SHALE OIL: POTENTIAL ECONOMIES OF LARGE-SCALE PRODUCTION, PRELIMINARY PHASE

by

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Energy Laboratory Report No. MIT-EL 79-012WP
Revised: June 1979

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ABSTRACT

Producing shale oil on a large scale is one of the possible alternatives for reducing dependence of the United States on imported petroleum. Industry is not producing shale oil on a commercial scale now because costs are too high even though industry dissatisfaction is most frequently expressed about "non-economic" barriers: innumerable permits, changing environmental regulations, lease limitations, water rights conflicts, legal challenges, and so on. The overall purpose of this study is to estimate whether improved technology might significantly reduce unit costs for production of shale oil in a planned large-scale industry as contrasted to the case usually contemplated: a small industry evolving slowly on a project-by-project basis.

In this preliminary phase of the study, we collected published data on the costs of present shale oil technology and adjusted them to common conditions; these data were assembled to help identify the best targets for cost reduction through improved large-scale technology They show that the total cost of producing upgraded shale oil (i.e. shale oil accpetable as a feed to a petroleum refinery) by surface retorting ranges from about $18 to $28/barrel in late '78 dollars with a 20% chance that the costs would be lower than and 20% higher than that range. The probability distribution reflects our assumptions about ranges of shale richness, process performance, rate of return, and other factors that seem likely in a total industry portfolio of projects.

About 40% of the total median cost is attributable to retorting, 20% to upgrading, and the remaining 40% to resource acquisition, mining, crushing, and spent shale disposal and revegetation. Capital charges

account for about 70% of the median total cost and operating costs for the other 30%.

There is a reasonable chance that modified in-situ processes (like Occidental's) may be able to produce shale oil more cheaply than surface retorting, but no reliable cost data have been published; in 1978, DOE estimated a saving of roughly $5/B for in-situ.

Because the total costs of shale oil are spread over many steps in the production process, improvements in most or all of those steps are required if we seek a significant reduction in total cost. A June 1979 workshop of industry experts was held to help us identify possible cost-reduction technologies. Examples of the improved large-scale technologies proposed (for further evaluation) to the workshop were:

- Instead of hydrotreating raw shale oil to make syncrude capable of being refined conventionally, rebalance all of a refinery's processes (or develop new catalysts/processes less sensitive to feed nitrogen) to accommodate shale oil feed -- a change analogous to a shift from sweet crude to sour crude.

- Instead of refining at or near the retort site, use heated pipelines to move raw shale oil to existing major refining areas.

- Instead of operating individual mines, open-pit mine all or much of the Piceance Creek Basin.

- Instead of building individual retorts, develop new methods for mass production of hundreds of retorts.

SHALE OIL

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ACKNOWLEDGMENT

Funding for this preliminary work on a potential U.S. shale oil industry was supplied by grants from the Edna McConnell Clark, Ford, and Alfred P. Sloan Foundations, and we are grateful to them. We have also profited from discussions with individuals in the U.S. Department of Energy and in companies currently active in shale oil development.

1. INTRODUCTION

The purpose of this study is to consider whether production of shale oil on a large scale could present opportunities for significant cost reduction through better technology. Large-scale production of shale oil is one possible means for reducing the need to import petroleum. Our definition of "large-scale" is 10-25% of current consumption of liquid fuels in the U.S., or about 2 to 5 million barrels per day.

As this introduction is being written (April 1979), newspaper headlines again feature the sharply rising prices and uncertain supplies of imported petroleum. If there is any aspect of energy upon which most informed people agree, it is that our heavy, and prospectively heavier, reliance on foreign petroleum is not good for the United States. The unfavorable nature of such dependence may be seen as arising from national security or foreign policy considerations or as stemming from strictly economic effects; in any case the overall conclusion is the same, and the headlines seem to confirm that conclusion.

There is much less agreement about which particular alternatives are less objectionable for the United States than importing so much oil. One broad alternative is to consume less liquid fuel through conservation or through substitution of other forms of domestic energy like coal, gas, and renewable sources. Another broad alternative is to reduce imports of liquid fuels by increasing supplies of domestic substitutes like coal liquids, frontier oil, tertiary oil, and shale oil. A third broad alternative, gaining favor recently, is encouraging more production in and importing more oil from Western Hemisphere rather than presumably less benign Eastern Hemisphere sources.

The debate over the alternatives--the specific ones even more than the broad ones--has been exhaustive and public. It is not our purpose to review the advantages and disadvantages of each or to choose among them. Unhappily, all the alternatives seem to have significant economic penalties or significant environmental penalties or both associated with them. In fact, government policy is likely to employ all the alternatives simultaneously to various degrees. We are considering some of the possibilities for shale oil in order to determine whether shale oil could become a more desirable alternative than it now seems to be. Our concentration on shale oil implies no judgment about the desirability of shale oil compared to other alternatives.

1.1 THE SIGNIFICANCE OF SHALE OIL

Interest in shale oil is motivated largely by the enormous size of oil shale deposits in the United States. Known rich and accessible resources contain about 600 billion barrels; a recovery of about one-third of that resource would equal almost one hundred years of imports of petroleum at the current rate.

A further reason for interest in oil shale processing is that processes for the production of liquid fuels from oil shale appear cheaper than those that start from coal.[1] This is primarily because oil shale contains a very much higher ratio of hydrogen to carbon, and process costs tend to correlate directly with the increase in the net H/C ratio required. This cost advantage is somewhat offset by increased

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[1]e.g. Stanford Research Institute, "A Western Regional Energy Development Study: Economics, Volume 1", SRI Project 4000, November 1976, p. 7; or U.S. Department of Energy, Policy and Evaluation Division, cited in "Inside D.O.E.", May 18, 1979, p. 6.

materials handling required by shale. But, on balance, it has been recommended that most liquid synfuels be produced from shale.[1]

1.2 BACKGROUND

Oil shale processing has been practiced on an industrial scale since the 1860's. Much "coal oil" produced in the United States before the discovery of petroleum was in fact shale oil. Production of 2,500 B/D was maintained by the Scottish oil shale industry for long periods of time over its 100-year history. A Manchurian oil shale industry, begun in 1929, reached outputs of 35,000 B/D while under Japanese control during World War II. The Chinese expanded the Manchurian operation, and output during the Korean War is believed to have been as high as 40,000 B/D.[2]

During the 1960's, shale oil R&D was being carried on by several of the major oil companies, and by The Oil Shale Company (TOSCO), newly formed expressly to become a major factor in a new shale oil industry. With the announcement of the sale of U.S. Government shale leases in Utah and Colorado in early 1974, the level of R&D was increased somewhat.

This lease sale, taking place at the height of the 1973-74 Arab oil embargo, elicited over 1/2 billion dollars in bids from several major oil companies plus TOSCO. These companies appear to have been acting largely on the belief that some combination of the following conditions would

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[1]"Recommendations for a Synthetic Fuels Commercialization Program", Synfuels Interagency Task Force Report to The President's Energy Resources Council, November 1975, Vol II, p. 18, Fig. 8, p. H-27.

[2]Hammond, Ogden H. and Robert E. Baron, "Synthetic Fuels: Price, Prospects, and Prior Art", American Scientist (July-August 1976), pp. 407-417.

obtain: (1) world oil prices would continue to rise, and the cost of shale oil production would then be at a level that would make the industry viable at world oil prices, and/or (2) shale oil would be "needed", and therefore prices would be paid that would make its production profitable, regardless of the market prices and costs, and/or (3) the government would take whatever steps might be necessary to ensure that the necessary technology and regulatory environment would be available, and that Federal subsidies in some form would be available if needed for construction of the early plants,[1] and/or (4) improvements in technology would reduce the real costs of shale oil.

Since the lease sale, each of the lessees has been conducting engineering and feasibility studies, studying environmental impact, etc., but only modest progress has been made in either the technology or the conceptual development of the shale oil industry with the possible exception of Occidental's modified in-situ process.

1.3 TECHNOLOGY

Oil shale processing technology is simple in principle. Oil shale contains a carbonaceous material called "kerogen". When oil shale is retorted, i.e. heated to about 800°F, the kerogen decomposes (pyrolyzes) to yield an oil (raw shale oil), gas, and residual carbon which remains in the shale. The total solid residue from retorting is known as spent shale. Typical "rich" U.S. shales under consideration yield about 25 to 40 gallons of raw shale oil per ton of rock heated.

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[1]Whitcombe, J.A., et al. "Shale Oil Production Costs and the Need for Incentives for Pioneer Plant Construction", TOSCO, Feb. 1-3, 1976.

Research has been done on other ways of recovering shale oil from its rock, for example by extraction with solvents or by the action of microorganisms. But no method other than heating has shown any real potential for commercial application.

The retorting of oil shale may be done in two general ways: above-ground and in-situ. For above-ground retorting, the shale rock is mined, crushed to appropriate sizes, and heated in steel vessels of various configurations located on the surface. For in-situ retorting the shale rock is heated while it remains underground.[1] Many variations of both above-ground and in-situ retorting have been investigated. Each variation has its advantages and disadvantages. No variation has been tested on a commercial scale in the United States although both above-ground and in-situ processes have been operated commercially abroad; no domestic shale oil project has ever exceeded 700-800 B/D--a number which can be compared with our current oil imports of 7-8,000,000 B/D.

Regardless of the retorting method used, the resulting raw shale oil is ordinarily "upgraded" to reduce contaminants--nitrogen, sulfur, and metals--so that it may then be processed further by the same techniques used to process crude petroleum.

The relatively small amount of oil recovered--roughly 10-15% by weight of the shale rock heated--means that there are substantial technical problems resulting from the sheer volume of rock that must be mined and transported to a commercial-scale processing plant which uses

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[1]Occidental Petroleum's Modified In-Situ process, however, requires at least 20% of the shale resource to be mined and brought to the surface where it can be retorted conventionally.

above-ground retorting. Furthermore, since the shale expands by as much as 50% during crushing and retorting, the volume of spent shale to be disposed of is greater than the volume of shale that was mined. Spent shale also often has a high content of alkaline minerals, a factor that must be considered in the disposal process. Interest in in-situ retorting stems largely from the fact that in-situ processes can avoid handling most or all of the shale rock and spent shale handled in above-ground processes.

Oil shale processing currently requires about one to four barrels of water per barrel of shale oil produced. This water is used in the shale processing itself as well as for dust control but the largest single amount, up to half or more of the total, is usually for environmentally acceptable disposal and revegetation of the spent shale. Water availability is a problem in the arid shale regions of the West, and opinions about its importance as a constraint on production are often expressed with intense emotion. As a result, one typical conclusion is that "...water is estimated to be the single most limiting restraint (on shale production)."[1] However, the same source points out that Colorado water can be desalinated for about 5¢/barrel;[2] at the extreme limit, fresh water can be brought to the area from 1000 miles away for well under $1/barrel.[3] Also, there are other tradeoffs between cost and

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[1]Ramsey, W.J. et al, "Institutional Constraints and the Potential for Shale Oil Development," Lawrence Livermore Laboratory, UCRL-52468, July 6, 1978, p. 24.

[2]Ibid., p. 16.

[3]Probstein, R.F. and Gold, H., Water in Synthetic Fuel Production, M.I.T. Press, Cambridge, 1978, p. 59.

level of water consumption. Thus, the cost of water is significant but need not be an absolute economic barrier if the institutional barriers are overcome.

1.4 THE EVOLUTIONARY VIEW AND THE IN-PLACE VIEW

As would be expected, shale oil studies in both the private and public sectors have emphasized what we will call here an "evolutionary" or project approach. Costs are estimated for a single plant, looking at that plant as a totality within itself, not part of a complex, an industrial park, or a shale oil industry. It is not clear whether this oversimplification tends to result in costs that are too high or too low on the average for a whole industry.

In some ways, the first is the cheapest. For example, the highest quality shale would be mined first, and the lowest-cost water would be used first; local environmental pollution would be lowest with the first plants; demand for labor and steel would be limited and would not drive up price levels. However, other economies would result from the existence of a cluster of plants. For example, a separate grass-roots community need not be built for each plant--one larger (lower unit cost) community could serve several plants; product transportation costs would be lower for an industry pipeline than for any mode scaled for a single plant; unit equipment manufacturing costs would be lower if many units were replicated.

This latter set of possibilities encourages us to raise the question of the economics of an industry, once in place. Might not a shale oil industry be the beneficiary of economies that simply would not be applicable to a single plant, and therefore have not been considered seriously in studies to date? Might these economies be significant? Might an industry be viable whereas a plant or a few plants might not be? Investigating the fruitfulness of this line of thinking is the purpose of this study. The questions we are asking are the questions one might ask when reflecting on, say, U.S. shipbuilding dynamics early in World War II. The decision to build several Liberty ships a week resulted in structural and technical changes that permitted economies that simply were not possible when shipbuilding was considered a one-at-a-time process.

1.5 SCOPE OF THE STUDY

This study is the first phase of what may evolve into a longer and more ambitious program. At this point, our objectives have been to:

1. Define a study which has not already been done, which can be done with the resources available, and which might contribute to our understanding of the potential for a large shale oil industry. The study defined is an examination of the economic advantages possible through technology in a large in-place industry.
2. Discuss the study objective with people knowledgeable about shale oil. We have talked to shale experts in industry and government and have gotten encouragement to proceed, but with frequent reminders that it may be very difficult or impossible to get from "here" to "there" (the large-place industry), regardless of how economically attractive "there" seems to be.
3. Collect existing publicly available information on the costs of producing shale oil by currently contemplated methods, in order

to help identify areas in which a large-scale industry could have major impact on costs. This report summarizes the information we have obtained.

4. Plan and conduct a workshop[1] involving experts in both oil shale and shale-applicable technology to identify opportunities that could have a significant impact on unit costs in a large-scale industry, e.g. mining technology, transportation methods, equipment manufacturing.

In order to focus on the issue we want to consider, we will not study in this first phase a number of other important issues despite our recognition that these other issues may be controlling in the development of a shale oil industry in the United Sates.

- We will not consider how the industry got built, but will rather consider it already in place at steady state; in chemical terms, we are concerned with equilibrium rather than kinetics.
- We are looking only at the economic consequences of technological alternatives; we are not evaluating other alternatives, financial or tax devices for example, to reduce cost.
- We are not reevaluating process economics, nor are we trying to make fine comparisons among various competing processes; we have made an effort to obtain the latest data available from the most active players, accepting their data at face value.

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[1]That workshop was held on June 4-5, 1979 in Lexington, Massachusetts. A summary of that workshop is reported by the authors in "Shale Oil: Potential Economies of Large-Scale Production, Workshop Phase", Energy Laboratory Report No. MIT-EL 79-031WP, July 1979.

- We assume that the environmental specifications which must be met are those presently established.
- We are not taking account of unique project features inapplicable on a large scale, for example, the recovery for sale of alkaline minerals along with the shale.
- As noted previously, we are not comparing shale oil to other alternatives for reducing oil imports.
- We are not evaluating current or potential government policies affecting shale.

In other words, for the moment we are deliberately taking a narrow technologist's view of the potential for reducing costs through technology in a large distant-future shale oil industry.

1.6 THE STUDY, THE INDUSTRY, AND TECHNOLOGICAL CHANGE

Industry is being clear, as demonstrated by both its behavior and its public statements, that it does not regard shale oil ventures as attractive now. Industry dissatisfaction is most frequently expressed about the "non-economic" barriers--innumerable permits, changing environmental regulations, tax and pricing uncertainties, lease limitations, water rights conflicts, legal challenges, and so on--but the crucial barrier is the fact that shale oil simply costs more than imported oil now. If shale oil cost less, we would probably see more determined and more successful efforts by both industry and government to surmount the non-economic barriers. ("Non-economic" is shorthand, of course; there are costs, often large ones, resulting from those barriers.)

Industry's continued interest in shale oil, despite its current unattractiveness, is sustained primarily by the belief that the real cost of imported oil will continue to rise, ultimately catching up to and then surpassing shale oil at some unpredictable future date. Government assistance is sought by industry before that date on the grounds that a) there is a public value, which cannot be directly captured by a company undertaking a shale oil venture now, in reducing imported oil--for reasons discussed at the start of this introduction, and b) we need to start now if we want to have significant shale oil production in place when the cost curves do intersect.

A secondary reason for industry's continued interest is the belief that the real cost of producing shale oil may be reduced through technological improvement.[1] That belief raises the issue of how the process of technological change occurs, and what the consequences might be for two different paths of the shale oil industry. One set of consequences would result from the industry following the usual evolutionary path, and one would result from the industry-in-place path described in the preceding section.

It is convenient to think of technological change occurring in five stages termed: 1. Invention, 2. Development, 3. Introduction, 4. Diffusion, and 5. Maturity. These stages are described in detail in Appendix A. The normal evolution of technology--shale oil technology as well as other technologies--would progress through each of these stages. Thus, a shale oil industry in a Maturity phase would make use of those mining, retorting, and upgrading technologies which had proved superior

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[1]There are quite different views on the prospects for reducing cost through improvement of current technologies. For example, Merrow ("Constraints on the Commercialization of Oil Shale," Rand/R-2293-DOE, September 1978) is pessimistic but Hutchins ("Oil Shale 1979," presented at the Twelfth Annual Oil Shale Symposium, April 1979) is optimistic.

to competing technologies during extended commercial-scale operation in the Introduction and early Diffusion phases.

If an industry were put in place in some unspecified way, the Introduction and early Diffusion phases would be skipped. As Appendix A points out, the primary purpose of those phases is to narrow the range of cost uncertainty rather than to reduce the probable cost, although technical changes which result in reduced (or increased) cost certainly occur in those phases. Thus, the later Diffusion and Maturity phases would be entered with less certainty that the best technologies were being used.

A crucial question to be faced is the probability of the economies of an industry in place being greater than the diseconomies of skipping some intermediate stages. In general, the economies that might result from the industry-in-place approach fall into two categories. One is the economy of scale. An industry can solve problems more economically than individual plants and can justify the development of technology not otherwise supportable. Examples of economy-of-scale savings would include (as illustrations, not proposals):

- Mining. All or much of the Piceance Creek basin might be open-pit mined, with the resulting oil shale distributed to individual retorting sites.
- Combinations. An industry basis might better accommodate an optimum balance between surface and in situ retorting.
- Infrastructure. An industry might support larger, more economical cities.
- Transportation. Pipelining product out, say to existing refineries, might offer cost savings.

- Spent shale disposal may be more economical on an industry basis.
- Environmental Impact Statement. A simple EIS for the entire industry may well be more cost-effective than separate studies and statements for each plant.
- Environmental control (e.g., particulates, NO_x, SO_2) may be more economical for an industry.
- Water supply and disposal could be much more practical for an industry, through such means as bringing in water from remote sources.

The other possible source of cost reduction lies in the dimension of mass production economies for the suppliers to the shale oil industry. If suppliers were to know and could count on the construction of an industry of, say, 5,000,000 bbl./day over a relatively short time frame, say 8 to 15 years, then perhaps economies could be realized through the planned mass production of retorts, mining machinery, pipe and valves, etc.

2. THE COSTS OF PRODUCING SHALE OIL

Generating reliable cost estimates is difficult for any large energy facility. The Shoreham nuclear plant on Long Island was estimated to cost $261 million in 1969 with a completion date of 1975. Present estimates indicate a cost of $1.3 billion and a completion date of 1980. The ratio of actual final cost to original estimate was still higher for the Alaskan pipeline, vividly illustrating the hazards of cost estimating of even "old" (i.e., pipeline) technology in a wholly new environment.

Estimating the costs of an oil shale complex is attended by an additional set of difficulties due to the infant nature of the industry. Fundamental questions with pioneer complexes are whether the various components of such facilities will function well together and continuously when erected on a commercial scale, and whether the impacts on a sensitive environment will be acceptable without further costs. Semi-works operations and tests provide limited information. Even if the facility is of sound engineering design, lack of experience about its construction and operation make it highly probable that unexpected costs will arise.

In relying upon published cost estimates, as we rely, there are additional uncertainties. We rarely can find out enough about the detail and recency of the estimates to judge their credibility. A 1978[1] study of the history of cost estimates for producing shale oil shows startling increases in those estimates since 1970. (It is customary and comforting, but not necessarily prudent, to assume that now we are a lot smarter than we used to be and therefore that current estimates are

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[1]Merrow, op. cit.

close to the "truth.") In addition, the assumptions are not always fully specified so that comparisons with other shale oil technologies, much less technologies for other sources of energy, are often unreliable; different sets of estimates use different assumptions about taxes, costs of capital, water, community needs, and so on in addition to the differences in basic technology.

In summary, because of the general difficulties inherent in estimating costs, the additional problems of costing pioneer plants, and the differences in basic assumptions and comprehensiveness, conclusions based on published cost estimates are the subject of much confusion.

We have not emphasized the confusion in order to reduce the significance of such estimates. Rather, by identifying the types of problems that arise in estimating costs, we are explaining the need to characterize costs over a range of probability. Accordingly, this section attempts to perform two tasks:

(1) to review available industry cost estimates, put them in comparable forms, and generate average industry cost estimates; all costs are expressed in late-1978 dollars per barrel of "syncrude" produced and thus the cost calculations make assumptions about yields in each step of the total process sequence.

(2) to consider those estimates in light of the problems outlined above and to perform a simple sensitivity analysis using a few important parameters in order to provide a range of costs with associated probabilities.

The estimates include total costs for syncrude plus costs for each of the three major sections of the total process: solids preparation and disposal (including lease acquisition, mining, crushing, spent shale disposal, and revegetation); retorting of crushed rock to raw shale oil; and upgrading of raw shale oil to a refinery-acceptable feed. Each major section is charged with its share of common facilities, and each section is assumed to include those control facilities required to conform to presently established environmental regulations.

Where possible, we have separated total costs into capital charges and operating costs. Capital charges include allowance for return on total investment, depreciation, start-up costs, income tax, construction time, etc. Capital charges were assumed to equal about 28% of total all-equity investment annually for a 15% return, and about 15% annually for a 10% return.

The cost estimates are, unfortunately, confined to surface retorting processes. Only Occidental has carried out enough work on any type of in-situ process to back up a meaningful commercial-scale cost estimate, and Occidental's cost estimates are not available to us. The most recent public DOE estimates[1] place the costs of vertical modified in-situ (i.e., Occidental-process) shale oil at $15-25/barrel and surface retort shale oil at $20-30/barrel; the DOE in-situ numbers are not based on detailed engineering design, to the best of our knowledge.

2.1 SOLIDS PREPARATION AND DISPOSAL

The costs included in this section are the costs required to:

- acquire the lease,

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[1] Commercialization Strategy Report for Oil Shale: Part II, 1978, DOE Task Force (H.D. Guthrie, Chairman), TID-28845.

- mine the shale rock,
- crush the rock to a feed acceptable to the particular retort used, and
- dispose of the spent shale and revegetate it.

Appendix B describes the sources of our cost data in detail. Lease acquisition costs per barrel were assumed equal to those of the Colony project. Costs of the other steps were based on averages of estimates by Colony, Cameron Engineers, and Paraho. All those estimates assumed 100% underground mining; we adjusted the estimates by assuming that 15% of the industry's shale rock would be mined by open-pit methods at a total cost equal to 60% of the cost of underground mining. DOE's estimate is that less than 20% of oil shale areas are minable by open pit methods.[1]

In order to calculate how the costs might vary with changes in some important parameters, we also made the following assumptions:

Parameter	Value	Probability
DCF Return	15%	0.7
	10%	0.3
Shale Richness	35 gal/ton	0.8
	25 gal/ton	0.2
Retort Recovery	100% of F.A.[2]	0.7
	80% of F.A.	0.3

Figure 1 displays the results of our calculations, presented on cumulative probability coordinates. For example, the total cost of solids preparation and disposal has an 80% probability of exceeding $7, a 50% probability of exceeding $9, and a 20% probability of exceeding $11.

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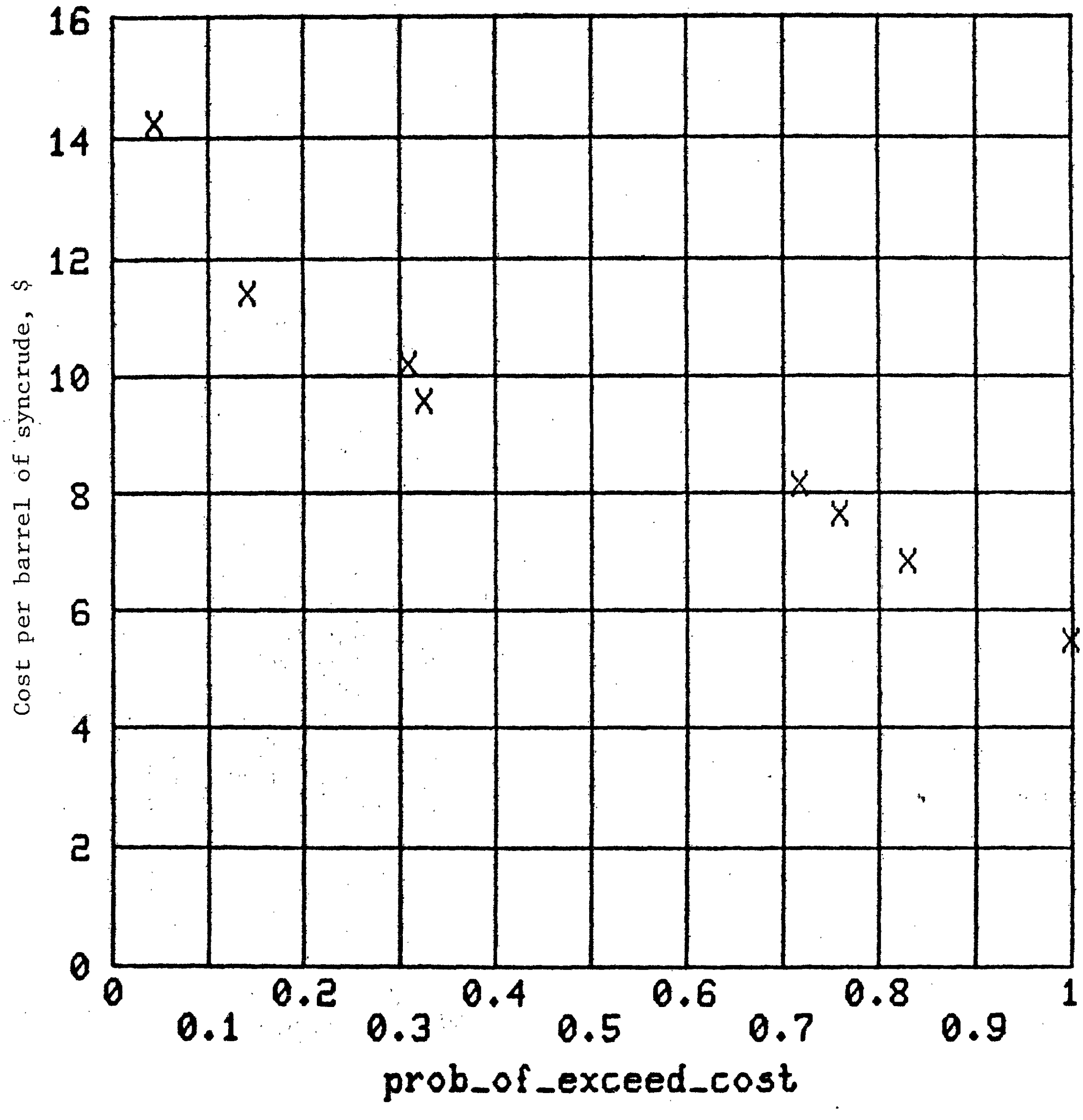
[1]Department of Energy, "Oil Shale Technology," February 1978, p. 25.

[2]Fischer Assay. This parameter affects the amount of rock that must be mined and retorted to produce a barrel of oil.

Figure 1: Cost of Solids Preparation and Disposal



For our purposes, and reflecting our confidence in the input data and assumptions, precision much better than the nearest dollar is not justified.

The median total of $9 is composed of:

Capital charges	6	Lease acquisition	2
Operating costs	3	Mining, crushing, disposal,	
Total	9	and revegetation	7
		Total	9

Different retorting processes incur different crushing costs and use different techniques for disposal and revegetation of spent shale. We do not have data to separate those costs easily. A reasonable guess for industry-wide average costs would be $4 for mining, $1 for crushing, and $2 for spent shale disposal and revegetation.

2.2 RETORTING

The costs included in this section are the costs required to:

- recover raw shale oil from heated crushed rock
- use, sell, or acceptably dispose of all gaseous and other liquid streams
- burn carbon on and recover heat from spent shale (if included)

Appendix B describes the sources of our cost data in detail. Costs were based on weighted average estimates for the Colony (Tosco), Paraho, Union, and Lurgi retorting systems.

In order to calculate how costs might vary with changes in some important retorting parameters, we made the following assumptions:

Parameter	Value	Probability
DCF Return	15%	0.7
	10%	0.3
Shale Richness	35 gal/ton	0.8
	25 gal/ton	0.2
Retort Recovery	100% of F.A.	0.7
	80% of F.A.	0.3
Annual Throughput	1.7x Design	0.01
	1.3 "	0.05
	1.1 "	0.15
	1.0 "	0.6
	0.9 "	0.15
	0.5 "	0.04

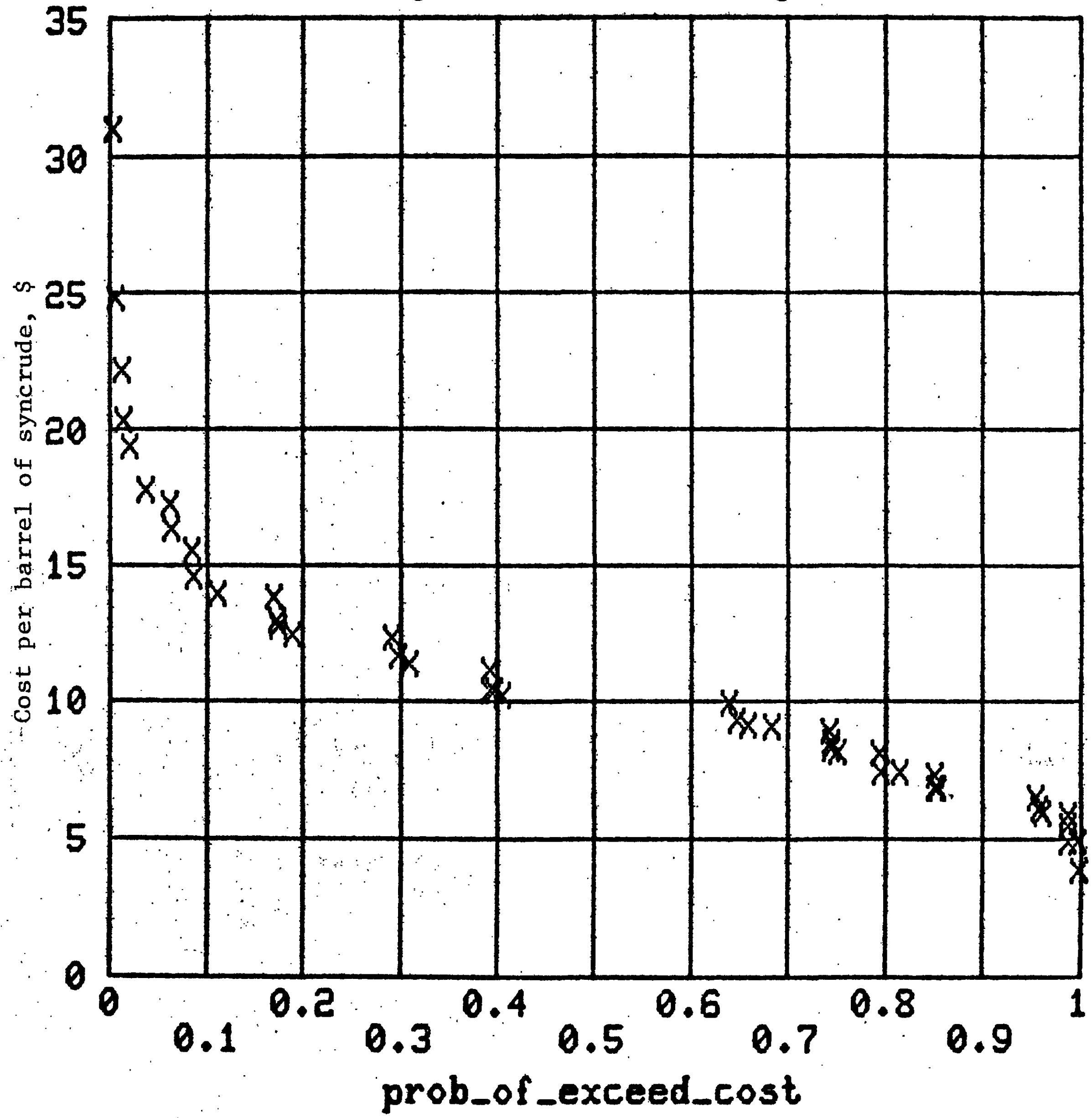
The throughput in effect lumps together on a calendar day basis the design service factor and the design stream day capacity.

Figure 2 displays the results, again plotted on cumulative probability coordinates. The total cost of retorting has an 80% probability of exceeding \$8, a 50% probability of exceeding \$10, and a 20% probability of exceeding \$13.

The median cost of \$10 is comprised of about \$7 in capital charges and about \$3 in operating costs.

Most of the retorting systems proposed can be designed in several variations which, for example, affect the quantity and quality of net fuel gas produced, or which recover heat by burning carbon on the spent shale. However, the unit shale oil costs from these more complex retorting systems are not significantly lower than from the simpler systems.

Figure 2: Cost of Retorting



2.3 UPGRADING

The costs included in this section are the costs required to:

- reduce nitrogen and metals (e.g. arsenic) in raw shale oil to levels permitting further processing to marketable products by customary petroleum refinery techniques
- make marketable byproducts (usually ammonia and sulfur) as a logical consequence of the upgrading process; byproduct values are credited against upgrading costs.

Appendix B describes the sources of our cost data in detail. Costs were based on upgrading estimates prepared by Colony, Paraho, and Chevron. A significant uncertainty--not quantified--that results from averaging the three sets of costs arises from the fact that the degree of upgrading, i.e. the severity of hydrogenation, differs among the three cases.

We made the same assumptions about DCF returns that we did for the solids and retorting sections and we assumed an overall cost (for each level of return) probability as follows:

Parameter	Value	Probability
DCF Return	15%	0.7
	10%	0.3
Total cost	1.5 x design	0.05
(at each	1.25 "	0.2
return)	1.0 "	0.5
	0.75 "	0.2
	0.5 "	0.05

We chose a distribution of overall costs rather than selected operating parameters because we believe that--even if no new technology is developed--a large scale shale oil industry will upgrade in some manner that is better integrated with other refining facilities than the isolated brute-force hydrogenation currently assumed in most shale oil project estimates. With closer refining integration, the process design for upgrading and the quality of upgraded oil are likely to be different than now assumed. Lacking any sound way to isolate the specific parameters that may change, we resorted to a distribution of overall cost probability that seems reasonable for this type of hydrogenation technology.

Figure 3 displays the results. The total cost of upgrading has an 80% probability of exceeding $3.5, a 50% probability of exceeding $5, and a 20% probability of exceeding $6.5. For the median total cost of $5, about $4 are capital charges and about $1 is net operating cost.

2.4 TOTAL COSTS

A probability distribution for the total costs of shale syncrude was calculated by combining all the individual cases computed for the three separate sections described in 2.1, 2.2, and 2.3. The results are shown in Figure 4.

Under the assumptions stated previously, there is a 50% probability that total costs will exceed about $23/barrel. Extending the probability range to cover from 20 to 80% results in a range of costs from 18 to 28 dollars per barrel. Not surprisingly, the curve is skewed to show that the small chance of very high costs is greater than the small chance of very low costs. Capital charges again dominate, accounting for about 70% of the total.

Figure 3: Cost of Upgrading

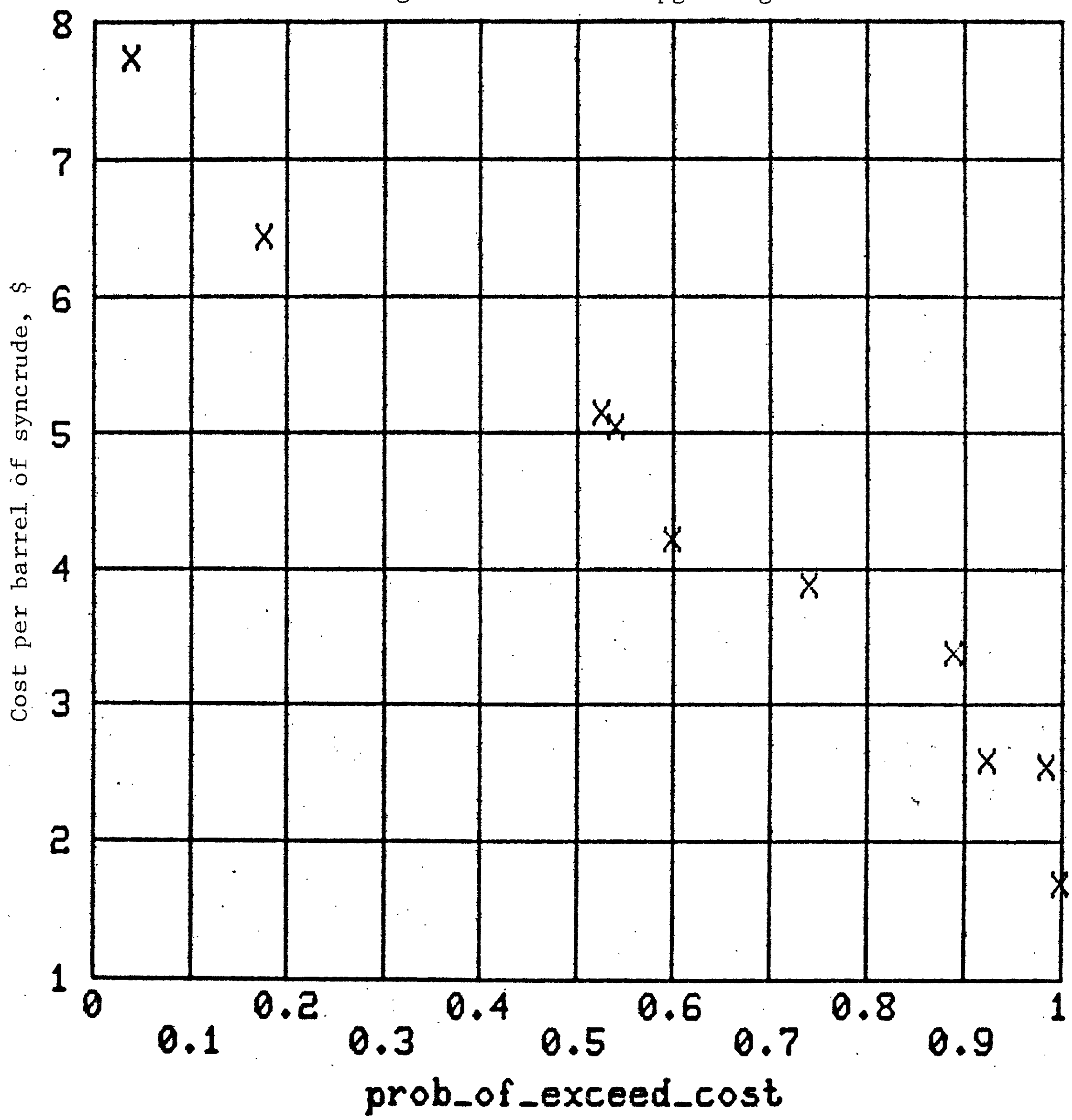
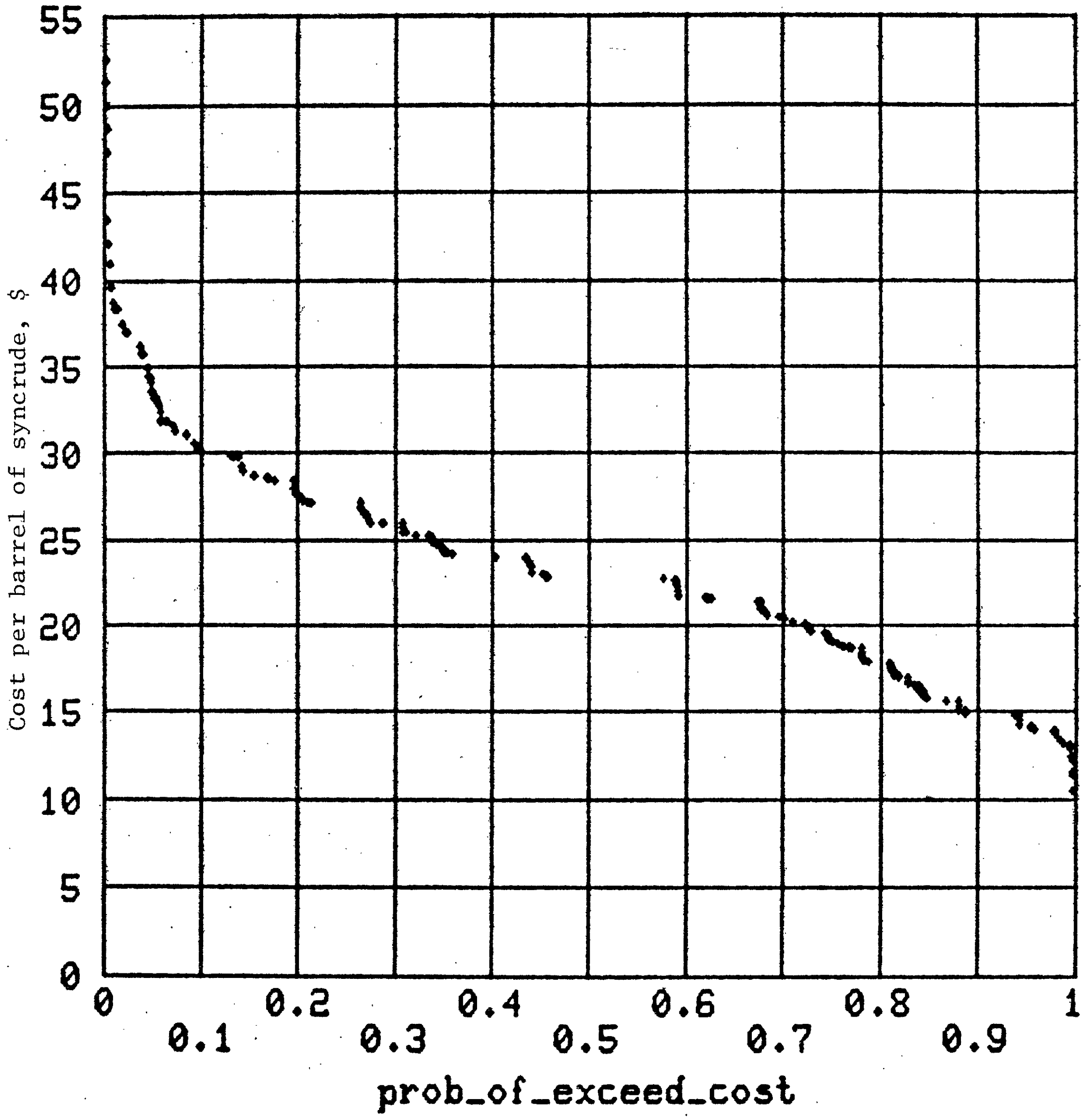


Figure 4: Total Cost of Shale Syncrude



Although our estimates of the uncertainty in cost may seem large, the true uncertainty is probably even larger. For example, we have not included uncertainty in the basic cost estimates even for a project with all parameters fixed. And, we have considered only a few of the variables. Therefore, even if we have exaggerated the uncertainties in the variables we did consider, the total true uncertainties remain large.

3. CONCLUSIONS

Currently the most popular view in the shale oil industry is that surface-retorted syncrude can be produced at a total cost roughly in the middle of the $20-30/barrel range. Our view of the data supports that consensus. A combination of favorable circumstances can result in lower costs for a particular project. But the total uncertainties suggest that industry-average costs for large-scale production are at least as likely to go up as go down if the industry moves along the normal evolutionary path.

The probable cost of shale oil is still substantially higher than the cost of landed imported petroleum. If the real price of crude increases at 5% per year, it will reach $25 in about 7 years, making shale oil reasonably competitive without subsidy at that time. No significant (in supply terms) rate of production of shale oil could be achieved in the United States within seven years short of a national effort comparable to some World War II activities.

The largest single component of cost of shale oil is retorting, but surface retorting costs are less than half of total costs. No potential breakthrough in surface retorting costs is under development (to our knowledge), and a revolutionary breakthrough would be required to have a major impact on total costs, since mining and upgrading costs would probably be unaffected.

In-situ technology has both its pointers-with-pride and its viewers-with-alarm. The pointers-with-pride hold forth the prospects of significant reduction of both cost and environmental problems, compared to surface retorting. Perhaps they will be proved correct, and most people agree that further R&D is well justified. But none of the three quasi-commercial scale tests conducted by Occidental to date has proved much more than technical feasibility.

A conspicuous feature of shale oil cost is its dependence on capital charges--65-80% of the total cost. A would-be investor in the industry is faced by the need to assemble large blocks of capital ($1 billion or so per commercial-scale plant) and spend it all up front--with attendant large risks or costs or both due to construction delays, permit or litigation delays, regulatory changes, engineering design deficiencies, or other factors that prevent or impede plant production and revenue generation. The capital charge must include a return on investment consistent with these risks in addition to other uncertainties (like the price of competitive fuels or any of the major government policies affecting the industry).

How can costs be reduced, by other than financial or tax devices? For an individual project, there are the obvious technology-independent advantages of richer, more accessible shale ore, adequate water, and waste disposal opportunities; and there are the obvious technology-dependent advantages of increased recovery and throughput, waste streams of minimum undesirability, and byproducts of maximum value. For the industry as a whole, technology may be able to provide further opportunities as described in Section 1.6 above.

A workshop convened by MIT was held on June 4-5, 1979, to identify some of those opportunities.[1]
The consensus of the workshop participants (from industry and MIT), most of whom were specifically expert in shale or shale-applicable technology, was optimism about the ability of improved technology to reduce the cost of producing shale oil on a very large scale.

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[1]See footnote, page 9.

APPENDIX A. THE PROCESS OF TECHNOLOGICAL CHANGE

by Ben C. Ball, Jr.

A.1 THE NATURE OF THE PROCESS

In order to evaluate properly the trade-offs in the "evolutionary" vs the "industry in place" alternatives, it is helpful to establish first a clear view of how new technologies are in fact commercialized in the United States.

Commercialization of a new technology occurs if it is available at a cost allowing the private sector an acceptable return on the total capital required, given the market prices of inputs, capital, and labor, given the regulatory restrictions, and given the marketplace.

A way in which this real-world process can be perceived is through the existence of four rather discrete stages which precede the establishment of a mature industry:

- Research or invention
- Development or demonstration
- Commercial introduction
- Commercial diffusion.

Invention is the generation of an idea. A functioning process or product is established. Economic issues are not dealt with in depth at this stage; technical, market, and regulatory uncertainties are very high. Costs, prices, and markets are usually poorly known.

In the development stage, design is optimized until the process or product is embodied in an actual model within a working environment. The principal function of this stage is to eliminate essentially technological uncertainty and thus determine the expected cost of mature production (e.g., production following the diffusion stage). However, the variance of this expected future cost may be rather high. This stage deals not at all with market or regulatory uncertainties.

The development stage need not, and in fact usually does not, require the construction of a full-scale production facility. Pilot plant is the usual approach here. The product may be real-life (e.g., a barrel of real shale oil), so that the product may be tested, but the production facilities are expected to be smaller than full size by virtue of our ability to scale. If they are readily scalable, then there are no significant technical uncertainties which require commercial-scale construction for their resolution. If a crucial sub-unit is not readily scalable, an alternative to a full-scale demonstration plant is to build a facility only of the crucial sub-unit, no larger than necessary to resolve the relevant technical uncertainties.

The purpose of the development stage is, thus, twofold:

- To reduce technological uncertainty
- To determine expected mature costs.

At the end of this stage, variance of the mature costs will be rather high. However, the expected value of this cost has been determined. If this cost is too high to offer adequate hope of profit (i.e., to offer hope that the technology will be commercialized), or, if the cost necessary to commercialize lies within the variance but at an inadequately low probability, then the techology is not commercial. The project is dropped, or perhaps the invention stage is reentered.

The development stage is not primarily intended to reduce costs. Rather, it determines them, within a broad range, given the output of the invention stage. It deals not at all with market or regulatory uncertainties.

It is the introduction stage that deals primarily with these issues, while further narrowing the range of cost variance. It is here that full-scale production facilities are put into operation in order to reduce market uncertainties (e.g., marketing programs, distribution channels, maintenance organizations, market segmentation and differentiation, character of the technology and of the industry, and the value of mystique) and regulatory and legislative uncertainties (e.g., environmental, tax, delays).

It is only after these cost, market, and regulatory uncertainties have been reduced during the introduction stage that the diffusion stage is considered. The diffusion stage is marked by widespread production in a growing number of full-scale production facilities, widespread usage and (normally) the entry of competitors. Actual costs begin to decrease as experience is gained.

What is the driving force for this process? Clearly, it is pursuit of economic gain by the individual actors in the private sector. This might best be viewed as a series of investment decisions, one before each of the four stages.

- The decision to conduct research is a decision to invest in the possibility of an option to "develop" a new idea, should one be forthcoming.
- The decision to "develop" a new idea is a decision to invest in an option to "introduce" a new product or process, should the

development stage indicate it technically feasible at attractive probable cost.

- The decision to "introduce" is a decision to invest in an option to "diffuse" should the market, regulatory, and cost issues addressed in the introduction stage indicate favorable resolution.

At no point in the process has a "profit" been made or have cash flows been positive, even undiscounted. Even the introduction stage is not normally expected to be profitable in its own right, though some revenues may obtain. Rather, it is another in a series of investments.

- The decision to diffuse is the decision to invest in multiple full-scale facilities and in market share, with the expectation of "profit" - that is, within the planning horizon, the discounted cash flows will be positive, including the investment in the three earlier stages.[1] At the point of the diffusion stage, technical uncertainties are nil, market and regulatory uncertainties have been reduced to manageable levels, and costs are known with a relatively high degree of certainty. The significant uncertainty is competitive action, which would affect individual actors in the process more than the progress of the process itself.

Should the reduction of market, regulatory, and cost uncertainty achieved during the introduction stage indicate a low probability of profitable diffusion, then obviously the process would stop, or be

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[1]A complicating factor is the fact that, at the point of the diffusion decision, investments in prior stages are sunk costs.

delayed until a significant change occurred in one of the key elements. In the latter case, the type of the change would indicate the stage in which it occurred, and therefore, the succeeding stage in which the process would pick up, for example:

- New idea (new technology) - introduction. Redevelop, etc.
- Lower cost-introduction/development. Reintroduce.
- New market or regulatory climate. Reintroduce or diffuse.

One would correctly expect the magnitude of the investment to increase significantly from invention through diffusion to maturity. The successful invention (i.e., one that is eventually "commercialized") normally has minuscule costs relative to the investment in the mature, diffused industry. Even the investment in "introduction" is very small relative to diffusion investment. And, in most cases, the cost of each stage (including introduction) is not recovered during that stage. "If when examined <u>at the end of its development</u>, a technology appears to be commercial in the long run, it usually will be introduced and 'commercialized' by the private sector."[1]

The cost of successful invention, development, and introduction are, thus, small relative to that of diffusion. One might say that it is the unsuccessful ones that are expensive. Viewed as a whole, the successful ones must more than pay for the unsuccessful. This is usually viewed in the private sector as "risk", and is thought of, not as an added

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[1]Jacoby, H.D., Lawrence H. Linden, et al., "Government Support for the Commercialization of New Energy Technologies - An Analysis and Exploration of the Issues", Policy Study Group, MIT Energy Laboratory Report MIT-EL 76-009, Cambridge, MA. November 1976. (Prepared for ERDA under Contract No. E49-18 2295.).

cost, but rather as the expected return necessary to justify "taking the risk", i.e., making the investments in invention, development, and introduction.

An additional word needs to be said about the declining costs in the mature phase following diffusion, as experience is accumulated. It has been found[1] for a wide variety of products and a wide variety of industries that costs (in constant dollars) decline through experience as the product matures. This is a well-known phenomenon for the manufacturing process ("the learning curve"); the principle applies similarly to the total infrastructure, i.e., manufacturing, management, distribution, marketing, etc. (the "experience curve"). This cost reduction is a function of the number of comparable units produced, and is expected to amount to a 20-30% reduction for each doubling of accumulated experience. On a log-log plot, the curve is a straight line, with a slope of 70-80%.[2]

Several characteristics of this phenomenon are important to note here:

- The early points on the plot are scattered, and do not begin to take form until the system as a whole becomes organized and routine, well into the diffusion stage.
- Largely, each firm follows its own experience curve. For example, if firm X led the diffusion phase and had progressed down the experience curve in Figure A-1 to point C at the point

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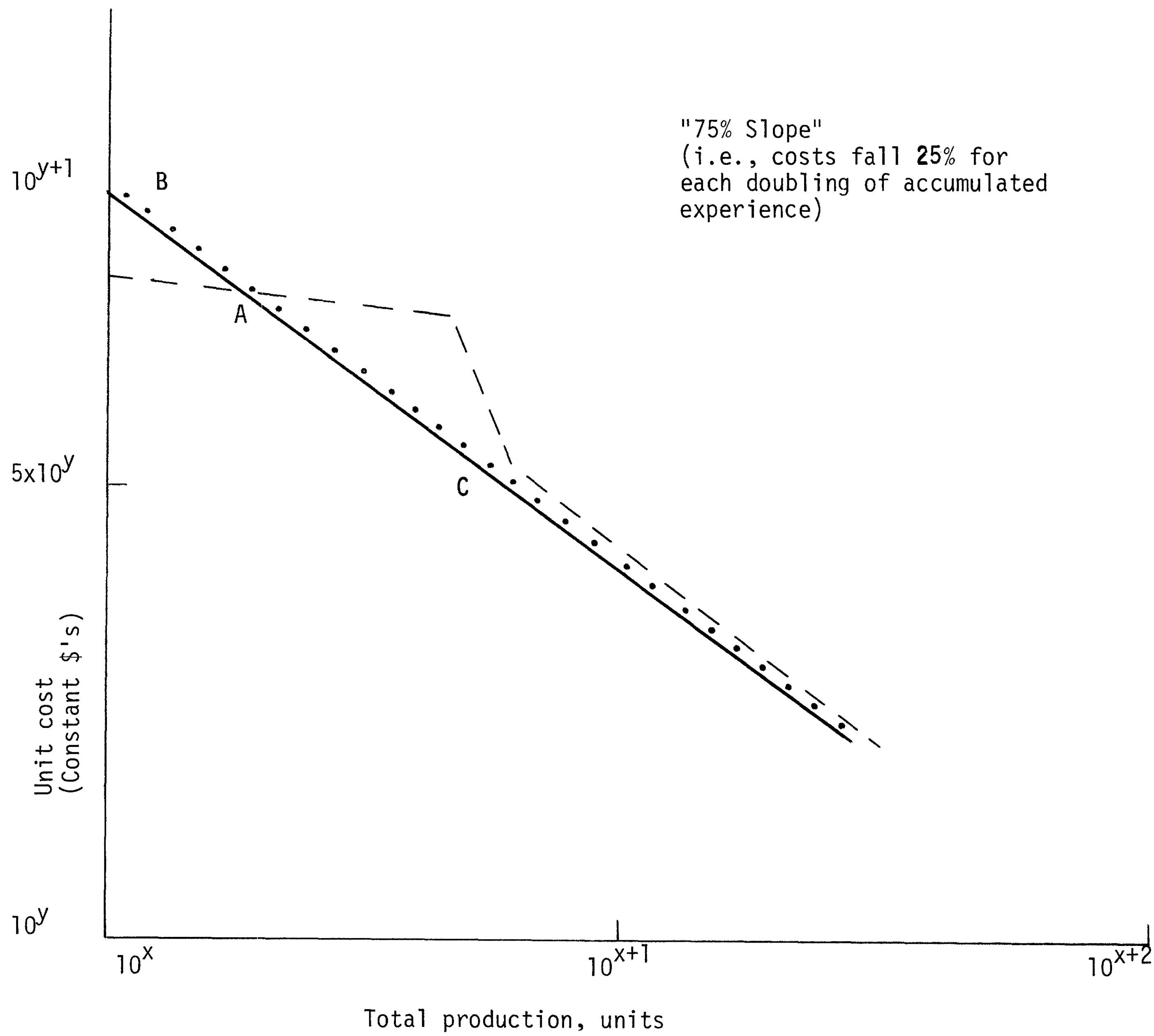
[1] Allan, Gerald B. "Note on the Use of Experience Curves in Competitive Decision Making", Intercollegiate Case Clearing House #9-175-174. Boston, 1975.

[2] See Figure A-1.



The Experience Curve

Figure A-1

in time firm Y decided to become a competitor, the latter would enter at, say, point B.

The implications of these characteristics are significant:

- In a fragmented industry (i.e., many equal competitors) all competitors would follow the experience curve more or less together. Prices would be expected to follow the dotted line, with the ordinal difference between the solid and dotted lines representing "profit" or return on total investment. Under these conditions, a firm is not likely to diffuse unless this ordinal difference is positive at or very near the beginning of the diffusion stage.
- If one firm were to adopt an aggressive pricing strategy, it might become the initiator of diffusion at point B, but price along the dashed line in order to dominate the market. Only at point A in experience would it begin to break even on current production, but at point C in experience it could begin reducing prices more sharply and remain profitable. Of course, the incentive for such a strategy would be increased profit (e.g., higher present value of net cash flows, properly discounted for the time value of money and for risk), due to "investment in market share".

One of the principal strategic reasons for a firm investing in invention, development, and introduction is to give it "a head start down the learning curve", i.e., more accumulated experience, and therefore lower unit costs than competition during diffusion. Strategically, this would lead to a dominant market share as maturity is reached.[1] (Other strategies are open to competition.) Either market failure or inadequate expected profit would prevent a firm from adopting this particular marketing strategy.

A.2 A SUMMARY VIEW

Figure A-2 presents a summary view of the process of technological change as outlined above.

- Invention is the generation of a new idea, with little knowledge of costs or of technical, market, or regulatory uncertainties. An investment represents an option to develop.
- Development is the design optimization of the idea until it is embodied in an actual model that will perform in the working environment.
  - Purpose: essentially eliminate technological uncertainty, and get an idea of the cost. In the language of the "Commercialization" paper,[2] mature cost $C(X)$ is estimated, but with high variance $G^i(C(X))$.
  - Market and regulatory uncertainties are not dealt with.
  - Criteria of success: a product which management can expect to sell at a profit.

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[1] Allen, Gerald B., "A Note on the Boston Consulting Group Concept of Competitive Analysis and Corporate Strategy", Intercollegiate Case Clearing House #9-175-175, Boston, 1975.

[2] op. cit., p.108.

- Investment: option to introduce.

- Introduction is the establishment of initial full-scale production facilities, marketing programs, distribution channels, maintenance organizations, etc.
  - Purpose: reduce market and regulatory uncertainty.
  - Cost: determined as $C^*(X^*)$, reducing the variance of $C(X)$ from $G^i(C(X))$ to $G^d(C(X))$.
  - Criteria of success: not profit, but option to diffuse profitably.
- Diffusion is widespread production and use, usually accompanied by the entry of competitors.
  - Purpose: profit, sometimes accompanied by a strategy to dominate the market.
  - Cost: $C(X)$ is determined, and the slope of the experience curve $C(X) = f(X)$, is established.
  - As maturity is approached each competitor progresses down his own learning curve.

Thus, each stage performs its own function. For example, if the cost of a particular technology emerging from the development stage is expected to be noncompetitive, the indication is to invent a new technology, not introduce the noncompetitive one. Similarly, if technology emerging from introduction does not appear profitable, the indication is to invent a new one, not diffuse the unprofitable one.

A.3 AN INTERPRETATION

At the present time, even those enthusiastic about proceeding with the construction and operation of full-scale shale oil plants expect the

	Invention		Development		Introduction		Diffusion	Maturity
Nature	Generation of a new idea.	-	Design optimization until embodied in actual model in working environment.	-	Establish initial production facilities, marketing program, distribution channels, maintenance organization, etc.	-	Widespread usage, with entry of competitors.	Equilibrium
Function	New idea.	-	1. Eliminate Technological uncertainty. 2. Estimate diffusion cost C(X) with high variance G^1 C(X).	-	1. Reduce market and regulatory uncertainties. 2. Determine Introduction cost C* (X*) and thereby reduce cost variance from G^1 to G^d (C(X)).	-	Market, expand, and compete profitably.	Expand profitably, but more slowly. Market and compete profitably.
Citeria of Sucess	A new idea with practical potential	-	A product which management can expect to sell at a profit.	-	Not profit, but an expectation to to diffuse successfully.	-	Positive net present value (including prior Investments).	Net cash flow.
Investment in	Option to develop		Option to introduce		Option to Diffuse		Profit	Net cash flow.
Cost	Unknown	Possibility of C (X)	Estimate of C (X)	C(X)	C* (X*) determined	C (X)	C (X) determined	C (X) = f (X) determined
Uncertainties: Cost	oo	-	high	G^1 (C (X))	reduced	G^d (C (X))	low	nil
Uncertainties: Technolog.	high	-	nearly eliminated	low	reduced	nil	nil	nil
Uncertainties: Market & Regulatory	oo	-	not dealt with	high	reduced	low	low	low

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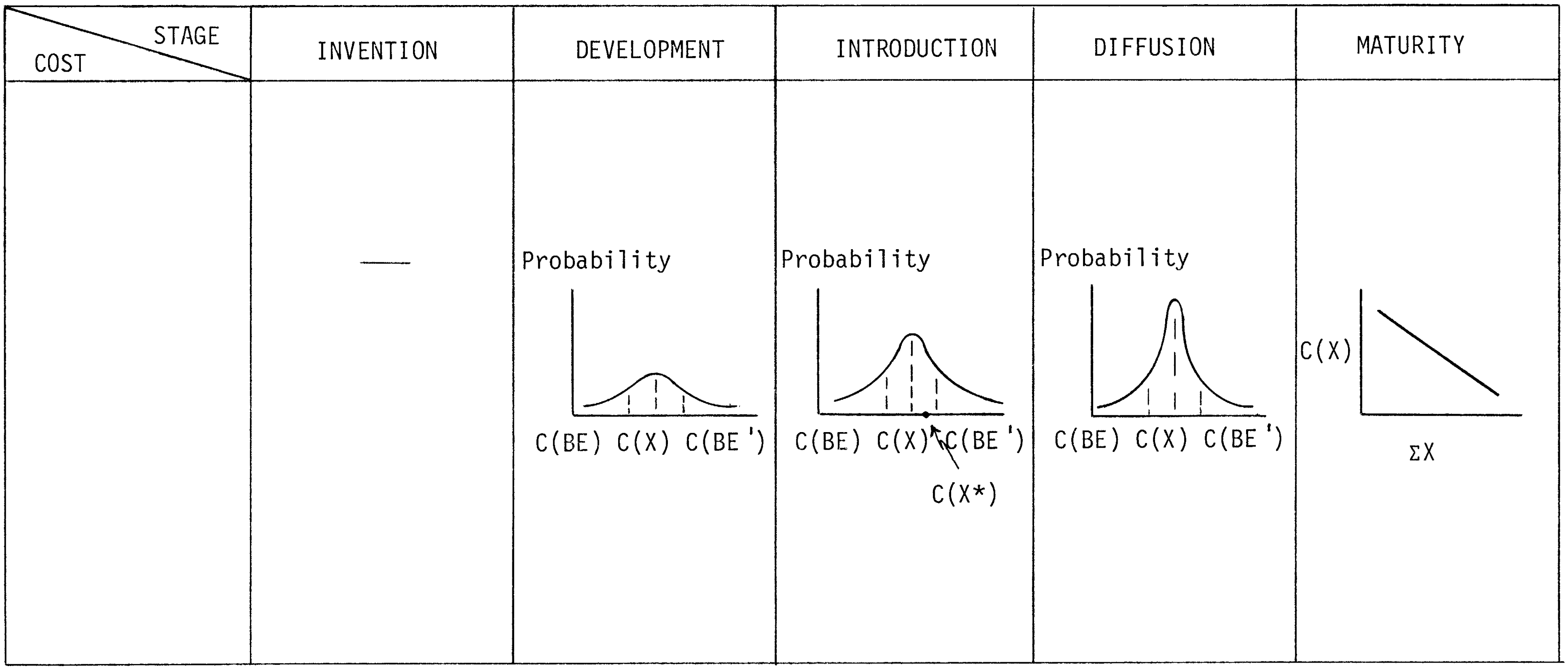
Figure A-2

Commercialization and the Process of Technological Change cost to exceed competitive prices (i.e., the world oil price). Their argument for proceeding is based on the need to reduce uncertainties (whether technological or regulatory), and to have the plants ready when competitive prices rise to the level of their costs. Most of those who make these arguments believe that a government subsidy of some form (e.g., special tax treatment) is appropriate in order to provide private incentive for the construction of these plants.

The description of the process of technological change is useful in interpreting these arguments. We are now at the "development" stage; the cost uncertainty is high, but is expected to exceed break-even prices. As displayed on Figure A-3, at the Development stage, probable cost is greater than break-even cost, $C(X) > C(BE)$. This analysis indicates the technology is simply not viable. Effort is indicated at the Invention stage, to develop a lower-cost technology. If technological risk is too high, effort is indicated at the Development (pilot plant) stage, not at the Introduction ("demonstration") stage. Effort at the Introduction stage is possibly appropriate to reduce regulatory uncertainty;[1] however, the purpose of doing so is not clear as long as the <u>expected</u> cost exceeds break-even, <u>even after reducing</u> the uncertainty. The argument for government subsidy or incentives would hinge on a demonstration that the private discount rate exceeds the public, or that the social value of shale oil exceeds the market value (or, perhaps, the existence of some other form of market failure). That is to say, if the break-even price is to rise from $C(BE)$ to $C(BE')$ over some time frame,

[1]However, it needs to be emphasized that there are alternative methods for reducing regulatory risk which may well be much more cost-effective.



Cost Uncertainties and Break-Even Costs

Figure A-3

then investment in Introduction/Diffusion may well be economically attractive now, even at C(X), depending on the discount rate. The question raised by this analysis is, if the investment is not attractive to the private sector now, how is it attractive to the public?

The process of technological change is normally driven by the expectation that C(X)   C(BE), the difference representing the possibility of a profit. (This is represented on Figure A-3 as C(X) C(BE').) This relation must hold for each phase in the process for investment in the next phase to be attractive. If this relation does not hold at any phase, then the process (properly) ceases.

A.4 THE SHAKEDOWN PERIOD

Introduction and Diffusion reduce uncertainty, not expected cost. One of the ways in which this occurs is that, by simple trial and error, marginally equivalent methods, technologies, processes, combinations, and permutations are tried against each other, and the marginally best is thereby identified. This begins to occur during the Introduction stage and continues through the early Diffusion stage. Thus in shale oil, the various approaches to retorting would compete against each other in the real world, as would in-situ and modified in-situ; by the closing of the Diffusion stage, industry would have learned the optimum process, the key situational parameters, and how to obtain maximum profit, given any particular set of circumstances.

An example here may be helpful. During World War II, catalytic cracking of gas oil was discovered as a practical means of increasing the yield of high-octane gasoline (i.e., avgas) from crude. At the end of the Development stage, three competing processes were identified: FCC, TCC, and HCC.[1] Any of the three was far superior to none, but it was not clear which was the best of the three. Therefore, all three competed in the real world, and by the middle of the Diffusion stage, the FCC was found to be superior to the two competing approaches in all applications. That is to say, against a refinery without catalytic cracking, any of the three processes was highly attractive. However, against a refinery with FCC, the other two were very unattractive.

The point here is that the cost advantage of FCC over TCC or HCC is an order of magnitude less than the cost advantage of any of the three processes over no catalytic cracking at all. Applying this point to shale oil, we can see that, as far as the process of technological change is concerned, the important issue is the range of expected costs of any of the competing processes, relative to expected break-even cost. This is illustrated on Figure A-4, which compares the expected costs of Processes A, B, and C with the break-even cost C(BE'). The process of technological change depends on $C_A(X)$, $C_B(X)$, and $C_C(X)$ relative to C(BE'), not relative to each other. However, during the shakedown period of the process of technological change, the uncertainties of $C_A(X)$, $C_B(X)$, and $C_C(X)$ relative to each other are reduced significantly, and the appropriate processes are sorted out from the competing ones.

A.5 "EXPERIENCE" COST REDUCTION

It is important to distinguish this "sorting out" during the shakedown period from the cost reductions which occur during maturity.

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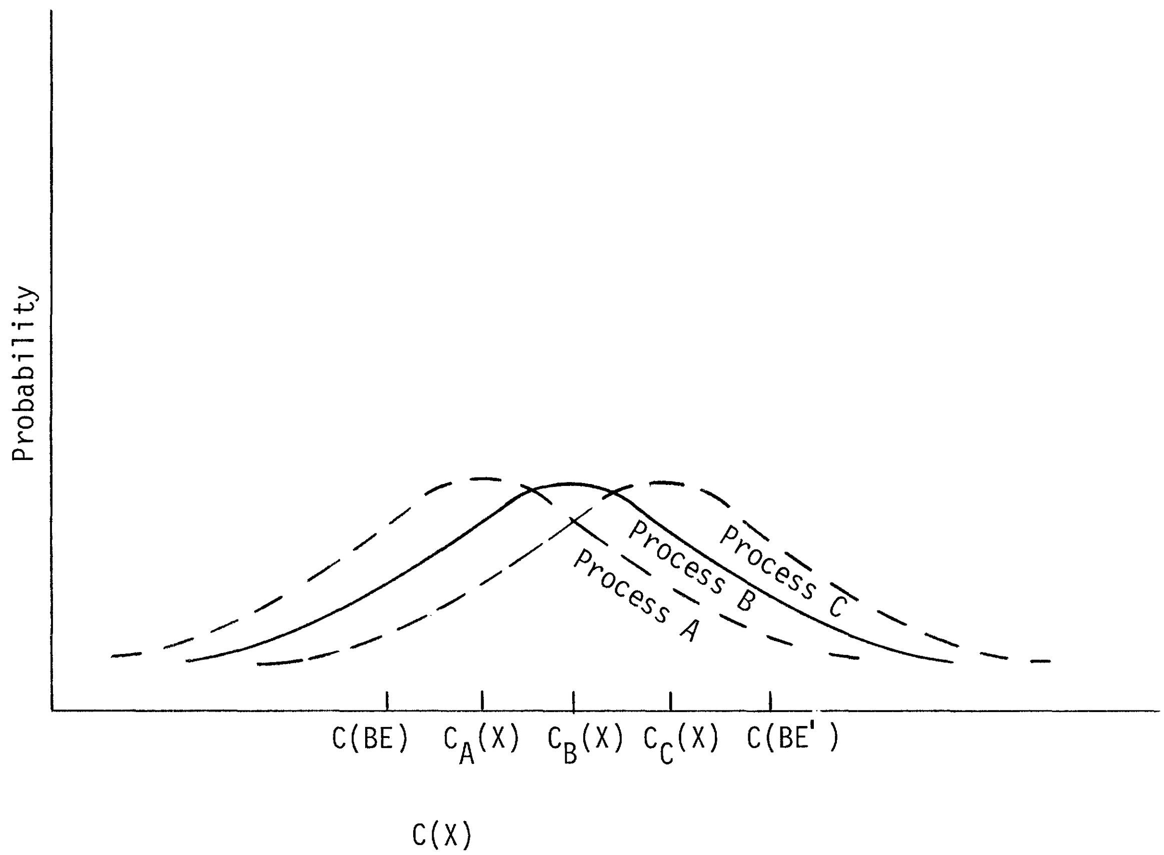
[1]Fluid catalytic cracking, Thermofor catalytic cracking, and Houdry catalytic cracking, respectively.



The Shakedown

Figure A-4

The former is the determination of which process, technique, etc., is most cost-effective. Once this has been determined, then this knowledge becomes the basis for the rest of the Diffusion stage and for the Maturity stage. It is only after the established process, technique, etc., has become repetitive that the continuing cost reduction of the "experience curve"[1] become applicable. Thus, the shakedown period is one of cost determination, by selecting the marginally optimum process, while the experience curve effects continuing cost reduction, resulting from the accumulation of experience in repeating the same functions.

These two dynamics are not only different in both nature and in consequences, they are also separated in time. In fact, at any single point in time, they are, by definition, mutually exclusive.

A.6 APPLICABILITY TO THIS STUDY

Having proposed a model for understanding the process of technological change, and having analyzed the present shale oil industry through the framework of this model, hopefully now we should be able to articulate the question this study intends to raise in more precise and succinct terms.

If an industry were to be put in place, as compared with evolving through the process of technological change, then we would, in effect, be jumping from the end of the Development stage to the end of the Diffusion stage. Since we are focusing here on technological costs, the major phase bypassed would be the shakedown period. Thus, a non-optimum

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[1]As defined and discussed in Section A.1.

process or technique may be the one selected for the industry in place. To use again our World War II analogy from the refining industry, we might have built a refining industry on the basis of the HCC process. The question of this study is, then, what is the probability of the economies of an industry in place being greater than the diseconomies of skipping the shakedown period?

This question can be seen graphically on Figure A-4, if Processes A, B, and C represent presently competing shale oil techniques, and C(BE) represents the break-even cost of shale oil. What is the probability of the cost of shale oil from an industry in place being less than C(BE), <u>even if Process C is chosen as the basis for the industry</u>?

Our analytic framework permits asking this same question an additional way. Note that in the process of technological change, cost <u>reductions</u> occur at only the stages at each extreme of the process: Introduction, on the one side, and Maturity, on the other. Thus, normally, if a technology at the end of the Development stage has an expected cost greater than C(BE), then the technology is abandoned. The question here is, could the economies of an industry in place reduce the expected cost from greater than break-even to less than break-even? This is displayed graphically on Figure A-5.

This picture raises quite naturally the question about the possible role of experience cost reduction (as this term is rather narrowly defined in this paper). After all, this kind of cost reduction has played a rather spectacular role in other industries, IC's being the classic example. However, in the shale oil industry, such reductions are not expected by anyone to be significant, principally for two reasons.

In the first place, the dynamics of limited resources is expected to be overwhelming from the very beginning. In the second place, none of the components of the shale oil industry is new (i.e., mining, retorting, materials handling); we are already so far down the learning curve on each of them that additional accumulated experience within the shale oil industry is expected to result in negligible cost reductions.

Thus, the picture of shale oil is basically one of continually increasing, rather than decreasing, costs. Any viability at all depends, not on increasing economies, but on increasing break-even costs (i.e., increasing world oil price). This is, in fact, a poorly understood notion, and is contrary to most experience. There are no analytical tools capable of dealing adequately with issues of marginal costs exceeding average costs.[1]

Over against this, the question raised by this study is a rather fundamental one: When viewed from the perspective of an industry in place, are there possible economies not yet perceived, which might permit costs to decline (in real terms) rather than to rise, over the long term?

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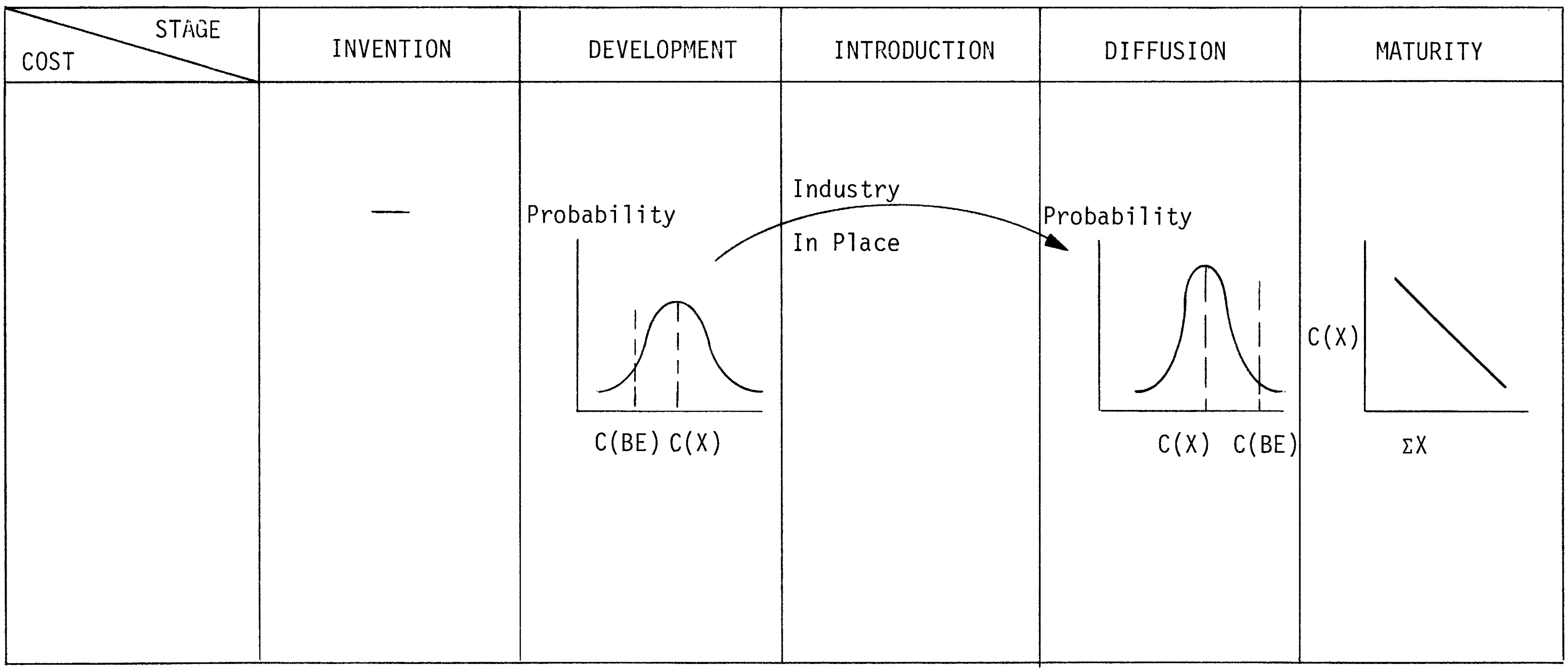
[1]Ball, Ben C., Jr., "Energy: Policymaking in a New Reality", Technology Review, October/November 1977.



An Industry in Place

Figure A-5

APPENDIX B: Estimating the Costs of Shale Oil Production

by Robert J. Barbera

B.1 Introduction

This appendix explains the approach employed to estimate the costs of oil shale production. In particular, a review of available industry cost estimates is performed, put in comparable forms and an average industry cost estimate is generated using 4th quarter 1978 dollars.[1]

The approach taken involved five steps. First, Oil Shale Industry representatives were consulted and the most recent relevant information collected. Next, this information was evaluated and relevant cost figures extracted; thirdly, each cost estimate's development was reviewed and characterized in terms of its firmness. Fourthly, the different cost estimates were adjusted to as close to equivalent forms as possible, and then, taking into account the reliability of each estimate, a weighted industry average cost was determined. Finally, Section 2 of the main report explains the sensitivity analysis performed on the industry average cost and provides a range of costs and associated probabilities.

Organization of Cost Estimates

Shale oil production was divided into the following component parts:

Mining for Surface Retorting

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[1]To secure a DCFROR of 15% for a commercial shale venture, in consideration of Federal and Colorado taxes, we estimate that an annual capital charge of 28% of capital costs is required. Similarly for a 10% DCFROR a 15% annual capital charge is needed.

Surface Retorting

Upgrading

For each of these parts the following information appears:

(1) A brief process description

(2) A summary of the degree of testing and the success of testing the process

(3) A qualitative description of the cost information available

(4) A table summarizing the cost estimates

B.2 MINING FOR SURFACE RETORTING

Introduction

There are two basic approaches to mining shale for surface retorting, underground mining and open pit mining. The approach taken depends of course upon the physical characteristics of the resources to be mined. Although present open-pit mining technology can be applied to some shale deposits close to the surface, much of the richer deposits are deep and not presently amenable to this technique. For this report we assume that 15% of the shale available can be mined in such a fashion.

Summary of Industry Cost Estimates

The cost to underground mine shale for surface retorting has been addressed in a number of studies. Cameron Engineers provide an in-depth evaluation of the costs of this technique.[1] The study evaluates four types of underground mining:

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[1] Cameron Engineers, Inc., A Technical and Economic Study of Candidate Underground Mining Systems for Deep, Thick Oil Shale Deposits, Bureau of Mines, 11/76.

(1) Chamber and pillar

(2) Sublevel stoping with spent shale backfill

(3) Sublevel stoping with full subsidence

(4) Block caving

The Colony Development Operation, a planned 50,000 BPD commercial facility also presents cost estimates for underground mining.[1] Colony's figures are part of an Engineering Contractor's estimate performed in order to evaluate the economic viability of their proposed operation. Paraho, in the commercial evaluation of their process also estimate the costs of mining.[2] Finally, we used a rule-of-thumb estimate that the cost of surface mining of shale is 60% of the cost of underground mining.

Table B1 summarizes the cost figures for all these firms. These costs have been adjusted to reflect the same shale resource (35 GPT) as well as updated to reflect 4th quarter 1978 dollars.

Table B1 also contains a figure labeled the Industry Average Cost Estimate. This figure, an average of the each of the estimates presented, represents an estimate of the expected value of the cost of mining shale (given the optimistic bias inherent in figures that assume "all goes well"). In section 2.1 of the main text we identify parameters that can affect the cost and indicate the sensitivity of cost to the values of certain of these parameters.

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[1]Nutter et al., "Oil Shale Economics Update", TOSCO, April 18, 1978.

[2]Pforzheimer, "Commercial Evaluation of an Oil Shale Industry Based on the Paraho Process," Paraho, 9/77.

TABLE B-1: MINING COSTS[1]

	Mine Size (tons/day)	Capital Costs $M	Oper. Costs $M/Yr.	Total Equivalent Cost ($/BBL) 10% return	15% return
Underground:					
Cameron[2]	85,000	170	59	3.80	4.80
Tosco[3]	66,000	270	38	4.80	7.00
Paraho[4]	157,421	750	97	5.40	7.90
Surface[5]				2.80	4.00
Industry Average[6]				4.40	6.20
Industry Average Including Leasing Costs				5.50	8.20

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1. Includes costs incurred to mine the shale rock, crush the rock and dispose of the spent shale. The final industry average also contains an estimate of leasing costs.

2. Cameron Engineers, A Technical and Economic Study of Candidate Underground Mining Systems for Deep, Thick Oil Shale Deposits, B.O.M., 11/76. Cost Estimates are for a mine producing 85,000 tons per days of shale rock for a 355 day year.

3. Tosco, "Oil Shale Economics Update," Nutter et al, 4/78. Cost estimates are for a mine producing 66,000 tons per day of shale rock with a .9 stream factor.

4. Paraho, "Commercial Evaluation of an Oil Shale Industry Based on the Paraho Process," Pforzheimer et al, 9/77. Cost estimates are for a mine producing 157,421 tons per day with a .9 stream factor.

5. We assume that 15% of the shale can be surface mined at a cost of 60% of the industry average cost for underground mining.

6. The Industry Average Cost was computed using the following weights: for underground mining (85% of total); .30 (Cameron), .35 (Tosco), .35 (Paraho).

B.3 SURFACE RETORTING

Introduction

Surface retorting of shale can be performed in any one of a number of ways. The three major techniques are: (1) circulation of inert solids through the vessel; (2) upflow of shale using solids pumps and; (3) downflow of shale through a vessel. This section reviews four commercial designs, the Tosco II, Lurgi-Ruhrgas, Union and Paraho Direct retort processes. This selection affords each of the generic retort approaches representation by a potentially competitive design. The choice of retorts is dictated, however, not only by commercial potential but also by the availability of information. The following section reviews the cost estimate for each of these retort designs and provides a weighted industry average cost of retorting.

Summary of Industry Cost Estimates for Surface Retorting

The Tosco II Retort

Retorting for the Tosco II process occurs in a solid-to-solid heat transfer retort. Preheated oil shale, crushed to a size of 1/2-inch or smaller, is fed into the retort along with 1/2-inch externally heated ceramic balls. The process recovers 100 percent of the total crude oil produced by Fischer assay as well as matching Fischer assay yields of medium Btu gases.[1]

The Tosco II retort has been tested in both a 25 ton-per-day pilot plant and a 1,000 ton per day semi-works. The 1,000 ton-per-day

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[1] It should be noted that part of the processed gas must be used to preheat the shale and ceramic balls thereby lowering the net energy yields of the retort.

semi-works plant, tested between 1965 and 1972, has retorted 220,000 tons of oil shale and produced about 180,000 barrels of crude shale oil. No indication of duration of operation or operating performance (stream factor) is provided. TOSCO corporation reports do label this demonstration effort as successful.

Cost calculations for a commercial size Tosco II operation were performed in 1974. Engineering contractors perpared a detailed design and cost estimate for a 66,000 ton-per-day operation. The facility requires a series of six 11,000 ton-per-day Tosco II retorts. Recently an updated version of the cost of this facility has been made available (Nutter et al., "Oil Shale Economics Update", Tosco, 4/78). Table B2 summarizes these costs.

The Lurgi/Ruhrgas Retort

The Lurgi operation retorts shale by placing it in direct contact with hot solids. Oil shale, crushed to sizes smaller than 1/4 inch, is mixed in the retort with six to eight times as much hot, spent shale. The heat required for the retorting process is obtained by burning a portion of the residual carbon on the spent shale. The retort produces 105 weight percent of Fischer assay crude shale oil as well as a medium Btu gas.

The basic Lurgi retort has an extensive operating background. A 4000 TPD retort exists and has been commercially applied to both coal and liquid petroleum feedstocks. Application to oil shale, however, remains small. To date only a 20 TPD pilot plant has operated on Colorado oil shale. Lurgi publications report a successful test.

Assuming the basic 4000 TPD Lurgi retort is easily adaptable to oil shale, scale-up requirements necessitate only a doubling of the retort output to 8000 TPD. The commercial complex envisioned includes eight 8000 TPD retorts that will combine to produce 50,000 BPD of crude shale oil from 30 GPT shale.

An estimate of the combined total costs for the retorting section of a 50,000 BPD Lurgi operation is available. The cost assumes the plant is constructed in Germany and the figure based on the 4th quarter 1975 dollars and a Deutschmark-to-dollar exchange rate of 2.5. No attempt was made to consider other capital costs such as those required for utilities, community support etc., nor are any operating costs presented. The estimate (adjusted for inflation) appears in Table B-2. Assumed values for operating costs and off-site costs are also included.

The Union Retort

In the Union process shale is moved up through the retort by means of solids pumps. Crushed shale, reduced to sizes less than 2 inches, enters a rock pump at the bottom of the retort and is forced upward through the device. Heated gas enters the top of the retort and upon contact with the shale releases both liquid and gaseous fuels which collect at the bottom of the retort. The process produces 100% of the Fischer assay crude shale oil as well as producing medium Btu gases.[1]

Although Union has a long history of retort design experience, the current retort has a limited testing background. A 1200 TPD semi-works reflecting an earlier Union design was constructed in the late 50's, however, the retort's low Fischer assay yields and its production of large quantities of low-Btu gases (of little commercial value) rendered it an economically undesirable design. The current Union retort design,

[1]A portion of the gas must be used in the retorting process thereby lowering the net energy yields of the retort.

a modified version of the first, has only been operated as a 3 TPD pilot plant. Union publications do report that the pilot plant tests have been successful. Future plans for the Union retort call for the construction of a 10,000 TPD commercially-sized retort and the necessary support operations to allow the production of 9000 BPD of crude shale oil from 41 GPT shale. Additional retorts will be added along with refining capacity contingent on the first retort's success.

Only the most general cost information is available for the Union retort. A combined estimate of the total capital costs for the mining, retorting and support facilities for the 10,000 TPD plant is available as well as an estimate of the operating costs for this complex (Hopkins et al., "Development of Union Oil Company Upflow Retorting Technology", p. 12). No breakdown of these costs is provided. The cost figure (adjusted for inflation) is presented in Table B-2.

The Paraho Retort

In the Paraho process retorting results from direct gas-to-solids contact. Rising recycled gas entering the bottom of the retort is heated by the retorted shale. Additional process heat requirements are generated by burning some of the gas as well as gasifying some of the carbon in the retorted shale. The Paraho process yields 90% of Fischer assay oil as well as three times the Fischer yield of medium grade Btu gas. The yields of oil plus gas, on a Btu basis, are 103% of Fischer assay yields.[1]

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[1]Note, these yields are net of requirements for retort heating. Indirect heated retorts have carbon on the shale and burn retort products in fuel process heaters. Paraho figures indicate that if Paraho retort yields include process fuel the Paraho retort's efficiency increases to 114% of assay.

TABLE B-2: SURFACE RETORTING COSTS[1]

Retort:	Retort Size, Bbl/Day	Capital Costs $M	Oper. Costs $M/Yr.	Total Equivalent Cost ($/BBL) 10% return	15% return
Tosco[2]	55,000	510	43	7.60	11.80
Union[3]	10,000	92	N.A.	8.00	12.50
Lurgi[5]	50,000	30	N.A.	5.20	12.50
Paraho[5]	100,000	700	81	5.30	7.90
Industry Average[6]				6.50	9.90

1. Includes costs incurred to recover raw shale oil; to use, sell or dispose of all product streams; and to burn carbon from spent shale if applicable.

2. Tosco, "Oil Shale Economics Update," Nutter et al, 4/78.

3. Union, "Shale Oil--A Synthetic Fuel Whose Time Has Come," Hartley, 11/78.

4. Lurgi, "Economic Data for a 50,000 BPD Lurgi/Ruhrgas Shale Oil Plant," Harnell 3/76.

5. Paraho, "Economic Evaluation of an Oil Shale Industry Based on the Paraho Process," 9/77.

6. The Industry Average Cost was computed using the following weights: .4 (Tosco), .1 (Union), .1 (Lurgi), .4 (Paraho).

The Paraho retort has been tested extensively at the semi-works scale. The most recent test run for the 300 TPD semi-works plant, performed during 1977-1978, was labelled a great success. The retort operated with over a 90% stream factor and a record run of 105 days of continuous operation. To date, the semi-works has retorted over 200,000 tons of shale to produce over 100,000 barrels of crude oil. No Paraho retort larger than 300 TPD, however, has operated on oil shale.

The costs of a Paraho complex have been estimated by Paraho.[1] A detailed cost evaluation of a commercial operation was performed for 5 alternative strategies. Each of these strategies looks at a specified mixture of Paraho direct retorts and Paraho's indirect retort. Alternative 1 (18 direct, 6 indirect, syncrude fuel production) was chosen as the most representative figure of Paraho's costs; table B2 summarizes this cost estimate.

Industry Cost Estimate Summary

The cost information available for each retort is summarized in Table B2; the costs have been put into a comparable form and adjusted to reflect 4th quarter 1978 dollars. (Union and Lurgi figures lacked any detail; therefore several heroic assumptions had to be made to isolate the retorting cost/bbl using either of these processes).[2]

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[1]Pforzheimer et al., "Commercial Evaluation of an Oil Shale Industry Based on the Paraho Process," 11th Israel Conference on Mech. Eng., 9/77.

[2]In particular the lack of cost breakdowns between mining and retorting for the Union plan and the absence of operating cost estimates for the Lurgi retort render our cost figures for these technologies tenuous at best.

To generate an industry average value for the cost of surface retorting, weights were required for each retort's costs. These weights were meant to reflect consideration for the firmness of each estimate and were not judgments about the desirability or cost of individual retort technologies. Accordingly each retort's testing history and cost estimate were reviewed in terms of the following criteria:

(1) Size of operational retort designed specifically for oil shale

(2) Scale up required for existing retort to produce retort of commercial size

(3) Engineering performance record of operational retort

(4) Availability of detailed cost information

(5) Degree of effort put into generation of cost estimates

The retort estimates were also evaluated in terms of the level of ease with which we could put these estimates into comparable form. Unsurprisingly, the Paraho and Tosco II processes received the high weights. Both have had successful engineering tests on oil shale, detailed cost information published, and significant effort put into the generation of these estimates. Union and Lurgi's figures come with limited testing experience, and are incomplete and undetailed. Thus they received low weights. The average figure is used in the sensitivity analysis performed in Section 2 of the main report.

B4. Upgrading

Raw shale oil must be treated to allow for further processing by conventional refining techniques. Levels of nitrogen and metal concentrations must be reduced. Byproducts, such as ammonia and sulfur, do result from such processes and byproduct credits are accounted for in the figures provided.

The cost estimates we employed for computing the Industry Average cost estimate were prepared by Paraho, Tosco, and Chevron. A summary of the figures from these estimates is given in Table B-3.

TABLE B-3: UPGRADING COSTS[1]

	Reactor Size Bbl/Day	Capital Costs $M	Net Oper. Costs $M/Yr.	Total Equivalent Cost ($/BBL) 10% return	15% return
Retort:					
Paraho[2]	100,000	460	55	3.50	5.30
Tosco[3]	66,000	210	5.2	2.30	3.90
Chevron[4]	100,000	600	33	4.20	5.90
Industry Average[5]		N.A.	N.A.	3.30	5.00

1. Includes costs incurred to reduce nitrogen and metals in raw shale oil and make marketable byproducts. All costs are adjusted to 4th quarter 1978 dollars.

2. Paraho, "Commercial Evaluation of an Oil Shale Industry Based on the Paraho Process," Pforzheimer et al., 8/77.

3. Tosco, "Oil Shale Economics Update", Nutter et al., 4/78.

4. Chevron, "Refining and Upgrading of Synfuels from Coal and Oil Shales by Advanced Catalytic Processes," 8/78.

5. The Industry Average Cost was computed using the following weights: .34 (Paraho), .33 (Tosco), .33 (Chevron).