants to roads and utilities, mine tonnage, and mining methods will vary from site to site within the Green River Formation. Environmental regulations will also differ among plants in Utah and Colorado, and will probably vary from place to place within a state because of proximity to national parks or other industrial development.

Third, if the past is any indication, learning from engineering design changes will be blocked or severely reduced by tightening environmental and occupational safety regulations. Oil shale development is (and will be for a long time) a highly contentious environmental issue. When development begins, one can count on environmentalists to file numerous lawsuits, closely monitor environmental regulation enforcement, and lobby in local, state, and national arenas for stricter standards. A prudent person would expect at least some of these efforts to be successful, forcing design changes in many parts of shale operations, based not on cost improvement but on new regulations.

Fourth, to the extent that learning is captured by plant purchasers (i.e., the oil companies) rather than A-E firms, experience is unlikely to be duplicated under current and long-standing federal leasing rules. Developers are forbidden by the Minerals Leasing Act of 1920 from holding

more than 5120 acres of federal shale lands--enough to sustain only one commercial plant. If learning is specific to the A-E industry as a whole, however, it should become widely available through the marketplace.

Fifth, and finally, any ride down the learning curve is likely to be abbreviated for the initial buildup of shale capacity because of limited water availability, as discussed in Chap. 4 below. It appears unlikely that a surface shale industry producing more than 2 million barrels per day could be sustained in the Piceance and Uintah basins. Even this figure may prove optimistic in light of political pressures on water allocation. Realistically, only 15 to 20 plants would ever be in operation at one time with the present processes.

For these reasons, it appears wise to entertain only modest expectations of learning for oil shale technologies, probably not greater than a 2 or 3 percent reduction for every doubling of industry capacity. Whatever learning may occur will probably be captured by individual A-E firms that will have little or no incentive to risk losing a competitive advantage by sharing expertise with other members of the A-E industry.

Implications for Energy Commercialization Planning

The first and most important implication of this discussion for commercialization planning is that a cost estimator who makes a learning assumption must justify it carefully in terms of the realities of the particular technology. It would be rash to apply a 90 percent learning curve (a 10 percent learning factor) merely because it is "standard" for capital-intensive technologies. That standard has a very weak empirical basis. As shown in Fig. 3.5 an assumption of significant learning can be extremely important in determining the time when shale will become competitive and therefore in scheduling commercialization.

A second implication is that even if it is reasonable to expect significant learning for a technology, our meager knowledge about the shape of the learning curve offers little guidance in planning for the costs of a subsidy program for the technology. If the learning curve

is S-shaped on a log scale, rather than log-linear, the costs of a subsidy program to the government may be considerably higher than expected, assuming that the program is designed to operate in the initial phases of the technology's deployment. More research will be needed to establish an adequate empirical basis for predicting the shape of a learning curve for a new technology.

The likelihood that individual A-E firms will monopolize learning has two implications. First, it points up the need to relax or remove the restriction on the amount of land that any one oil company can lease from the federal government, so that oil companies can apply their experience with one plant to succeeding plants. This could increase the amount of learning to be expected in construction costs, because plant purchasers usually make significant inputs to plant design, and, more especially, because utilization rates would increase.*

Second, the rate of learning for the industry as a whole will be less than that for any particular A-E firm, each of which will be on its own learning curve. This fragmentation may also exacerbate bottlenecks in A-E services.

POTENTIAL BOTTLENECKS IN OIL SHALE PLANT DEPLOYMENT

Government planners have been concerned that oil shale development, especially within the context of an accelerated energy process plant subsidy program, might encounter or provoke bottlenecks in plant construction that would retard the growth of the industry and increase the costs of shale oil. Obviously, bottlenecks cannot be considered solely in the context of oil shale plants; they may occur in the demand for components and construction services generally, and other government-subsidized deployment programs may compete for the same resources.

This is a grave issue. The widespread bottlenecks and price increases associated with capital construction in 1973-74 shocked both industry and government in their scope and severity, and prompted the creation of the National Commission of Supplies and Shortages. This

* It is possible that oil companies with experience in operating shale plants might be hired as operators of plants by other firms.

experience has been unusual in the United States; since World War II, only the Korean War and 1973-74 have been periods of major bottlenecks in capital construction. If only for that reason, little data exist that would enable us to model and quantify price and shortage responses to different oil shale buildups.* The following discussion, therefore, must be largely qualitative.

It is important to recognize that "bottlenecks" is a relative term.[†] Any increase in delivery times for a component, or a demand-induced increase in price, could be considered a bottleneck. But this sort of bottleneck is generally short-lived. The one in 1973-74 lasted about 18 months and was brought to an end by a combination of increased supply and sharply reduced demand for capital construction. In real terms, the DuPont Chemical Process Plant Cost Index actually declined in 1975 and 1976.

For our purposes, we define a bottleneck as a major disequilibrium in factor input markets, measured by one or more of the following criteria: (1) lengthening of construction schedules due to unavailability of components or services, (2) large, rapid price increases, and (3) diminution in the quality of construction or components with a shifting of reliability and quality-assurance responsibility to the purchaser. Bottlenecks are also often reflected in changes in contract terms for components and engineering services. Contract terms changed from a fixed price basis in 1972 to a cost-plus-fee basis for engineering services, and to a price-quoted-on-delivery basis for some components with no firm delivery date promised.

As the government considers its commercialization policies for oil shale and other energy process plants, it is important to distinguish

* *Government and the Nation's Resources*, Report of the National Commission on Supplies and Shortages, December 1976.

[†] Bottlenecks rarely mean that an input cannot be obtained at *any* price. For example, even during the height of the 1973-74 period one could generally obtain a component if one was willing to pay a premium price to the supplier to "steal" the item from some other customer. In some cases that premium was 40 to 50 percent over the list price. Curtis M. Sides and D. Keith Dodson, *Escalating Costs of Process Plant Construction*, Brown and Root, Inc., 1975..

between economy-wide shortages such as occurred in 1973-74 and the possibility that commercialization activities themselves could induce shortages for inputs into energy process plants and related capital construction. Economy-wide shortages are and should be of considerable concern to the government, but they do not enter into energy commercialization planning. The possibility that energy plant commercialization efforts could induce bottlenecks is more directly relevant to energy planners for two reasons: If bottlenecks occurred, commercialization strategies could be disrupted; and bottlenecks induced by synthetic fuels development could also affect other capital construction projects, which would constitute an external cost of a commercialization program.

Often, the most important effects of bottlenecks on the costs of capital plant construction are not confined to the direct increases in the costs of the factor input in question. Indirect effects can be equally or more severe. Bottlenecks can decrease worker productivity because of schedule delays, increase the likelihood of false starts for a project, lower the quality of components in short supply (or shift the burden of quality maintenance from the supplier to the purchaser), and increase engineering services costs by inducing redesign to obviate the need for particular components. The ultimate result can be a plant that is delivered later, operates less well, and costs more than if the bottlenecks had not arisen. Obviously, there is a tradeoff between these three factors of delivery schedule, reliability, and cost, all of which are ultimately translated into less favorable economics for the product.

Bottlenecks generally arise when a large and rapid increase in demand takes place for an industry which cannot or will not rapidly increase output. The most likely reason for rapidly increased demand for oil shale would be a major government effort to deploy a large synthetic fuel industry at a rapid rate, a rapid increase in world oil prices, or, less likely, a repeat of the confluence of factors that led to the 1973-74 bottlenecks. These factors were (1) an end to price controls, (2) an upswing in the economy, (3) devaluation of the dollar, (4) unusually

large worldwide demand for capital plant construction, and (5) significant hoarding of many items.*

On the supply side, the principal factors affecting the ability to meet a surge in demand are the size of the supplier sector (number of firms), their ability to expand capacity, and the ease of entry for new firms.

We examined bottleneck possibilities for oil shale in skilled construction labor markets, component and material suppliers, and A-E services by reviewing the relevant literature and interviewing representatives of the appropriate industries. Our examination of the potential for bottlenecks in process plant construction will be reported on separately. Assuming an energy process plant buildup to 3.5 to 4.0 quads over a 10 to 12 year period as a result of a government subsidy program, our tentative conclusion is that the most serious potential problem for an accelerated program would be in A-E services.†

Architect-engineering firms design, act as general contractor for, and supervise the construction of large projects. A-E services were subject to severe bottlenecks in 1973-74; costs of services rose sharply, and some firms could not accept all of the business offered. As we have suggested, the 1973-74 period was a result of a number of special circumstances that make it inappropriate for projection into the future. But a bottleneck in A-E services is a distinct possibility for oil shale and other large energy plant projects if accelerated deployment becomes government policy. Although there is a very large number of U.S. A-E firms, only about 6 or 8 would be attractive candidates for undertaking oil shale and other large energy plant projects, for a number of reasons.

The A-E for the initial oil shale plants will need to have responsibility for the project from initial design through construction and shakedown. Most firms specialize in either design or construction, not

* Standard items such as pipes, valves, and fittings were hoarded. Such large inventories of some items were accumulated by the end of 1974 that the inventory surplus is expected to continue through the end of 1978.

† Possible shortages of skilled construction labor and various components and materials are also being examined.

both. A wide range of experience including knowledge of solids handling, mining, and gas and liquid processes will be wanted. Experience with the construction management of very large plants is critical if construction schedules are to be met and costs controlled. Finally, a desirable, although not necessary, characteristic of the oil shale A-E is the ability to procure components and materials in spot markets worldwide, to keep costs down. So although the market for A-E services appears heavy, it is in fact quite thin once these criteria are introduced. There are a number of reasons why these firms might not be able or willing to meet the demands of an accelerated program.

First, there are long lead times in personnel development in the A-E industry, especially in construction management. An engineer's university training must be followed by about five years on the job before he can become a supervisor. Although the supply of engineers in general has been expanding, the number of chemical engineers has increased very slowly, and very few universities offer preparation for engineering construction.

Second, wide fluctuations in U.S. demand for A-E services discourage expansion of A-E firms. Like all industries faced with wide demand fluctuations, the A-E industry is reluctant to expand its capacity to meet peak demands and then be forced to either carry or dismiss surplus personnel after the boom period has ended. In any case, rapid expansion to meet peak demands is limited by the quantity of available engineers.

A third factor making adjustment to an accelerated program difficult is that the major A-E firms have important and long-term commitments to foreign construction projects, especially in the Middle East and Latin America. Although such commitments might be broken, A-E firms would be reluctant to do so except in a major crisis. Foreign projects account for as much as 80 percent of the total business of some of the major U.S. firms that could build energy process plants, and have the virtue of greater stability over time than the U.S. market. Because capital construction programs in the Middle East, especially

for petrochemical plants, are expected to be very long term, this situation could prevail for many years.*

A final factor discouraging rapid adjustment is uncertainty about government plans and energy demand growth. Government planning for large energy plants lacks credibility in the wake of the past few years, in which major programs have been proposed, changed, defeated, and withdrawn. Increased uncertainty about the demand for energy has made planning difficult for all of the energy supply sector, including architect-engineering.

The bottleneck in A-E services would not, however, be an absolute impediment to building an accelerated energy process plant. If the most qualified firms were unavailable, other firms would undoubtedly fill the gap. The consequence would likely be somewhat more expensive and less reliable plants and less chance of effective learning in capital plant construction, although these effects cannot be quantified.

SUMMARY

The cost of oil shale from surface retorting is uncertain both now and, particularly, in the future. Current estimates of \$20 to \$26 per barrel are more confidently bounded on the low side than on the high side. In addition, a number of factors, including a continuation of historical upward trends in capital and operating costs for process plants, tighter environmental and safety regulations, and the fact that major gains from learning are unlikely for oil shale, render the economics over the next 15 years or so highly uncertain. In several ways, some of the conditions that have promoted rapid cost increases in light water reactors since the start of commercialization appear likely for oil shale: regulations leading to plant redesign and lengthened construction times, and the need to tailor each plant to a specific site.

Given the unfavorable basic costs of surface shale technologies, hopes for near-term commercialization of shale resources must depend on modified or pure *in situ* processes or on R&D to discover new alternatives.

* Walter McQuade, "The Arabian Building Boom is Making Construction History," *Fortune*, September 1976.

These conclusions are, of course, subject to a caveat: If world oil production peaks sooner and declines more rapidly than is generally expected, then oil shale development with surface technology will become more likely. It is thus relevant to note that even at the high end of the currently estimated price range, oil shale is less expensive than current estimates of the price of other nonpetroleum refinery feedstocks.*

*Linden, op. cit.

Chapter 4

INSTITUTIONAL CONSTRAINTS ON OIL SHALE COMMERCIALIZATION

Every new technology is introduced into an organizational and political as well as economic context. In some cases, the organizational and political--i.e., institutional--milieu is highly supportive of the technology's commercialization. The initial period of nuclear reactor commercialization, for example, took place in a climate of political support for peaceful uses of atomic energy and at a time when nuclear power was widely viewed as a clean and safe alternative to conventional electricity generation.* Conversely, a technology may be introduced into an inhospitable institutional climate. The principal determinant of institutional constraints is the extent to which the technology is perceived as consonant or dissonant with the interests and values of those affected by its use.

Institutional constraints stem from the organizational and political context and impede a technology's commercialization. Most commonly, they consist of governmental actions and regulations, not only laws and administrative procedures at all levels of government, but also decisions of federal and state courts and litigation by private citizens and corporations. In some cases, a government may take action to reduce a social cost (an externality) imposed by the application of the technology, such as environmental damage. In other cases, an institutional constraint may be an unintended consequence of an action taken for reasons not directly related to the technology. Natural gas price regulation, for example, has impeded the commercialization of solar heating and cooling.

Less often, institutional constraints may arise independently of government. For example, if a new technology displaces workers, labor

* For a discussion of the institutional context in which nuclear power reactor commercialization began, see L. L. Johnson, et al., *Alternative Institutional Arrangements for Developing and Commercializing Breeder Reactor Technology*, The Rand Corporation, R-2069-NSF, November 1976, and A. Gandara, *Electric Utility Decisionmaking and the Nuclear Option*, The Rand Corporation, R-2148-NSF, June 1977.

unions may oppose it; or an industry may resist it if it requires major changes in the industry's investment patterns or established ways of doing business and, for noneconomic reasons, the industry is slow to adjust.

In assessing institutional constraints, one must be careful not to equate a constraint with a "problem" to be overcome or removed. The most obvious example of this is environmental regulations. If the effect of an environmental regulation is to internalize the social cost (i.e., the negative value of environmental damage) of oil shale production into the price, then no distortion has occurred that requires remedy. An institutional constraint is clearly inappropriate only if it leads to a divergence between market price and the price that would reflect the full social cost.*

The importance of an institutional constraint depends on its severity, i.e., how nearly it constitutes a barrier to commercialization, and the extent to which a lowering of the constraint can be traded off with technical performance goals and economics. Because there is considerable uncertainty about a number of institutional constraints on oil shale, one must add a probability (generally subjective) of the constraint's becoming operative.

The commercialization of surface oil shale technology is beset by a number of real or potential institutional constraints, listed in Table 4.1. Some, such as environmental constraints, are common to most energy

* In general, there are no methodologies that can accurately quantify social costs to permit calculation of the appropriate prices for the product with social costs fully internalized. Several analyses, however, have made steps in this direction for energy prices, both with respect to specific technologies or resources and in a general way. See, for example, Marquis R. Seidel, "Economic Benefits of Energy Conservation," *Energy Systems and Policy*, Vol. 2, pp. 1-30, 1977; T. H. Bingham, et al., *Cost-Effectiveness of a Uniform National Sulphur Emission Tax*, U.S. EPA, 600/5-74-009, February 1974. The proper internalization of social costs refers only to allocative efficiency. Questions of the distribution or redistribution of wealth that are often germane to discussions of institutional constraints do not enter here as a consideration. But distributional questions may be central to the political realism of remedies for institutional constraints.

Table 4.1

INSTITUTIONAL CONSTRAINTS ON OIL SHALE COMMERCIALIZATION

Factor	Potential Problem	Organization Involved
<i>Federal Policies</i>		
Leasing	5120-acre limitation on lease holdings by a single firm; complexity of regulations; uncertainty of offerings on a timely basis.	DOI, DOE
Entitlements	Entitlements must be made available for oil shale purchasers as long as they are in effect.	FEA
<i>State and Local Government Policies</i>		
State control	State control over energy leasing and development has increased; state governments can insist on prior approval; new state rules limiting energy export.	State governments, DOI, DOE, courts (?) on export laws
State taxation	Increases in severance and other state taxes on energy development should be expected as revenue-raising and energy development control measures.	State, industry
Local zoning	Rio Blanco (a major oil shale county in Colorado) recently rezoned all unused land for agriculture. Variances will be necessary for major shale development. Contests between local and federal government for control of federal land use likely.	Local governments, DOI
<i>Multiple Responsibility</i>		
Water availability and allocation	Water rights are now controlled by all levels of government, interstate compact, international treaty, Indian tribes, and individual owners. State control has increased over federal projects; environmental and, later, agricultural groups will probably oppose allocation of water to shale development.	All parties
Environmental issues:		
Meeting current regulations	A problem in meeting particular ozone regulations has been identified. Particulate regulation can be changed by administrative action; ozone might require legislation.	Colorado, EPA, citizens groups, Congress (?)
Changes in regulations	Changes in regulations could be a source of serious difficulty for industry, starting with proposed changes to the Clean Air Act. Increasing costs and uncertainty facing industry.	States, Congress, EPA
Environmental opposition	Opposition by regional and national environmental groups can be expected at every step of the administrative and regulatory process. Opposition will be maximized by an accelerated federal deployment program. No nonadversary processes are now available to achieve compromises.	Courts, DOE, DOI, industry
<i>Investment Climate</i>		
Taxation on "old" oil	Potential effect on oil company rates of return.	Oil companies, Congress, Administration
Vertical and horizontal divestiture	Effect on incentives to invest, availability of capital.	Oil companies, Congress, Administration

supply technologies. Others, such as water allocation, are particularly salient for oil shale.

The sections below discuss institutional constraints on oil shale commercialization, following the order of Table 4.1. Constraints in the first three categories--federal policies, state and local government policies, and multiple responsibility--affect oil shale commercialization directly. The constraints in the final category indirectly affect the willingness and ability of oil companies to invest in oil shale production.

FEDERAL POLICIES

Even without an accelerated deployment or commercialization program, the federal government is already deeply involved in oil shale development: as owner of about 80 percent of the high-grade shale reserves, as regulator of petroleum prices, and through taxation policies that directly affect oil shale economics.

Federal Leasing Authority and Practice

The federal government is the primary owner of oil shale lands in the West, owning over 80 percent of the highest-grade and most accessible reserves. Although the development of oil shale could begin on privately held lands, it would be limited to only a few plants, and in most cases even private land development would require rights-of-way or disposal of spent shale on federal land, or both. Two leasing issues could pose institutional constraints on oil shale development: acreage limitations and the possibility that lease offerings could be delayed or halted.

Rules in effect since the passage of the Minerals Leasing Act of 1920 limit federal lease holdings to 5120 acres of oil shale lands by any one company. A company may hold an interest in several leases as long as the total does not exceed 5120 acres of federal land. This policy effectively precludes a small number of firms from developing a strangle hold on oil shale production, but it also reduces the advantage that a crude-short oil company could obtain because it limits output per company to the equivalent of a single large operation, i.e.,

100 to 150 thousand barrels per day. As discussed in Chap. 3, the acreage limitation also decreases the chances for learning to take place by a potential plant purchaser, because the number of plants operated by a single company is limited.

A potentially more serious problem arising out of federal ownership is whether the government can establish a leasing policy for oil shale lands so that tracts can be offered without serious delay. The Department of the Interior took the first step toward a leasing policy in 1969 with a study to determine if shale lands should be made available. From that first step grew the Prototype Oil Shale Leasing Program. Over the next four years, six tracts were nominated by industry, the environmental impact statement for the program was completed, and by the end of April 1974, four of the six tracts offered had been leased for bonus bid payments of \$447 million.* The bonus bids were to be paid in five equal installments, the first upon acceptance of the bid, followed by payments on the anniversary date for four years. The last two payments could be offset dollar for dollar by investment in developing the tract. The Prototype Program was intended to (1) make tracts of high-quality oil shale available to a number of developers, (2) demonstrate the environmental acceptability of oil shale production, and (3) develop administrative procedures for future oil shale lease sales. The first goal was accomplished; four oil company consortia were formed to purchase two tracts in Colorado and two in Utah. The second and third goals were not met.

Almost from its inception, the program became enmeshed in bitter disputes between environmentalists, developers, and the government. Environmentalists felt that National Environmental Policy Act (NEPA) requirements were not fully met, and that they had had insufficient opportunity to comment on the environmental effects of oil shale development. (However, a great deal of environmental baseline data had been gathered by developers as a necessary step toward development.) The Prototype Program has encountered continuing difficulties from

* Two tracts each were offered in Colorado, Utah, and Wyoming. The Wyoming tracts, which are suitable for *in situ* recovery, received no bids.

governments at several levels. Industry officials complain that the lease regulations were both very long in the making and difficult to understand when completed. A number of lawsuits were threatened by environmentalists, and in the wake of the suspensions of the leases by the Secretary of the Interior in 1976, a suit was filed, which has since been dismissed.* The State of Utah has challenged the leases in that state on grounds that the oil shale lands should have been deeded to it in settlement of claims dating back to statehood. The owners of Colorado Tract A (C-a) have threatened to sue Interior if the lease suspension granted in 1976 is not continued. Continuation would probably lead to a reactivation of the environmentalists' suit under the Minerals Leasing Act and NEPA. Finally, changes in development plans originally filed by the owners of C-a and C-b will likely result in yet another suit by environmentalists arguing that a new environmental impact statement under NEPA will be required before development can proceed. If that suit materializes and is successful, the Prototype Program would be delayed one to three years and could be abandoned altogether.† Against this background, and with the continuing difficulties encountered by the federal coal leasing program over the past seven years, developers are understandably uncertain about the ability or political willingness of the federal government to lease shale lands in the future.

Entitlements

Several oil shale developers expressed concern that even with subsidies that would bring the required selling price for oil shale into...

* Environmental Defense Fund, Inc., et al., v. Kleppe and Rutledge. The suit alleged that the suspensions of the lease and deferral of bonus bid payments were in violation of the Minerals Leasing Act and NEPA because the real reason for the suspensions was the unfavorable economics of oil shale rather than "for reasons of conservation" as required by the law. The suit was dismissed by the U.S. District Court for the District of Columbia on a technicality: the plaintiffs' failure to include shale developers as defendants.

† Yet another possible suit may be filed by Occidental Petroleum against the C-a owners alleging infringement of patent rights on the modified *in situ* process now being planned for C-a.

line with OPEC prices, the FEA would have to extend the entitlements program to oil shale before they could compete. All that is required is a definitional change in FEA regulations to explicitly include synthetics as uncontrolled oil use by a refiner. Although there is little reason to believe that the FEA would not make such an extension, oil companies would be more comfortable if it did so immediately. The effect of the administration's proposed tax on "old" oil would be to phase out entitlements over the next few years. Nonetheless, developers would feel more confident if the change to allow entitlements were made now.

Unless entitlements were extended to shale oil, shale crude would have to sell to refiners at a *lower* price than imported oil in order to compete. An extension of entitlements to shale and other syncrudes is a form of implicit subsidy, although the transfers are confined to the private sector. But because entitlements are also a subsidy to the use of imported oil, an extension to syncrude would not affect the relative economics of syncrude and world oil.*

Federal Taxation

Two federal tax policies pertain directly to shale oil costs. The first is the depletion allowance for oil shale; its elimination would require an increase of over 12 percent in the selling price to maintain a 15 percent DCF return. The virtual elimination of the petroleum depletion allowance has raised industry concern that the allowance on oil shale might be similarly dispatched. That eventuality, although it could affect the required selling price of shale oil, would not place oil shale at an unfair disadvantage vis-à-vis petroleum crude. Unlike an extension of entitlements, the depletion allowance provides a subsidy to shale oil not generally available to petroleum, although it is not nearly enough to offset the higher basic costs. To eliminate the depletion allowance for shale would either further postpone the time when the private sector could undertake shale commercialization on its own or increase the level of government subsidy necessary to initiate a shale oil industry.

*The potential indirect impact of the proposed tax on shale investment by oil companies is discussed below under "investment climate."

A second tax policy important to oil shale developers is the 10 percent investment tax credit currently applying to all capital investment by businesses. For several reasons, it is especially relevant to shale development. Oil shale production is more capital-intensive than the production of petroleum crude, which means that the tax credit is relatively larger for shale than for petroleum. In addition, because the credit can be taken in the year in which investments are made, it improves cash flow during construction years, in which heavy investments are made but no revenues are received from the plant. This effect is enhanced if a substantial portion of the plant is financed by a loan, because the tax credit can be taken against debt as well as against equity funds by the plant purchaser.

The only differential advantage of the tax credit results from the capital-intensiveness of surface shale production. Thus, if shale production from modified *in situ* is less capital-intensive than surface retorting, the tax credit will be smaller. The improvement in cash flow during construction does not create an investment bias toward shale vis-à-vis any other capital investment.

Although the depletion allowance and tax credit improve oil shale's economic prospects, they are also a source of uncertainty for shale developers. Developers' uncertainties about tax and leasing policies will in some fashion be incorporated into any future government subsidy program by raising the minimum acceptable levels of subsidy necessary to induce investment.

Federal policies on leasing practices and procedures appear to be the most important potential constraints. Entitlements and taxation policies trade off with economic constraints in a straightforward way. And the chances are good that these constraints will not materialize. But the failure of the U.S. government to lease on a timely and efficient basis would pose a significant barrier to shale development that could not be easily surmounted. In addition, difficulties in Western coal leasing, the controversy surrounding the Prototype Oil Shale Leasing Program, and continued intense opposition to leasing by environmentalists suggest that leasing constraints could indeed materialize when the basic economics improve as a result of new technology, increases in world oil prices, or government subsidy.

STATE AND LOCAL GOVERNMENT POLICIES

The Rocky Mountain states hold not only all of the high-grade oil shale, but large deposits of coal, some petroleum and natural gas, and virtually all of the nation's uranium reserve. As a result of environmental regulations that have increased the attractiveness of low-sulphur Western coal, and as a result of the increase in energy prices, energy development has quickened in the area and is expected to continue to do so.

Unlike most other parts of the country, the Rocky Mountain states have had a tenuous legal position regarding control of energy development within their borders because the federal government is the principal owner of energy lands in the region.

In the past several years, the affected states have become increasingly assertive in their attempt to wrest control over energy development on federal lands from the U.S. government. These attempts have met with substantial success in several areas. The Western governors won a pledge from the Secretary of the Interior that no major energy development would proceed in one of their states without the prior approval of its governor. In environmental matters, state regulations tend to take precedence over federal regulation when they are stricter. State and local permits have generally been sought for development on federal lands even though the official federal position has been that such permits are usually unnecessary. The states have also sought and gained much greater say over how water from federal projects will be allocated. The governor of Colorado recently won from the Department of the Interior the right of prior approval of most water allocations from federal facilities to energy projects.*

Although the goal of increased state control of energy development is shared among the states of the area, their incentives vary markedly.

*The Memorandum of Understanding between Colorado Governor Lamm and the Secretary of the Interior expresses Colorado's concern that water from federal reclamation projects "not be reallocated, transferred or reassigned from agriculture, municipal or light industrial uses to energy production-conversion uses in the State of Colorado in ways which are inconsistent with the policies and program of the state." *Denver Post*, July 10, 1977.

In Colorado, energy development has become an important political issue, especially as energy development competes with state environmental goals. Politics in Colorado divide along traditional Democratic and Republican party lines, with the Democratic party generally espousing a cautious attitude toward energy development, and the Republicans citing the need for greater energy and economic development. The parties are very evenly matched in electoral strength, with the Democrats currently controlling the state house and the Republicans the legislature. Because energy development is a contentious political issue, Colorado governors have had very strong incentives to attempt to manage the process. The desire for control was accentuated by what Colorado officials saw as unilateral federal action on the 1975 Synthetic Fuels bill. They complained that they did not receive advance copies of either the Inter-agency Synfuels Task Force Report or the 1975 legislation.

Utah's incentives to wrest control of energy development from the federal government stem from frustration and a belief that the federal establishment has not moved fast enough to allow development. A consistent complaint of Utah officials is that the federal agencies are overly sympathetic to the wishes of environmentalists, and that the agencies constitute the primary roadblock to the development of oil shale and coal within the state. There is very little political disagreement in Utah on the advisability of energy development. In stark contrast with Colorado, Wyoming, and Montana, which are considering export limitations on converted energy resources,* Utah officials hope that the state can become a major net exporter of energy in all forms.

In addition to winning concessions from the Department of the Interior, the oil shale states can use taxation both to control the pace of energy development and raise revenue. Thus far, only Montana

*The export controls mentioned most often would limit the percentage of output from an energy conversion plant, e.g., electricity station, coal gasification facility, and possibly oil shale, that could be consumed outside the state. This limit would be part of the permit process. A bill proposed in Montana would limit export to 25 percent of total output; a similar bill introduced in Wyoming would enact a 50 percent limitation. If such legislation is ultimately passed by any state, it will undoubtedly be subjected to a test of constitutionality under the Interstate Commerce Clause.

has used taxation to slow energy development. The state imposed a 30 percent severance tax on coal (about ten times the average in the region) as a reaction to the severe environmental and socioeconomic effects of the opening of the first two Colstrip mines and associated power generation stations by Montana Power, a privately owned utility.

The oil shale states of Colorado and Utah are not now disposed to use severance taxes to control development. Colorado has clearly stated, however, that it will use whatever means it can to counter any federal attempts to force the pace of development faster than the state desires. Utah and Colorado currently view severance taxes simply as revenue-raising measures; as long as they maintain this view, severance taxes will be limited. Attempts to increase the Colorado severance taxes substantially were defeated this year by the legislature.

Local governments in the Rocky Mountain region have also become more assertive in claiming independent rights to control development within their jurisdictions. In the past, local governments in the oil shale area have had very few problems. The area is sparsely populated and predominantly agricultural. With the advent of new coal mine openings, however, many of the social ills of instant urbanization, such as boom towns, have afflicted rural Montana, Wyoming, and Colorado. The social problems found in boom towns--breakdown in local government services, mixing of opposing life styles, crime, mental illness, and so forth--have been thoroughly explored elsewhere.* From observing the tribulations of their neighbors, the principal shale counties have learned that they must prepare in advance if they are to have any control over the reshaping of their communities. The clearest example of an attempt to gain preemptive control is in Rio Blanco County, the most important shale county in Colorado. The county supervisors have rezoned all vacant portions of the county, including federally owned shale lands,

* See, for example, William R. Freudenberg, "The Social Impact of Energy Boom Development on Rural Communities: A Review of the Literature and Some Predictions," paper presented at the annual meeting of the American Sociological Society, August 1976; John S. Gilmore, "Boom Towns May Hinder Energy Resource Development," *Science*, Vol. 191; William Christiansen and Theodore Clack, Jr., "A Western Perspective on Energy: A Plea for Rational Energy Planning," *Science*, Vol. 194.

for agricultural use only. Thus, variances would have to be sought for shale development. The legality of local zoning of federal lands is highly questionable. To date, however, Department of The Interior policy has been to request that developers of federally owned lands comply with all local ordinances and permits; and of course the issue does not come to a head at all when counties zone nonfederal lands for agricultural use only. In such cases there is no doubt about the legality of counties' requiring a permit for development.

Counties' attempts to exert some control over the development process should not be interpreted as opposition. Most public officials in these counties welcome the economic improvement that would accompany oil shale development. In addition, socioeconomic problems created by commercialization are easily exaggerated. Firms opening new mines in Western states have shown an increasing willingness to aid local governments both financially and with planning. Oil shale developers have all made plans to alleviate some of the ills of urbanization, if only to help ensure a stable work force. An accelerated oil shale subsidy program, however, would undoubtedly bring pressure on the federal government to share at least part of the costs of social services. If it did not, the withholding of county permits could retard development.

The extent to which state and local governments stand in the way of development will depend heavily on the negotiating skills of developers and federal agencies. The regulatory processes at both the state and local levels are becoming more and more complex, particularly in Colorado, with a marked increase in the number of points of control in the past few years. These governments apparently will be in a strong position to control the pace and nature of shale development if they believe their interests are threatened.

Although federal energy impact aid and industry expenditures on the community can help defuse state and local government opposition to development, there is a political and human relations component to the issues that cannot be ignored. Rocky Mountain state and local government officials view the federal government as a sometimes benevolent and sometimes autocratic landlord who is largely unresponsive to their problems. Federal attempts to spur the development of oil shale have

further inflamed the situation. When resentment of the federal government is widespread, it is politically difficult for governors to achieve compromises on energy development issues. In addition, because of the great heterogeneity of the Rocky Mountain states, it is difficult to fashion federal policies that are workable for the whole region. If the federal government elects to accelerate oil shale development, even with a modest demonstration program, it may have to engage in a great deal of consultation with *each* state and local government to pacify the opposition.

AREAS OF MULTIPLE RESPONSIBILITY

The availability of water and the impact on the environment by oil shale development are potential constraints that will cut across jurisdictional lines. Both are contentious issues, and both are subject to uncertainties.

Water Availability

The amount of water that can or will be made available for energy development in the Western states has been a serious concern to the federal government, industry, and the states. A recent report concludes that "Under conservative estimates for water availability, consumptive use reaches alarming levels in the West even by 1980."* The concern predates the drought of the past two years, but was undoubtedly heightened by the record low-flow levels in most rivers in the Rocky Mountain region.

Water availability for oil shale development has been of special concern because of the lack of flexibility in siting and the generally more severe water constraints in the Colorado River Basin than in other watersheds. The critical constraints posed by water are oil shale water demands, physical availability, and water rights.

Analyses of water use by a surface shale industry have converged at between 140 to 175 thousand acre-feet per year as consumptive requirements (i.e., with no return flow) for a one-million-barrel-per-day

* Environmental Constraints on Rapid Development of Fossil Fuels As Energy Sources, Report to the Energy Resources Development Agency by the Inexhaustible Energy Resources Task Force, 1977, p. 24.

industry and accompanying urban development.* Although that is a great deal of water for this part of the country, its allocation to oil shale does not necessarily constitute a profligate use of water resources relative to agriculture or alternative energy development. If one accepts willingness to pay as a criterion of allocative efficiency, industrial uses of water almost always are more efficient than agricultural uses in the Rocky Mountain area. Farmers in Colorado are willing to pay about \$20 per acre-foot for water rights; energy developers have paid \$50 per acre-foot when necessary.† Even if oil shale developers paid \$60, the increase in operating costs would amount to only about 1.7¢ per barrel. In addition, on an energy efficiency basis, oil shale development is a relatively efficient use of water, as illustrated in Fig. 4.1. The most meaningful comparisons in this respect are between oil shale and coal-fired electricity generation, coal gasification, and coal liquefaction. A 1000 Mwe coal-fired generation station, assuming most efficient design and an 80 percent load factor, consumes about 15,000 acre-feet per year for the plant alone, or about 146 gallons per 10⁶ BTU generated. An oil shale plant by contrast will consume only about 20 to 30 gallons per 10⁶ BTU output. Ten to twelve large coal-fired generation stations would consume as much water as a one-million-barrel-per-day oil shale industry.

In terms of physical availability, there is ample unused water in both the Colorado and Utah portions of the Upper Colorado basin. Nevertheless, water availability could pose serious problems for the creation of a large oil shale industry using surface technologies, for several reasons. The Upper Colorado River is governed by a Byzantine set of water use regulations involving federal and state laws, interstate

* See, for example, U.S. Department of the Interior, *Report on Water for Energy in the Upper Colorado River Basin*, July 1974; U.S. Geological Survey, *Water Demand for Expanding Energy Development*, Circular 703, 1974; J. M. McKee and S. K. Kunchal, "Energy and Water Requirements for an Oil Shale Plant Based on the Paraho Processes," paper presented at the Ninth Oil Shale Symposium, Colorado School of Mines, April 1976; and Felix L. Sparks, "Water Prospects for the Emerging Oil Shale Industry," *Quarterly of the Colorado School of Mines*, Vol. 69, No. 2, April 1974.

† Calef, op. cit., p. 8.

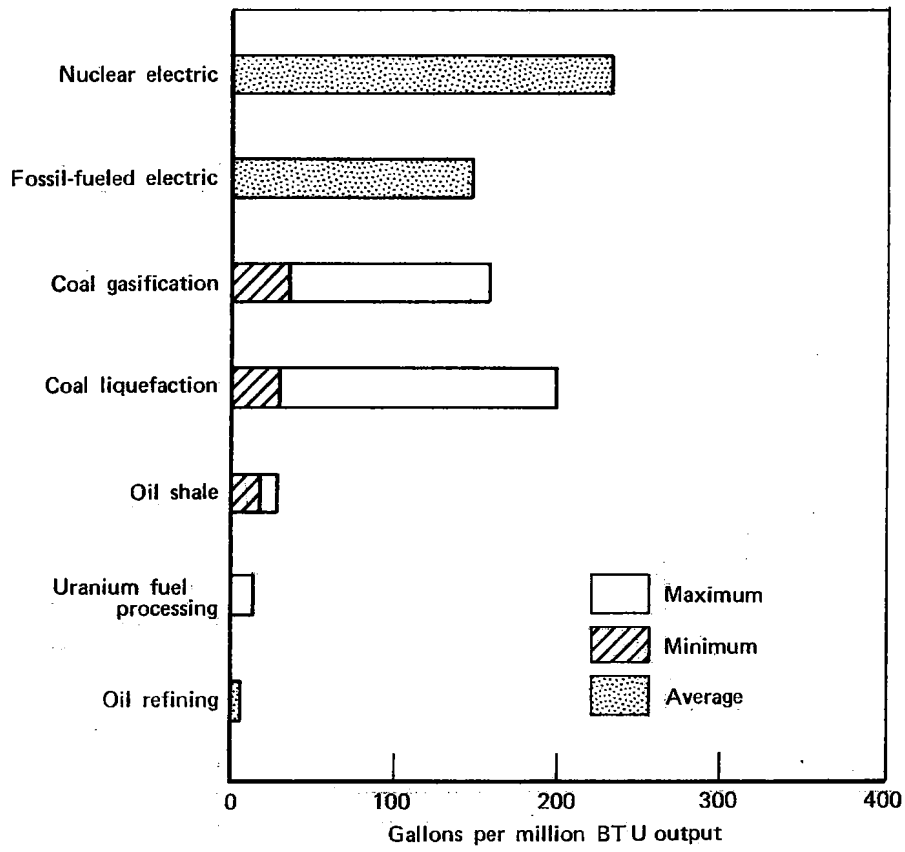


Fig. 4.1—Consumptive water use of energy conversion processes
(from *Water Demands for Expanding Energy Development*,
U.S. Geological Survey, Circular 703, 1974)

compacts, Indian treaty obligations, and international agreements. The Colorado has been called "the most regulated river in the United States."^{*} The Colorado River Compact of 1922, subsequent legislation, and court decisions have allocated the river's water between the Upper and Lower Basins and within the states of the Upper Basin.[†] The Lower Basin states are guaranteed an average of 7.5 million acre-feet per year measured over a 10-year period. The rest is allocated among the Upper Basin states of Colorado, Utah, and Wyoming.

Water availability for oil shale is not expected to be a problem in Utah because oil shale development is limited by the small high-grade reserves and because Utah has ample unused and uncommitted water from the Upper Colorado River Basin.[†] Colorado confronts a different situation. It contains about four-fifths of the high-grade shale reserves, and all of the state's water allocation from the Colorado Basin is either being consumed or is bound by conditional decrees that commit it for future use. Table 4.2 summarizes the Colorado allocation.

Colorado has granted more water rights for future use than it has water available from the Colorado to grant. The importance of that overcommitment is not in and of itself a bar to development beyond apparently available supplies; some of the water rights might be relinquished, and some senior rights might be purchased. Claims for appropriative water rights can be filed with the state, stipulating how much water would be withdrawn and at what periods and for what uses. If the Water Court finds that the claim is for a "beneficial use," a conditional water right has been established. That does not mean that the water is in fact available; actual use of water is determined by seniority. Water rights now owned by most shale developers are

^{*} *Report on Water for Energy in the Upper Colorado River Basin*, p. 2.

[†] In addition to the 1922 Compact, the Mexican Water Treaty of 1944, the Boulder Canyon Project Act of 1928, the Boulder Canyon Project Adjustment Act of 1940, the Upper Basin Compact of 1948, and the Colorado River Storage Project Act of 1956 are integral parts of the complex legal arrangements for control of the river's waters.

[†] Project Independence Task Force on Oil Shale estimates uncommitted water in Utah for oil shale at 116 thousand acre-feet per year.

Table 4.2

ALLOCATION OF COLORADO RIVER WATER IN COLORADO
(In thousand acre-feet/year)

State share from River Compact	2976
1974 use	-1855
Storage evaporation	-269
Currently unused	852
Committed future use	-916
Overcommitment	64

SOURCE: FEA, *Project Independence Task Force Report on Oil Shale*, Washington, D.C., November 1974, p. 169.

essentially worthless because of their junior status.* Private water rights might be purchased from agricultural holders as utilities currently do for power plants. The use of private rights may be limited, however, because the courts must authorize a change in use, and the change must not lead to the injury of any other water-rights holders even if their claims are junior to those purchased. The logical and most promising sources of water for an oil shale industry in Colorado are federal reclamation projects. Existing projects might supply enough for a one-million-barrel-per-day industry.

The overcommitment of water rights has taken on more serious implications in the past few months because the state government has indicated that it may not allow the diversion to energy use of water from federal projects--water that was expected to provide the bulk of oil shale water in Colorado. In addition, the Secretary of the Interior has agreed to give the governor of Colorado considerable say in whether water from federal projects may be diverted to oil shale use.

Because the availability of surface water is uncertain, the possibility of tapping large underground supplies has received more attention. The extensive use of aquifers, however, is at best a short-term solution for a shale industry and could encounter insurmountable environmental obstacles. Although as much as 25 million acre-feet may be

* Sparks, op. cit., p. 97.

trapped beneath the shale region, the underground replacement rate is only about 29,000 acre-feet per year. At a modest rate of use, therefore, a shale industry would begin to draw down the underground reserves. In time, springs and surface streams fed from underground reserves would be decreased, and fresh-water aquifers might be contaminated with saline underground water.*

The water problem in Colorado is exacerbated by the political sensitivity of allocation policies. Agriculture is by far the largest consumer of water in the state, and allocation and water development policies have been established with the farmer in mind. Some farmers contend (no doubt correctly) that oil shale development would lead to higher prices for water and possible revisions in water allocation procedures. Environmentalists perceive oil shale water use as a threat to the environment and a strong issue on which to gain support. There is thus considerable political pressure on state government not to allow major water diversions to energy development.

Water for oil shale development is predominantly a political-institutional problem. Enough water can be made available from federal reclamation projects and from the purchase of senior water rights to begin an oil shale industry in Colorado. Beyond a production rate of about one million barrels per day, entailing about 1,600,000 acre-feet of consumptive water use per day, obtaining further water for oil shale would require some potentially difficult political actions, such as building new reclamation projects or assigning oil shale a higher priority than agriculture for existing appropriable water.

Environmental Constraints

Any kind of energy development involves some amount of assault on the physical environment. The effects of surface oil shale extraction on the environment are distinguishable in three ways: (1) Very large quantities of solid waste (spent shale) will be produced in addition to normal industrial air and water emissions, (2) shale development would take place in an area that is currently unspoiled by industrial developments, and (3) the bulk of that development would take place in

* Ibid.

Colorado, a state with unusually active citizen environmental organizations. Environmental considerations present three kinds of challenges to any shale industry: meeting current regulations, coping with changes in regulations during development and deployment, and facing citizen and government opposition to shale development based on environmental grounds.

Meeting Current Regulations. Oil shale processing is affected by federal and state air quality standards, federal water quality standards, and environmental strictures written into federal shale leases. Although spent shale disposal has been the subject of considerable debate, air quality is the only major uncertainty in the ability of surface shale facilities to meet existing standards. In 1976, the industry reported that its monitoring program had discovered background levels of particulates, hydrocarbons, and ozone in excess of standards. It was in part on the basis of these findings that the bonus bid payments on the four federal leases were suspended pending the resolution of the environmental issues. State air quality officials in Colorado could foresee no air quality barrier to oil shale development, noting that their air monitoring efforts had not recorded as high levels as had the industry. It is now expected that EPA will be able to remove any regulatory roadblock to oil shale development by administrative action. The industry also considers it essential that the oil shale region be designated a Class II area, a standard that would allow some minimal degradation of air quality.* Such a redesignation is expected. Developers believe that they can ultimately meet all existing environmental standards, but that a further tightening of air quality standards

* Utah and Colorado may clash over the classification problem. Utah has petitioned EPA to designate the immediate area of oil shale plants as Class III, which would allow air quality to be degraded to national ambient air quality standards, and that the region between the plants and the Colorado border be designated Class II. Colorado has protested that because of prevailing winds, this would jeopardize its ability to maintain a Class II designation for its oil shale area because Colorado would receive cumulative emissions from both Utah and Colorado shale development. This issue will not come to a head until Colorado requests redesignation, but then could result in prolonged litigation.

proposed in a recent amendment to the Clean Air Act might prove insurmountable. As discussed in Chap. 2, however, meeting environmental standards is costly, affecting both capital and operating costs.

Although the principal environmental effects of shale development are thought to be known, some uncertainty remains in a few areas, particularly in regard to toxic substances that will ultimately be regulated under the Toxic Substances Control Act of 1976.

Changes in Regulations. A great deal remains to be learned about the effects of environmental pollutants on human health, particularly the health effects and pathways to man of potentially toxic trace elements. As more is learned, new regulations will be promulgated, some of which will affect oil shale. In addition, the institutional context in which oil shale environmental impacts are regulated is now changing. In Colorado, local governments are expected to increase their role in environmental regulation, and the adoption of state standards for water quality and solid waste disposal is likely. Furthermore, in the West, and in Colorado in particular, emissions standards are sometimes used not simply to control emissions but as mechanisms for controlling land use and development. This can lead to the adoption of more stringent emission and effluent regulations than would be warranted on the basis of air or water quality alone.

Developers are aware that environmental regulations may change and render oil shale all the more risky an undertaking. Stronger regulations could increase costs both directly by forcing costly design changes and indirectly by inhibiting learning, as discussed in Chaps. 2 and 3. Equally important, changes in the institutional context for promulgating and enforcing environmental regulations would delay routinization of these processes. Whenever regulatory functions are shifted to a new agency, a period of start-up and shakedown is inevitable. The industry then must deal with a new set of actors with different skills and points of view. The effect of such changes is to make "safe passage" of a project through the regulatory process less certain even if the formal regulations themselves remain unchanged.

Environmental Opposition to Shale Development. The politics of environmental protection are likely to give the industry perennial difficulty. Formal regulatory requirements are never completely clear, and frequently are less important than informal political processes. Oil shale development is no exception. Starting with the Prototype Oil Shale Leasing Program and continuing to the present, oil shale development has been a highly contentious environmental issue in Colorado. Environmental groups believe that they were improperly, if not illegally, excluded from effective participation in the Leasing Program decisionmaking as required by NEPA,^{*} and that this exclusion has continued throughout the government's commercialization planning for oil shale. They contend that federal agencies, including the Department of the Interior and DOE, must take primary responsibility for the failure to negotiate cooperative compromises. With one interesting exception, only adversary routes have been taken in trying to resolve environmental disputes: lawsuits, threats of lawsuits, and lobbying against legislation that would encourage oil shale development. Federally created bodies such as the Oil Shale Environmental Advisory Panel have had little discernible effect on the political aspects of the process.[†] The ability of DOE (which became the lead agency for oil shale commercialization efforts in 1975) to find acceptable ways to incorporate the concerns of environmental groups (or state and local governments) was seriously hampered by the lack of any effective organization in the Rocky Mountain area, as well as a legacy of ill will inherited from previous oil shale efforts.

It would be difficult to find common ground even if adequate organizational means existed to aid in effecting a compromise between the

^{*} See Katherine Fletcher and Malcolm Baldwin (eds.), *A Scientific and Policy Review of the Final Environmental Impact Statement for the Prototype Oil Shale Leasing Program of the Department of the Interior*, Environmental Impact Assessment Project, Washington, D.C., 1974.

[†] The difficulty of establishing mechanisms for the amicable resolution of environmental disputes in oil shale development is discussed more fully in P. Ellickson and E. W. Merrow, *Resolving Environmental Issues in Energy Development*, The Rand Corporation, R-2335-DOE (forthcoming), June 1977.

need for environmental protection and energy development. It is an inescapable fact that oil shale development will significantly industrialize a previously rural, unspoiled environment in a sizeable portion of Colorado. There is a basic conflict of interests and values that cannot be fully reconciled.

Nonetheless, there may be more room for accommodation between environmental and development goals than has been exploited in oil shale. In preparation for its development on private lands, Colony Development Corporation engaged in a continuing dialog with environmental groups and modified its environmental research and development plans to allay some of their concerns. As a result, Colony believes that opposition to its project was considerably reduced. The Colony experience suggests that, at a minimum, mutual suspicion can be reduced and some strides toward accommodation may be possible.

Constant wrangling and inflamed rhetoric have persuaded some people in the industry that environmental groups will blindly oppose any oil shale or other energy development regardless of what industry may do to minimize environmental effects. In reality, most environmentalists in the Rocky Mountain area do not appear to hold this position. Many of them, however (and, for that matter, some industrial and government supporters of oil shale) believe in the "momentum theory of commercialization"--that once commercialization begins, development will proceed even if the environmental effects are considerably worse than expected. This belief has impelled environmental groups to attempt to stop oil shale and other energy developments in the early phases of development, when the programs are most vulnerable. If one accepts the momentum theory (and arguments and evidence can be produced pro and con), then the environmentalists' strategy of strong opposition early in development is entirely reasonable. The net effect on society, however, may be perverse, if the industry is subjected to extreme demands.

If reasonable protective mechanisms are allowed and employed, environmental protection does not necessarily lead to loss of technological innovation or productivity in the economy. Although an improved environment is not included as a good or service in calculating the

gross national product, it is in fact a valuable product. If, however, the politics of environmental protection work to prevent new technologies from being fully developed because they pose a *risk* of environmental damage, then technological innovation and productivity may indeed be adversely affected. Wide acceptance of the momentum theory drives the political process inevitably to that result. This problem is not confined to oil shale or even to development in the Rocky Mountain area. It was clearly a factor in policy debates over the commercialization program for the fast breeder reactor, and it will probably continue to be the case that new energy technologies will be subject to more complete environmental cost internalization than older, more established technologies. One can expect that they will be held strictly to all regulations, barring a major change in national environmental policy. While costly to developers and consumers, this generally will not create an insurmountable barrier to development. But even an informal requirement that new technologies be free of environmental risk before development proceeds could create an institutional barrier without obvious solution.

Oil shale inflicts some environmental damage, the costs of which cannot be fully internalized into the cost of production with any known technology. Although the environmental costs can be minimized, it would be difficult to compensate those who believe themselves injured by the environmental effects of oil shale production. The benefits of oil shale production (other than direct profits) would accrue to the nation as a whole, and some secondary benefits from economic development would accrue to residents of the immediate area in Colorado and Utah. Local residents could also be compensated directly for environmental damage, but the most intense environmental opposition to oil shale development at this time is based in Denver, far from the oil shale area, among those who value the oil shale area for its scenic and recreational amenities. This situation forms the irreducible political conflict in oil shale development. It is, moreover, becoming more common as energy development proceeds in the Western states.

THE INVESTMENT CLIMATE

The final institutional constraints that we will consider are those that may indirectly affect the ability or willingness to invest the billions of dollars necessary to create an oil shale industry. These factors are the borrowing and investment habits of the oil industry, the possible effects of the proposed tax on "old" crude, and the general political climate facing the oil industry that is best reflected in the continued discussion of divestiture legislation.

Borrowing and Investment Patterns

The oil industry is clearly the key component in oil shale development. The vertically integrated oil companies have performed much of the R&D on oil shale, are the principal investors, and have the requisite skills in transportation, refining, and, to an increasing extent, mining. A deployment of oil shale technology without a significant if not dominant oil company role would pose serious problems.* With the minor exception of a few A-E and mining firms, all private sector investment in oil shale has come from the oil industry.† In some cases, oil industry experience with oil shale technology dates back over twenty years, and many firms have been involved for a decade or more.

Over the years, the oil companies with the most substantial interest in oil shale as reflected in R&D investment, the construction of pilot plants, and the acquisition of reserves, have been crude-short,

* It is of course theoretically possible for the federal government to deploy a government-owned and contractor-operated (GOCO) shale industry or similar arrangement. Even if such a decision were made, the federal government would face many of the same constraints from local and state governments, environmentalists, and others, as the oil industry. In addition, the advantages of using private sector interest as a guide to appropriateness of commercialization would be lost. Surely, no private sector industries other than oil would be potential major investors in oil shale in the near future.

† Oil company investment in oil shale was conservatively estimated at \$540 million in 1975. Robert Smith, "Oil Shale--Big Strides Toward Development Halted by New Economic Uncertainties," *Engineering and Mining Journal*, March 1975, p. 181.

vertically integrated oil companies such as Union, ARCO, and Sohio.* Many of the large companies without a crude reserve problem have maintained a minimal position in privately held oil shale lands. These latter companies, however, have not supported oil shale development before the Congress, nor have they made significant R&D contributions in most cases.

The incentive of crude-short companies to invest in oil shale R&D was greater before the nationalization of most foreign sources of crude and the advent of entitlements, which have enabled crude-short refiners to obtain a subsidy on the use of imported oil. In addition, oil company interest in shale has fluctuated a great deal over the years, depending not only on price changes but on the personal interests of oil company executives.†

Taxation of "Old" Oil

The Administration has proposed, and the Congress is expected to pass, legislation that would place a substantial well-head tax on domestic crude oil from wells in production before 1973. The price of this oil is controlled at \$5.25 per barrel.

At present, the effect of such a new tax is uncertain. The Administration assumes that most of the tax will be passed on to consumers, thereby raising the retail prices of refined products and inducing conservation. The preference for a tax rather than decontrol of all oil prices is to preclude petroleum producers from obtaining "windfall profits" from old oil. If the Administration's assumptions are correct, the effect on oil company rates of return would be minimal.

*Of course, neither ARCO nor Sohio will be short of crude when the Alaskan pipeline comes on stream. Their investments in oil shale, however, predate the North Slope development.

†Although some oil companies have invested in oil shale technology R&D over a number of years, there has never been a major concerted drive to develop basically new technology, with the possible exception of Occidental's modified *in situ* work. Rather, the companies invested in various degrees of modifying old processes. This is not surprising, for two reasons: (1) Developing a wholly new technology would require more investment than oil shale would have warranted on economic grounds, and (2) oil companies generally have not invested heavily in R&D, and the companies interested in oil shale have little in-house R&D capability.

If the assumption of a pass-through of the tax to consumers is incorrect, however, oil company profits could fall dramatically. This case is based on evidence that petroleum refiners are currently pricing their outputs in accordance with the marginal (i.e., world oil price) costs of feedstock, rather than on the average (i.e., old oil price plus new oil price plus world oil price) costs of feedstock. The price control program effects a transfer of revenues from crude producers to refiners. The effect of decontrol on product prices if this argument is correct would be essentially nil.* A tax on old oil, however, would substantially reduce profits to the refining sector, with little or no effect on price in the short run. In the long run, prices would increase, but via an exit of capital from the industry. Even a major decline in oil industry profits would not in itself halt oil shale commercialization if oil shale production were expected to be profitable. But the prospect of the crude oil equalization tax increases the climate of uncertainty facing oil companies, making financial planning more difficult and risk-taking actions less likely.

The Threat of Divestiture

Even if the oil industry were not adverse to higher debt/equity ratios as a matter of corporate policy, and if the tax on old oil could be passed on to consumers, there are other reasons why oil industry planners may be reluctant to undertake any major new departures.

The oil industry is under more political pressure today than it has been since the first decades of the century. Some people view the industry as one of the main culprits in the energy crisis. Horizontal divestiture is a live issue in the Congress. Exactly how oil shale or coal liquefaction would be treated under horizontal divestiture is unclear, although one presumes they would be exempt. Horizontal divestiture could, however, lead to a withdrawal of capital from the oil industry because of falling stock prices, and make borrowing more difficult. Vertical divestiture would disrupt potential investment in all

* C. E. Phelps and R. T. Smith, *Petroleum Regulation: The False Dilemma of Decontrol*, The Rand Corporation, R-1951-RC, 1977.

capital-intensive refinery feedstock development, for at least a time. If in response to these pressures the industry decides to maintain a low profile, oil shale will face a cloudy future. The commencement of major surface shale development could touch off a political storm in Colorado that might easily seize national attention.* Although the oil industry in the past has been willing to suffer criticism for the sake of profits--as witness the Alaskan pipeline--the climate is clearly less favorable today. Five major oil companies, for example, have withdrawn from four large, high-visibility energy projects in the last year or so.†

Finally, oil companies are subject to higher uncertainty about market prices than at any time in the recent past. The creation of OPEC, combined with an expanded government role in energy markets, makes corporate planning more difficult and presumably more risk-averse. Although there is no way to predict how long these factors will operate, they need to be considered in any short-term commercialization planning. We would expect that their effect would be to shift risk in a commercialization subsidy program from the oil companies and toward the government.

The climate for oil company investment could change, of course, and change rapidly. However, if as a result of divestiture legislation or severe financial problems the oil industry were unable or unwilling to undertake the commercialization of processes for producing petroleum substitutes, an entirely new dimension would enter commercialization planning: finding another catalyst for commercialization in the private sector. Two possible candidates would be the chemical industry, which possesses much of the necessary technical expertise, or, less likely or appropriate, the A-E industry. The withdrawal of the oil industry would under any circumstances necessitate more active

*This would not be unprecedented. Many of the same individuals and organizations who mobilized environmental opposition to the Kaiparowits power plant complex would lead the fight against shale development. We are not arguing that oil companies could not win such a fight; we question, however, that they would wish to wage it at this time.

†*The Energy Daily*, August 22, 1977, p. 2.

government involvement in the commercialization of oil shale, if production were to be accelerated.

SUMMARY

The number of current and potential institutional constraints on oil shale commercialization is considerable. Table 4.3 reviews those constraints and our (necessarily subjective) assessment of their importance and the likelihood of the constraints actually materializing.

Table 4.3

POSSIBLE IMPORTANCE OF INSTITUTIONAL CONSTRAINTS
ON OIL SHALE COMMERCIALIZATION

Potential Problem	Importance of Problem If It Occurs	Probability of Occurrence
<i>Federal Policies</i>		
Leasing	high	moderate
Entitlements	low	low
<i>State and Local Government Policies</i>		
State control	moderate	high
State taxation	low	high
Local zoning	moderate	variable
<i>Multiple Responsibility</i>		
Water availability and allocation	high	moderate or high ^a
Environmental issues:		
Meeting current regulations	high	low
Changes in regulations	moderate	moderate
Environmental opposition	moderate	high
<i>Investment Climate</i>		
Borrowing and investment patterns	moderate	low
Taxation on "old" oil	unknown	high
Vertical and/or horizontal divestiture	high	low

^aModerate for a one-million-barrel-per-day industry, high for a two-million.

The importance of a constraint was judged to be high if its occurrence would effectively block commercialization and it would be difficult to overcome. For example, an unwillingness on the part of the federal government to make shale lands available would constitute such a barrier. A constraint was judged to be moderate if its occurrence would slow but not necessarily block commercialization, and low if the effect on commercialization would be small.

In judging the importance of these constraints, one must remember that many of them have not been tested either by government or industry. Not until shale oil becomes competitive, either through forces of the market or government subsidy, can the high uncertainties that accompany many of the possible institutional constraints be reduced. Several of the companies that had been most active and important in oil shale development have withdrawn pending an improvement in oil shale economics. When the economics improve, these and other companies will address the institutional constraints on oil shale commercialization in earnest.

Of the many potential institutional constraints on oil shale commercialization, water availability appears to be the most serious (possibly because it is a physical input that is easy to quantify). Even so, we do not regard it as an insurmountable barrier to development at the one- to two-million-barrel-per-day level. If development proceeds slowly, there could be a gradual accretion of water rights to a shale industry and the cumbersome markets in senior water rights would have time to work. In addition, during a slow buildup, sounder water-use practices and less water-intensive technologies could be developed. Any attempt to launch an accelerated deployment program for surface retorting, however, would encounter a serious barrier at around one million barrels per day unless the political power and will existed to reallocate water in the Upper Colorado River Basin.

It is also possible that water might be imported from outside the upper Colorado River Basin if the problems of reallocation and reclamation within the Basin prove insurmountable and government and industry wish to develop a large oil shale industry. To date no plans for water importation have been seriously considered, and will probably not be unless shale oil's competitiveness improves.

Several other potential institutional constraints exist, any one of which could amount to a veto of shale development: an unwillingness of the federal government to lease, a failure to win state or local government approval, and new environmental regulations. We believe it unlikely that any of the agencies that could veto shale development would risk doing so. A flat veto on development would put any agency or government in a vulnerable position politically; more likely, opposition would take the form of foot-dragging.

Chapter 5

PROSPECTS FOR OIL SHALE

The unfavorable economics of oil shale from surface retorting have quieted the policy debates of 1974-1976 over whether the government should begin a large scale commercialization program to get the industry started. Both the private sector and government have lowered their expectations for oil shale and other energy process plant technologies, and even the long-run competitiveness of existing surface oil shale processes is in doubt. Although a major government subsidy program for oil shale has not been enacted, and appears unlikely in the foreseeable future, the program has not been without cost. Industry investment in development efforts, including about \$450 million for the Prototype leases, will be lost at least in part. In addition to the direct costs to the several federal agencies involved in surface oil shale process development, there have been losses in terms of credibility to the Congress, and more especially a considerable loss in the form of ill will among state governments and citizens groups in the shale region. These outcomes must be placed in perspective: The commercialization of any new technology by industry alone or with government support is an inherently risky undertaking. It is important, however, to see what lessons can be garnered from the oil shale experience that might reduce the costs of energy technology commercialization efforts in the future.

COMMERCIALIZATION VS. DEPLOYMENT

The goal of a government-supported commercialization effort is to accelerate the introduction of a technology that presumably would be introduced somewhat later by the private sector alone. The effort succeeds when, after a period of government support, the private sector continues commercialization of the technology and the social benefits of the accelerated introduction exceed the costs of the effort. Success for a government-supported effort requires a special set of circumstances. First, the technology for the new process must be

sufficiently developed for large-scale use. Second, the private sector must have economic or institutional reasons to defer commercialization, even though commercialization would yield net social benefits. Third, those economic or institutional constraints must be either temporary or removable in some fashion. In early 1974, available information indicated that all three of these conditions appeared to exist for oil shale. The technology was sufficiently advanced so that a jump to full commercial-sized plants involved minimal technical risk. And it appeared that the primary hesitation on the part of private investors was due to uncertainty about the stability of the oil cartel (and therefore oil prices), and institutional factors such as those discussed previously. Under those circumstances, supporters of a government-sponsored effort to initiate a shale industry argued that it could become self-sustaining by the private sector. By the end of 1974, however, further information indicated that those conditions did not in fact exist; in particular, it confirmed the presence of a cost barrier to shale commercialization. As explained in Chap. 3, the economic barrier to surface oil shale commercialization is likely to persist for some time to come.

Under these circumstances it is inappropriate to contemplate a commercialization effort for surface oil shale processes. A government commercialization effort, even for an energy technology promising very large social benefits, presumably will be limited in time and cost. The longest such effort to date, the Power Reactor Demonstration Program (PRDP), lasted only about 10 years and combined commercialization and development activities.* The point of a commercialization effort--to aid the development of an essentially private sector industry--is vitiated if the government commitment is open-ended.

However, if it is determined that the production of shale oil is in the national interest despite the high cost of shale oil relative

* It is also important to note that the PRDP projects that were most clearly commercialization oriented involved relatively small, closed-ended commitments of government funds. Neither price supports nor continuing operating subsidies were ever employed by the Atomic Energy Commission for PRDP projects.

to world oil prices, then a *deployment* program for surface oil shale plants might be considered.* A deployment program could involve either subsidies or a combination of subsidies and actions to reduce institutional constraints.

A number of subsidy options have been suggested: fixed or competitively bid price supports, fixed or competitively bid construction subsidies, nonresource loans guaranteed by the government, and government-owned and contractor-operated (GOCO) plants. Contingencies-- for example, a failure to meet new environmental regulations--could also be incorporated into the subsidy arrangements; so could profit-sharing arrangements if shale plants turn out to be considerably less costly than expected, or world oil prices rise rapidly, or both. Each type of financing arrangement has advantages and disadvantages, but in all cases a deployment program implies long-term and extensive government efforts.†

For a deployment effort, the government must also address institutional constraints. If the government were successful in taking steps to stabilize the institutional context for oil shale by, for example, guaranteeing adequate water supplies, assuring that any shale plants in operation or under construction would be "grandfathered" from tighter environmental regulations, and providing substantial community development assistance, then the minimum level of subsidy required by the private sector would be reduced and the manner in which risks are shared between the government and the private sector could be altered toward greater risk assumption by oil companies.

If a deployment program were to be seriously considered by the government, it is appropriate to inquire whether a demonstration

* This report has not examined the issue of whether a deployment program is justified, but proponents have offered numerous justifications: assured supplies for national security reasons, reductions in the balance of payments deficits to OPEC nations, demonstrating U.S. commitment to solving the world-wide oil supply problem, weakening the cartel, and providing some insurance against the possibility that world oil production will peak sooner than expected.

† The relative merits of alternative subsidy schemes have been explored in some detail by other studies of synthetic fuels development. See, for example, the *Synthetic Fuels Task Force Report*.

project for surface shale would be useful. A demonstration plant might range in size from a single retort module (about 5000 barrels per day output) to a full 50,000 barrels per day complex. A modular demonstration plant has the advantage of limiting the government's and industry's exposure to about \$150 million. Such a demonstration was proposed in the 1976 version of the synfuels legislation, (HR 12112), and preliminary plans for such plants have been made by industry in anticipation of government support.* The value of such a demonstration would be quite limited. If considerable uncertainty prevailed about the technical feasibility of scaling-up to commercial-sized retorts, then a single-retort demonstration might be valuable. But in the opinion of oil shale plant designers, little uncertainty remains about retort scale-up and a single commercial-scale module demonstration would not provide much better information about plant costs than is already at hand. In addition, the plant would not provide a full test of institutional constraints; its water-use and environmental effects would be much smaller than those of a commercial-scale plant; and most plant designers and potential plant purchasers do not believe that a small plant could later be effectively enlarged to a more economic size.

A full-scale pioneer surface oil shale plant, of 50,000 barrels per day or more, on the other hand, could provide much useful data upon which to base a deployment program decision. The current range of capital-cost estimates presumably would be narrowed, especially at the upper end of the range, and realistic operating cost data could be developed. The environmental effects of surface oil shale development and water use could be confidently assessed, and some knowledge gained of the difficulties that might be involved in the permitting process and in legal challenges to oil shale.

Oil shale commercialization may yet take place within the next decade using modified *in situ* processes and without significant federal support. Both C-a and C-b operators are planning a gradual sequential approach to shale development that will allow them ample opportunity

* Union Oil Company, Paraho, and Gary Oil have developed plans for a modular plant.

to withdraw if the economics become unfavorable.* When viewed in terms of the framework discussed in Chap. 1, modified *in situ* technology appears to have a number of characteristics that make it a more likely candidate for commercialization, although the levels of uncertainty surrounding technical, economic, and institutional constraints are generally higher than for surface retorting processes.

Modified *in situ* appears to be less subject to economies of scale. Investment can be made gradually by expanding the number of retorts being mined and ignited without significant losses in efficiency. As discussed above, a modular approach to surface retorting is generally considered extremely inefficient. This means that for modified *in situ* development, initial capital exposure can be limited, especially if a decision to construct upgrading facilities is delayed until the retorting costs are well established. The fact that modified *in situ* investment can be made gradually is of special relevance to holders of Prototype leases, because the fourth and fifth bonus bid payments can be credited against investment. Those credits, amounting to a potential \$82 million and \$46 million for C-a and C-b respectively, could cover a large portion of starting production for modified *in situ* development, but only a very small fraction of the costs of a surface retorting facility.

In terms of institutional constraints, modified *in situ* retorting appears to have advantages over surface retorting in the areas of environmental impacts (especially a reduced need for spent shale disposal) and water consumption. Some environmental uncertainties remain, however, particularly for ground water pollution and control of retort gases. Equally important, environmentalists' perception of modified *in situ* as less damaging may reduce legal challenges.

Despite the promise of modified *in situ* processes, however, our analysis of surface retorting suggests strongly that the government

* This report has been limited to an examination of the constraints on surface retorting because the data available on modified *in situ* are very fragmentary, and data on the process for which the most optimistic economics have been reported, the Occidental Petroleum process, have not been publicly available.

should await the completion of further technical tests and an independent definitive design and cost estimate for *in situ* before attempting to launch its commercialization.

RELATIONSHIPS BETWEEN TECHNICAL, ECONOMIC, AND INSTITUTIONAL CONSTRAINTS

Technical, economic, and institutional constraints interact in ways that determine whether oil shale commercialization will be successful. But oil shale also illustrates that there is a rough hierarchy or sequentiality to considering and resolving the sets of constraints in the initial period of commercialization. Obviously, the system's technical characteristics come first, and often are the result of a long period of development. Until technical development is far along and definitive engineering designs are completed, it is not possible to know with confidence whether cost will constrain commercialization. It is equally obvious that many institutional factors cannot be assessed until the system's technical characteristics are known. For example, oil shale's environmental effects and water consumption depend heavily on technical characteristics.

Oil shale also illustrates that until basic plant economics are competitive, it is difficult to adequately assess the importance of many institutional constraints. By basic plant economics we mean the constituents of required selling price from plant construction and operation. Not included as basic costs would be items that result from institutional constraints. In unregulated industries, basic plant costs must result in roughly competitive prices; this is a necessary condition for all other facets of a commercialization effort. Even in regulated industries (such as for substitute natural gas) basic plant economics are a critical benchmark against which to weigh the advisability of undertaking a subsidized deployment effort. Many studies, amounting to thousands of pages, have examined every conceivable institutional constraint on surface oil shale commercialization. And yet any measure of the severity of those constraints will necessarily remain imprecise until the private sector gains the economic incentives to address the constraints in earnest.

As discussed in Chap. 4, during the brief period when industry did perceive surface shale economics to be favorable, significant compromises on environmental constraints were achieved. Until the economics are again perceived as favorable, it will be difficult to distinguish real from apparent institutional constraints. It is therefore hard to say which constraints may require legislative action, which can be settled by administrative action, which can be settled by the private sector alone, or even whether the constraint *should* be removed at all.

We strongly suspect that, in oil shale development, institutional problems appear more severe than they would turn out to be if the basic economics were favorable. The importance of economics merely underscores what is by now a common observation about commercialization planning: To the maximum extent possible, the private sector rather than the government should pace the programs. Colony's suspension of all plans for development in September 1974, primarily for cost reasons, should have delivered a clear signal to government that a reassessment of oil shale commercialization prospects was in order.

Although technical, economic, and institutional constraints must often be dealt with sequentially in a development and commercialization effort, it would be a serious error in strategy to fail to consider all three areas together as fully as possible. Even though economic and institutional constraints cannot be accurately assessed until the basic characteristics of the technology are understood, it is possible to gauge the extent to which the technology is *adaptable* to different economic and institutional conditions. This is germane to the commercialization prospects for modified *in situ* oil shale retorting mentioned above.

SUMMARY OF IMPLICATIONS FOR COMMERCIALIZATION PLANNING

This examination of the problems in commercializing oil shale raises several issues that may be applicable to other energy technologies. First, and probably most important, the oil shale experience suggests that cost estimates, whether made by industry or government, may be very inaccurate for new technologies and may continue to be so even after a long development period involving a number of pilot plants.

Cost-underestimation sabotages rational energy-supply and commercialization planning.

In making commercialization plans for a single technology, promoting the execution of a definitive design and cost estimate as soon as technologically appropriate may produce reasonably accurate cost estimates upon which governmental and industry planners can base their strategies. But for commercialization and supply planning across a range of technologies, government decisionmakers need a method of estimating the chances that some technologies will prove much more expensive than was predicted during the development process. One suggestion for addressing this problem was presented in Chap. 2.

It is widely agreed that the prospects for oil shale commercialization with surface technologies directly hinges on trends in world oil prices. Without significant real increases in those prices, large government subsidies would be necessary to support commercialization. Our analysis also suggests, however, that trends in capital and operating costs for large process plants should also be of considerable concern to government planners. If the past decade's trend of declining productivity in this sector continues, commercialization prospects for oil shale and other energy process plants become dimmer still. Learning effects may do little to counteract this trend.

Numerous institutional constraints could impede commercialization, but favorable economics for oil shale must reemerge first before planners can realistically assess their strength and importance.

Appendix A

DESCRIPTION OF PROCESSES

by

Christopher Worthing

This appendix presents an overview of the various oil shale retorting technologies. It is addressed to a nontechnical audience.

Oil shale is the common term used for a sedimentary rock containing a waxy organic material sometimes known as "kerogen," which has been compacted within deposits of clay, mud, and silt. When the shale is heated, the kerogen decomposes and oil can be obtained. (Several other methods are possible, including the use of thiophillic (sulfur-seeking) bacteria and the use of solvents, but these methods are uneconomic and more difficult.) When the shale is heated to temperatures of 800°F and 1000°F, the kerogen undergoes a chemical change (or pyrolysis) whereby about 65% of the kerogen is converted to liquids, about 10% to a gaseous product, and about 25% to a carbonaceous residue. After heat-treating and prerefining, the liquid product can be turned into a high-quality synthetic crude oil that substitutes for conventional crude oil.

The method of heating the oil shale to obtain the liquid and gas products is known as "retorting." In the discussion to follow, retort design refers to any combination of techniques and methods for charging a vessel with oil shale, heating the shale to pyrolysis temperatures, and discharging the pyrolysis products.

Currently, there are three retorting techniques. The first, "surface retorting," is to mine, crush, and then heat the shale in a retort vessel above ground. A second technique, "*in situ* retorting," is to heat the rock in place in the ground and then force the volatile products of kerogen conversion through fractures in the rock formations to be condensed and brought to the surface. A "*modified in situ*" technique combines the above two processes, whereby part of the shale is mined and retorted on the surface, while the balance is retorted in the ground. These approaches will be discussed in turn.

SURFACE RETORTING

Figure A.1 is a flow diagram of the surface retorting operation. After mining by conventional methods, the shale is crushed into pieces that have a large surface-to-mass ratio so that it can be heated efficiently in the retort. Eight retort designs are currently available or under development. They fall into three categories, depending on the heat sources they use. Three processes (Gas Combustion, Paraho Kiln, and Union Retort "A") use heat generated from internal combustion of the carbonaceous residue from the spent shale. Four other processes (Union Retort "B", Paraho Kiln (alternate), Petrosix, and Union SGR) use direct heat by circulating externally heated gases or recycled gases through the shale. The last two (Lurgi-Ruhrgas and TOSCO II) use hot circulating solids with no internal combustion.

U.S. BUREAU OF MINES GAS COMBUSTION RETORT

Figure A.2^{*} depicts the Gas Combustion retort developed by the U.S. Bureau of Mines during the late 1940's and early 1950's. It is a vertical shaft furnace through which there is a continuous downward flow of crushed shale. The furnace is equipped with charging and discharging devices and gas flow distributors, while heat is supplied by internal combustion of the organics.

As the shale enters the top of the retort it contacts a rising volume of hot gases which heats the shale as it moves down through the retort, concurrently cooling the product gases as they rise. As the shale becomes pyrolyzed, vaporized liquids and gaseous products are released, become entrained in the upward-flowing gas stream, and are removed from the top of the retort to an electrostatic precipitator. The liquid products coalesce in a separator and are collected and stored. The remaining gases are split, with a portion being injected at the bottom of the retort for heat recovery from the spent shale, another portion being injected with air into the combustion zone in order to sustain combustion of the carbonaceous residue, and the

*² Figures are from Fluor Engineers and Constructors, Inc., Fluor Utah, Inc., Solid Fuels Technology Department, *Oil Shale Process Technology*, Report SFT 102, October 1974.

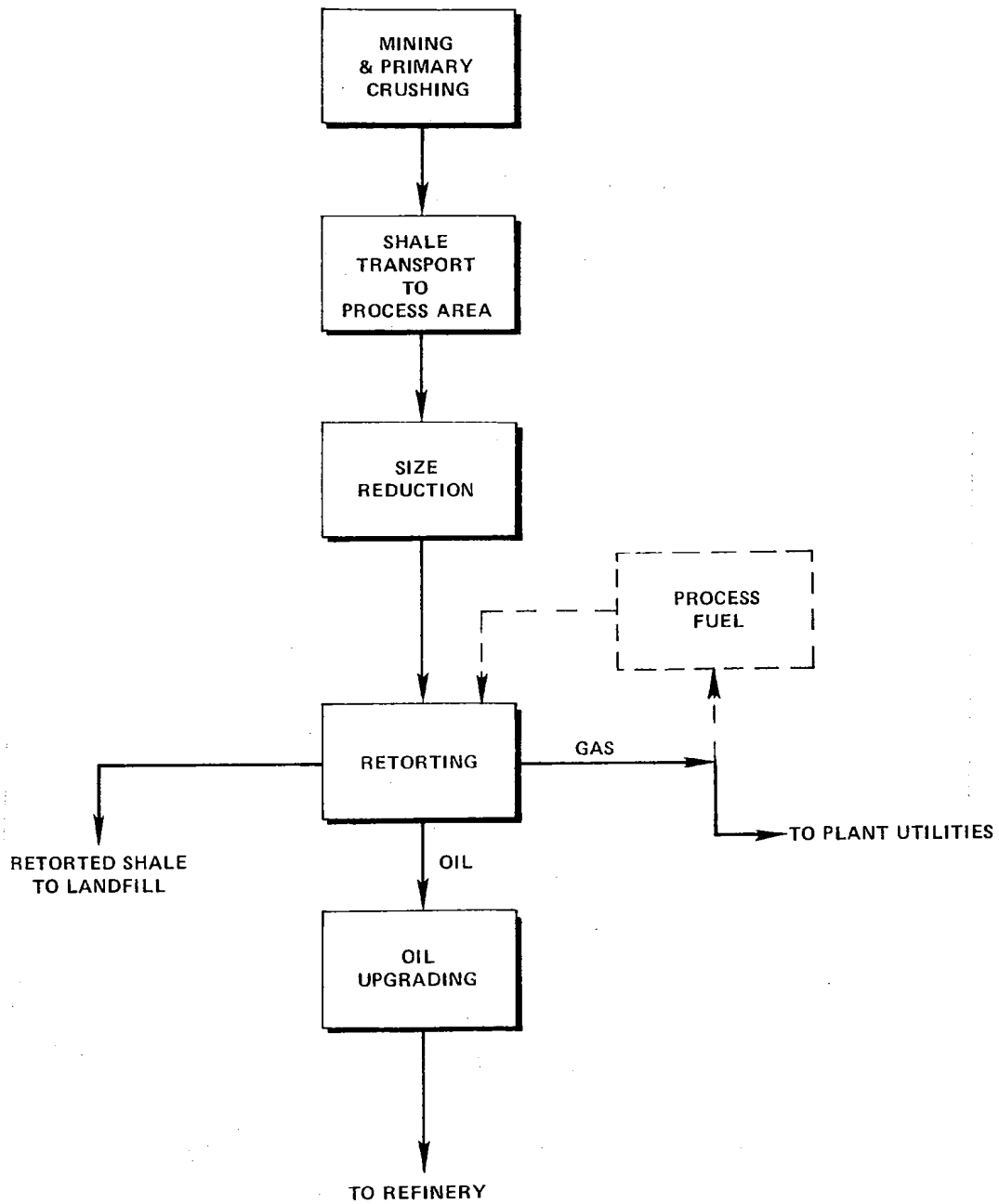


Fig. A.1--Generalized schematic flowsheet for processing oil shale

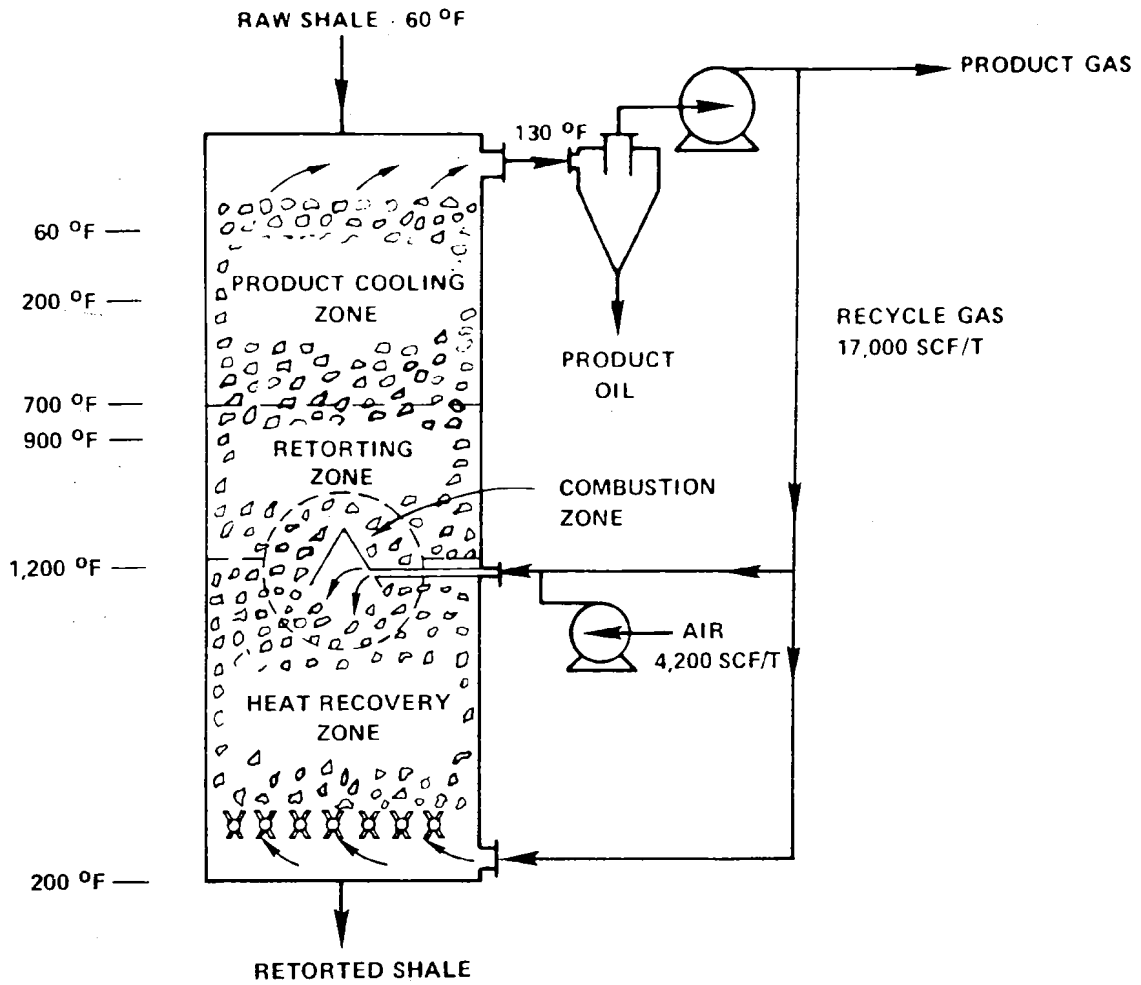


Fig. A.2 Gas combustion process

balance going to disposal or on-site use. The hot spent shale passes from the combustion zone into the spent shale zone, where it is cooled by recycled product gas entering from the bottom of the retort. It then leaves the retort through a discharge grate and is sent to disposal.

Oil yields from the Gas Combustion retort are relatively low, being about 82% to 87% of Fischer assay (typical of internal combustion retorts).^{*} Retort gas has a low heating value because it is diluted by nitrogen and carbon dioxide, making on-site consumption necessary. It also has a high sulfur content, which complicates disposal problems. Feed shale containing very fine shale, even in limited quantities, can cause severe operating problems. The "fines" affect channeling of the gas flows, which results in uneven heat release, potential plugging, and reduced oil recovery. Air injection is a problem that has not been satisfactorily resolved, and difficulties have been encountered in oil mist formation. Process problems are encountered with shale richer than 33 gallons per ton.

PARAHO KILN

The Paraho Kiln (Fig. A.3) was developed by Development Engineering, Inc. (DEI). It is a modified version of the Bureau of Mines Gas Combustion retort, differing from it in having an improved raw-feed distribution device, a patented discharge grate, and a multilevel gas injection distribution system. It is basically designed for internal combustion, but has been tested as a gas recycle retort. The kiln was originally intended as a limestone calciner. In mid-1974 testing began with a semiworks oil shale unit. An extensive testing program was completed in 1976.

As in the Gas Combustion retort, the shale is fed into the top of the retort and passes downward. At the same time, hot gases rise upward, causing oil vapors and gas from the pyrolyzed shale to enter the gas stream flowing to the top of the retort, to be recovered through collecting tube headers.

^{*} Retort yields are normally expressed in terms of the Fischer assay, which is the generally accepted laboratory retorting procedure for evaluating oil shale.

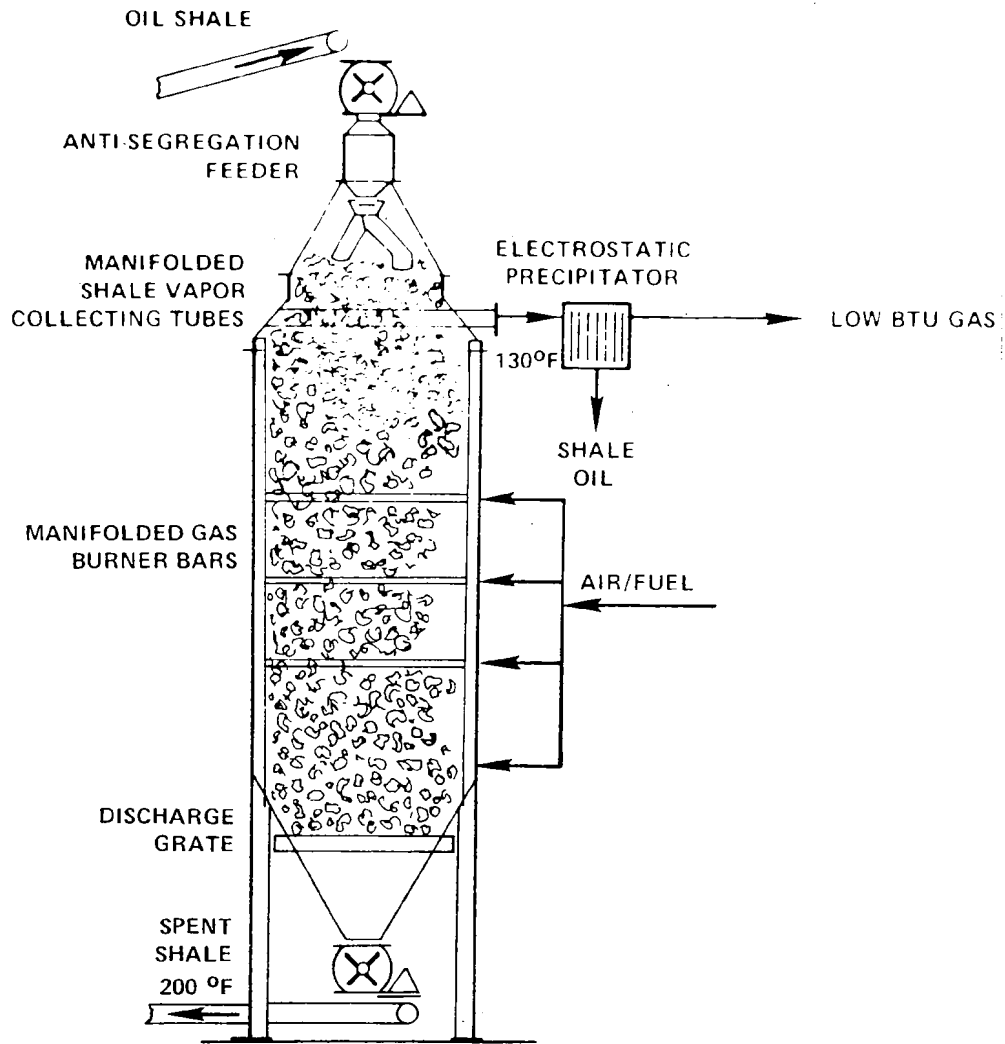


Fig. A.3--Paraho kiln

In the externally heated alternate version, the product gas is split into two streams after passing through the collecting headers, one stream being passed again into the furnace at various points. One result of the use of recycled gas for heating is that the gas driven off during the retorting process does not become diluted with combustion products and nitrogen from the atmosphere, and the product gas is a high-BTU gas suitable for use elsewhere in the operating complex.

The kiln should have low crushing and screening costs, because it can handle feed shale in large sizes. Like the Gas Combustion retort, it is unable to handle large amounts of fine feed shale, but its improved discharge grate makes it more tolerant of fines. Oil yields have been projected to be around 90% of Fischer assay. Large amounts of low-BTU gas will be produced during commercial operation, which will have to be consumed on site; and since only a third of the power generated will be needed for plant operation, the other two-thirds would be sold off-site.

UNION "A" RETORT

The Union Oil Company of California designed the Union "A" retort in the late 1940's. Early development included a 2-ton-per-day and a 50-ton-per-day pilot plant in Brea, California, and then a 350-ton-per-day-semiworks unit near Grand Valley, Colorado on Parachute Creek. Before the semiworks unit suspended operations in 1958, it had achieved a flowthrough of 1200 tons per day.

A unique feature of the Union retort is its "rock pump" (see Fig. A.4). It consists of hydraulic pistons and sealing mechanisms that move the shale upward through the retort at regulated rates. This is in contrast to the gravity flow designs of Gas Combustion and Paraho Kiln. Union engineers developed this technique perhaps because they were aware of problems with the gravity-feed system of the Gas Combustion retort.

In the Union "A" retort, air is forced downward along the retort axis. Combustion of the shale residue takes place near the top of the retort. The air is heated as it is forced down, reaching a temperature of about 2,000°F in the combustion zone. As the air passes subsequently

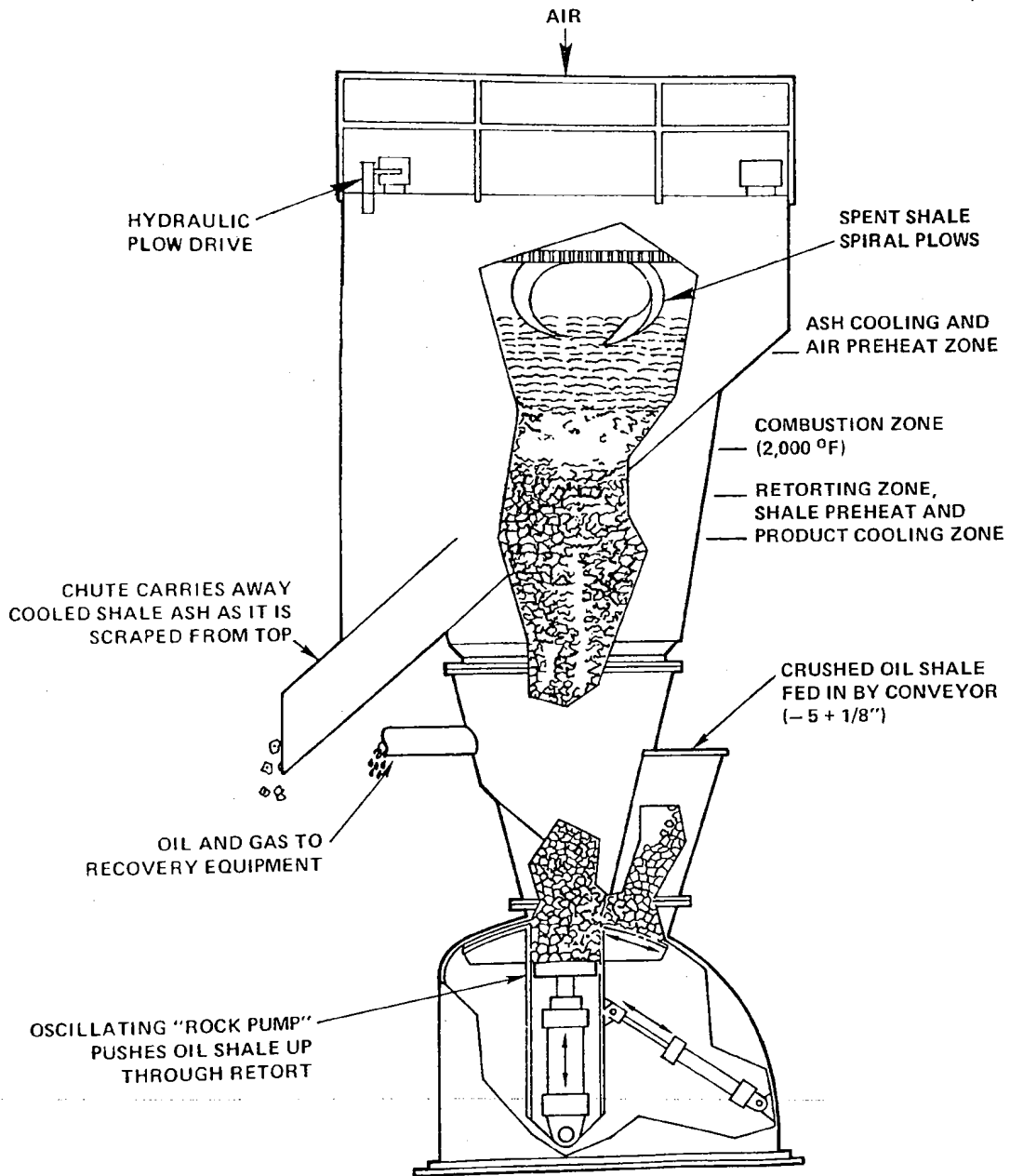


Fig. A.4--Union retort "A"

through the retorting zone, oil and product gas are produced from the shale. These elements flow downward, heating the incoming shale, and are recovered near the bottom of the retort.

Oil yields from this retort are about 85% of Fischer assay and the product gas has a very low heating value.

UNION "B" RETORT

The Union "B" retort is much the same as Union "A", but uses external heating and recycling of the gaseous product. The heat carrier is recycled product gas, which is reheated in a separate furnace before being injected into the retort. The residual carbon does not combust, and the shale leaving the top of the retort is pyrolyzed but not decarbonized. Oil yields are higher in the "B", and the product gas has a higher heating value, but the unit has a lower thermal efficiency than the "A". The "B" has been tested in California at the Union research facility in Brea, but has not undergone large-scale testing.

UNION SGR SYSTEM

In June 1974, Union unveiled a new retorting system called the Steam Gas Recirculation System (SGR) (see Fig. A.5). It uses the "B" retort to extract oil and gas from the shale. The heat source is a combination of hot gases from a coke gasifier and gases from the recycle gas heater. After the shale has been retorted it passes from the retort to the gasifier, where it is brought into contact with oxygen and steam. The carbon on the retorted shale reacts with these gases, yielding a synthesis gas that is rich in carbon monoxide and hydrogen; a portion of this gas is returned to the retort in conjunction with recycle gas, and a portion is drawn off for use elsewhere in the plant or for sale. If air is used as the oxidant in making the coke gas, the product gas from the retort is a low-BTU fuel gas. When oxygen is used, the effluent gas is a moderately high-BTU stream that can be upgraded to SNG quality.

Union claims that the SGR process yields 100% of Fischer assay and has a high thermal efficiency (82%).

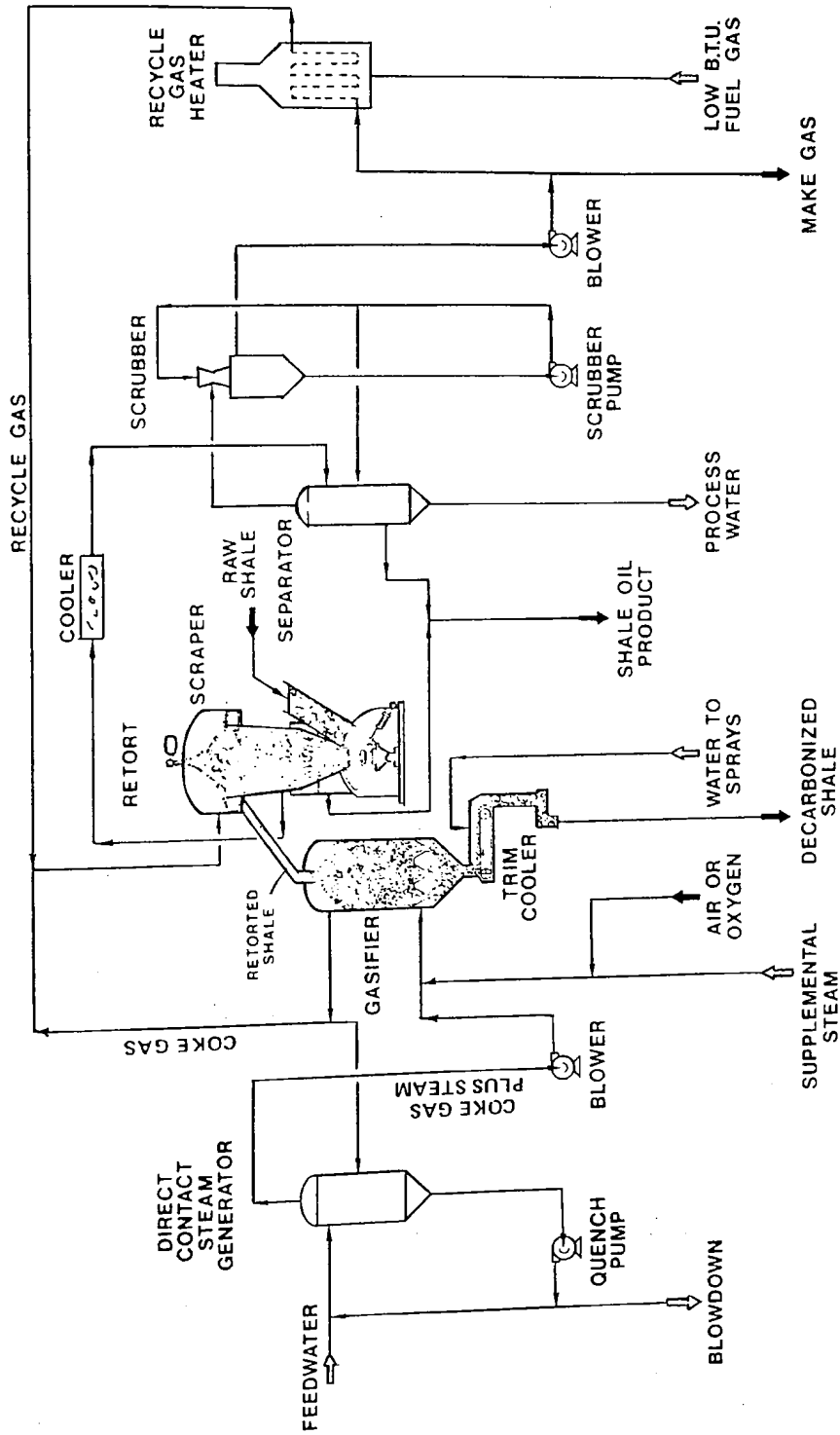


Fig. A.5--SGR retorting plant

Combinations of the Union retorts are possible that may enable improvements in product yield and thermal efficiency.

PETROSIX RETORTING PROCESS

The Petrosix plant in Brazil is the largest operating oil shale facility in the world, with a nominal capacity of 2500 tons per day. It was developed from Gas Combustion technology by Cameron Engineers of Denver, Colorado. It uses hot recycled gas for retorting in a kiln similar to that of Paraho (Fig. A.6).

Oil shale enters the top of the retort through a special feeder. As it moves along the vertical axis of the retort, the shale encounters a stream of rising hot recycled product gas that heats it to pyrolysis temperatures. Oil vapors are entrained in the hot rising gases, which pass out the top of the retort, whereupon the oil is separated and collected from the gas. Some of the cool product gas is channeled to the bottom of the retort, where it is injected to recover heat from the retorted shale. Some of the gas is directed to the middle of the retort after passing through a heater to help induce pyrolysis. The gases have a high heating value and can be readily processed for the recovery of sulfur, ammonia, and condensable hydrocarbons. Shale at the bottom of the retort passes through a discharge grate, after which it is mixed with water and sent in a slurry to a disposal area.

The process is expected to produce good-quality oil and product gas with high heat value. Thus far the process has been applied only to Brazilian shales with a 23-gallon-per-ton average.

LURGI-RUHRGAS PROCESS

The Lurgi-Ruhr gas system (Fig. A.7) is a slightly modified version of a coal carbonization process developed in the 1950's by Lurgi and Ruhr gas A. G. It uses a recirculating stream of heated finely divided solids as the heat transfer medium (usually sand or coke).

The retorting takes place in a mechanical screw mixer in which pulverized oil shale feed is rapidly mixed with fine, hot, burned shale. The screw or mixer passes the retorted shale feed to a reactor or hopper, while oil vapors and gas are withdrawn and dedusted in a

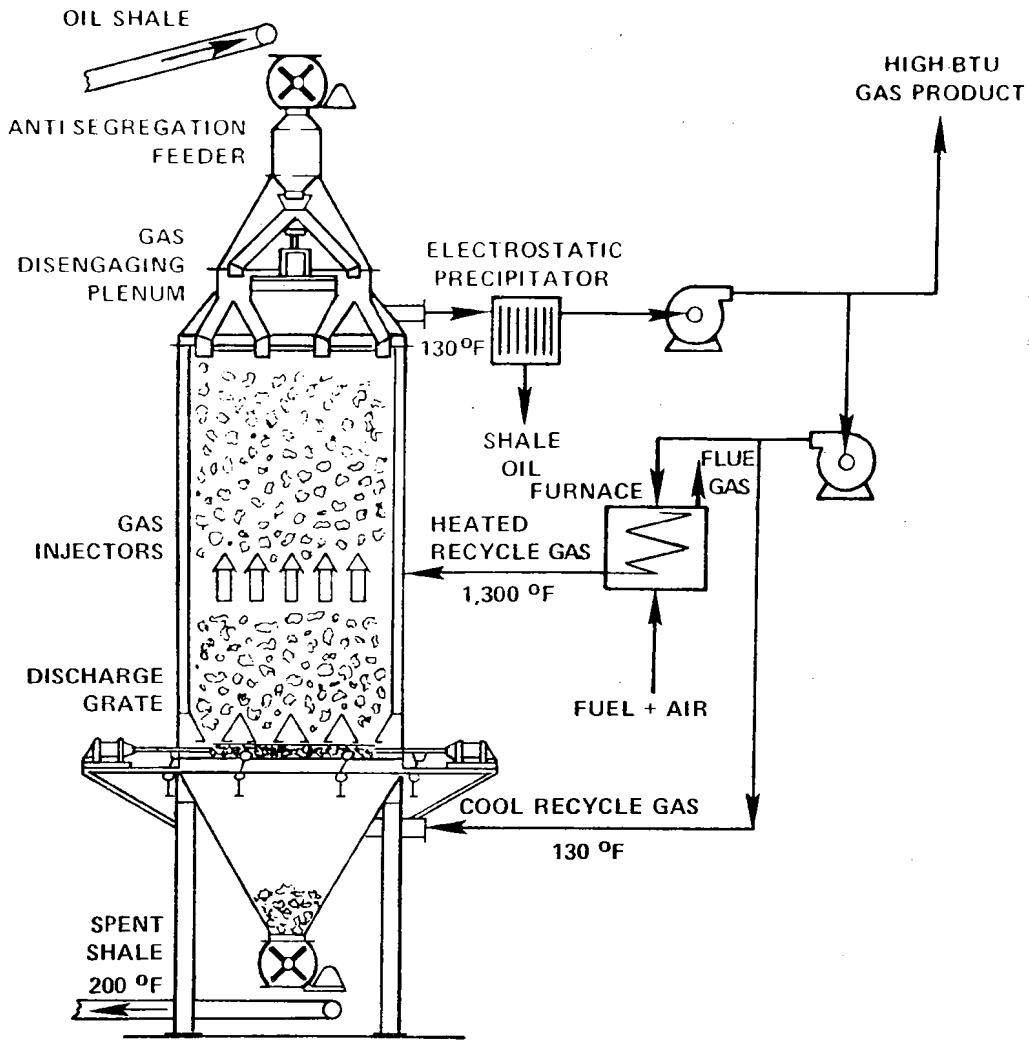


Fig. A.6--Petrosix process

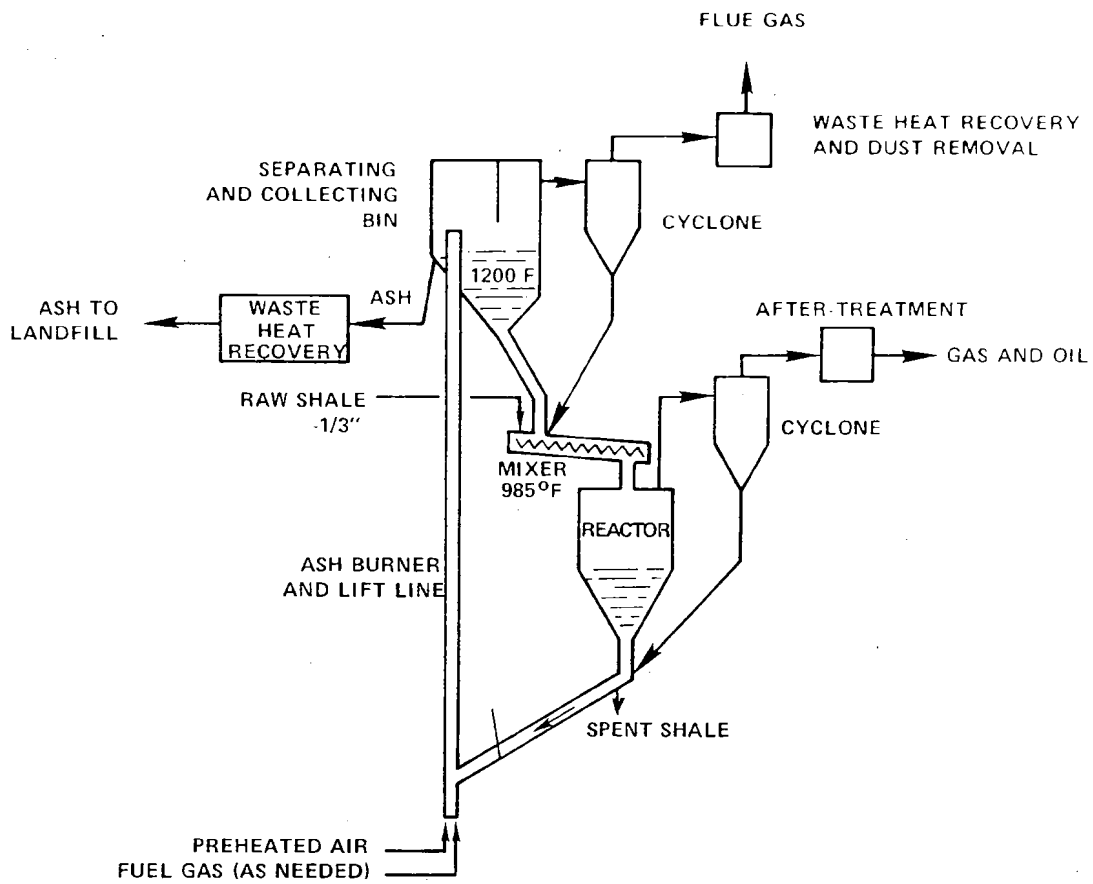


Fig. A.7--Lurgi-Ruhrgas process

cyclone separator and thereafter passed to an after-treatment system. The mixture of spent and burned shale that has been passed into the reactor is drawn into the bottom of a pneumatic lift pipe where it is heated by preheated air and carried to the surge bin. Air in the lift pipe ignites the residual carbon in the shale. If the resulting heat is insufficient for process heating, an auxiliary fuel in the form of low-BTU gas or residual oil from the process is injected to achieve the temperatures required for retorting. Combustion gases and very fine solids are separated from the larger heat-carrier particles in the surge bin.

Oil yields greater than 100% of Fischer have been reported for the process using 34-gallons-per-ton oil shale, and higher yields have been predicted for large-scale plants. Since no combustion takes place in the mixer, the product gas has high heat content.

This system can process fine shale or fines, an advantage it shares with the TOSCO II process, but it cannot process large shale chunks; consequently, although it could handle the entire output of a shale mine, crushing and screening costs would be high.

TOSCO II RETORT

The TOSCO II process (Fig. A.8) originated in the Aspeco process, which the Oil Shale Corporation (TOSCO) purchased from Aspergren & Co. of Stockholm, Sweden in 1952. It is unique in that it uses ceramic balls as the heating medium.

Shale is first preheated by streams of hot gas coming from the ball heater as they pass through a lift pipe. The shale then passes into a rotating drum similar to a cement kiln, where it is mixed with the hot ceramic balls. The shale's temperature then rises to the pyrolysis range. At that point the shale loses its physical strength as the kerogen decomposes and is crushed into a fine powder. Oil vapors and gases pass from the accumulator through cyclones and washers and then are processed further. Noncondensable gases are separated and used to fuel the ball heater. Cooled balls and retorted shale pass from the drum and enter a perforated rotating drum (trommel). The shale powder passes through the perforations and then to disposal,

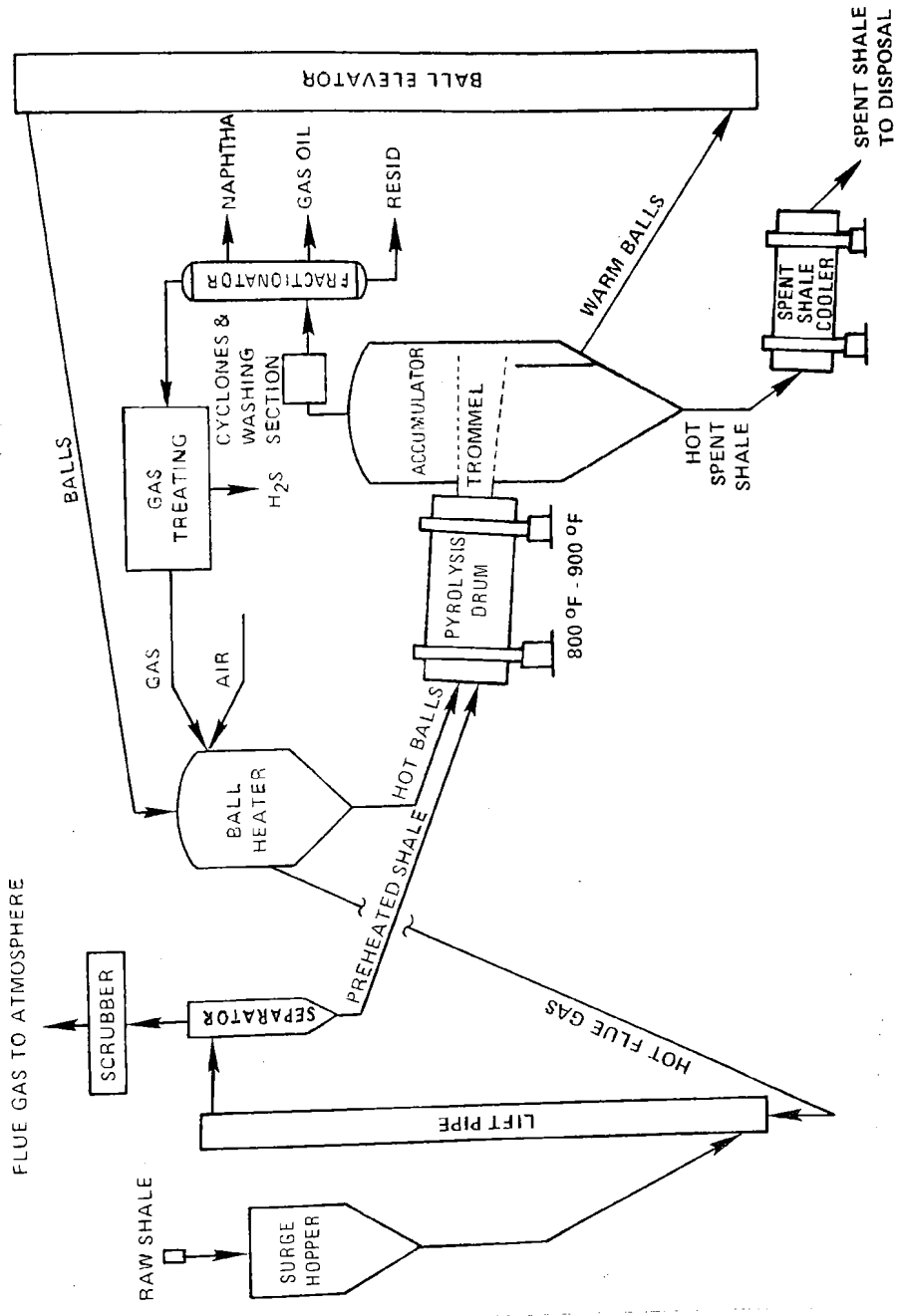


Fig. A.8--TOSCO II process.

while the balls pass over the trommel and are conveyed back to the ball heater by a ball elevator.

The TOSCO II yields about 105% of Fischer assay.

IN SITU PROCESSES

In situ (in place) processing is currently being considered in lieu of surface processes.

To retort shale in the ground, a heat carrier must come in contact with the shale and heat it to pyrolysis temperatures so that the kerogen decomposes and the oil vapors can be drawn off. Some *in situ* processes use the natural permeability of selected shale zones for the passage of a heat carrier fluid, as natural fissures sometimes occur in the shale beds. A heating fluid is forced down injection wells into these fissures and is thereby passed into the shale body. The heat carrier and the volatile products of kerogen conversion are recovered in adjacent production wells. (See Fig. A.9.)

Instead of using natural fissures, it is possible to create artificial permeability in the beds through electrical, hydraulic, or explosive fracturing singly or in combination, after which the process is the same as described above. Another technique is to mine a portion of the shale bed (which is retorted in the conventional manner), collapse the adjacent portions of the shale bed with explosives, and retort these portions in place.

The chief problem with *in situ* retorting is the fact that shale beds are not normally permeable, and artificial permeability must therefore be created for deep deposits. This restricts the immediate commercial application of this method. Further research on the *in situ* method is being conducted by DOE at the Laramie Energy Research Center and the Lawrence Livermore Laboratory.

Mine-assisted retorting (modified *in situ*) is currently being seriously considered by oil shale developers. The concept involves mining a portion of the shale bed (or an interval of adjacent strata) sufficient to provide the total void volume specified for the retort. The void volume is then distributed through the "retort" volume by collapsing the roof of the mine with controlled blasting. The mine tunnel is then sealed, heat carrier supply and exhaust lines are installed,

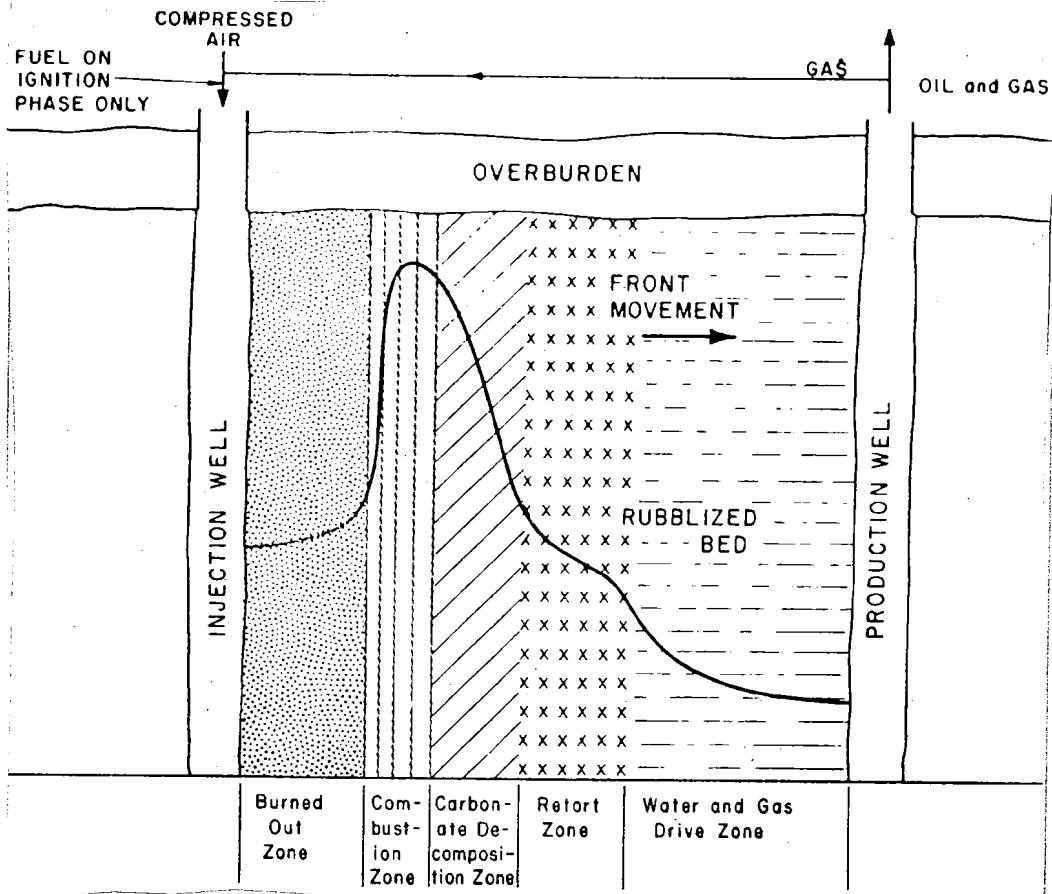


Fig. A.9--*In situ* retorting (reproduced from V. D. Allred, "Some Characteristic Properties of Colorado Oil Shale Which May Influence *In Situ* Processing," *Quarterly of the Colorado School of Mines*, No. 3, 1964, p. 49. By permission of the *Quarterly*.)

and retorting commences. Oil flows down through broken shale to a sump at the bottom of the retort and is pumped to the surface. (See Fig. A.10.)

Work on this concept dates back to the 1940's, when oil shale was retorted in collapsed mines in Germany. Occidental Petroleum, currently a developer of the C-b Tract in Colorado, has been the principal domestic developer of this concept. Another mine-assisted *in situ* development is being organized by the Western Oil Shale Corporation, which has formed a consortium of ten energy companies to finance the effort in the Uintah Basin shale in Utah, and the process is being considered by the owners of the C-a tract as well.

The advantages of *in situ* over surface processing include the reduction of shale mining and shale transport, elimination or reduction of shale disposal problems, and substantial reduction of surface installations and manpower requirements. Oil recovery is lower, however, because particle size and void distributions cannot be well controlled, and because the fracturing of shale deposits is not well understood.

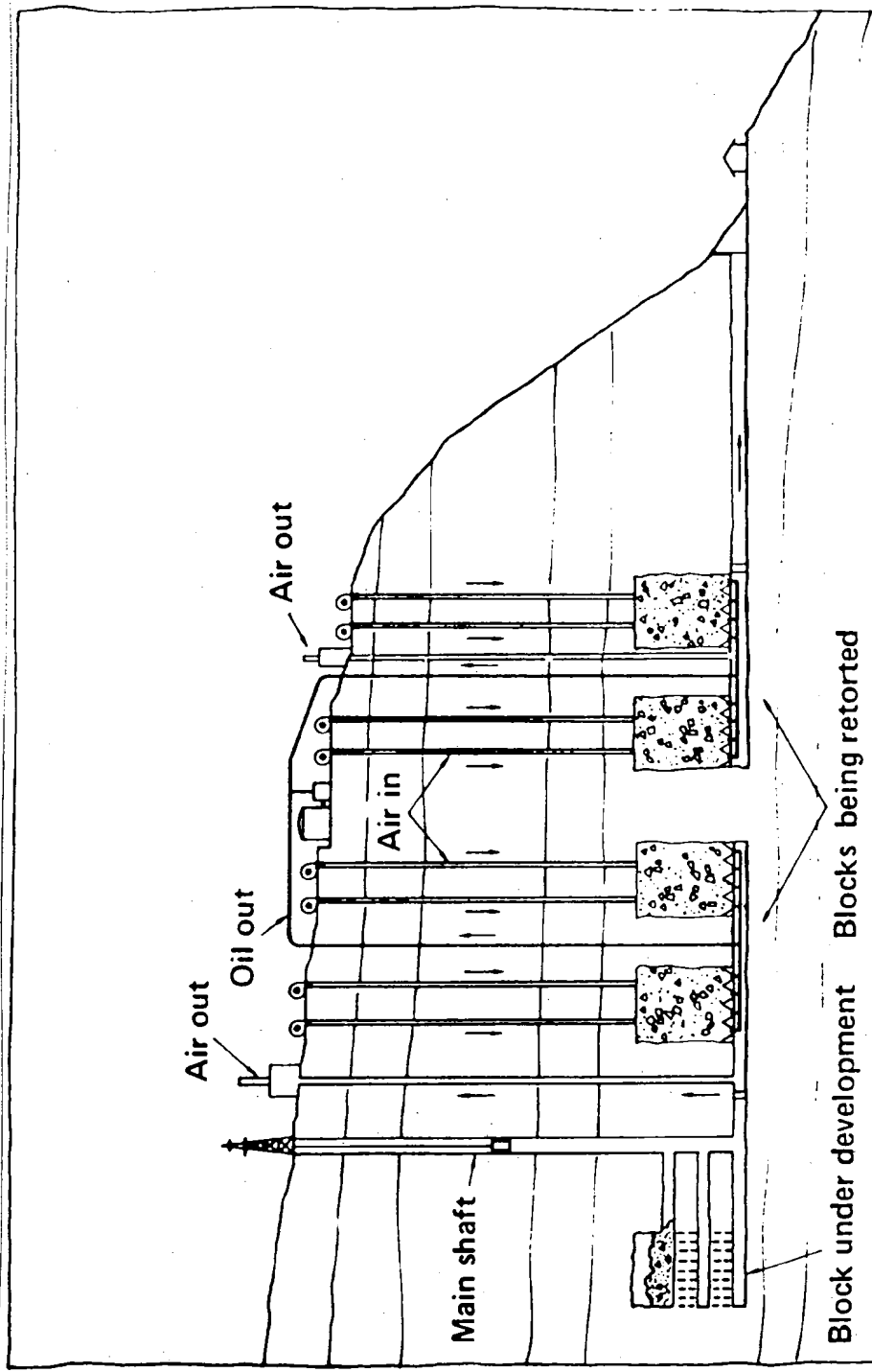


Fig. A.10--Mine-assisted (modified) *in situ* retorting (from James S. Kahn, "A Proposal for an AEC *In Situ* Oil Shale Program," in *In Situ Recovery of Shale Oil*, UCSD/NSF (RANN) Workshop sponsored by National Science Foundation, September 3-7, 1974, Fig. V.6.1, p. 249. Reproduced by permission of the author.)

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Appendix B

COST ESTIMATES FOR SURFACE RETORTING SINCE 1950

Figure B.1 and Tables B.1 and B.2 form the data base from which Figs. 2.1 and 2.2 were constructed. Figure B.1 gives the point estimates for the capital costs (per barrel of daily capacity in 1977 dollars) for a surface oil shale facility. The uncertainty of estimates before 1974 is illustrated by the considerable variation from one study to another, even for studies performed in the same time frame. This figure also illustrates the sharp discontinuity in estimated capital

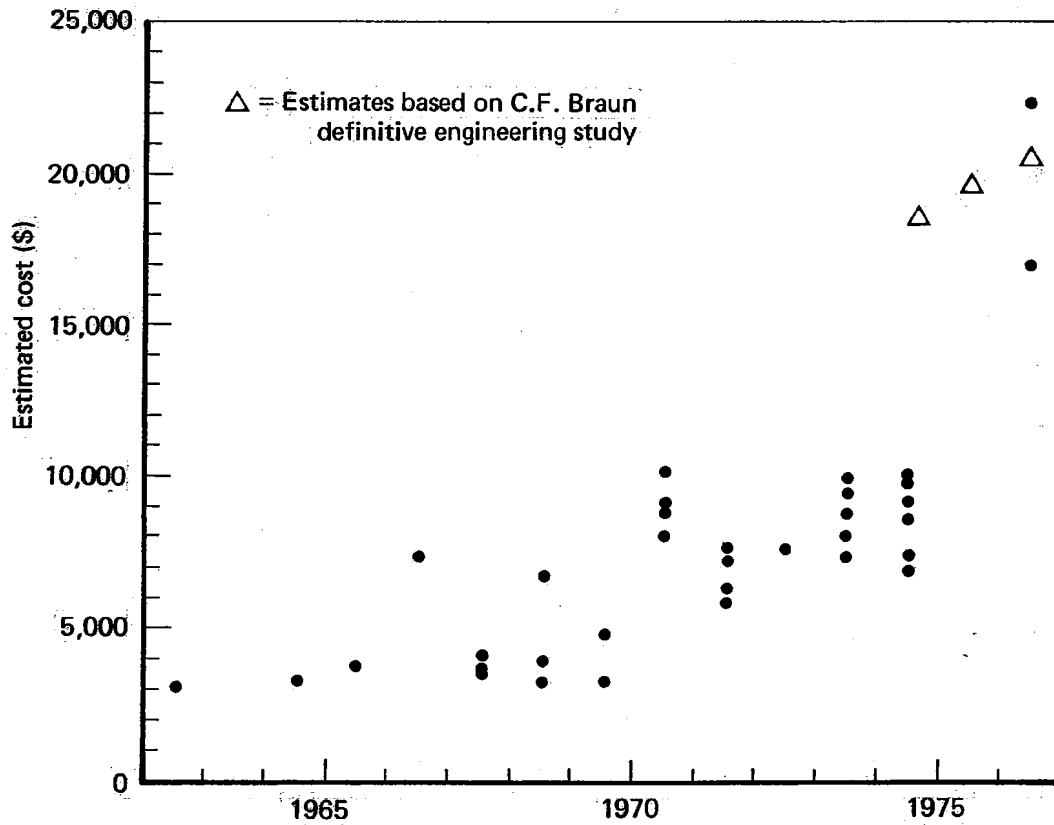


Fig. B.1— Estimated surface shale oil facility construction costs (capital costs/barrel/calendar day; constant \$ 1977)

costs that occurred with the completion of the first definitive engineering design for a surface oil shale plant (depicted by triangles in the figure).

Table B.1 presents the data on oil shale capital and operating costs and selling prices as given in various studies of oil shale over the years. Table B.2 presents the same data adjusted to constant 1977 dollars.

For the most part, the tables represent the results of a review of the literature dating back to 1950, and the data are presented in both historical dollars and in real 1977 dollars. (See "References, Appendix B" for publications from which data were obtained.)

To make the data comparable and usable, certain assumptions were made concerning variables that needed to be held constant. Among these assumed constants were: 100 percent equity financing; 15 percent depletion allowance; surface retorting complex and underground mine; exclusion of oil shale reserve costs; exclusion of R&D cost recovery; 48 percent income tax; and 10 percent investment tax credit. This normalization, although it eliminated some data points, ensured the inclusion of the greatest number of comparable data points from our data collection efforts.

The sources of the estimates are a diverse array of Congressional hearings, journal articles, and government publications. We corroborated the most pertinent later estimates by discussions with A-E firms, technology developers, and potential plant purchasers. The actual sources of the estimates were either the U.S. Bureau of Mines, technology developers such as Cameron & Jones, Inc. and Union Oil Company of California, or potential plant purchasers such as Colony Development Operation. The principal independent estimates were identified as those of (1) Ford, Bacon, & Davis (Corps of Engineers, 1951); (2) Cameron & Jones, Inc. (Miller and Cameron, 1958, and Cameron, 1969) and Steele in conjunction with Cameron & Jones (Steele, 1963 and 1968); (3) U.S. Bureau of Mines (A Cost Analysis of an Oil Shale Installation in Colorado (Circa 1966), Katell and Wellman, 1971, and Project Independence, Potential Future Role of Oil Shale, 1974); (4) National Petroleum Council (U.S. Energy Outlook, 1972); (5) Union Oil Company of California (Parker,

1957, Hartley, 1958, and "Oil on the Rocks," 1974); and (6) the 1972, 1974, 1975, and 1976 estimates of Colony Development Operation (Whitcombe, 1976, and Whitcombe, Vawter, and Nutter, 1976).

As discussed in the text, all the pre-1974 estimates are preliminary design or "black box" estimates, with quite apparent interdependence over time among many of the earlier and later figures. The most striking data points in Fig. B.1 are those indicating the effective doubling in real terms of the estimated costs of an oil shale complex corresponding to the completion of the first definitive detailed design and capital control estimate by C. F. Braun, engineers for the Colony Development Operation. The results of the C. F. Braun definitive design and estimate have been replicated in the estimates of other potential plant purchasers.

Table B.1
 HISTORICAL ESTIMATED COSTS OF OIL SHALE DEVELOPMENT
 (In \$ historical)

Year to Which Estimate Applies	Study	Retort Type ²	Plant Capacity, bbl/CD	Gal/ton Oil Shale	Estimated Capital Cost/bbl	Estimated Operating Cost/bbl	Required Selling Price			Domestic Price of Crude Oil	Posted Price of Saudi Arabian Light Crude Oil
							10% ROI	15% ROI	ROI as Specified		
1950	Ford, Bacon & Davis, Inc.	GC	10,000	30	4,272	3.35	4.67	5.33	2.51	1.71	
1956	Steele (1957)	GC	50,000	50	5,777	3.43	5.78 ^b		2.53	1.71	
1957	Miller and Cameron	U	250,000	30	3,500				3.09	2.01	
		GC	250,000	30	2,800			3.95 (12%) 3.00 (12%)			
	Parker	U			3,000-5,000				3.01	2.08	
1962	Steele (1963) Steele (1968) ⁴	GC	25,000	30	1,577	1.46			2.90	1.80	
		GC	250,000	30	1,577	1.16		2.00 (14.7%) ^c			
1964	<i>Oil & Gas Journal</i>	GC	25,000-50,000		1,100-1,700				2.86	1.80	
1965	<i>Oil Shale</i> (Senate Hearings)		25,000		2,000	2.00 ^b			2.88	1.80	
			50,000 100,000			1.76 ^b					
1966	Bureau of Mines	GC	35,020	30	4,198	1.82			2.80	1.80	
1967	<i>Competitive Aspects</i> (Senate Hearings)		25,000	30	2,088	1.48 ^e			2.91	1.80	
			58,000		2,240						
1968	Savage, Holt, and Sims	SF	250,000	30	1,883	1.70			2.94	1.80	
		GC	250,000	30	2,306	1.89					
	Bureau of Mines	GC	35,000	30	3,942	2.68-3.38					
1969	Cameron				2,000-3,000	2.35-3.20			3.09	1.80	
1970	<i>U.S. Energy Outlook</i> (National Petroleum Council)	T/L	100,000	25	6,504-7,466						
			100,000 100,000	30 35	5,756-6,558 5,226-5,912			5.58-5.79 5.10-5.29	7.03-7.29 6.43-6.72	3.18	1.80
1971	Katell and Wellman	GC	100,000	30	4,262		3.14	4.72	3.39	2.21	
	<i>Oil Shale</i> (Senate Hearings, 1971)	T	50,000		4,000-5,000	1.95			3.75 (n.s.)		
1972	Whitcombe	T	43,200		6,028	1.82	4.40	6.60	3.39	2.47	

1973 Vyas and Bodel GC 54,521 7,714 4.57 3.89 3.30

Butcher & Singer:

- Colony Development Operation
- National Petroleum Council
- Bureau of Mines

Prien, Schanz, and Doran

Katell, Stone, and Wellman

Fluor Engineers & Constructors, Inc.

Project Independence (Bureau of Mines estimates)

Searl (1972 \$)

Oil Shale Development, Part II

"Oil on the Rocks"

Whitcombe, March 1974ⁱ

August 1974^d

Whitcombe, Sept 1975^k

Colorado School of Mines Res. Institute

Whitcombe, Vawter, and Nutter (1975 \$)

Rio Blanco Oil Shale Project^l

Paraho Development Project^l

6.85^g

2.60^f

6,580

7,370

5,380

5,900

6,550

5,589

5,224

8,140

7,400

5,589

5,224

6,042

6,000

7,000-8,000

12,000-15,000

9,838

15,115

17,361

50,000

43,200

7,200

100,000

16,170

11.53

6.74

5.66 (12%)
5.15 (12%)

3.21
2.89

2.37
2.15

3.445
3.09
3.10

4.80

3.13

4.30

4.55

8.00

11.50

12.70

8.35 (14%)
8.35 (16%)

12.00

17.25

19.05

7.81

12.38

8.13

12.73

19.35

16.70 (12%)

6.50

4.77

7.50

14.20

20.80

19.00

NOTE: Cost figures were generated under the following assumptions:

- o 100% equity financing;
- o 15% depletion allowance;
- o Surface retrofit/underground mine, unless otherwise stated;
- o Cost of reserves not included;
- o Selling prices and operating costs are for hydrotreated oil at the plant gate unless otherwise specified.

^aRetort types:
GC = gas combustion
U = Union
SF = sequential flow
T = Tosco
L = Lurgi
P = Paraho
^bIn Los Angeles.
^cIncludes \$0.53 transportation to Los Angeles.

^dReestimation of 1962 mining and transportation costs.
^eAt Four Corners.
^fIncludes \$0.50 transportation to Chicago.
^gIn Chicago.
^hSurface mine.
ⁱBased on C. F. Braun control estimate.

^jBased on C. F. Braun completed detail design and capital estimates.
^kUpdated estimate by C. F. Braun.
^lPersonal communication.

Table B.2

HISTORICAL ESTIMATED COSTS OF OIL SHALE DEVELOPMENT

(A) (In \$ 1977)

Year to Which Estimate Applies	Study	Retort Type ^a	Plant Capacity, bbl/CD	Gal/ton Oil Shale	Estimated Capital Cost/bbl	Estimated Operating Cost/bbl	Required Selling Price			Domestic Price of Crude Oil	Posted Price of Saudi Arabian Light Crude Oil
							10% ROI	15% ROI	ROI as Specified		
1950	Ford, Bacon & Davis, Inc.	GC	10,000	30	10,760	8.43	11.76	13.42	6.32	4.31	
1956	Steele (1957)	GC	50,000	30	12,424	7.38	12.43 ^b		5.44	3.68	
1957	Miller and Cameron	U	250,000	30	7,246			8.18 (12%)	6.40	4.16	
	Parker	U	250,000	30	5,797			6.21 (12%)			
1962	Steels (1963)	GC	25,000	30	3,010	2.79			5.53 (14.7%) ^c	4.20	
	Steels (1968) ^d	GC	250,000	30	3,010	2.21			5.53	3.44	
1964	<i>Oil & Gas Journal</i>	GC	25,000-50,000		2,041-3,154						
1965	<i>Oil Shale</i> (Senate Hearings)		25,000			3.64 ^b			3.71-4.64 (10%-20%)	3.34	
			50,000						5.21	3.28	
			100,000			3.21 ^b					
1966	Bureau of Mines	GC	35,020	30	7,443	3.23			5.11	3.19	
1967	<i>Competitive Aspects</i> (Senate Hearings)		25,000	30	3,588	2.54 ^e			5.00	3.09	
	<i>Federal Oil Shale Program</i> (Senate Hearings)		58,000		3,849						
1968	Savage, Holt, and Sims	SF	250,000	30	3,107	2.81			4.85	2.97	
		GC	250,000	30	3,805	3.12					
	Bureau of Mines	GC	35,000	30	6,505	4.42-5.57					
1969	Cameron				3,150-4,724	3.70-5.04			4.87	2.83	
1970	<i>U.S. Energy Outlook</i> (National Petroleum Council)	T/L	100,000	25	9,707-11,143				4.75	2.69	
		T/L	100,000	30	8,591-9,788			8.33-8.84	10.49-10.88		
		T/L	100,000	35	7,800-8,824			7.61-7.90	9.63-10.03		
1971	Katell and Wellman	GC	100,000	30	6,088		4.49	6.76	5.34 (12%)	4.84	
	<i>Oil Shale</i> (Senate Hearings, 1971)	T	50,000		5,714-7,143	2.79			5.36 (n.s.)		
1972	Whitcombe	T	43,200		8,337	2.52	6.08	9.13	4.69	3.42	

Year	Project Name	Category	Cost	Value	Value	Value	Value	Value	Value	Value
1973	Vyas and Bodel	GC	54,521	10,097	5.98				5.09	4.32
	Butcher & Singer:									
	• Colony Development	T	50,000	8,613	3.40 ^f				8.96 ^g	
	• National Petroleum Council	T	100,000	9,647						
	• Bureau of Mines	GC	100,000	7,042						
	Prien, Schanz, and Doran	T	50,000	7,723						
		GC	100,000 ^h	8,573						
1974	Katell, Stone, and Wellman	GC	50,000	6,638	3.81				8.00	13.69
		GC	100,000	6,204	3.42					
	Fluor Engineers & Constructors, Inc.	T	100,000	9,667	2.81					
		GC	100,000	8,789	2.55					
	Project Independence (Bureau of Mines estimates)	T	50,000	6,638	4.09				9.92 (14%)	
		GC	100,000	6,204	3.67				9.92 (16%)	
		GC	100,000 ^h	7,176	3.68					
	Searl	GC	100,000	8,299	6.64					
	Oil State Development, Part II			8,314-9,501						
	"Oil on the Rocks"			14,252-17,815						
	Whitcombe, March 1974 ⁱ	T	43,200	11,684	2.72		9.50	14.25		
	August 1974 ^j	T	43,200	17,951	5.11		13.66	20.49		
1975	Whitcombe, Sept 1975 ^k	T	43,200	18,850	4.94		13.79	20.68	8.48	13.44
	Colorado School of Mines Res. Institute		50,000	10,857-21,716						
1976	Whitcombe, Vawter, and Nutter (1975 \$)	T	43,200	20,835	5.18		15.42	23.56	8.40	12.78
		T	7,200	38,455	8.14		22.58			
	Rio Blanco Oil Shale Project ^l			20,661-24,793						
	Paraho Development Project ^m	P	100,000	16,705	6.71		19.99	17.25 (12%)		

NOTE: Cost figures were generated under the following assumptions:

- o 100% equity financing;
- o 15% depletion allowance;
- o Surface retort/underground mine, unless otherwise stated;
- o Cost of reserves not included;
- o Selling prices and operating costs are for hydrotreated oil at the plant gate unless otherwise specified.

^aRetort types:
 GC = gas combustion
 U = Union
 SF = sequential flow
 T = Tosco
 L = Lurgi
 P = Paraho

^bIn Los Angeles.
^cIncludes \$1.01 transportation to Los Angeles.

^dReestimation of 1962 mining and transportation costs.
^eAt Four Corners.
^fIncludes \$0.65 transportation to Chicago.
^gIn Chicago.
^hSurface mine.
ⁱBased on C. F. Braun control estimate.

^jBased on C. F. Braun completed detail design and capital estimates.
^kUpdated estimate by C. F. Braun.
^lPersonal communication.

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