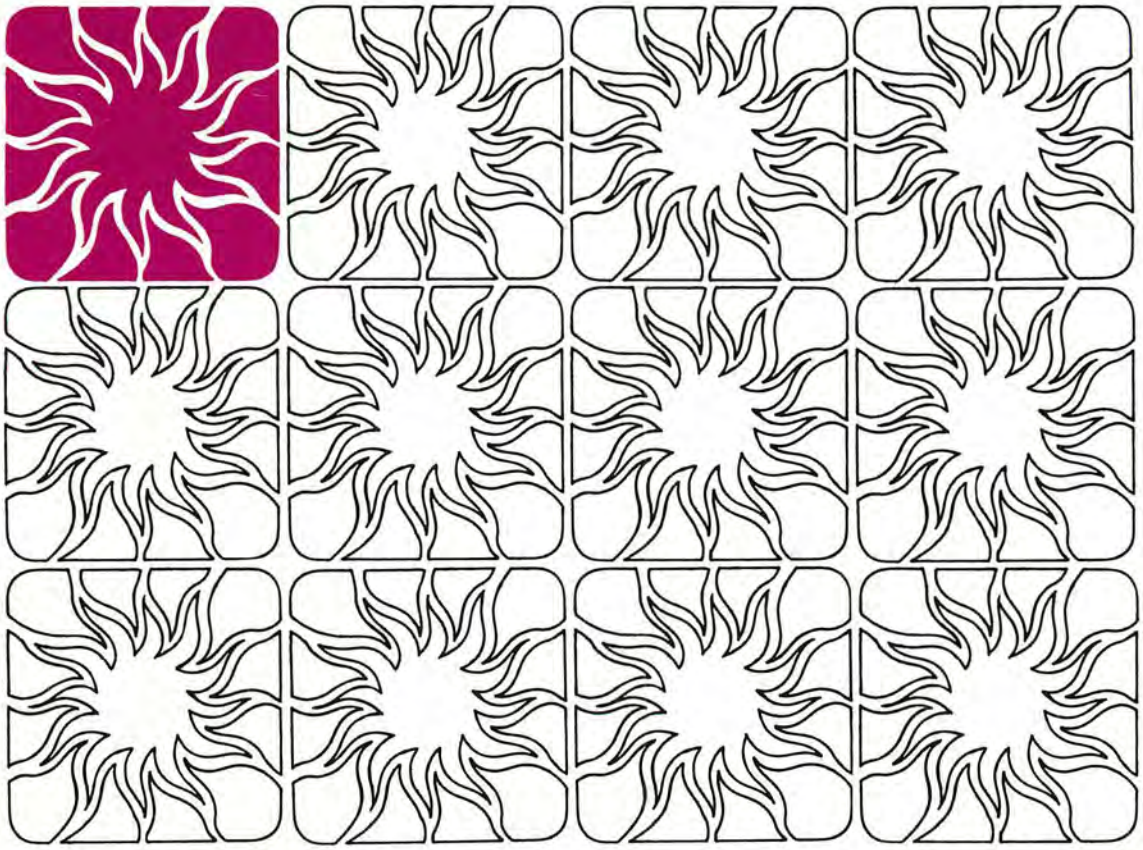

U.S. Energy Outlook

Oil Shale Availability

National Petroleum Council

U.S. Energy Outlook

Oil Shale Availability

A Report by the
Oil Shale Task Group of the
Other Energy Resources Subcommittee
of the National Petroleum Council's Committee
on U. S. Energy Outlook

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Union Oil Company of California

National Petroleum Council

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PREFACE

On January 20, 1970, the National Petroleum Council, an officially established industry advisory board to the Secretary of the Interior, was asked to undertake a comprehensive study of the Nation's energy outlook. This request came from the Assistant Secretary-Mineral Resources, Department of the Interior, who asked the Council to project the energy outlook in the Western Hemisphere into the future as near to the end of the century as feasible, with particular reference to the evaluation of future trends and their implications for the United States.

In response to this request, the National Petroleum Council's Committee on U.S. Energy Outlook was established, with a coordinating subcommittee, four supporting subcommittees for oil, gas, other energy forms and government policy, and 14 task groups. An organization chart appears as Appendix 2. In July 1971, the Council issued an interim report entitled *U.S. Energy Outlook: An Initial Appraisal 1971-1985* which, along with associated task group reports, provided the groundwork for subsequent investigation of the U.S. energy situation.

Continuing investigation by the Committee and component subcommittees and task groups resulted in the publication in December 1972 of the NPC's summary report, *U.S. Energy Outlook*, as well as an expanded full report of the Committee. Individual task group reports have been prepared to include methodology, data, illustrations and computer program descriptions for the particular area studied by the task group. This report is one of ten such detailed studies. Other fuel task group reports are available as listed on the order form included at the back of this volume.

The findings and recommendations of this report represent the best judgment of the experts from the energy industries. However, it should be noted that the political, economic, social and technological factors bearing upon the long-term U.S. energy outlook are subject to substantial change with the passage of time. Thus future developments will undoubtedly provide additional insights and amend the conclusions to some degree.

TABLE OF CONTENTS

FOREWORD

The objective of the Oil Shale Task Group, in the final phase of the U.S. Energy Outlook study, was to analyze changes in industry and government policies and economic conditions that could affect the production of fuels from oil shale. The task group approached these objectives by preparing analyses of supply elasticity and various parametric factors.

The economic data developed for this purpose is not an attempt to predict absolute cost levels for future shale oil production, since neither the effect of inflation nor improvements resulting from experience are included in the cost estimates. Rates of return do not take into account the inclusion of resource cost or debt in the financial structure of a shale oil industry.

The basic engineering and economic data from the NPC Initial Appraisal were used in this study. Not all of the material contained in the Initial Appraisal has been incorporated into this report. For completeness, both reports should be considered together.

Any uses made of the data from this study should be consistent with the objectives stated above.

Chapter One

INTRODUCTION

BACKGROUND

The Initial Appraisal Oil Shale Task Group report projected shale oil production as having a high potential for development within the study period 1971-1985, under government policies and technology existing at that time.* The report discussed in detail the energy reserve potential in U.S. oil shale and described a method of development that might utilize these reserves. It also discussed the various technologies of mining and crushing oil shale, retorting the shale to produce crude shale oil, and upgrading the crude shale oil to a pipeline quality syncrude which would be a premium feedstock to a conventional petroleum refinery. A capital investment and operating cost estimate for the various parts of a commercial syncrude venture, based on the method of development assumed in the Initial Appraisal, was also given.

The objective of this current study is to analyze changes in industry and government policies and in economic conditions that could affect the production of fuels from oil shale, with a particular view to the possibilities for increasing the production of such fuels beyond that level projected in the Initial Appraisal.

The task group approached these objectives by preparing a supply elasticity study, which comprises the first part of this report. This study evaluates the effect that syncrude price could have on recoverable commercial reserves of oil shale and on the syncrude production rate through 1985, utilizing the costs developed in the Initial Appraisal. The assumption is made that all oil shale reserves, both government and private, will be available for development. A royalty charge, based on the U.S. Department of the Interior's proposed Prototype Oil Shale Leasing Program of 1971, is assumed for oil shale mined on both state and federal holdings, and an equivalent charge is applied to private holdings. Also estimated is a maximum construction rate for oil shale plants, under non-emergency conditions.

This report also contains a study of factors that could influence the economics and thus the growth rate of the shale oil industry. The effects of government leasing policies on making oil shale reserves available and of government tax policies on syncrude economics have been studied, as well as laws and regulations concerning environmental control, health and safety.

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* NPC, *U.S. Energy Outlook, An Interim Report, An Initial Appraisal by the Oil Shale Task Group 1971-1985* (February 25, 1972).

The impact of improvements in present technology and of new technology is difficult to assess quantitatively, although some potential improvements are now in view and others may be anticipated. The sensitivity of syncrude economics to changes in investment and operating costs has been evaluated.

Consideration is also given to requirements for direct regional support of a shale oil industry, including mine and plant operating manpower, water and electric power supply, roads, pipelines and community services.

SUMMARY AND CONCLUSIONS

Using the economic data developed for the Initial Appraisal, a supply elasticity study has been made to determine the effect that the "price" placed on shale oil syncrude would have on the syncrude production rate through 1985.* The anticipated effect of government policies, legislation and technologic changes on availability and "price" of syncrude are discussed, and regional considerations for supporting an oil shale industry are delineated.

This supply elasticity and parametric study is not an attempt to predict absolute cost levels for future shale oil production, since neither the effect of inflation nor improvements resulting from experience are included in the cost estimates. The objective of the study is to indicate the sensitivity of shale oil production to various economic factors and government policies.

Government and private oil shale reserves are all assumed to be available for commercial development, with payment of royalty on the oil shale produced. Oil shale reserves, equivalent to 54 billion barrels of syncrude, in the Piceance Basin of Colorado and Uinta Basin of Utah are considered to be the most economically recoverable portion of the Green River Formation oil shale resources. Projected development through 1985 would commit less than 6 billion barrels of these reserves, all located in the Mahogany Zone of the Piceance Basin.

The commercial operation expected to be used in the mining of oil shale through 1985 is the underground, room-and-pillar mining method. Approximately 35-gallon per ton oil shale in the Mahogany Zone of the Piceance Basin in Colorado is expected to be recovered. This mining method and the processes for production of shale oil and its upgrading to syncrude have been described in the Initial Appraisal Oil Shale Task Group report. Investment and operating costs, based on contant 1970 dollars, are given in that report and are also used in the present supply elasticity study.

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* As used in this study, "price" does not mean a specific selling price as between producer and purchaser and does not represent a future market value. The term "price" is used to refer generally to economic levels which would, on the basis of the cases analyzed, support given levels of activity for the particular fuel.

The syncrude product upon which this projection is based is a 46°API, hydrotreated distillate, essentially free of sulfur and low in nitrogen, thus constituting a premium refinery feedstock.

Development schedules have been estimated for the four cases specified for the U.S. Energy Outlook study:

- Case I: Maximum syncrude production rate by the end of 1985--750,000 barrels per day (750 MB/D)
- Cases II and III: Most probable syncrude production rate--400 MB/D
- Case IV: Minimum syncrude production rate--100 MB/D.

These schedules assume that syncrude "prices" are adequate to encourage commercial development.

The Case I maximum feasible production rate under non-emergency conditions takes into account, aside from syncrude "price," other factors which limit the rate of growth of production capacity. These factors are the logistics of plant design, engineering and construction and industry's capability of supplying heavy mine and plant equipment. The most probable development rate, Cases II and III, was discussed in the Initial Appraisal. It was estimated to be 400 MB/D by 1985 on the assumptions that no process was ready for immediate commercialization, that time was required for operation of a prototype unit, and that only private lands were available. The minimum, Case IV, rate of 100 MB/D by 1985 might result from unexpectedly restrictive environmental factors.

The "price" level at which initial syncrude production becomes economically attractive depends upon the desired rate of return on the investment in light of the risks involved. Syncrude "prices" in constant 1970 dollars, f.o.b. the syncrude plant, were based on the initial production being from 36-gallon per ton shale with first generation technology. These "prices" are calculated for three discounted cash flow (DCF) rates of return on total investment and are shown in the following tabulation.

DCF Rate of Return (Percent)	Syncrude "Price" ($/bbl)
10	3.90
15	5.00
20	6.35

To pipeline this premium product to major refining centers will cost about $0.50 to $0.75 per barrel.

As production expands from the initial plant, lower production costs are anticipated, owing to more experience, improved plant performance, addition of incremental capacity, larger scale equipment, the introduction of new technology, better matching of process units, and other factors. Industrial experience, including petroleum refining, suggests that a learning curve improvement can be anticipated. This factor has not been evaluated, although experience indicates that it has offset increases due to inflation. Projections of future inflation have not been considered.

Effects that governmental policies and legislation might have on stimulation or deterrence of shale oil commercialization have been considered in the parametric study. Federal leasing policies will influence the level of production because about 80 percent of the in-place oil shale resources of the Green River Formation in Colorado, Utah and Wyoming are on federal lands. A policy which makes adequate reserves available and permits individual company holdings of 10,000 to 20,000 acres per state would be a stimulant to commercialization. This size range of leasehold is needed to provide adequate minable shale in the Mahogany or other rich zones for a long-term commercial enterprise. Permitting credit of a company's mining and processing research and development costs toward payment of royalty charges could also be a positive factor in the Federal Government's oil shale leasing program.

The task group evaluated tax policies as to their effect on syncrude "price" when retorting 35-gallon per ton shale. The following effects were noted at a 15-percent DCF rate of return.

- Increasing the depletion allowance from the present 15-percent rate on crude shale oil to 22 percent on syncrude will permit reduction in required syncrude "price" of $0.35 per barrel.

- Continuing the investment tax credit of 7 percent, as recently reinstituted, reduces syncrude "price" by $0.26 per barrel.

- Decreasing present depreciation life of 10 years on mining capital and 15 years on plant capital to 5 years on all capital, as proposed in current legislation, will reduce syncrude "price" by $0.23 per barrel.

- Suspending the present Federal Government royalty on oil shale, graduated up to $0.17 per ton for 35-gallon per ton shale, will reduce syncrude "price" by $0.19 per barrel.

- Removing the limitation that restricts the application of depletion allowance to not more than 50 percent of taxable income will reduce syncrude "price" $0.18 per barrel when 22-percent depletion is allowed on syncrude.

The combined effect of increased depletion allowance, investment tax credit and shorter depreciation life is a $0.70 per barrel reduction in the required "price." Applying this reduction to the first plant would give a starting "price" of $4.30 per barrel of syncrude.

Costs described in the Initial Appraisal provide sufficient allowance to meet present-day environmental standards. Environmental control costs will increase if legislation becomes more restrictive. Sensitivity of syncrude "price" to this factor shows, for example, that a 10-percent increase in total initial mine and plant investment would increase syncrude "price" $0.40 per barrel at a 15-percent DCF rate of return, or would reduce rate of return 1.5 percentage points at constant syncrude "price." However, the same total additional investment, made in equal increments over a 15-year period, would increase syncrude "price" by only $0.15 per barrel.

Chapter Two

SUPPLY ELASTICITY STUDY

DEVELOPMENT OF SUPPLY ELASTICITY CURVES

The development of the relationship between potential syncrude production and syncrude "price," which has been termed "supply elasticity study," is based on the assumption that sufficient shale lands in the Green River Formation are available for projected commercial operation. The procedures for making the study are as follows:

- Land in the Piceance Basin was blocked out in tracts, each containing 634 million assay barrels of reserves in place in a selected minable seam. This reserve is based on a 20-year supply of oil shale, 60-percent recovery of shale in the seam, 96-volume-percent of Fischer assay as syncrude yield, and a production from each tract of sufficient crude shale oil to yield 50 MB/D of syncrude. Each tract thus represents a potential syncrude reserve of 365 million barrels. Because less information on the reserves is available, the Uinta Basin tracts were subdivided in larger blocks of 730 million barrels of potential syncrude to yield 100 MB/D of syncrude. The Wyoming oil shale resources were not included in this study because of their depth and poorer quality and because of the lack of detailed information on these deposits.

- The average Fischer assay was estimated for each tract.

- Each tract was designated for adit or shaft mining, depending upon the type of terrain. Variations between 400 and 1,300 feet in lifting height were considered as not appreciably affecting the cost of shaft mining.

- The potential syncrude reserves were totaled for the separate categories of adit or shaft mining and assay value of shale.

- A syncrude "price" in dollars per barrel was calculated for each category, using data from the Initial Appraisal and adding royalty costs. This was done for three DCF rates of return: 10, 15 and 20 percent.

- For each rate of return, potential syncrude production was cumulated at increasing syncrude "prices." These data were plotted to give the supply elasticity curves.

The selected reserves are within the Class 1 and 2 resources defined in the Initial Appraisal. The four classes of resources are described as follows:

Class	Description
1, 2	These are the resources satisfying the basic assumption limiting resources to deposits at least 30 feet thick and averaging 30 gallons of oil per ton of shale, by assay. Only the most accessible and better defined deposits are included. Class 1 is a more restrictive cut of these reserves and indicates that portion which would average 35 gallons per ton over a continuous interval of at least 30 feet.
3	Class 3 resources, although matching Classes 1 and 2 in richness, are more poorly defined and not as favorably located. These may be considered potential resources and would be exploitation targets at the exhaustion of Class 1 and Class 2 resources.
4	These are lower grade, poorly defined deposits ranging down to 15 gallons per ton which, although not of current commercial interest, represent a target in the event that their recovery becomes feasible. These may be considered speculative resources.

The assumption was made that the deposits would be developed by underground room-and-pillar mining, utilizing a selected minable seam in the Mahogany Zone. The extent of the Mahogany Zone is indicated in Figure 1. This zone comprises the richest, most continuous and shallowest oil shale section in the Green River Formation. In outlining the minable tracts, an attempt was made to obtain a statistical summary of the number and quality of such units rather than to delineate their boundaries. As an aid in estimating the cost of syncrude production, the tracts were identified as being accessible by either adit or shaft mining.

The potential recoverable reserves, estimated for all of the available lands and produced as syncrude, are 15.4 billion barrels obtainable by adit mining and 38.8 billion barrels by shaft mining (see Table 1). Thus, there are 54.2 billion barrels of total potential syncrude reserves in the selected minable section of the Mahogany Zone in the Piceance and Uinta Basins. Of this total, 6.6 billion barrels are estimated to be available in the Uinta Basin. No capacity is assigned to the Green River and Washakie Basins in Wyoming. Less than 6 billion barrels of Class 1 reserves, located entirely in the Piceance Basin, would be developed through 1985 at the maximum level of commercial production projected later in this chapter. None of the resources in either Utah or Wyoming are high enough quality or well enough defined to be utilized during this period at the stated syncrude economic level.

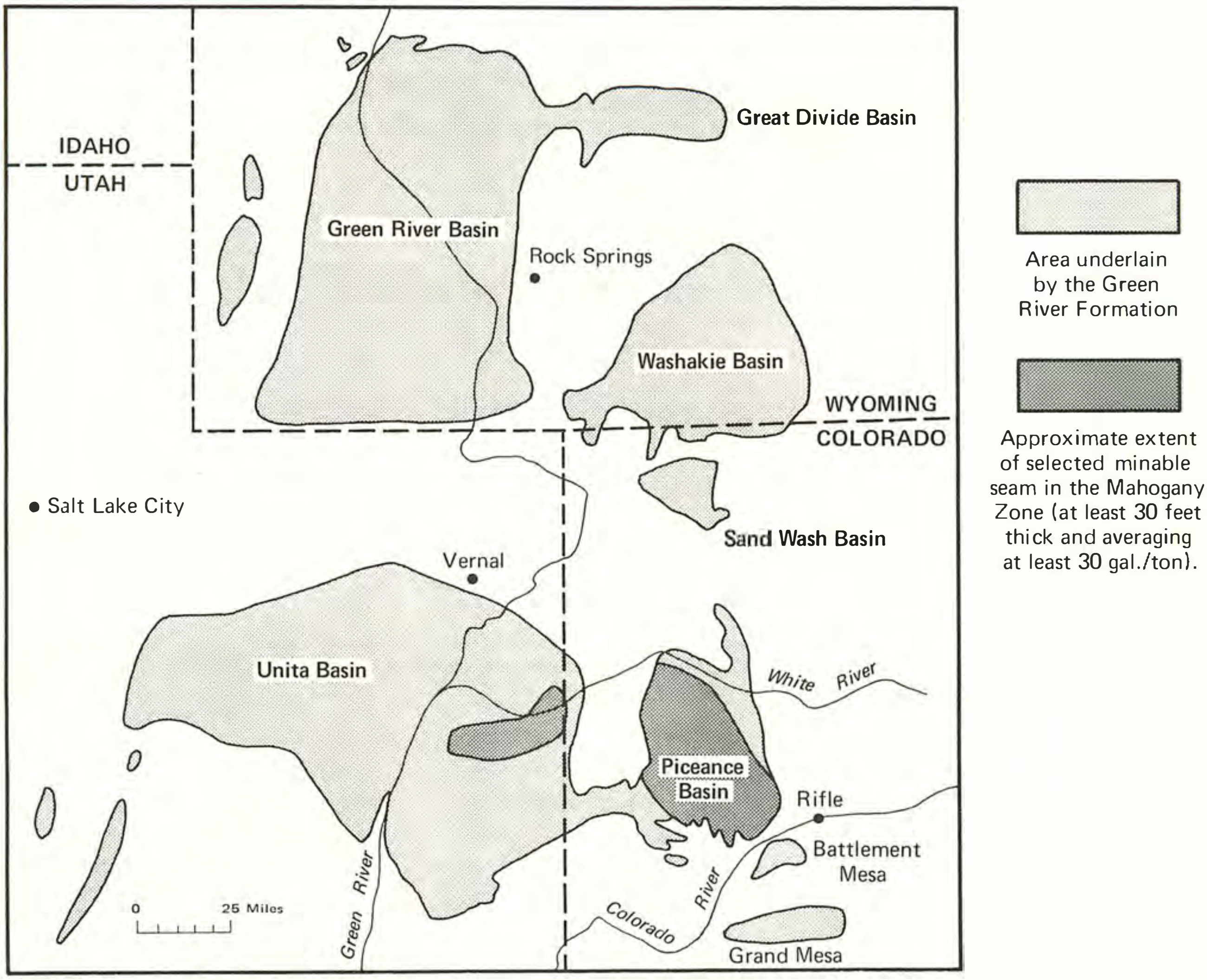

Figure 1. Mahogany Zone Reserves Used in This Study for Calculation of Required "Prices" for Various Levels of Production.

The limited available information indicates that only a relatively small fraction of the Class 1 and 2 reserves would be minable by surface methods, either by stripping or open pit, at costs comparable to underground mining. There does not appear to be enough of this type of reserve in the entire Green River Formation to have any appreciable effect on the supply elasticity study. Because of the abundance of the Class 1 and 2 recoverable reserves and the greater depth and poorer definition of the Class 3 resources, the latter have not been brought into this present study.

The estimated recoverable reserves given in the Initial Appraisal are about 20 billion barrels of equivalent syncrude more than the above total of 54 billion barrels. This difference results mainly from the present study being based on a commercially minable section of the Mahogany Zone rather than on the entire zone. Thus, not all of the contiguous shale in the zone that would

TABLE 1

POTENTIAL SYNCRUDE RESERVES FROM A
SELECTED MINABLE SEAM IN THE
MAHOGANY ZONE OF THE PICEANCE AND UINTA BASINS*

Shale Assay (Gal/Ton)	Recoverable Oil Shale Reserves as Syncrude (Billion Barrels)			
	Piceance Basin		Uinta Basin	
	Adit Mine	Shaft Mine	Adit Mine	Shaft Mine
30	2.9	6.9	2.9	3.7
31	2.6	2.2	–	–
32	1.1	4.7	–	–
33	2.5	4.4	–	–
34	1.5	4.4	–	–
35	1.5	7.7	–	–
36	0.4	3.7	–	–
37	–	1.1	–	–
Total	**12.5**	**35.1**	**2.9**	**3.7**
Total Reserves	**54.2 billion barrels as syncrude.**			

* Bases for estimate: (1) Wyoming deposits are not well defined but are believed to be too lean and thin or too deep for including in these reserves; (2) continuous minable section at least 30 feet thick and averaging at least 30 gallons per ton; (3) 60-percent recovery of the oil shale; and (4) 96 volume percent of Fischer assay as syncrude yield.

average out to at least 30 gallons per ton is necessarily included. Addition of this shale to the recoverable reserves would tend to reduce the average assay value of the shale mined and retorted, thus increasing the operating costs and the "price" required for the syncrude produced.

As stated by the proposed prototype leasing program of the U.S. Department of the Interior, the royalty is $0.12 per ton for 30-gallon per ton shale, with $0.01 per ton increment for each gallon per ton additional assay value of the shale mined. This royalty charge is applied to oil shale mined on both state and federal holdings. For the purposes of this study, an equivalent royalty charge is applied for private lands. Because of the uncertainty as to future bonus payment levels, no attempt was made to evaluate the effect of this cost.

Segregation of the tracts as to type of mining was made because the Initial Appraisal developed somewhat different investment and operating costs for adit than for shaft mining. Using these costs, Figure 2 was prepared to show the "price" of syncrude from oil shale with either adit or shaft mining. As assumed previously, one shale mine would supply one retorting plant, and the output from two plants would be upgraded in a single 100 MB/D upgrading facility. Using constant 1970 dollars, curves are shown in Figure 2 for the two mining methods and for DCF rates of return of 10, 15 and 20 percent on the total investment in the project. Royalty for oil shale mined was converted to an equivalent charge in units of dollars per barrel of syncrude produced. This charge is given in Table 2 for various assays of shale.

TABLE 2

ROYALTY CHARGE FOR OIL SHALE

Shale Assay (Gallon/Ton)	Tons of Shale Mined/ bbl of Syncrude*	Royalty Charge	
		$/Ton of Shale†	$/bbl of Syncrude
30	1.46	0.12	0.18
31	1.41	0.13	0.18
32	1.37	0.14	0.19
33	1.33	0.15	0.20
34	1.29	0.16	0.21
35	1.25	0.17	0.21
36	1.22	0.18	0.22
37	1.18	0.19	0.22

* Based on syncrude yield of 96-volume-percent assay.

† Schedule of $0.12 per ton for 30-gallon/ton shale, allowing $0.01 per ton additional for each 1-gallon/ton increment, as stated in the proposed prototype leasing program of the U.S. Department of the Interior.

Utilizing the above information, the supply elasticity data for syncrude available from oil shale in the Mahogany Zone were calculated for the three DCF rates of return. The first step was to calculate the "price" of syncrude, f.o.b. the syncrude plant, produced from each of the blocks of potential syncrude reserves, as shown in Table 3. Cumulating the reserves at increasing syncrude "prices" gave the total supply that may be obtained at a given level of syncrude "price" as shown in Table 4. These results are plotted in Figure 3.

SIGNIFICANCE OF SUPPLY ELASTICITY RELATIONSHIP

The supply elasticity relationship given in this report is dependent upon the basic assumptions stated in the Initial Appraisal Oil Shale Task Group report.* These assumptions have also been included in this report. However, one exception is made in that all shale lands comprising the Green River Formation are now assumed to be available for utilization. The possible effects of government policies and legislation and of changes in technology on syncrude "price," and thus on supply elasticity, are discussed in Chapters Three and Four.

The "price" level at which syncrude production becomes economically attractive depends upon the desired rate of return on the investment. This study presents economics based on the use of first generation shale oil production technology. Syncrude "prices"

* NPC, *Initial Appraisal by the Oil Shale Task Group*, pp. 119-122.

TABLE 3

ESTIMATED SYNCRUDE VOLUMES AND ECONOMICS

Oil Shale Assay (Gal/Ton)	Recoverable Reserves as Syncrude (Billion bbl)	Syncrude Production Capacity (MB/D)	Required Syncrude "Price" ($/bbl) f.o.b. Syncrude Plant (DCF Rate of Return) 10%	15%	20%
Piceance Basin–Private Adit Mines					
31	2.2	300	4.24	5.48	6.91
32	0.7	100	4.17	5.38	6.79
33	2.5	350	4.10	5.28	6.67
34	1.5	200	4.03	5.19	6.56
35	1.5	200	3.97	5.10	6.45
36	0.4	50	3.91	5.02	6.34
Total	8.8	**1,200**			
Piceance Basin–Private Shaft Mines					
33	1.5	200	4.23	5.48	6.94
35	0.4	50	4.09	5.29	6.72
Total	**1.9**	**250**			
Piceance Basin–Public Adit Mines					
30	2.9	400	4.32	5.58	7.03
31	0.4	50	4.24	5.48	6.91
32	0.4	50	4.17	5.38	6.79
Total	**3.7**	**500**			
Piceance Basin–Public Shaft Mines					
30	6.9	950	4.47	5.79	7.29
31	2.2	300	4.38	5.68	7.17
32	4.7	650	4.30	5.58	7.05
33	2.9	400	4.23	5.48	6.94
34	4.4	600	4.16	5.38	6.83
35	7.3	1,000	4.09	5.29	6.72
36	3.7	500	4.02	5.20	6.62
37	1.1	150	3.95	5.12	6.52
Total	**33.2**	**4,550**			
Unita Basin–Public Adit Mines					
30	2.9	400	4.32	5.58	7.03
Unita Basin–Public Shaft Mines					
30	3.7	500	4.47	5.79	7.29

TABLE 4

SUPPLY ELASTICITY OF SYNCRUDE FROM OIL SHALE
(Constant 1970 Dollars)

Maximum Syncrude Value ($/bbl) f.o.b. Plant	Cumulative Recoverable Reserves as Syncrude (Billion Barrels)* 10% DCF Rate of Return	15% DCF Rate of Return	20% DCF Rate of Return
3.90	0.0		
4.00	2.9		
4.10	18.2		
4.20	23.7		
4.30	35.4		
4.40	43.4		
4.47	54.2		
5.01		0.0	
5.10		1.8	
5.20		8.0	
5.30		18.2	
5.40		23.7	
5.50		30.7	
5.60		41.2	
5.70		43.4	
5.79		54.2	
6.33			0.0
6.40			0.4
6.50			1.8
6.60			4.4
6.70			10.6
6.80			19.4
6.90			23.7
7.00			30.7
7.10			41.2
7.20			43.4
7.29			54.2

* Produced from a minable seam in the Mahogany Zone of the Piceance and Uinta Basins, with average assay of at least 30 gallons/ton.

in constant 1970 dollars, f.o.b. the syncrude plant, have been calculated with initial production being from the highest quality 36-gallon per ton oil shale reserves. These "prices," at three DCF rates of return on total investment are: $3.90 per barrel for a 10-percent rate of return, $5.00 per barrel for a 15-percent rate and $6.35 per barrel for a 20-percent rate. The "price" of syncrude delivered to a refinery in the Chicago area would be about $0.50 to $0.75 per barrel higher than the above amounts due to transportation costs.

The supply elasticity curves in Figure 3 are significant because they indicate that, once the economic incentive exists to initiate production of syncrude, relatively small increases in syncrude "price" bring large increases in recoverable reserves.

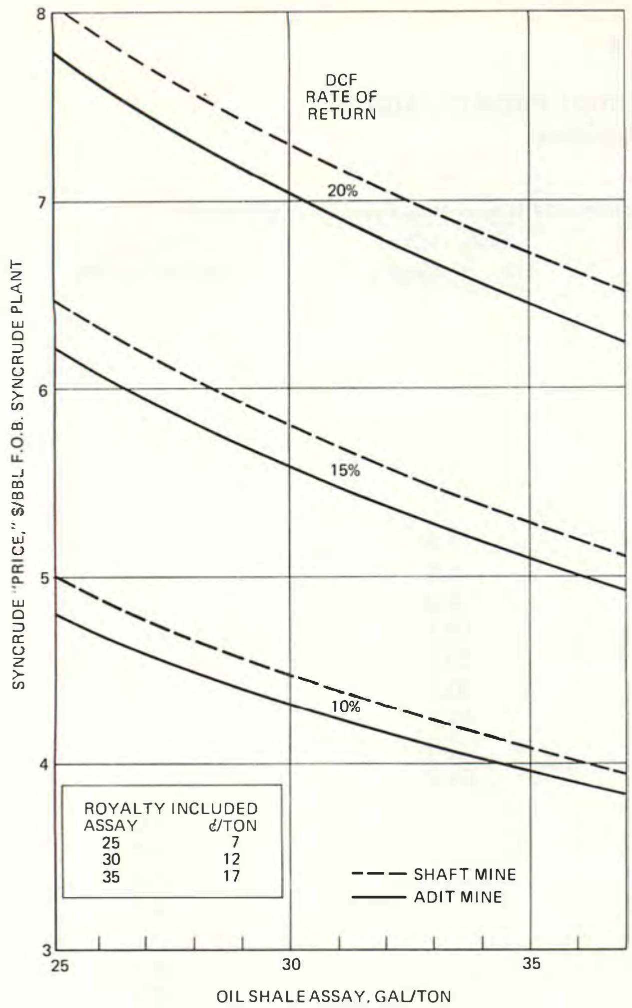

Figure 2. Value of Syncrude from Oil Shale with Adit or Shaft Mining and First-Generation Technology (Constant 1970 Dollars).

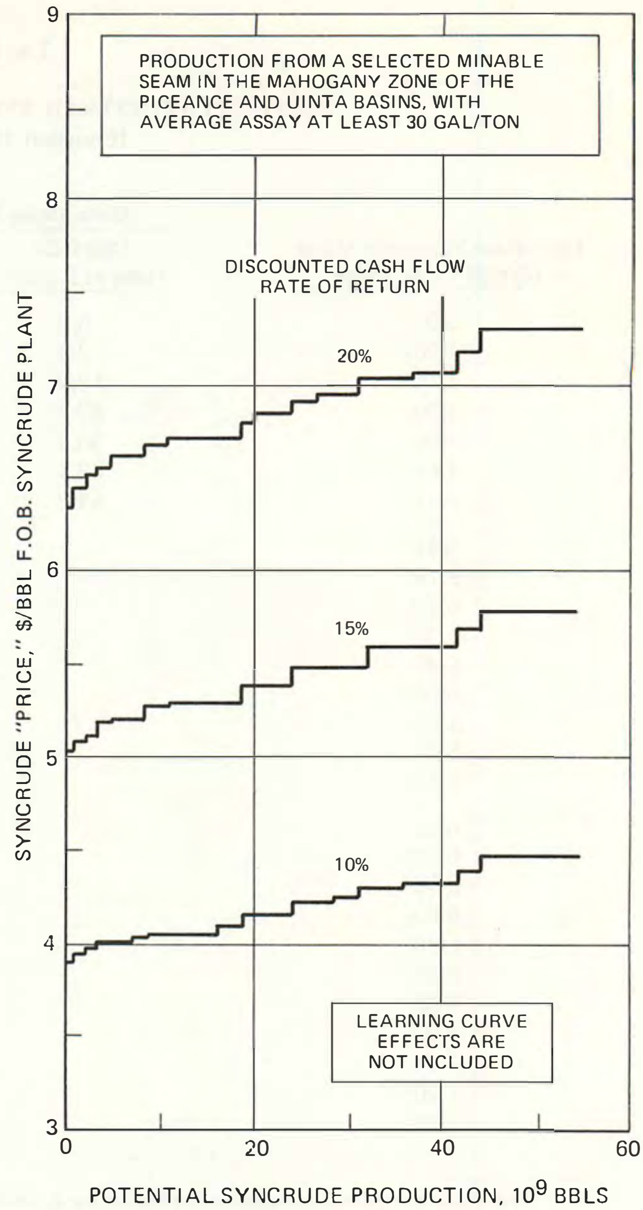

Figure 3. Required "Prices" for Syncrude from Oil Shale (Constant 1970 Dollars).

As the quality decreases to 33 gallons per ton, the "price" at a 15-percent rate of return must increase $0.26 per barrel to bring in the first 10 billion barrels of potential syncrude production. Above this level, increases averaging $0.12 per barrel in syncrude "price" make available 10-billion-barrel increments of potential syncrude production. Neither the effect of inflation nor improvements resulting from experience are taken into account in developing these relationships.

In the calculation of syncrude "prices," the unit values and quantities of byproducts given in the following tabulation are used for each 100 MB/D of syncrude production.

Byproduct	Unit Value ($/Ton)	Quantity (Tons/D)
Coke	4.00	1,450
Ammonia	30.00	250
Sulfur (Long Ton)	15.00	100

The total value of byproducts is equivalent to $0.15 per barrel of syncrude. Table 5 shows that this value has a 0.6 to 0.9 percentage point effect on the DCF rate of return at constant syncrude "price."

DEVELOPMENT SCHEDULE AT MAXIMUM RATE

Development schedules for Cases I through IV were specified for the U.S. Energy Outlook study. As applied to shale oil syncrude production, these are--

- Case I: Maximum production rate
- Cases II and III: Most probable production rate
- Case IV: Minimum production rate.

The most probable rate was estimated in the Initial Appraisal to be 400 MB/D by 1985. A minimum rate of 100 MB/D by 1985 might result from unexpectedly restrictive environmental factors. The assumption is made that syncrude "prices" will be adequate to encourage commercial development.

In consideration of the Case I, maximum, non-emergency rate, factors other than "price" will undoubtedly limit the production of syncrude through 1985. Factors which may affect the development of commercial shale oil production during this period are construction

TABLE 5

ECONOMIC EFFECT OF BYPRODUCT CREDIT
(100 MB/CD Syncrude Capacity)

	DCF Rate of Return (Percent)		
Syncrude Value ($/bbl) f.o.b. Plant	Standard Case*	No Credit for Byproducts	Difference Due to Byproduct Value†
3.50	7.7	6.8	0.9
4.00	10.2	9.5	0.7
4.50	12.5	11.8	0.7
5.00	14.6	14.0	0.6
5.50	16.5	15.9	0.6
6.00	18.4	17.8	0.6

* Based on adit mining of 35-gallon/ton oil shale with royalty on shale at $ 0.17 per ton; constant 1970 dollars.

† Total byproduct credit is equivalent to $ 0.15 per barrel of syncrude.

logistics, availability of personnel, restrictive environmental criteria, and lack of employee housing and supporting commerce and industry. Also important are the rate of development of second generation technology and availability of financing. However, in determining the maximum development rate, construction logistics are concluded to be the only limiting factor. The other factors are discussed later in this report. Reserves certainly will not be limiting within the study period 1971-1985.

The logistics involved in construction of plants determines the maximum number of plants which can be constructed simultaneously and the timing of plant construction starts. On the basis of non-emergency, normal contracting procedure, up to 400 MB/D of capacity encompassing eight mines, eight retorting plants and four upgrading plants are assumed to be under simultaneous construction. This assumes no interference from other construction programs. Moreover, the construction start of the plants should be staggered over at least a 2-year period.

Assuming that up to 400 MB/D of capacity could be under construction simultaneously, a development schedule was structured to define the maximum syncrude production rate that might be expected through 1985. Other factors used in working up the schedule are as follows:

- Engineering and purchasing time is 3 years per plant up to 200 MB/D simultaneous construction and 3.5 years per plant from 200 MB/D up to 400 MB/D simultaneous construction. Longer delivery times for purchased equipment are assumed necessary when total construction commitment exceeds the 200 MB/D level. No lead time was allotted for obtaining environmental approvals, although it is recognized that this is an important consideration.

- Field construction time is 3 years per plant up to 200 MB/D simultaneous construction and 3.5 years per plant from 200 to 400 MB/D simultaneous construction. Longer delivery times are again a factor. Field construction starts lag behind engineering and purchasing starts by 6 months.

- The start of each construction job lags behind the start of the previous job by 6 months or more depending on the status of the 400 MB/D simultaneous construction limitation.

The schedule, charted in Figure 4, is based on simultaneous development of two retorting processes (called Process A and Process B). It assumes that Process A is currently being demonstrated and that the demonstration will be completed satisfactorily in 1972. Field construction of the first 50 MB/D commercial plant then follows, starting in 1974, and the completed plant becomes operational in 1977. Process B is assumed to require 4 years for construction and operation of a demonstration plant, delaying start of field construction of the first 100 MB/D commercial plant until 1977. The first Process B plant is operational by 1980.

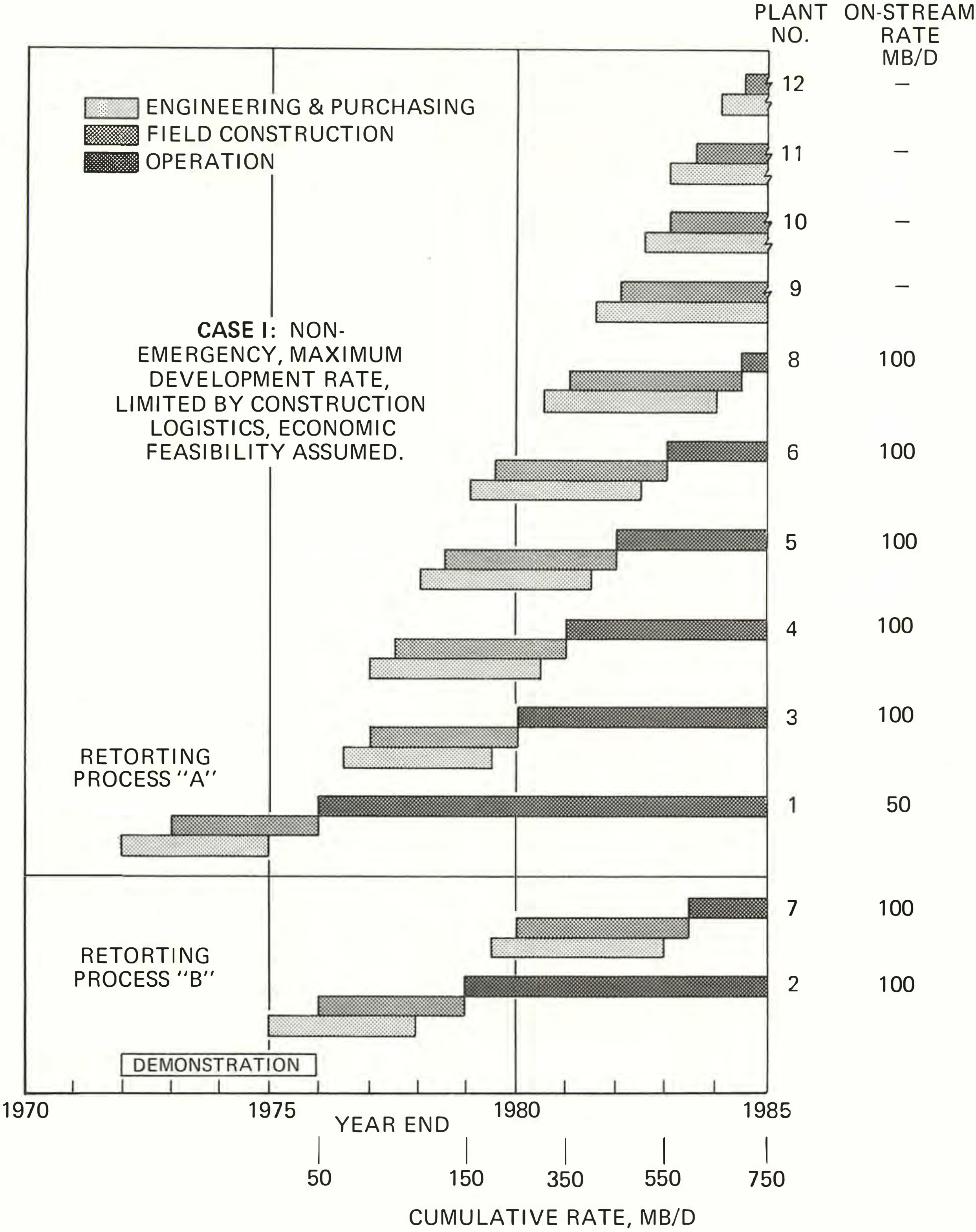

Figure 4. Development Schedule for Production of Syncrude from Oil Shale--Case I.

Process A continues its development with a 100 MB/D plant starting construction after 1 year of operation on the 50 MB/D plant. Thereafter, 100 MB/D Process A plants are started at 6- to 12-month intervals because of the 400 MB/D simultaneous construction limitation. Process B continues its development with the start of construction of another 100 MB/D commercial plant after the first 100 MB/D plant has operated for 1 year. No further plants can be started on this process before 1985 because of the 400 MB/D simultaneous construction limitation.

Syncrude production design capacities were cumulated from the development schedule and are given in the following tabulation:

	Syncrude (MB/D)
1972-1976	0
1977-1979	50
1980	150
1981	250
1982	350
1983	450
1984	650
1985	750

Also, as shown in Figure 5, the rate of 750 MB/D is the maximum that is believed to be obtainable by the end of 1985 under a non-emergency situation, with the assumed limitations due to mine and plant construction logistics.

The production schedule for Cases II and III developed by the Initial Appraisal attained a maximum of 400 MB/D of syncrude by 1985, as shown in Figure 5. This was based upon the consideration that no process was ready for immediate commercialization in 1971. Therefore, additional time would be required to demonstrate the technical and economic feasibility of the first process in a prototype unit before constructing an initial 100 MB/D plant. A conservative development schedule was then followed, which involved delaying start of the second plant until the initial plant had demonstrated the feasibility of commercial operation. In the Initial Appraisal, availability of shale lands was assumed to be limited to those in private hands. This study assumes that all lands would be open to commercialization and thus would permit a more rapid development rate.

The effect of change in syncrude "price" on production rate is an important factor in assessing the timing of oil shale development. Establishment of this relationship is a prime objective of this study and is obtained by converting the potential syncrude production, shown in Figure 3, to a daily rate on the basis that 100 MB/D of syncrude production for 20 years uses up 730 million barrels (MMB) of syncrude reserves. The resulting plot of daily

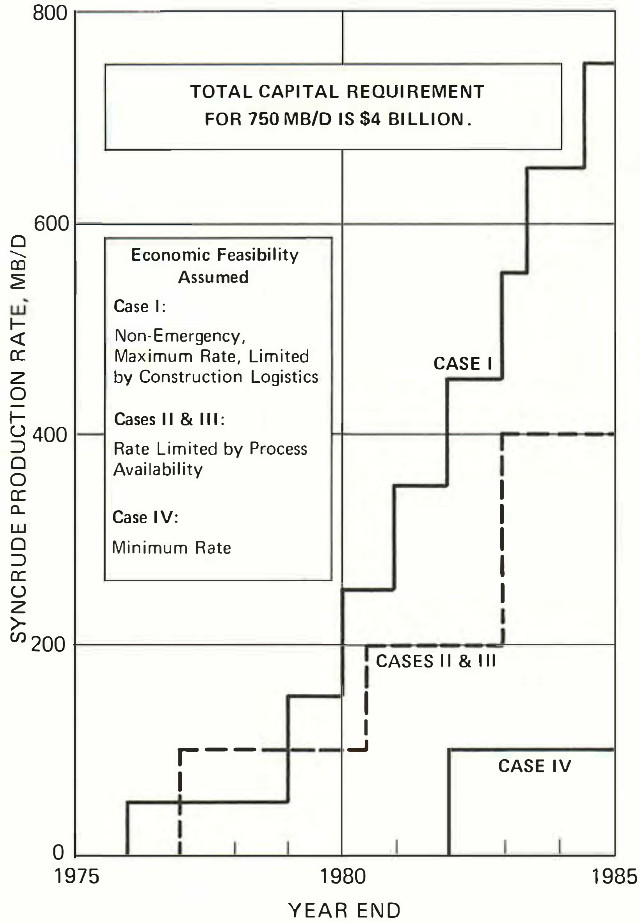

Figure 5. Production Schedule of Syncrude from Oil Shale--Cases I-IV.

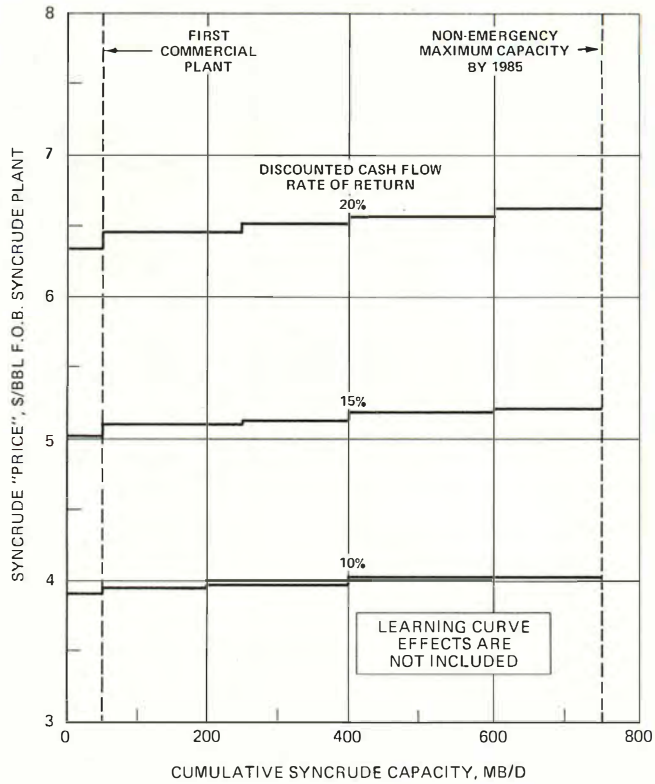

Figure 6. Required "Prices" for Syncrude Production from Oil Shale Through 1985 (Constant 1970 Dollars).

design production rate, up to the maximum of 750 MB/D, is shown in Figure 6 for DCF rates of return of 10, 15 and 20 percent. Syncrude "prices" required for start of the first 50 MB/D production are $3.90, $5.00 and $6.35 per barrel, f.o.b. syncrude plant, respectively for 10-, 15- and 20-percent DCF rates of return. Syncrude "prices" required to maintain a particular rate of return increase with each increment of production. At the maximum design production rate of 750 MB/D, these "prices," f.o.b. syncrude plant, are $4.00, $5.20 and $6.60 per barrel for the three rates of return.

The capital requirement has been estimated for the development schedule shown in Figure 7. Both the annual and cumulative investments are given. The cumulative investment ranges up to a maximum of nearly $5.2 billion through 1985 for the 12 plants shown scheduled. Capital for only those 8 plants in operation by the end of 1985 and producing 750 MB/D of syncrude amounts to $4.0 billion.

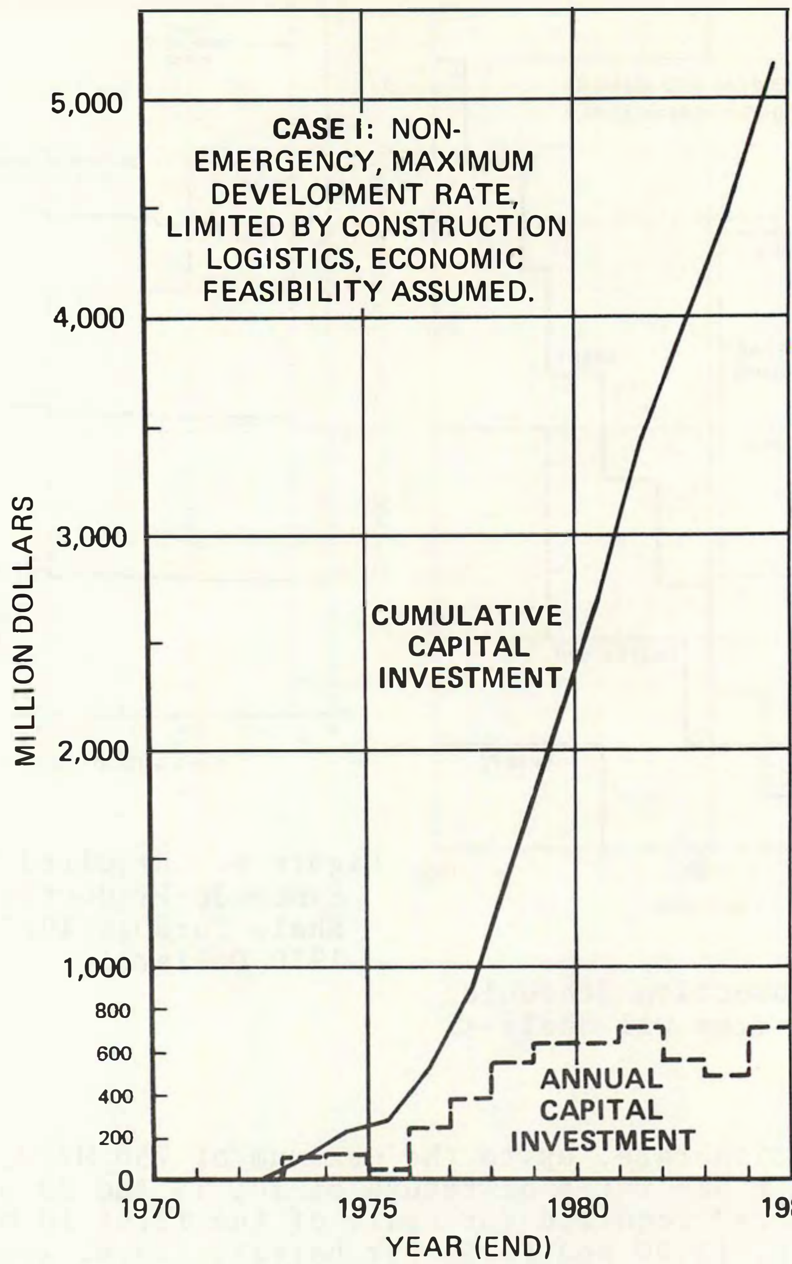

Figure 7. Investment for Syncrude from Oil Shale (Constant 1970 Dollars).

Chapter Three

EFFECT OF GOVERNMENT POLICIES AND LEGISLATION

LEASING OF FEDERAL OIL SHALE RESERVES

The only U.S. oil shale deposit of potential commercial significance is the Green River Formation in Colorado, Utah and Wyoming. The richest and largest deposits are in Colorado, the poorest in Wyoming. About 80 percent of these estimated in-place resources are federal holdings. Hence, federal leasing policies are important in oil shale development.

Sufficient oil shale is in private ownership in the southern Piceance Basin of Colorado to allow establishment of a fledging industry. The privately held deposits are relatively thin, rich sections of the Mahogany Zone. Although the privately owned resource may be sufficient to start a shale oil industry, federal resources will be required to attain the projected 750 MB/D by 1985.

The title to portions of federal oil shale resources is clouded by unpatented claims. The Department of the Interior is moving in the direction of clearing titles on these lands through administrative action and litigation.

Federal Leasing Proposals

Oil shale was designated a leasable mineral by the Mineral Leasing Act of 1920. Prior to that time, it had been a locatable mineral, under the 1872 mining law. Executive Order No. 5327, on April 15, 1930, withdrew all federal oil shale from leasing. Since that time, there have been a few leasing proposals and one lease sale, but no federal acreage has been leased.

In 1968, the Department of the Interior's Oil Shale Test Lease Program presented three tracts in the Piceance Basin of Colorado for competitive bonus bidding with rentals and royalties. These sites represented different geologic settings and involved 1,255, 5,120 and 5,083 acre tracts, for a total of 11,458 acres. Exploratory drilling was provided for by permit. Three bids were received on two of the tracts but they were not accepted.

A new Prototype Oil Shale Leasing Program was announced in 1971. This proposal differed from the previous one in that interested parties obtained permits to drill on sites selected by them in publicly owned shale holdings in Colorado, Utah and Wyoming. Permit holders were required to allow others to participate pro rata in drilling costs and information. Six tracts, about 5,120 acres each, were selected by the Department of the Interior from 25 nominations. A decision on whether to proceed with the lease sale will be made after mid-summer 1972 and will depend upon evaluation of the core hole data and consideration of the environmental studies.

If the decision is made to proceed, the sale is scheduled to begin in the latter part of 1972. Leases on the selected tracts will be sold by competitive bonus bidding, with additional rent and royalty charges. The bonus will be payable in five annual installments, with the last two installments cancelled if the lease is relinquished by the third year. Royalty will be assessed on the oil shale at $0.12 per ton for 30-gallon per ton shale and varying, within limits, up or down $0.01 per ton for each gallon per ton change in shale assay.

The intent of the proposed 1971 lease program makes it clear that an operator will be required to comply not only with the environmental regulations published prior to the start of development, but also with any new regulations or restrictions that may be imposed during the life of the project. Limited relief may be realized through the provisions of the 1971 leasing program which permits credit for exceptional environmental protection costs against royalty payments otherwise due the Government. However, the open-ended nature of environmental controls is a hazard to a developer because he will be unable to project these costs with certainty.

Mineral Leasing Acts of 1920 and 1971

The Mineral Leasing Act of 1920 limits a company to a maximum of 5,120 acres of oil shale resources. In the southern part of the Piceance Basin, this acreage restriction would support only one oil shale plant of limited size. This does not permit taking full advantage of scale and fails to provide an opportunity for expansion. In the center of the basin, the deposits are much thicker, and the in-place hydrocarbon would be adequate to support a larger plant on a tract. However, the technical and economic problems of producing the more deeply buried resources do not have early solutions in sight.

The Interior Solicitor ruled in 1971 that, while a party is limited by law to hold only 5,120 acres of oil shale leases, partial holdings in any lease amounting to less than 10-percent interest are not counted against the limit. Thus, a company or person might hold a number of small interests of less than 10 percent each in lease areas which would be exempt from the overall limit of 5,120 acres. The Solicitor also ruled that, if a lease should expire, terminate or be transferred, the lessee would not be barred from acquiring another oil shale lease.

The proposed Mineral Leasing Act of 1971 would raise the limitation on federal oil shale lease holdings to 10,240 acres in any one state. If passed, this legislation would relieve the acreage limitation problem for the time being and make federal oil shale reserves more readily available for development.

Modifications to Oil Shale Leasing Regulations

The task group concluded that the following changes to existing and proposed leasing laws would encourage development of an oil shale industry.

- Encourage additional research and development leading to shale oil commercialization by permitting expenditures on appropriate programs to be applied to royalties otherwise due.

- Increase the federal oil shale leasing limitation in any one state to at least 10,240 acres (as per the proposed 1971 Act).

- Apply the acreage limitation only to oil shale resources not under commercial development, thus encouraging development by permitting additional acreage to be obtained as commercial operation proceeds in response to demand for oil.

Work Program

Industry's interest in oil shale reserves is related to its conviction that production of syncrude for sale in a future market environment will be both technically and economically feasible. This feasibility will depend to a large extent on the existence of one or more proved economical shale oil recovery techniques. At the present time, these are at various stages of development.

A work program arrangement, whereby a party obtains credit against royalties otherwise due the Government on a federal lease for monies spent in shale oil recovery research and development, would be a means of stimulating industry participation in early commercialization of shale oil.

Revision of Acreage Limitations

Oil shale acreage leased to a single party should be increased from 5,120 acres to at least the 10,240 acres provided by the proposed 1971 Leasing Act. This increase represents less than 1.5 percent of the federal acreage available. The additional acreage is needed even by a joint venture of two or more parties to assure a sufficiently large shale reserve that will permit commercial operation at the more economically viable 100 MB/D level over an extended period of time.

The acreage limitation should not be applied to reserves actually under commercial development. Development will thus be encouraged by permitting additional acreage to be obtained as commercial operation proceeds in response to demand for more oil.

The monetary and technological demands of a commercial shale oil venture are so great that the available number of potentially interested parties or groups will be quite limited. Companies will be encouraged to participate in this industry when they can foresee a long life for the project and good prospects for expansion. These prospects will be enhanced not only by providing sufficient leasable acreage for development but also by permitting the company to obtain additional acreage as it continues to develop its holdings.

Other Factors Affecting Industry's Response to Oil Shale Leasing Programs

Major changes in the Mineral Leasing Act of 1920, which are expected to stimulate leasing of shale reserves, have been discussed above. These changes alone will not guarantee favorable action by industry. Technologic, economic and environmental factors are also important.

TAXES AND ROYALTIES

As part of the U.S. Energy Outlook parametric studies, the following possible changes in tax policies have been studied for their effect on the required syncrude "price" and DCF rate of return. These parameters are--

- Increasing the depletion allowance from the present 15 percent on crude shale oil to 22 percent on syncrude
- Continuing the investment tax credit of 7 percent, as recently reinstituted
- Decreasing present depreciation life of 10 years on mining capital and 15 years on plant capital to 5 years on all capital, as proposed in current legislation
- Suspending the present Federal Government's royalty on oil shale, graduated up to $0.17 per ton for 35-gallon per ton shale
- Removing the limitation that restricts the application of depletion allowance to not more than 50 percent of taxable income.

DCF rate of return calculations were made for adit mining of 35-gallon per ton oil shale with royalty charged on the shale at $0.17 per ton. The Initial Appraisal study was used as a standard of comparison. This study used a depreciation life of 10 years on mining equipment and 15 years on retorting and refining plant equipment, royalty charge on the oil shale, no investment tax credit and a 15-percent depletion allowance on the crude shale oil.

DCF rates of return and net profits are given in Table 6 for syncrude "prices" ranging from $3.50 to $6.00 per barrel, f.o.b. syncrude plant. Data are given to compare with the standard case the effect of each of the above first four parameters and of a combination of the first three parameters. The effect of rate of return on the required syncrude "price" is shown in Figure 8.

TABLE 6

ECONOMIC EFFECT OF GOVERNMENT TAX AND ROYALTY POLICIES*

Syncrude "Price" ($/bbl) f.o.b. Plant	(1) Standard Case†	(2) No Royalty on Shale	(3) 5-Year Depreciation Life	(4) 7% Investment Tax Credit	(5) 22% Depletion on Syncrude	(6) Combination of (3), (4) & (5)
			DCF Rate of Return (Percent)			
3.50	7.7	8.7	8.5	8.5	8.1	10.5
4.00	10.2	11.1	11.0	11.2	11.1	13.0
4.50	12.5	13.2	13.3	13.5	13.7	15.4
5.00	14.6	15.3	15.6	15.6	16.1	17.9
5.50	16.5	17.2	17.8	17.6	18.4	20.2
6.00	18.4	19.0	19.9	19.5	20.4	22.5
			Increase in DCF Rate of Return (Percent)			
3.50		1.0	0.8	0.8	0.4	2.8
4.00		0.9	0.8	1.0	0.9	2.8
4.50		0.7	0.8	1.0	1.2	2.9
5.00		0.7	1.0	1.0	1.5	3.3
5.50		0.7	1.3	1.1	1.9	3.7
6.00		0.6	1.5	1.1	2.0	4.1

* For all of these cases, the application of depletion allowance is restricted to not more than 50 percent of taxable income for any given year.

† Based on adit mining of 35-gallon per ton oil shale with royalty on shale at $0.17 per ton; constant 1970 dollars.

The reduction in syncrude "price" at constant rates of return is shown in Figure 9. Except for the removal of royalty charge on the shale, the parameters have greater effect as the required syncrude "price" is increased. The effect of the combined parameters is, in general, somewhat less than the sum of the effects of the individual parameters. This is mainly due to the 50-percent taxable income limitation on depletion allowance. A similar study made on mining and retorting 30-gallon per ton shale showed effects of the parameters to be about $0.05 to $0.10 per barrel of syncrude greater than for processing 35-gallon per ton shale.

Perhaps a more meaningful comparison may be made by assuming a constant syncrude "price" and determining the effect of the parameters. This applies to the more realistic situation in which a particular market "price" exists for the syncrude. Modifications in tax policies may then be evaluated as to their effect on the project's profitability as measured by DCF rate of return.

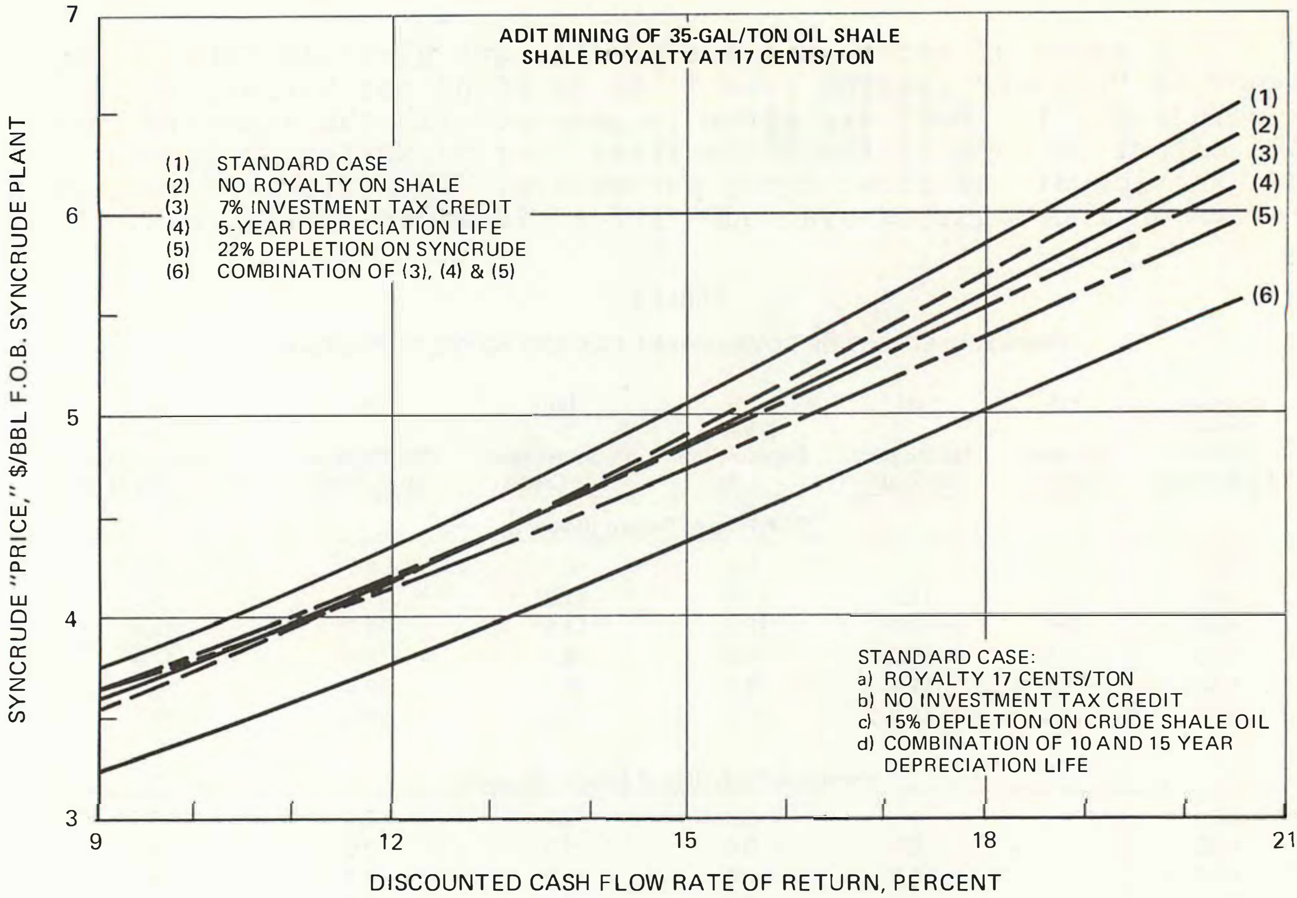

Figure 8. Changes in Government Tax and Royalty Policies (Constant 1970 Dollars).

A separate study was made of the effect on the rate of return of removing the 50-percent taxable income limitation in calculation of the depletion allowance. The results of this study are given in Table 7 and Figure 10 for two cases: one being the standard case of 15-percent depletion on the value of the crude shale oil and the other having a 22-percent depletion on the value of the syncrude.

At a 15-percent depletion allowance on the crude, the rate of return was not materially increased by removal of the limitation. At a 22-percent depletion on the syncrude, the effect was an increase of about 1.3 percentage points in DCF rate of return at a $4.00 per barrel syncrude "price" and 0.3 percentage points at $6.00 per barrel.

ENVIRONMENTAL CONTROL LEGISLATION

Facilities and operating costs described in the Initial Appraisal will meet or surpass 1970 environmental control standards. Environmental control costs will increase if legislation becomes more restrictive. Therefore, economic evaluations were made to

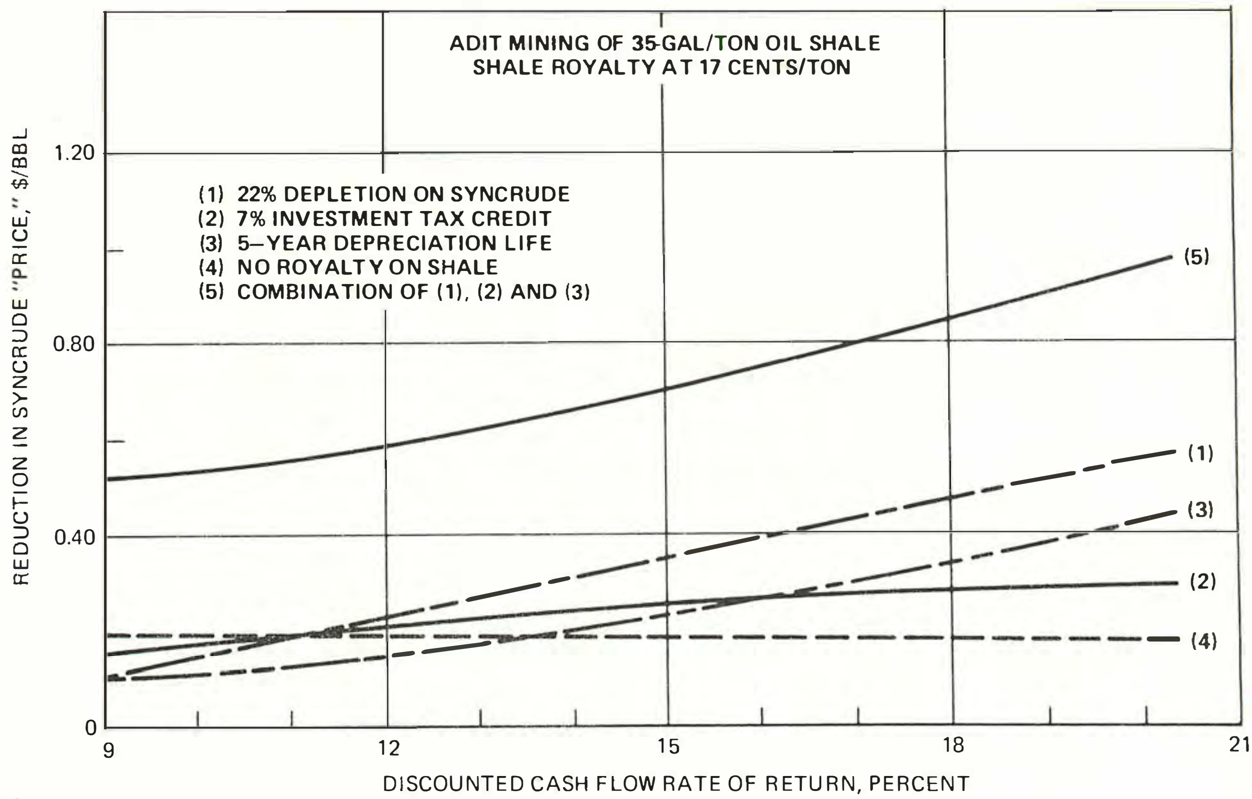

Figure 9. Reduction from Standard Case Syncrude "Price" Effected by Changes in Tax and Royalty Policies (Constant 1970 Dollars).

give a basis for estimating the possible effect of the post-1970 legislation on the incremental cost of producing syncrude. Due to the inability to accurately define future environmental constraints, an investor can only resort to delaying a construction decision until the syncrude "price" rises sufficiently to balance the risk.

Post-1970 environmental legislation could result in--

- Increased capital investment and operating costs of new plants required to provide for new environmental control standards which were not in effect during 1970
- Additional annual investment and increased operating costs occurring during the first 15 operating years of the plant to provide for change in environmental control standards being made during that period
- A delay in startup of the new plant resulting from unexpected changes in environmental specifications that required a period of time for modifications.

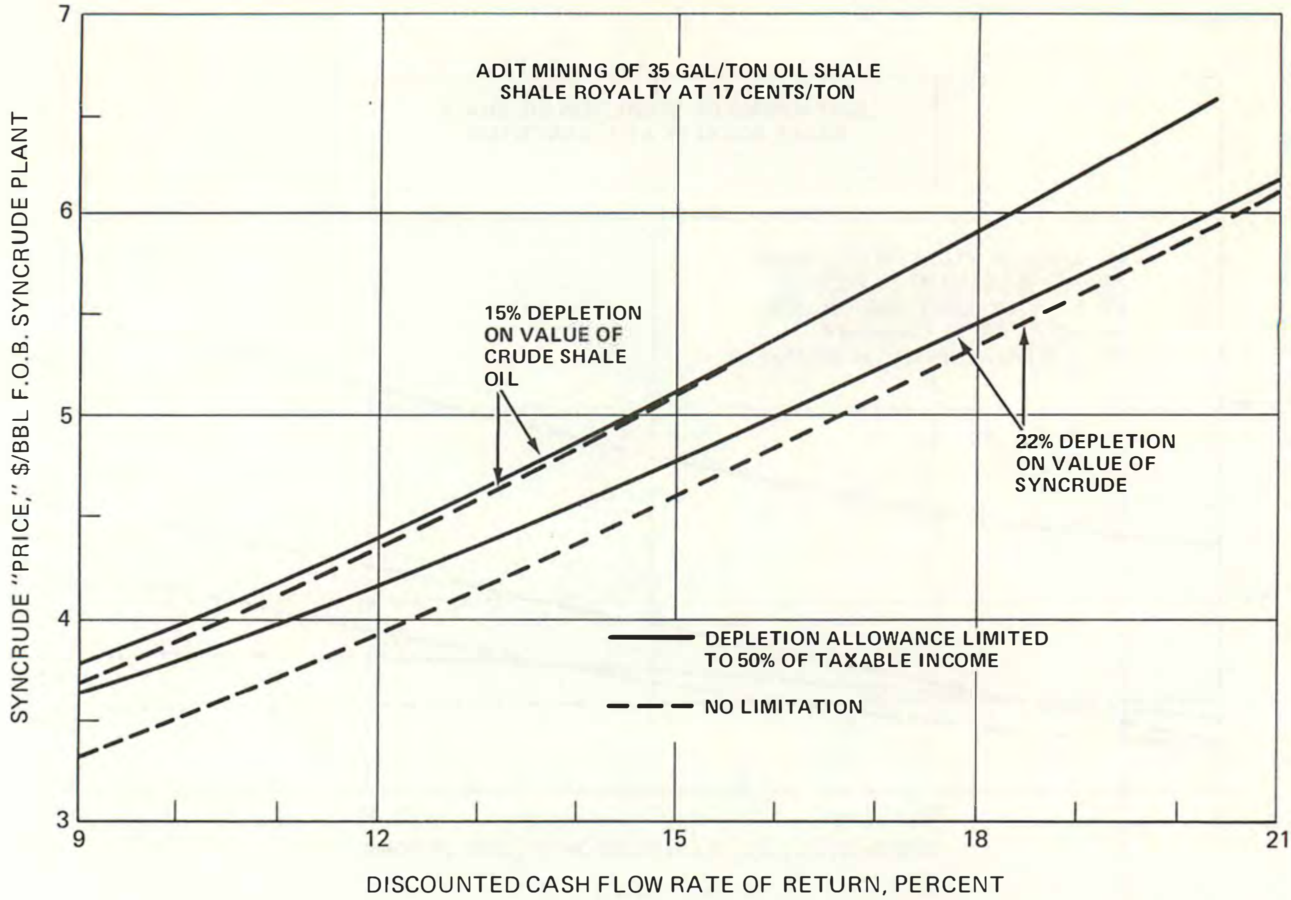

Figure 10. Removal of Taxable Income Limitation in Calculation of Depletion Allowance (Constant 1970 Dollars).

In each of these cases, the studies were made for the mining and retorting of 35-gallon per ton shale, and the standard case was assumed to be the same as that used in the study of tax and royalty policies.

In the first two cases, where environmental control has been assumed to require additional capital investment, no attempt was made to determine the actual amount of investment that might be needed. The percentage increases used in this study are only for the purpose of establishing the sensitivity of the required syncrude "price" to this type of problem.

Operating costs were increased to provide for the additional annual cost of the extra investment. On an annual operating cost basis, they were calculated to amount to 5 percent of the additional accumulated investment and to cover the additional operating costs relating to the added investment.

With respect to the first case, the effects of increases of 5, 10 and 15 percent in initial investment were evaluated. The increase in annual operating costs is 5 percent of the additional investment. This amounts to approximately 2, 4 and 6 percent of the original annual operating costs for each of the initial investment increases of 5, 10 and 15 percent, respectively. Comparison of the effect of these higher cost levels with the standard case is made in Table 8 and Figure 11. For example, at a constant 15-percent DCF rate of return, each 5-percent increase in capital raises the required syncrude "price" by $0.20 per barrel. Assuming a constant syncrude "price" of $5.00 per barrel, which provides a 14.6-percent DCF return for the standard case, each 5-percent capital increase reduces the rate of return by about 0.7 percentage points.

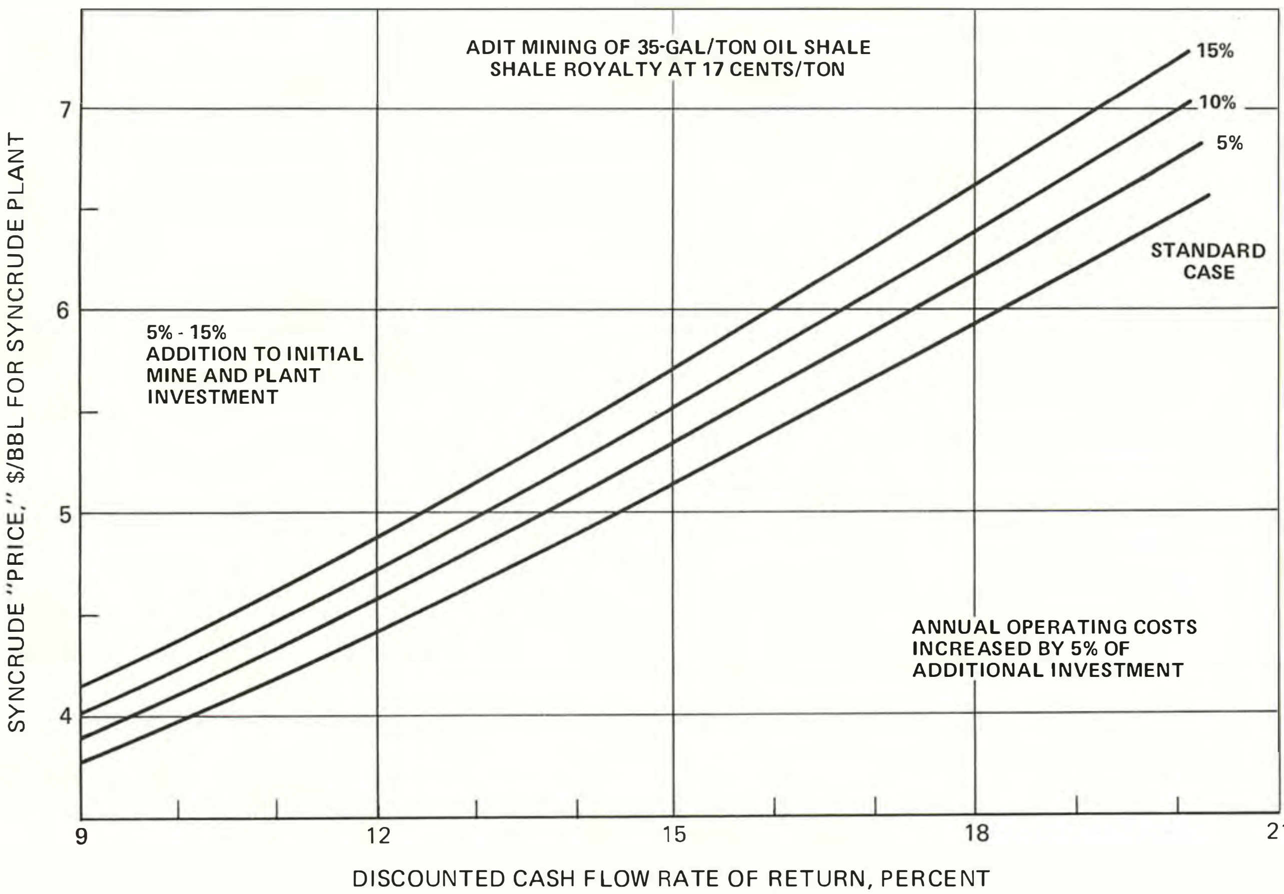

Figure 11. Effect on Required "Price" of Increased Investment and Resultant Operating Costs for Environmental Control (Constant 1970 Dollars).

In the second case, the assumption was made that more stringent environmental standards would require a continuing increase in capital investment during the first 15 years of the project life. Results are shown in Table 9 and Figure 12 for 0.5-percent and 1.0-percent annual additions to the initial capital investment of the entire mine, retorting and upgrading plant. Annual operating costs were increased yearly by 5 percent of the incremental investment. At a constant 15-percent DCF rate of return, 1-percent annual additional investment increases the required syncrude "price" by $0.20 per barrel. At a constant $5.00 per barrel syncrude "price," the rate of return is decreased by 0.9 percentage points.

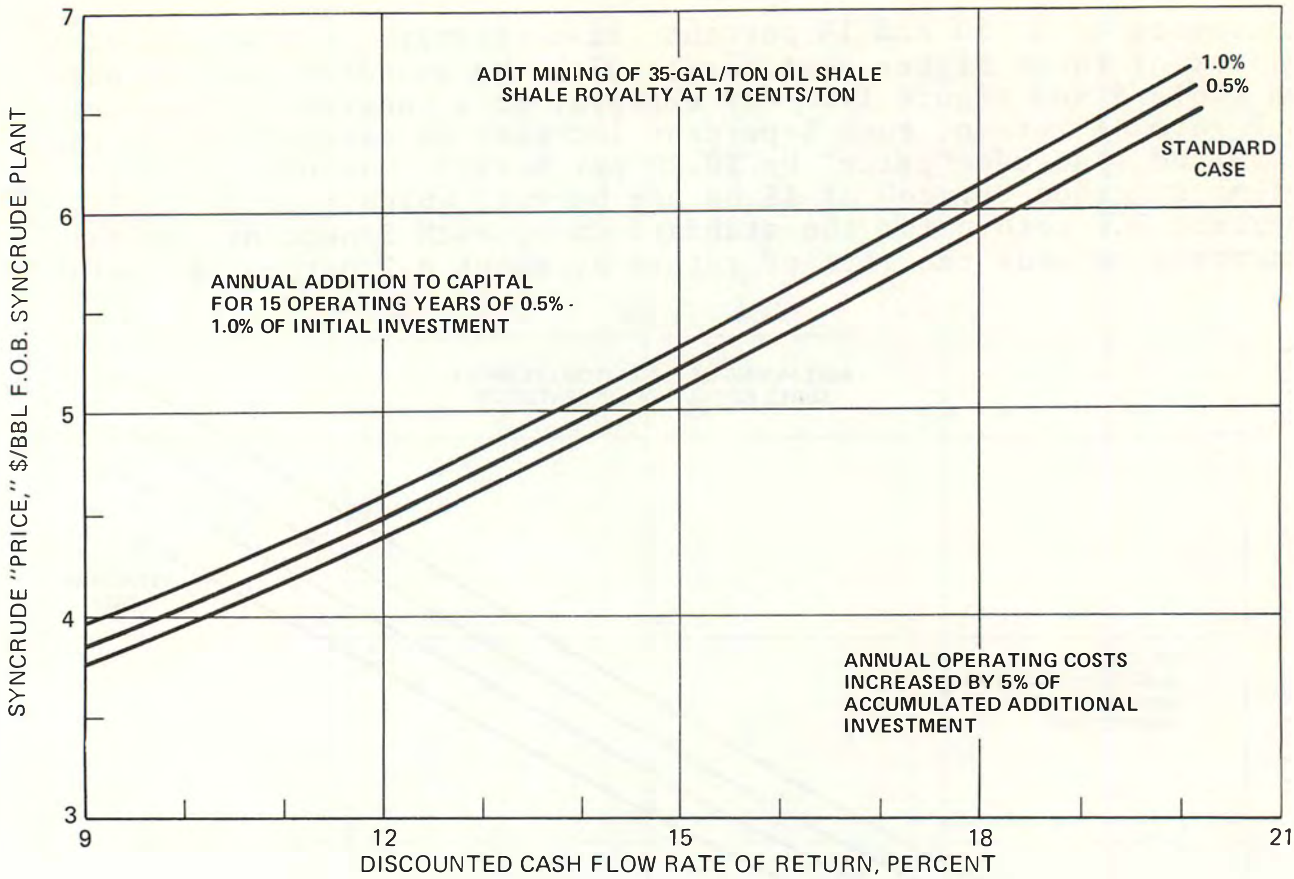

Figure 12. Effect on Required "Price" of Equal Annual Additions to Investment and Resultant Operating Costs for Environmental Control (Constant 1970 Dollars).

The third case of this study is an evaluation of the effect of prolonged delay in plant startup on syncrude economics. Environmental control problems are envisioned as causing the delay, possibly by requiring the installation of additional plant equipment prior to operation. The effect of the added investment has already been discussed and is not included in this case.

In the standard case, startup time is assumed to be 3 months. This provides for getting the retorting and crude shale oil upgrading units onstream at full capacity and assuming full operating costs during this period without any attendant income. The present study assumed 12- and 24-month delays in initiation of the normal plant startup after completion of construction. Total project life is extended by the length of the delay. Operating costs during this delay time are assumed to be 25 percent of the normal operating costs to provide for retention of supervisory and some maintenance labor, overhead costs and utilities during the time the plant is awaiting startup.

Economic effects of a prolonged delay in plant startup, as shown in Table 10 and Figure 13, are very substantial and would constitute a serious problem. For example, at a constant 15-percent

DCF rate of return, a 12-month delay in initiating startup requires a $0.55 per barrel increase in syncrude "price." At a constant syncrude "price" of $5.00 per barrel, this delay reduces the rate of return by 1.7 percentage points.

The economic model treats negative income tax as a positive cash flow, assuming it is applied against the taxable income of the parent company or the joint venture participants. The above case, in particular, incurs a large amount of negative income tax during the years of startup delay. The effect of carrying these negative income taxes forward during the 5 subsequent years, as could be done by an independent syncrude company, is shown in Figure 13. The further reduction in rate of return for the 12-month delay is 0.2 percentage points.

OCCUPATIONAL SAFETY AND HEALTH ACT (OSHA) OF 1970

Effective April 28, 1971, when Chapter XVII of Title 29 of the Code of Federal Regulations was issued pursuant to authority in OSHA, a new chapter was opened in employer-employee relations in the United States. The Code of Federal Regulations delineated the established federal standards and national consensus standards for occupational safety and health. Administration of the Regulations was set up in the office of the Assistant Secretary of Labor for Occupational Safety and Health.

A survey of the mining and plant construction fields indicates that the Initial Appraisal incorporates quite effectively the federal standards enumerated by OSHA. With regard to operating costs, the same conclusion applies. Occupational safety and health administration staffs were included in the overhead cost estimates.

TABLE 7

ECONOMIC EFFECT OF REMOVING TAXABLE INCOME LIMITATION FROM DEPLETION ALLOWANCE CALCULATION

Syncrude Price (S/bbl) f.o.b. Plant	15% Depletion on Value of Crude Shale Oil: 50% Limit*	15% Depletion on Value of Crude Shale Oil: No Limit	22% Depletion on Value of Syncrude: 50% Limit	22% Depletion on Value of Syncrude: No Limit
	DCF Rate of Return (Percent)			
3.50	7.7	8.1	8.1	9.9
4.00	10.2	10.5	11.1	12.3
4.50	12.5	12.6	13.7	14.6
5.00	14.6	14.7	16.1	16.7
5.50	16.5	16.6	18.4	18.8
6.00	18.4	18.4	20.4	20.7
		Increase in DCF Rate of Return (Percent)		
3.50		0.4	0.4	2.2
4.00		0.3	0.9	2.1
4.50		0.1	1.2	2.1
5.00		0.1	1.5	2.0
5.50		0.1	1.9	2.3
6.00		0.0	2.0	2.3

* Standard Case: Adit mining of 35-gallon per ton oil shale; royalty on shale at S0.17 per ton; constant 1970 dollars.

TABLE 8

ECONOMIC EFFECT OF INCREASED INITIAL INVESTMENT FOR ENVIRONMENTAL CONTROL

Syncrude Price (S/bbl) f.o.b. Plant	Return on Base Investment*	Increase in Total Initial Investment†: 5%	10%	15%
	DCF Rate of Return (Percent)			
3.50	7.7	7.0	6.4	5.9
4.00	10.2	9.6	9.0	8.4
4.50	12.5	11.8	11.2	10.6
5.00	14.6	13.8	13.1	12.5
5.50	16.5	15.7	15.0	14.3
6.00	18.4	17.5	16.8	16.0
		Reduction in DCF Rate of Return (Percent)		
3.50		0.7	1.3	1.8
4.00		0.6	1.2	1.8
4.50		0.7	1.3	1.9
5.00		0.8	1.5	2.1
5.50		0.8	1.5	2.2
6.00		0.9	1.6	2.4

* Based on adit mining of 35-gallon per ton oil shale with royalty on shale at S0.17 per ton; constant 1970 dollars.

† Effect shown on DCF rate of return includes the effect of increased annual operating costs related to increased initial investment in equipment and assumed to equal 5 percent of the additional investment. A 20-year operating period is assumed for each installation.

TABLE 9

ECONOMIC EFFECT OF EQUAL ANNUAL ADDITIONS TO INVESTMENT OVER 15 YEARS FOR ENVIRONMENTAL CONTROL

Syncrude Price (S/bbl) f.o.b. Plant	Return on Base Investment*	Annual Addition to Initial Capital Investment†: 0.5%	1.0%
	DCF Rate of Return (Percent)		
3.50	7.7	7.1	6.6
4.00	10.2	9.8	9.3
4.50	12.5	12.1	11.6
5.00	14.6	14.2	13.7
5.50	16.5	16.1	15.7
6.00	18.4	18.0	17.6
		Reduction in DCF Rate of Return (Percent)	
3.50		0.6	1.1
4.00		0.4	0.9
4.50		0.4	0.9
5.00		0.4	0.9
5.50		0.4	0.8
6.00		0.4	0.8

* Based on adit mining of 35-gallon per ton oil shale with royalty on shale at S0.17 per ton; constant 1970 dollars.

† Investment assumed to be made in equal increments over the first 15 years of a 20-year operating period. Resultant decrease in DCF rate of return includes the effect of incremental additions to annual operating costs related to the increased investment in equipment and assumed to be 5 percent of the accumulated incremental investment.

TABLE 10

ECONOMIC EFFECT OF PROLONGED START-UP OELAY

Syncrude Price ($/bbl) f.o.b. Plant	Standard Case*	Delay in Initiating Start-Up†: 12 Months	24 Months
	DCF Rate of Return (Percent)		
3.50	7.7	7.0	6.4
4.00	10.2	9.2	8.4
4.50	12.5	11.1	10.1
5.00	14.6	12.9	11.6
5.50	16.5	14.5	13.0
6.00	18.4	16.1	14.3
		Reduction in DCF Rate of Return (Percent)	
3.50		0.7	1.3
4.00		1.0	1.8
4.50		1.4	2.4
5.00		1.7	3.0
5.50		2.0	3.5
6.00		2.3	4.1

* Based on adit mining of 35-gallon per ton oil shale with royalty on shale at S0.17 per ton; constant 1970 dollars.

† Operating costs during delay were charged at 25 percent of normal costs. No income during delay; project life extended by length of delay.

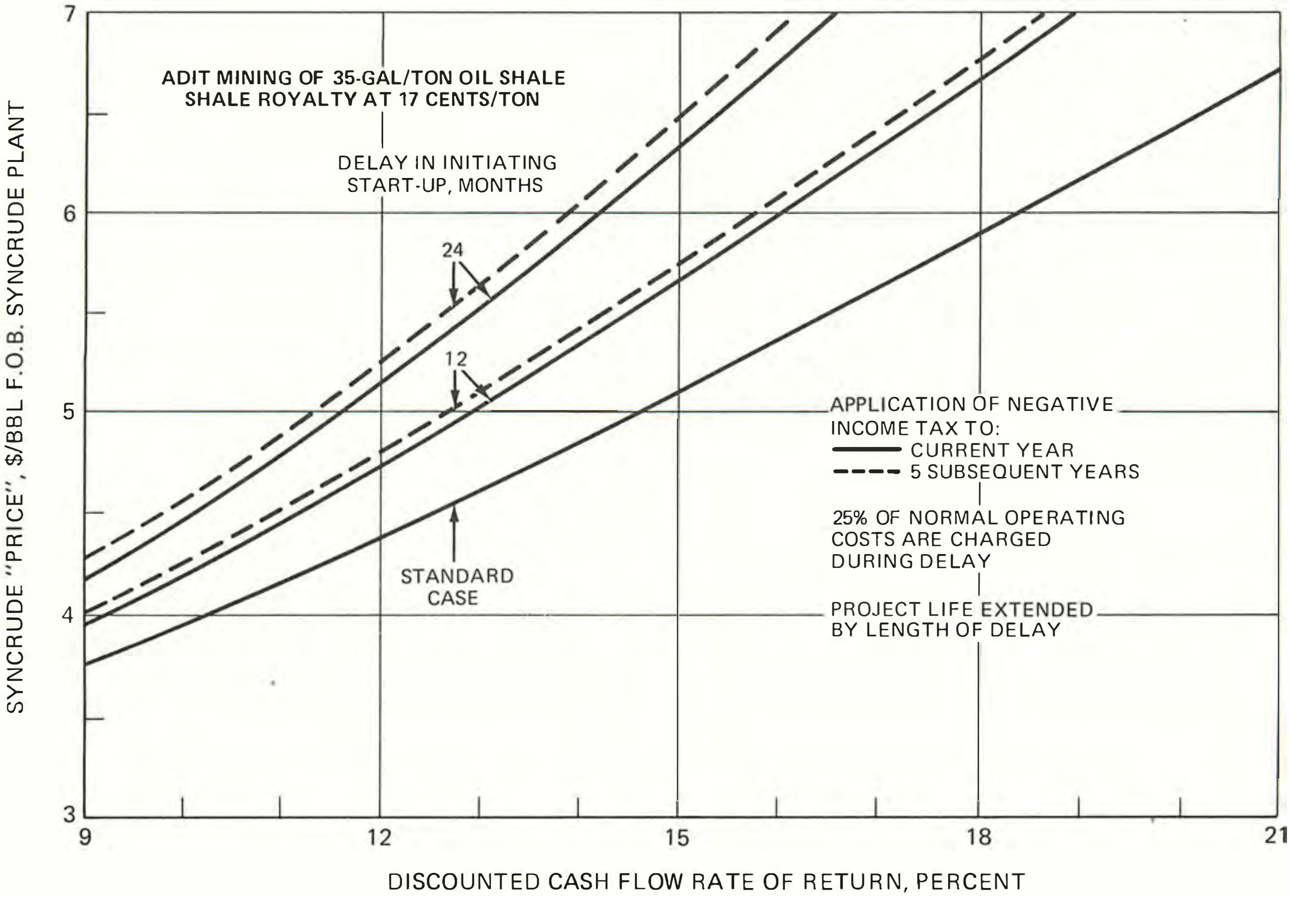

Figure 13. Prolonged Delay in Initiating Startup (Constant 1970 Dollars).

Chapter Four

CHANGES IN TECHNOLOGY AND THE "LEARNING CURVE" EFFECT

The oil shale industry will employ some processes, equipment and systems not utilized before on an industrial scale. Thus, there will be numerous opportunities for technological innovation. The so-called "learning curve" is a means of quantifying improvements which include not only the application of new technology in a developing industry, but also the cumulative effect of a number of learning factors that tend to improve performance and reduce costs. This learning curve is completely independent of inflation, product value changes and such economic factors.

Some of the learning factors are--

- *Experience:* As designers and operators become more familiar with the equipment and processes, numerous improvements accrue. Longer operating periods between shutdowns, improved equipment life, elimination of unnecessary operations, more effective utilization of personnel, and better yields occur for any new industrial operation.

- *Incremental capacity:* Most plants, expecially those employing new processes, are over designed. After initial performance expectations are achieved, "bottleneck removal" adds to capacity at a much lower unit cost than for the original installation. A part of this lower cost per unit of product is that site development and similar costs are not repeated.

- *Larger, more efficient single units of equipment:* The history of the process industries is that larger and larger single units of equipment become possible. Catalytic crackers originally were limited to 10 to 15 MB/D throughput. Now units are in the 50 to 100 MB/D range. Both investment and operating costs are significantly lower. Examples could be cited for each industry that are similar. This results in a considerably greater learning effect than for units of constant size.

- *Automation:* Although most industries now use a high degree of automation, the ability to automate increases with greater knowledge of the processes and equipment being employed.

These effects have been discussed in the technical literature and evaluations have been made of the learning rate experienced in the aircraft assembly, petroleum refining and other industrial activities.* For example, it has been shown that, when cumulative

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* W. B. Hirschmann, "The Learning Curve," *Chemical Engineering* (March 30, 1964), pp. 95-100.

production is doubled, the unit cost is reduced about 10 percent (a learning curve factor of 90 percent) for either a complete petroleum refinery or individual units of the same size and is considered typical of a machine-paced operation that involves little direct labor. A more labor-intensive operation, such as airframe assembly, shows a reduction of about 20 percent. Investment as well as operating costs are believed to be susceptible to improvement through experience.

Most learning curve improvement can be expected in the more labor-intensive parts of the operation, such as mining and material handling, and in those areas where new technology is used, such as retorting and environmental control. A learning curve factor in the range of 90 percent for oil shale development would seem reasonable.

Specific potential technologic improvements that are presently in evidence are discussed in the following section. In addition to these improvements, appreciable economic advantage may become possible by significant changes in oil shale processing methods, such as *in situ* retorting or shale gasification.

MINING IMPROVEMENTS

The present-day demonstrated room-and-pillar method of mining oil shale has a considerable cost advantage over other underground mining methods because the large size of mine openings, coupled with high production rates, permits use of larger equipment than normally found in other underground mining operations. Underground oil shale mining costs were estimated for the Initial Appraisal on the basis of using presently available front-end loaders, trucks and fixed crushing plants.

Concepts for improved room-and-pillar mining utilize equipment such as mobile crushers and conveyor systems. In addition, improvements in drilling, blasting and roof-bolting equipment and techniques are anticipated.

Radical changes in underground mining methods are also being considered. During recent years, large size boring machines have been used successfully for drilling tunnels in hard rock. A similar type of machine has been proposed for mining oil shale.* Some type of continuous mining machine could reduce both capital and operating costs by an appreciable amount.

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* H. E. Carver, "Oil Shale Mining: A New Possibility for Mechanization," and W. H. Hamilton, "Preliminary Design and Evaluation of an Alkirk Oil Shale Miner," *Proceedings of the First Five Oil Shale Symposia: 1964-1968* (Colorado School of Mines), pp. 215-265.

These potential improvements in underground mining and crushing eventually could reduce mine and crusher operating costs by increasing productivity from improved mechanization and, thereby, reducing manpower requirements. A reduction in initial and deferred capital investment in mining and crushing also may be anticipated.

RETORTING IMPROVEMENTS

A retorting method utilizing hot recycled solids was selected for the Initial Appraisal as representative of a commercial operation. This selection was made because a retort was needed that could satisfactorily handle oil shale having an assay of about 35 gallons per ton. Improvements to this type of retort are possible mainly in increased size and capacity of the individual units, resulting in reductions in both capital investment and operating costs.

Improvements may be anticipated in those retorting processes which use hot gases to supply the retorting heat. These are lower capital-cost retorts than the recycled hot solids type. Should modifications to design and operation of the hot gas retort permit it to be used for 35-gallon per ton shale and to obtain yields comparable to the hot solids retort, even greater reductions in required syncrude "price" might be anticipated than obtainable by improvements in the recycled hot solids process.

SHALE OIL UPGRADING IMPROVEMENTS

Reduced shale oil upgrading costs are expected to result mainly from improvements in catalysts for hydrodesulfurization and hydrodenitrogenation and from improved methods for processing the residual fraction. These improvements could reduce both capital and operating costs.

SENSITIVITY OF SYNCRUDE "PRICE" TO CAPITAL AND OPERATING COSTS

At present, definitive estimates cannot be made of capital and operating cost reductions that may be obtained by learning curve improvements and technological changes. However, the sensitivity of the syncrude "price" required for a stated DCF rate of return can be related graphically to these cost reductions. Figure 14 has been prepared to show these effects. A simplifying assumption made in the development of the relationships was to apply the cost reduction, either capital or operating, pro rata across the entire mining, retorting and upgrading operation.

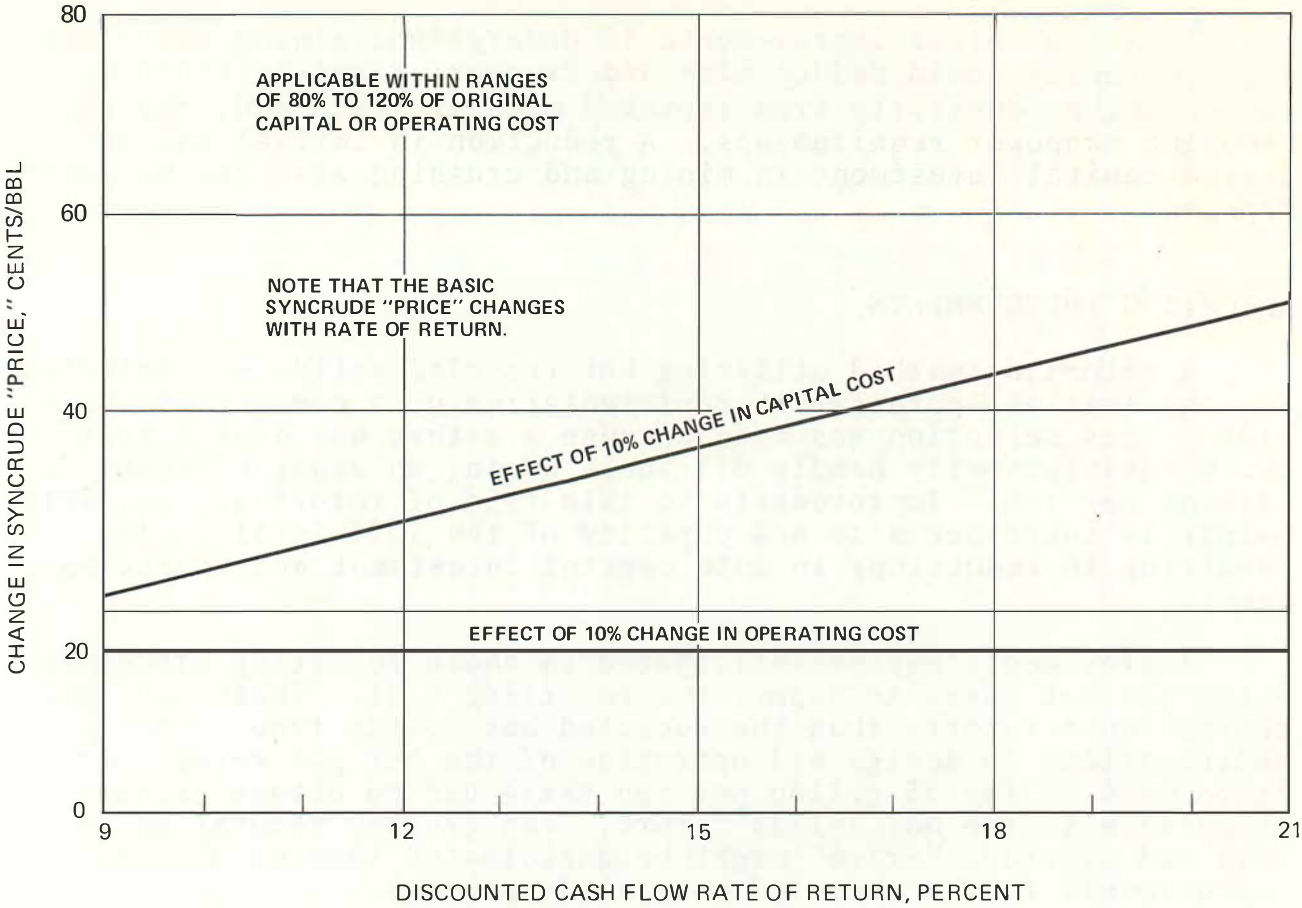

Figure 14. Sensitivity of Syncrude "Price" to Change in Capital and Operating Costs (Constant 1970 Dollars).

DEVELOPMENT OF *IN SITU* RETORTING

Development of feasible and economic *in situ* methods are important for eventual recovery of the deeply buried oil shale resources in the Green River Formation. At present, *in situ* retorting appears to have a potential for producing shale oil from these strata, but it is assumed that no significant commercialization will occur before 1985.

Proposed methods for retorting oil shale in place generally fall into three major categories: (1) forming a block or "chimney" of broken shale in place and retorting as if it were a fixed-bed, batch retort, (2) forming fractures in a shale strata between two groups of wells and retorting by forcing air or hot gases through the fractures, and (3) working in a zone of native permeability and porosity to accomplish contact between the shale formation and the retorting media.*

* P. F. Dougan, F. S. Reynolds and P. F. Root, "The Potential for *In Situ* Retorting of Oil Shale in the Piceance Creek Basin of Northwestern Colorado," *Colorado School of Mines Quarterly*, Vol. 65, No. 4 (October 1970), pp. 57-72.

Retorting Chimneys of Broken Shale

One scheme in the first type of operation which has occasioned considerable discussion is the use of one or more nuclear blasts to form the chimney. Preparations would then be made to retort the broken shale in the chimney and to recover the shale oil by drilling wells to communicate with the top and bottom of the chimney. Air, mixed with recycled gases, could then be pumped into the top of the bed of shale, combustion initiated, and the chimney operated as a large batch retort. Condensed oil, vapors and gases would be drawn off from the bottom of the bed.

This scheme appears to be fairly attractive from an economic viewpoint, providing favorable assumptions are made regarding thickness and richness of the shale strata, yield level of the nuclear devices used, oil recovery obtained, and air compression costs. However, several serious questions arise concerning this operation.

Residual radioactivity in the shale chimney may result in excessive radioactivity in the oil and gas produced. A related problem is the possibility of radioactive contamination of underground water, particularly in the deep, central area of the Piceance Basin where aquifers appear to feed into the White River. Due to the mass of loose material on top of a lower zone of the retorted and burned shale, compaction may occur, resulting in excessively high pressure drop through the bed and exorbitant air compression costs. Thus, the operation could become uneconomical or infeasible before completion. Experimental work on a prototype scale would be required for thorough evaluation of this type of *in situ* method.

The present governmental pricing policy for nuclear devices, and the depth of chimney needed to effectively utilize the oil shale in place, favor the use of devices of the 250-kiloton yield range. Seismic effects of a series of shots of this size, made frequently over the years of contemplated commercial shale oil production, probably would preclude this type of operation. Development of technology in the use of a series of small nuclear shots might be the solution to the seismic problem.

Retorting Fractured Strata

Methods for *in situ* retorting of fractured oil shale strata have been subjected to laboratory and field tests by various companies and by the U.S. Bureau of Mines over a period of about 20 years.*

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* For work reported by industry, see following articles in *Proceedings of the First Five Oil Shale Symposia: 1964-1968:* B. F. Grant, "Retorting Oil Shale Underground, Problems and Possibilities," pp. 39-46; V. D. Allred, "Some Characteristic Properties

of Colorado Oil Shale Which May Influence *In Situ* Processing, pp. 47-76; A. L. Barnes and R. T. Ellington, "A Look at *In Situ* Oil Shale Retorting Methods Based on Limited Heat Transfer Contact Surfaces," pp. 827-852.

For work reported by U.S. Bureau of Mines, see: N. M. Melton and T. S. Cross, "Fracturing Oil Shale with Electricity," and J. A. Miller and W. D. Howell, "Explosive Fracturing Tested in Oil Shale," *Proceedings of the First Five Oil Shale Symposia: 1964-1968*, pp. 611-640. See Also: E. L. Burwell, H. C. Carpenter and H. W. Sohns, "Experimental *In Situ* Retorting of Oil Shale at Rock Springs, Wyoming," *Oil Shale Program Technical Progress Report*, U.S. Bureau of Mines Report No. 16 (June 1969); G. G. Campbell, W. G. Scott and J. A. Miller, "Evaluation of Oil-Shale Fracturing Tests near Rock Springs, Wyoming," *Report of Investigation*, U.S. Bureau of Mines R.I. 7397 (June 1970); E. L. Burwell, T. E. Sterner and H. C. Carpenter, "Shale Oil Recovery by *In Situ* Retorting--A Pilot Study," *Journal of Petroleum Technology* (December 1970), pp. 1520-1524; H. E. Thomas, H. C. Carpenter and T. E. Sterner, "Hydraulic Fracturing of Wyoming Green River Oil Shale: Field Experiments, Phase I, *Report of Investigation*, U.S. Bureau of Mines R.I. 7596 (1972).

Fracturing of the strata usually is considered necessary to provide flow paths for air or other retorting gas and for the products. Fracturing techniques include use of hydraulic pressure, explosives such as desensitized nitroglycerine, and high-voltage electric current.

Contact is made from the surface of the ground to the shale strata through wells drilled at spaced intervals. After fracturing, some of these wells are used to conduct air or preheated gases to the shale, and other wells return oil vapors and gases aboveground.

Bureau of Mines' extrapolation of field test data indicate that *in situ* production of shale oil may be competitive with the more conventional underground mining and *ex situ* retorting methods. In these studies, an optimistic viewpoint was taken of the potential technical problems, and overburden thickness was limited to 500 feet. A relatively thin production zone was assumed in medium-grade shale. The economics would be improved materially, through reduction in well-drilling cost, by operation in thicker strata of richer shale.

Details of work by private industry during recent years on *in situ* retorting of oil shale have not been extensively published. Therefore, the status of this technology cannot be fully evaluated. However, information available from the Bureau of Mines indicates that considerable field work still remains to be done to demonstrate the technology of commercial-scale *in situ* retorting. Some of the problems that appear are development of fracturing techniques applicable over a wide range of situations, maintenance of the fractures during retorting to allow a reasonable pressure drop for gas flow, and efficient recovery of the oil from the strata. Deeper strata than those tested by the Bureau of Mines, which are only a few hundred feet deep, may present problems due to sealing of the fractures from swelling of the shale when heated and from compaction by the weight of overburden.

Retorting in Natural Permeability

Retorting shale in a naturally permeable zone might well eliminate many of the problems associated with nuclear explosives and fracturing methods. The permeability of the zone should increase as kerogen is converted during the retorting step. However, new problems may arise. The unconfined nature of a natural permeable zone may create difficulties in the loss of working fluids or products. Ground water contamination may be a greater potential problem with this technique.

GASIFICATION OF OIL SHALE

New gas for the United States, whether liquefied natural gas (LNG) imports, Arctic gas, or gas manufactured from coal or petroleum liquids, will cost several times the present regulated field price of natural gas. The question arises as to whether or not gas from oil shale can be competitive in this market.

A precise appraisal is difficult because little research has been aimed at the production of gas from oil shale in the United States. Most of the effort has been limited to a modest program during the 1950's by the Institute of Gas Technology (IGT) which investigated the hydrogasification of oil shale.

However, gas has been a primary product of the Estonian oil shale industry, where production in 1968 was reported to be about 100 million cubic feet (MMCF) per day. Gas is also a major objective of Brazil's oil shale development program. A 2,200 metric ton per day prototype retort, recovering 25 percent of the calorific value of the shale product as gas and liquid petroleum gas (LPG), is scheduled to go into operation during 1972.

Although IGT demonstrated that hydrogasification could produce a high yield of pipeline quality gas from oil shales, introduction of the shale into its high-pressure, high-temperature reactor and removal of spent shale from the system presents formidable mechanical problems. Results from IGT's current coal hydrogasification pilot plant program will be useful in evaluating the processing of oil shale by this method, but the demonstration of commercial-scale equipment is not in prospect for several years.

The gasification of oil shale in Estonia used a modified coke oven, fired with low-BTU gas from other oil shale retorts. The shale is of very high grade--70 gallons per ton. This technology is unlikely to be used in the United States, especially since U.S. oil shales are of lower grade than those in Estonia. Its significance is that gas production from oil shale has been accomplished on an industrial scale.

Processes, such as that being developed in Brazil, which yield gas as a co-product with the shale oil seem most applicable for U.S. oil shales. Certain configurations of several types of retorts can produce high-BTU gas as well as oil. Increased yields of gas are possible if economically justifiable.

With gas from coal and petroleum liquids being projected to cost in excess of $1.00 per million BTU's--the equivalent of $6.00 per barrel for oil--there would seem to be an incentive to produce a higher component of shale product as gas. Most oil shale retorting research in the United States has been conducted during the time that field prices for gas have been in the range of $0.10 to $0.15 per million BTU's--equivalent to $0.60 to $0.90 per barrel of oil. Thus, there was every reason to minimize gas as a product.

It was noted earlier that an appraisal of oil shale as a source of gas is difficult because so little effort has been devoted to shale gas in the United States. It seems likely, however, that the same basic retorting methods being developed to produce oil can produce gas as a co-product. Therefore, the technological status of gas production from shale is not greatly different from that to produce oil alone.

Yields of retort gas ranging up to 2,000 cubic feet of natural gas equivalent per ton of 35-gallon per ton shale are reasonable. Thus, gas yield from oil shale in 1985 could amount to 2 billion cubic feet (BCF) per day if the maximum projected shale mining rate of 1 million tons per calendar day is attained. Increased gas yield may be only partially at the expense of oil yield. Should gas yield be entirely at the expense of oil yield, the production of 2 BCF per day of gas would result in oil production being 250 MB/D less than the projected maximum of 750 MB/D.

INDUSTRY AND GOVERNMENT COOPERATION IN OIL SHALE RESEARCH AND DEVELOPMENT

Since 1945, industry and government together have spent more than $175 million in research and development on oil shale. Methods have been tested on pilot and semi-commercial scales for mining and retorting oil shale, *in situ* retorting, refining and upgrading the oil, and the utilization or disposition of wastes. The bulk of these expenditures to date have been made by industry. The expenditures have not been included in their entirety in the economic studies given in this report.

Industry has shown its willingness to conduct research and development on shale oil production technology and can be expected to maintain an adequate level of activity to support commercial production when the industry gets under way.

Possible roles of government in oil shale research and development can be categorized in five principal supportive areas:

- Geology and resources
- Fundamental research
- *In situ* techniques
- Environmental protection
- Cooperative research and development.

The Federal Government owns more than 80 percent of the oil shale resources that ultimately may be utilized. Geological data pertaining to these resources are limited. Therefore, a government-initiated program using both public and private means should be conducted to provide needed information on the federal oil shale holdings.

The Federal Government, through agencies such as the National Science Foundation, the Bureau of Standards, the Bureau of Mines, the Atomic Energy Commission and instrumentalities within the Department of Defense, has traditionally supported fundamental scientific research. Oil shale has been the object of a relatively small proportion of this effort in the past. This is a useful area of government-financed research and should be increased.

Considerable effort by both government and industry has gone into research on *in situ* methods of shale oil production, both nuclear and non-nuclear, but success has not been proclaimed to date. In addition to the obvious benefits of an efficient, economical, environmentally acceptable *in situ* shale oil production method, there are large potential reserves of oil shale that do not seem recoverable by mining techniques. *In situ* retorting warrants a fairly significant level of research by government, particularly on the basic concepts and technology involved.

Minimization of environmental effects and means of utilizing or controlling gaseous, liquid and solid wastes from an oil shale industry are subjects of concern. This area is receiving attention by both government and industry. It is appropriate that government participate with industry in an accelerated program in environmentally related oil shale research.

Federal Government participation in research and development of oil shale mining and process technology should be indirect in order to reduce the administrative requirement and minimize the costs. One way this could be accomplished is through a modification of the 1971 Prototype Oil Shale Leasing Program, which would provide that private expenditures on appropriate work programs in oil shale mining and processing research and development could be applied to future payment of royalties otherwise due the Government under the leasing program. Appropriate work programs may be designed for oil shale mining, *in situ* retorting, and processing research and development which lead to commencement of commercial installations. Credit would be given for expenditures made or contributions to a work program subsequent to acquisition of a federal lease and prior to any commercial development by the lessee. Such a program would not only be conducive to earlier oil shale commercialization by encouraging private industry to fund additional research and development, but it also would encourage participation in bidding for federal oil shale leases. Another way this could be accomplished is through government funding of assistance to industry-originated and operated programs.

Chapter Five

REGIONAL CONSIDERATIONS FOR DIRECT SUPPORT OF AN OIL SHALE INDUSTRY

The development of an oil shale industry will require direct support from regional resources, including manpower, water, electric power, roads, pipelines and community services. This chapter discusses the requirements for this support which relate directly to the installation and operation of plant facilities in the oil shale region. Support of urban and community facilities and needs are not considered.

MANPOWER FOR MINE AND PLANT

The number of permanent employees which will be needed for operation, maintenance, supervision and supporting services for a 100 MB/D syncrude first-generation plant are estimated in the following tabulation:

Mining	1,000
Retorting	200
Solid Residue Disposal	200
Shale Oil Upgrading	300
Total	1,700

Temporary construction manpower to build a 100 MB/D syncrude plant is estimated to average about 1,800 people over the construction life, peaking at about 3,800 during the final year.

For the proposed maximum development schedule discussed in Chapter Two, the manpower requirements would be those shown in Table 11.

WATER REQUIREMENTS FOR MINE AND PLANT USE

Water will be used in many of the operations associated with an oil shale industry. A specific input of water will be required for--

- Mine drilling operations
- Mine loading operations
- Crushing and screening plant dust control
- Flue gas cooling and moistening in retorting

TABLE 11

MANPOWER REQUIREMENTS FOR A SYNCRUDE PLANT

	Syncrude (MB/D)	Permanent Employees	Temporary Construction Personnel (Average)
1974	–	–	900
1975	–	–	900
1976	–	–	900
1977	50	850	1,800
1978	50	850	5,400
1979	50	850	7,200
1980	150	2,550	7,200
1981	250	4,250	7,200
1982	350	5,950	7,200
1983	450	7,650	7,200
1984	650	11,050	7,200
1985	750	12,750	7,200

- Spent shale wetting
- Cooling tower makeup in retorting and upgrading plants
- Boiler water makeup in retorting and upgrading plants
- Process water for upgrading
- Coke-cutting water for upgrading
- Personnel use.

The quantity of water input that will be required will depend somewhat on the process designs selected and on the amount of air cooling that can be used. Assuming that maximum air cooling is used, the water requirement for a plant complex producing 100 MB/D of syncrude has been estimated to be as shown in the following tabulation:

	Acre-Feet/Year
Mining	300
Retorting	6,000
Solid Residue Disposal	3,000
Shale Oil Upgrading	7,200
Total	16,500

There is some process effluent water produced, including retorting water separated and some saline blowdown water, amounting to about 2,500 acre-feet per year. If all of this water could be used to wet solid residue to facilitate compaction, the net fresh water input requirement would be reduced to about 14,000 acre-feet per year.

Based on the above estimates, it is probable that water requirements for 100 MB/D of syncrude production from commercial shale oil complexes will be in the range of 14,000 to 16,500 acre-feet per year. For planning purposes to evaluate the availability of fresh water supply, it is recommended that the larger quantity of 16,500 acre-feet per year be used.

Using the factor of 16,500 acre-feet per year per 100 MB/D syncrude production, water requirements for the proposed maximum development schedule outlined in Chapter Two would be as shown in Table 12.

The Department of the Interior estimates that water availability within the State of Colorado for a shale oil industry may vary from 86,000 to 456,000 acre-feet per year. The minimum estimate of 86,000 acre-feet per year would be marginally limiting if accurate. Anticipating that this low amount is not correct, the assumption is made that water will be available for developing up to 750 MB/D of syncrude.

ELECTRIC POWER GENERATION AND TRANSMISSION FACILITIES

Another factor which should be considered in evaluation of regional support is the input required for power generation and transmission. The 100 MB/D plants will use an estimated 110,000 kilowatts (KW) of power for syncrude production. Assuming that power plants are installed which use the proved technology of water cooling, the water input to produce this power is estimated to be about 800 acre-feet per year. Using these factors, the power and water requirements for the proposed development schedule of Chapter Two would be as shown in Table 13.

TABLE 12

WATER REQUIREMENT FOR A SYNCRUDE PLANT

	Syncrude (MB/D)	Water Requirement (Acre-Feet per Year)
1977-1979	50	8,250
1980	150	24,750
1981	250	41,250
1982	350	57,750
1983	450	74,250
1984	650	107,250
1985	750	123,750

TABLE 13

POWER AND WATER REQUIREMENTS FOR A SYNCRUDE PLANT

	Syncrude (MB/D)	Power (KW)	Water for Power (Acre-Feet per Year)
1977-1979	50	55,000	400
1980	150	165,000	1,200
1981	250	275,000	2,000
1982	350	385,000	2,800
1983	450	495,000	3,600
1984	650	715,000	5,200
1985	750	825,000	6,000

SECONDARY ROADS TO MINES AND PLANTS

Existing roads in the areas where developments would be expected to take place to 1985 are not presently adequate and would have to be improved extensively. Also, a web of new roads would have to be constructed to tie plant facilities together. For estimating the cost of building such a road system, it has been assumed that the Parachute Creek, Roan Creek, Conn Creek and Clear Creek county roads would be improved to first-class, heavy-duty roads with asphaltic concrete surfaces. The existing county highway on Piceance Creek would be resurfaced and widened. New roads to mines would be constructed on East Fork, West Fork, East Middle Fork and Middle Fork of Parachute Creek, on East Fork of Conn Creek and on Deer Park Gulch and Tom Creek. Interties between the Parachute Creek, Roan Creek and Piceance Creek systems would be constructed over the mesas. Expenditures required are shown in Table 14.

Costs of the roads were estimated from Collector road tabulations by the Colorado State Highway Department made for the National Highway Functional Classification and Needs Study. The terrain was classified as "rolling" for roads in valleys and "mountainous" for all other roads. The values developed in this way will be average estimates for the Western Slope of Colorado and are not specific to the oil shale areas. As such, they indicate only an "order-of-magnitude" cost, and the distribution between public and private sources of funds is undetermined.

TABLE 14

EXPENDITURES REQUIRED FOR ROAD IMPROVEMENT

	Miles	Expenditure
Improved County Roads	35	$ 4,000,000
Improved Piceance Creek Road	33	500,000
New Roads to Mines	30	8,500,000
Interties	20	7,000,000
Total	**118**	**$20,000,000**

SYNCRUDE PIPELINES

Shale oil from processing plants in the oil shale area would be moved to refining centers via pipelines. Part of the product oil may move west to Salt Lake City or Los Angeles. However, it is likely that most of the oil will move east to Chicago and other midwestern refining centers.

There are several possible routes by which a pipeline can connect with existing pipelines to midwestern areas: (1) north to Wamsutter, Wyoming, and then to Casper to connect to the Platte or Service lines moving east; (2) directly north and east to Fort Laramie to connect with either of these lines; and (3) directly east via Fort Collins for connection with the Arapahoe line near Sterling. A portion of the oil could go west to Utah.

COMMUNITY SERVICES*

The population of western Colorado is relatively small, and the largest community, Grand Junction, has a population in the urban area of approximately 30,000 persons. The major east-west highway of Colorado is Interstate 70, now under construction along the Colorado River.

This highway generally lies along the southern boundary of the principal oil shale area, as does the route of the Denver and Rio Grande Western Railroad main line. The northern boundary of the shale area is approximately marked by the White River Valley, a remote and isolated valley in a thinly settled area with two communities, Meeker and Rangely, each having a population of about 1,500.

The principal industries in the region are grazing of livestock and the extraction of minerals. Rangely, in Rio Blanco County, is the site of Colorado's largest oil field, and exists principally as an oil and gas center. Grand Junction, the principal community of western Colorado, is a transportation hub with rail, truck and highway communication with western Colorado and more distant points, and with frequent jet air service principally to Denver and Salt Lake City. Grand Junction is also a commercial and medical center for the region with a number of wholesale supply firms and services, as well as medical, educational and other professional services.

Rifle, situated in Garfield County on the Colorado River at the southwestern corner of the Piceance Creek Basin, has historically

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* This section is taken from *Report on Economics of Environmental Protection for a Federal Oil Shale Leasing Program,* prepared by a special committee of the [Colorado] Governor's Oil Shale Advisory Committee for the Director of Natural Resources of the State of Colorado (January 1971), pp. 167-169.

been oriented more towards industrial activity. It is the site of the Union Carbide vanadium-uranium mill and is the nearest community to the Bureau of Mines' plant at Anvil Points. The Denver and Rio Grande Railroad has made it a shipping point for livestock from the Piceance Creek Basin. A significant portion of the manpower needed for an oil shale industry in Rio Blanco County can be expected to locate in Rifle.

To the east is the county seat of Garfield County, Glenwood Springs, situated at the junction of the Roaring Fork and Colorado Rivers. This community has become the focal point of distribution of goods and services to the very large areas drained by the Colorado, Eagle, Roaring Fork, Frying Pan and Crystal Rivers. In addition, it has been a center for local, state and federal offices. It has a population of about 4,000 and is well served by medical and educational facilities. It is expected to absorb some of the population growth flowing from oil shale development.

The communities of New Castle, Silt, Grand Valley and Debeque on the Colorado River will take on added significance as population centers, but are not expected to absorb a major share of any population growth derived from an oil shale industry, at least in the early phases of its development.

The present public facilities in western Colorado, generally, can support a population somewhat in excess of the present population. To be sure, some dislocations will occur, but the regional development is quite advanced.

APPENDICES

APPENDIX 1

OIL SHALE TASK GROUP
OF THE
NATIONAL PETROLEUM COUNCIL'S
COMMITTEE ON U.S. ENERGY OUTLOOK

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Process Engineering & Development
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Cameron Engineers

Hugh J. Leach
Vice President
Research and Development
Cleveland-Cliffs Iron Company

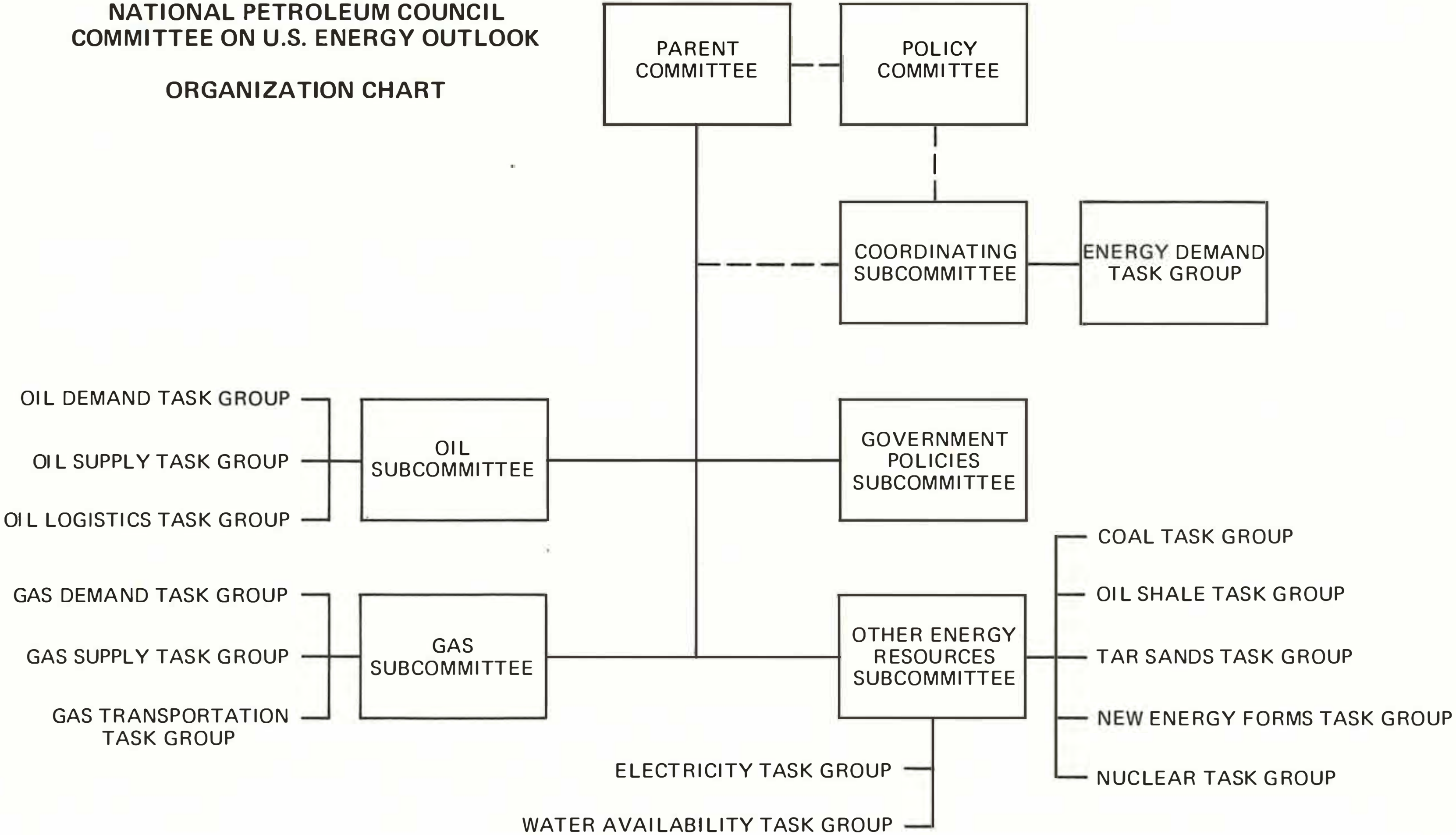
Harry Pforzheimer, Sr.
Assistant to the Senior Vice President
Natural Resources
The Standard Oil Company (Ohio)

ASSISTANT

Walter I. Barnet
Senior Engineering Associate
Union Oil Company of California

NATIONAL PETROLEUM COUNCIL
COMMITTEE ON U.S. ENERGY OUTLOOK

ORGANIZATION CHART



APPENDIX 3

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National Petroleum Council

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Sam Smith
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Coordinating & Planning Department
Continental Oil Company

Harry Gevertz, Manager
Special Projects
El Paso Natural Gas Company

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* Served until December 15, 1972; replaced by Duke R. Ligon.

APPENDIX 4

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American Public Power Association

R. B. Galbreath, Manager
Tar Sands Division
Cities Service Company

Leon P. Gaucher
Consultant (Texaco Inc.)

C. Donald Geiger
Resources Acquisitions
Carter Oil Company

Emanuel Gordon
Nuclear Fuel Products Manager
Atomic Industrial Forum, Inc.

J. Emerson Harper
Assistant & Power Engineering Advisor
Office of Assistant Secretary-Water and Power Resources
U.S. Department of the Interior

Donald Hunter, Director
Uranium Supply Division
Gulf Energy and Environmental Systems

V. M. Johnston, Manager
Economics Services
Island Creek Coal Sales Company

John J. Kearney, Vice President
Edison Electric Institute

Arnold E. Kelley
Associate Director for Research Process Engineering & Development
Union Oil Company of California

John E. Kilkenny
Senior Geologist
Union Oil Company of California

D. T. King, Director
Coal Preparation & Distribution
U.S. Steel Corporation

James N. Landis, Consultant
Bechtel Corporation

Olaf A. Larson, Staff Engineer
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Gulf Research & Development Co.

John E. Lawson, Director
Processing Group for Synthetic Crude and Mineral Operations
Atlantic Richfield Company

Hugh J. Leach, Vice President
Research and Development
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Dwight Miller
Assistant Director
Northern Marketing and Nutrition Research
Agriculture Research Service
U.S. Department of Agriculture

W. B. Oliver, Manager
Resources Acquisitions
Carter Oil Company

Harry Pforzheimer, Sr.
Assistant to the Senior Vice President
Natural Resources
The Standard Oil Company (Ohio)

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Chairman
Rochester & Pittsburgh Coal Co.

E. H. Reichl
Vice President, Research
Consolidation Coal Company

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Southern California Edison Co.

H. W. Sears, Vice President
Northeast Utilities Service Co.

John D. Selby
Deputy Division General Manager
Nuclear Energy Division
General Electric Company

Howard M. Siegel, Manager
Synthetic Fuels Research Department
Esso Research & Engineering Co.

Dr. George Skaperdas
Manager, Process Development
Research and Development
The M.W. Kellogg Company

Donald E. Smith
Staff Economist
National Rural Electric Cooperative Association

A. M. Wilson, President
Utah International Inc.

F. Leo Wright
Assistant to the Executive
Vice President
Nuclear Energy Systems
Westinghouse Electric Corporation

Dr. J. F. Wygant
Director
Products & Exploratory Research
American Oil Company

APPENDIX 5

BASIC ASSUMPTIONS FOR THE INITIAL APPRAISAL
(Established January 14, 1971)

U.S. AND STATE GOVERNMENT POLICIES

+ U. S. Lands.

    Titles which are not clear now will not be cleared.

    Blocking up of ownership parcels by exchange with private land parcels will not be done.

    The Naval Oil Shale Reserves will not be released.

    Leases will not be offered.

+ State Lands.

    There are no lands available in Colorado.

    Wyoming state lands will not be offered for lease.

    Utah state lands will be available for lease.

+ Adequate water will be available and obtainable in all states up to 1985.

+ Environmental factors regarding shale oil production.

    Air pollution standards on dust, particulate matter and sulfur dioxide will be set by the states and the Federal Government. These standards will be met by the oil shale facilities.

    Water pollution--surface and underground--standards will be set by the states and the Federal Government. The oil shale facilities will meet these standards.

    Disposal of solid wastes will be allowed in canyons and in mined out areas under specifications set by the states and the Federal Government.

    Ground surface effects.

        Surface renewal specifications after stripping operations will be set by the states and the Federal Government. These specifications will be met by the oil shale industry.

        Subsidence from underground mining or *in situ* operations is not expected to occur.

        Seismic effects will be compensated for.

+ The depreciation rate will be calculated by combination of double declining balance and straight-line methods.

+ Depletion allowance.

  The depletion allowance will be 15 percent of the value of oil and gas after retorting.

  The value of the oil and gas for the depletion calculation will be calculated by prorating the total revenue by the ratio of the cost of mining, plus retorting and ash disposal, to the total costs.

+ Investment tax credit will not be allowed.

+ Direct support of shale oil production.

  There will not be any subsidy.

  Geological investigations will be continued at about the present level or will not be increased enough to have any significant effect.

  Government research and development will be continued at about the present level but will not be increased enough to have any significant effect.

  Tax provisions will not be changed enough to have any significant effect.

OIL SHALE RESERVES

+ Minable--25-, 30-, and 35-gallon per ton assay value shale.

  Strip mining--30-foot minimum thickness of oil shale seam.

  Underground mining--30-foot minimum thickness of oil shale seam.

+ Recoverable reserves will average 60 percent of in-place resources.

TECHNOLOGIC FACTORS

+ *In situ* operation is not presently proved and will not be by 1985.

+ Gasification is not presently proved and will not be by 1985.

+ Technology is presently available for mining, retorting, refining and byproduct recovery.

SYNTHETIC FUEL QUALITY (See also "Properties of Crude Shale Oil and Syncrude")

+ Syncrude characteristics will be:

Pour point--+50°F
Viscosity--40 SSU at 100°F
Nitrogen--350 ppm
Sulfur--50 ppm.

Crude type assay specifications will be prepared by the Oil Shale Task Group

ECONOMIC FACTORS

+ Time bases for investment.

Capital investment costs will be based on 1970 dollars.

The engineering and construction time schedule for an oil shale plant will be 3 years.

The deferred investment schedule for mining and spent shale disposal will cover a period of 18 years from the start of plant operations.

The project life will be 20 years from the start of plant operations.

Plant startup time will be 3 months after completion of construction.

+ The size of unit plants will be:

Mining and retorting--equivalent to 50 MB/D syncrude. capacity.

Upgrading to syncrude specifications--100 MB/D syncrude.

+ Capital investment requirement.

Plant and equipment will be included in capital investment.

Land will not be included.

Initial expense will be capitalized.

Royalties on processes will be paid at the start of the project and capitalized.

+ Byproduct values--f.o.b. plant.

Green Coke--$4 per ton
Anhydrous Ammonia--$30 per ton
Sulfur--$15 per long ton.

LOGISTICS PROBLEMS

+ Manpower.

  Supply and training of manpower will be included as a part of plant startup cost.

  Housing--community development costs will be assumed by private investors.

+ Communications and transportation.

  Railroad spur connections will be included in the project cost.

  Private highway connections will be included in the private cost.

  Internal plant pipelines will be included in the project cost, but pipeline connections to common carrier lines will not be included.

+ Domestic water supply will be furnished by the municipalities.

+ Other domestic utilities will be furnished by the municipalities.

PROPERTIES OF CRUDE SHALE OIL AND SYNCRUDE

Typical properties of the crude shale oil and syncrude are:

	Crude Shale Oil	Syncrude
Gravity, °API	28.0	46.2
Pour Point, °F	75	50
Sulfur, wt %	0.8	0.005
Nitrogen, wt %	1.7	0.035
RVP, psi	-	8
Viscosity, SUS at 100°F	120	40
Analysis of Fractions		
Butanes and Butenes, vol %	4.6	9.0
C_5-350°F Naphtha		
Vol %	19.1	27.5
Gravity, °API	50.0	54.5
Sulfur, wt %	0.70	<0.0001
Nitrogen, wt %	0.75	0.0001
K Factor	11.7	12.0
Aromatics, vol %	-	18
Naphthenes, vol %	-	37
Paraffins, vol %	-	45
350-550°F Distillate		
Vol %	17.3	41.0
Gravity, °API	31.0	38.3
Sulfur, wt %	0.80	0.0008
Nitrogen, wt %	1.35	0.0075
Aromatics, vol %	-	34
Freezing Point, °F	-	-35
550-850°F Distillate		
Vol %	33.0	22.5
Gravity, °API	21.0	33.1
Sulfur, wt %	0.80	<0.01
Nitrogen, wt %	1.90	0.12
Pour Point, °F	-	+80
850°F-Plus Residue		
Vol %	26.0	None
Gravity, °API	12.0	
Sulfur, wt %	1.0	
Nitrogen, wt %	2.4	

CONCLUSIONS FROM THE INITIAL APPRAISAL (1971-1985)

Conclusions arrived at as a result of the Initial Appraisal study are as follows:

- Recoverable reserves of oil to 1985 from oil shale resources in the United States total about 17 billion barrels.
- Development of oil shale to 1985 will probably occur in the prime 35-gallon per ton holdings in private hands.
- Production of syncrude from these reserves could reach about 400 MB/D by 1985.
- Capital investment, adjusted to mid-1970 basis, in facilities to produce 100 MB/D of syncrude from oil shale will be of the order of $500 million.
- Syncrude "price," at a 15-percent DCF rate of return, varies from $4.35 to $5.30 per barrel at the upgrading facility in Colorado. (This is without royalty which, on 35-gallon per ton oil shale, amounts to $0.21 per barrel of syncrude.)

CAPITAL INVESTMENT AND OPERATING COSTS DEVELOPED FOR THE INITIAL APPRAISAL

Estimates of capital investment requirements and operating costs, based on mid-year 1970, were given in the Initial Appraisal in the sections dealing with mining (including raw shale crushing and ash disposal), retorting and upgrading. These costs have been used in Appendix Table 1 to calculate total capital investment and total annual operating costs for the 12 cases involving the four mining methods and three grades of oil shale. Setting up these 12 cases is not intended to imply that each case is considered feasible. The purpose is to indicate the relative economic advantage or disadvantage of the particular mining methods over a range of shale quality.

The initial mining, crushing and ash disposal capital includes investment in equipment to permit startup of these operations and also the cost of developing the mine to the full-scale output required by the retorting plant. The deferred capital provides for replacement of equipment during the life of the project. From 35 to 45 percent of the total capital investment in mining, crushing and ash disposal is in this deferred category.

Other investment items are the retorting plant (including gas processing plant, off-site structures and pipelines), the facilities for upgrading the crude oil to syncrude, and the water supply system. Working capital has been calculated from the annual operating costs by the following formula:

Working capital = [5 x (Mining, crushing and ash disposal) + 4 x (Retorting) + 3 x (Upgrading)] 1/12.

This provides cash for 1 month of total operating costs, a 1-month stockpile of raw shale and crude shale oil, 1 month of syncrude production in transit, and a 1-month delay in receiving payment for delivered syncrude.

Cost of oil shale reserves is not included in this total capital. At estimated 1970 values, cost would be about $20 million for a 20-year shale supply at 100 MB/D syncrude production rate.

Operating costs are defined in this study as including all the items such as labor, overhead, maintenance, utilities, supplies, insurance and property taxes. Not included are depreciation and income taxes. These are calculated separately, as discussed in the Initial Appraisal Oil Shale Task Group report.

For mining, crushing and ash disposal, provision is made by means of deferred capital investment for mine development and equipment replacement over the assumed 20-year project life. The major part of the retorting and upgrading plants are considered to have operable lives of at least 20 years. However, maintenance costs have been assumed to increase by 50 percent during the last 5 years, as shown by the step-up in operating costs.

The capital and operating costs given in Appendix Table 1 are for a syncrude production unit of 100 MB/D. As discussed in the Initial Appraisal, this is considered a reasonable scale of operation with two mines and associated retorting plants feeding crude shale oil to a single upgrading plant for production of 100 MB/D syncrude.* The quantity of shale of each grade, required to produce 104 MB/D of crude shale oil and, from this, 100 MB/D of syncrude, is shown in the following tabulation.

Shale Assay (Gal/Ton)	Shale Mined and Retorted (Tons/Calendar Day)
25	175,000
30	146,000
35	125,000

Unit capital and operating costs, for mining and retorting, are assumed to be applicable over this range of daily shale capacity for two units.

Compliance with the environmental control regulations in effect in Colorado in 1970 has been provided for in these investment and operating costs. The list given below comprises the main items of equipment and operating procedures being used for environmental control purposes. Many of these items have been in use for some time and are considered standard design and operating practice.

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* NPC, *An Initial Appraisal by the Oil Shale Task Group*, pp. 28-30.

Mining and Crushing:

(1) Blowers, ducts and baffles to conduct fresh air into the mine and to distribute it effectively.

(2) Dust control during drilling, loading and crushing operations--using water and dusty air collecting and cleaning equipment.

(3) Collection and reuse of water produced from the mine.

Retorting:

(1) Enclosure and sealing of dust-producing operations.

(2) Collection and cleaning of dusty air.

(3) Sealing of equipment to prevent hydrocarbon emissions.

(4) Use of mechanical seals on pumps to prevent hydrocarbon emission to the atmosphere.

(5) Oil-water separators.

(6) Recovery of sulfur and ammonia from retort product water.

(7) Use of excess water from mine and retort operations to moisten shale residue.

(8) Cyclones, electrostatic separators and wet scrubbers to clean stack gases before venting to the atmosphere.

Disposal of Shale Residue:

(1) Moistening to prevent dusting

(2) Compaction on disposal area to prevent blowing and percolation of natural precipitation through the residue.

(3) Routing of surface water around or through the residue disposal area by means of lined channels or conduits.

(4) Collection of water run-off or seepage from residue area and use in operations.

(5) Vegetation of the inactive residue disposal area.

Shale Oil Upgrading:

(1) Floating-roof tanks.

(2) Mechanical-sealed oil pumps.

(3) Flares.

(4) Recovery of hydrogen sulfide and ammonia from product water and gas streams.

(5) Sulfur plant for conversion of hydrogen sulfide to a storable and marketable byproduct.

(6) Oil-water separators.

(7) Return of clarified water to retort for moistening of shale residue.

Appendix Table 1

ESTIMATED COSTS FOR PRODUCING 100 MB/D SYNCRUDE FROM OIL SHALE*
(At Mid-Year 1970)

	25 Gal/Ton Shale	30 Gal/Ton Shale	35 Gal/Ton Shale
Oil Shale Mined & Retorted (Tons/D)	174,800	145,600	124,800
Crude Shale Oil Produced (B/D)	104,000	104,000	104,000

	25 Gal/Ton Shale				30 Gal/Ton Shale				35 Gal/Ton Shale			
	Surface		Underground		Surface		Underground		Surface		Underground	
Mining Method	Pit	Strip	Adit	Shaft	Pit	Strip	Adit	Shaft	Pit	Strip	Adit	Shaft
	Capital ($ Million)											
Mining, Crushing, Ash Disposal												
Initial	176.8	95.4	105.0	130.8	147.2	79.4	87.6	109.0	126.2	68.2	75.0	93.4
Deferred	94.2	79.4	71.4	74.0	78.4	66.0	59.4	61.6	67.2	56.6	51.0	52.8
Retorting	248.2	248.2	248.2	248.2	206.8	206.8	206.8	206.8	177.2	177.2	177.2	177.2
Upgrading	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8
Water System	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Total Investment	719.0	622.8	624.4	652.8	632.2	552.0	553.6	577.2	570.4	501.8	503.0	523.2
Working Capital	27.6	27.6	27.6	28.8	23.6	23.6	23.6	24.8	20.8	20.8	20.8	21.8
Total Capital (Not Incl. Land)	**746.6**	**650.4**	**652.0**	**681.6**	**655.8**	**575.6**	**577.2**	**602.0**	**591.2**	**522.6**	**523.8**	**545.0**
	Operating Costs ($ Million/Year)†											
Mining, Crushing, Ash Disposal	39.6	39.6	39.6	42.8	33.0	33.0	33.0	35.6	28.2	28.2	28.2	30.6
Retorting	20.4/25.6				17.0/21.2				14.6/18.2			
Upgrading	16.8/19.4				16.8/19.4				16.8/19.4			
Water System	0.4				0.4				0.4			
Total Operating Costs												
First 15 Years	**77.2**	**77.2**	**77.2**	**80.4**	**67.2**	**67.2**	**67.2**	**69.8**	**60.0**	**60.0**	**60.0**	**62.4**
After 15 Years	**85.0**	**85.0**	**85.0**	**88.2**	**74.0**	**74.0**	**74.0**	**76.6**	**66.2**	**66.2**	**66.2**	**68.6**

Unit Costs

	Mining, Crushing, Ash Disposal				Retorting Oil Shale	Upgrading Crude Shale Oil	
	Pit	Strip	Adit	Shaft			
Capital ($ per Ton/D)—Initial	1,011	546	601	748	1,420	($ per B/D)	1,854
—Deferred	539	454	409	424	–		–
Operating Cost (¢ per Ton)							
First 15 Years	62	62	62	67	32	(¢ per Bbl.)	44
After 15 Years	62	62	62	67	40	(¢ per Bbl.)	51

* Taken from the Initial Appraisal.

† Operating costs do not include depreciation.

APPENDIX 6

NPC OIL SHALE TASK GROUP
COMPUTER PROGRAM DOCUMENTATION

INTRODUCTION

DCF rate of return computer program WBCDFROR was used by the Oil Shale Task Group in the economic evaluation of syncrude production from oil shale. This program was developed by personnel in the Research and Oil Shale Departments of Union Oil Company of California, in consultation with personnel in Union's Economics and Corporate Planning Department and members of the Oil Shale Task Group. The principles utilized in these computations are in general use for this type of economic evaluation and do not comprise information proprietary to the Union Oil Company of California.

The program documentation provided by this report is being made available to the U.S. Department of the Interior, through the National Petroleum Council, in answer to the Department's request for the computer programs used in the U.S. Energy Outlook study.

OVERVIEW

In summary, the computer program WBDCFROR computes the DCF rate of return (Investor's Method) on capital investment for an oil shale mining and retorting and shale oil upgrading system. Input data include capital investment, annual operating costs, and quantity and value of shale oil syncrude and byproducts. Income tax rate, investment tax credit and depletion allowance are also inputs.

The annual net cash flow is computed, and then the discount rate which will make the sum of the discounted cash flows equal to zero is determined. In addition, annual and total net profits for the project are calculated.

COMPUTER REQUIREMENTS

The program WBDCFROR is written in Fortran IV, G level, for use on the IBM 360 or 370 systems. The program comprises a main routine and four sub-routines. In contains 700 source statements and has a total program size of 23,300 bytes.

Core requirements on the IBM 370/55 are 62K bytes. Running time, for example, with three independent cases and seven syncrude values for each case was 2 minutes real time and 17 seconds CPU time. Depending upon the printout option selected, up to 5 pages of output are printed for each rate of return calculation made.

INPUT DATA

Input data to WBDCFROR are entered on a deck of 15 cards, plus a series of optional cards which are read in as called for by the program. A sample of the input keypunch sheet, with the example problem entered, is shown on the following page. A listing and explanation of the input data and variable names shown on the sheet is given in Appendix Table 2.

OUTPUT DATA

Output is printed on a maximum of five sheets for each rate of return computation. Options provide for omission of selected sections of the full output and for printout of a summary sheet.

A description of the computation procedure and the printed values is given in Appendix Table 3. Examples of the standard output, produced from the input data listed in Appendix Table 2, are shown in Appendix Tables 4 through 8. Except for Appendix Table 6, these have been previously published in the Initial Appraisal Oil Shale Task Group report.

FORM 272 PAGE ____ of ____

DATA TO BE KEYPUNCHED

TYPE OF DATA: ________ DATE: ________

FOR: ________ PROJECT: ________ PHONE: ________ CARD FORM: ________

☐ VERIFY. ☐ PRINTING PUNCH. ☐ INTERPRET

INPUT TO WBDCFROR

CARD	1–80
1	DESCRIPTION
2	NCOYR, NOPYR, NDB, NSP, NTP, TAXES, TAXCR, CSOVAL, CSOBPD, CODE, PTXCOD, XINC
3	XCAP(1), XCAP(2), XCAP(3), XCAP(4), XPREX(1), XPREX(2), XPREX(3), XWCAP
4	CAPDEF, STLIFE, DEPLN, SYNDEP, DEPTPC, DETINT, ROYLTY, DELAY
5	CAPINC, FCOST
	YR, OP COST
6	MCA OP EXP 1
7	WATER OP EXP 1
8	RET OP EXP 1
9	REF OP EXP 1
	QUANT, YR, VALUE
10	SHALE OIL 1
11	COKE 1
12	AMMONIA 1
13	SULFUR 1
14	OTHER 1
	PRNT(N) N=1,8
15	INPUT DATA, REVENUE, ROY'TY,INT, DEPR'N,OPC., CASH FLOW, ROR, SUMMARY
	OPTION, NO. OF CAPFAC CARDS = FCOST
16+	CAPFAC, OPCFAC(N) N=1,7

Appendix Table 2

INPUT DATA FOR PROGRAM WBDCFROR

Card No.	Variable Name or (Item)	Value Used for Example	Units of Variables	Remarks
1	(Description)	-	-	80 alphameric characters for problem title.
2	NCOYR	3	years	Plant construction period.
	NOPYR	20	years	Plant operating period.
	NDB	0	none	Instruction to use only double-declining balance (DDB) depreciation for all four capital categories, if NDB>0.
	NSL	0	none	Instruction to use only straight-line (SL) depreciation, if NSL>0.
	NTP	1	none	Instruction to use SL depreciation for mining and water capital and DDB/SL combination for retorting and refining capital.
	TAXES	52.	%	Total income tax rate.
	TAXCR	0.	%	Investment tax credit.
	CSOVAL	0.	\$/bbl	(Optional) Value of crude shale oil for depletion calculation.
	CSOBPD	104000.	B/D	(Optional with CSOVAL) Daily crude shale oil production, for calculation of average crude shale oil value.
	CODE	1.	none	Instruction to carry income tax credit forward if CODE>0.
	PTXCOD	0.	none	Instruction <u>not</u> to calculate tax on preferences, if PTXCOD>0.
	XINC	0.	none	Number of times the initial value of shale oil (see Card 10) is incremented by \$0.50/bbl and a new computation is made.
3	XCAP(1)	75.0	\$MM	Initial capital for mining and crushing oil shale and for ash disposal.
	XCAP(2)	7.0	\$MM	Capital for water supply system (reservoir, etc.)
	XCAP(3)	177.2	\$MM	Retorting plant capital.

Card No.	Variable Name or (Item)	Value Used for Example	Units of Variables	Remarks
	XCAP(4)	192.8	$MM	Shale oil upgrading (refining) plant capital.
	XPREX(1)	0.	$MM	Startup preproduction expense.
	XPREX(2)	0.	$MM	Mine development preproduction expense.
	XPREX(3)	0.	$MM	Management preproduction expense.
	XWCAP	20.8	$MM	Working capital.
4	CAPDEF	51.0	$MM	Deferred capital for mining and crushing of oil shale and for ash disposal.
	STLIFE	0.	years	If STLIFE>0, sets depreciation life for capital items (1), (3) and (4) equal to STLIFE.
	DEPLN	15.	%	Depletion rate, defaults to 15%, if DEPLN=0.
	SYNDEP	0.	none	Depletion is calculated on value of syncrude if SYNDEP>0.
	DEBTPC	0.	%	Percent of total initial capital provided as debt capital.
	DETINT	0.	%/annum	Interest rate on debt.
	ROYLTY	0.	¢/bbl	Royalty charge, calculated on syncrude produced.
	DELAY	0.	years	Delay in initiating startup.
5	CAPINC	0.	%	Percent of initial capital added each of first 15 operating years (e.g., for environmental control).
	FCOST	0.	none	If FCOST>0, apply factors to capital and operating costs, read FCOST number of optional cards in sequence.
6	(YR)	1	none	Year number in which (OPCOST) is initiated.
	(OPCOST)	28.2	$MM/yr	Annual operating cost for mining, crushing and ash disposal. (Note that up to 4 other operating cost amounts may be entered, beginning at the subsequent year entered.)

Appendix Table 2 (continued)

Card No.	Variable Name of (Item)	Value Used for Example	Units of Variables	Remarks
7	(YR)	1	none	Year number.
	(OPCOST)	0.4	$MM/yr	Annual operating cost for water system.
8	(YR)	1	none	Year number.
	(OPCOST)	14.6	$MM/yr	Annual operating cost for retorting.
		16	none	Year number.
		18.2	$MM/yr	Annual operating cost.
9	(YR)	1	none	Year number.
	(OPCOST)	16.8	$MM/yr	Annual operating cost for upgrading (refining).
		16	none	Year number.
		19.4	$MM/yr	Annual operating cost.
10	(QUANT)	100000.	B/CD	Daily production rate of shale oil (syncrude).
	(YR)	1	none	Year number in which (VALUE) is initiated.
	(VALUE)	4.50	$/bbl	Sales value of shale oil (syncrude). (Note that up to 4 other values may be entered, beginning at the subsequent year entered.)
11	(QUANT)	1450.	Tons/CD	Daily production rate of shale oil coke.
	(YR)	1	none	Year number in which (VALUE) is initiated.
	(VALUE)	4.00	$/ton	Sales value of coke.
12	(QUANT)	250.	Tons/CD	Daily production of ammonia.
	(YR)	1	none	Year number.
	(VALUE)	30.	$/ton	Sales value of ammonia.
13	(QUANT)	100.	Long Tons/CD	Daily production of sulfur.
	(YR)	1	none	Year number.
	(VALUE)	15.	$/long ton	Sales value of sulfur.
14	(QUANT)	0.	Unit/CD	Daily production of other byproduct.
	(YR)	0.	none	Year number.
	(VALUE)	0.	$/unit	Sales value of other by-product.

Card No.	Variable Name of (Item)	Value Used for Example	Units of Variables	Remarks
15	PRNT(N)	9	none	Instruction to print various sections of output, if PRNT(N)>0.

Optional Cards

16+	CAPFAC	0	none	Factor to apply to previously entered initial, deferred and working capital items.
	OPCFAC(N)	0	none	Factors (up to 7) applied in sequence to operating costs, for the same CAPFAC. (Note that a new rate of return value is calculated after each OPCFAC(N) is entered.)

Appendix Table 3

COMPUTATION PROCEDURE AND OUTPUT
DESCRIPTION FOR PROGRAM WBDCFROR

Output Sheet 1 (See Appendix Table 4)

Input data are tabulated.

Initial capital, working capital and preproduction expense are distributed over 3 construction years, the first operating year in the precentages given below:

	Construction			Operation
Year Number	1	2	3	4
Capital				
Mining	20	30	50	-
Water supply	50	50	-	-
Retorting	10	45	45	-
Refining	10	45	45	-
Working	-	-	50	50
Preproduction Expense				
Startup	-	-	65	35
Mine Development	-	50	50	-
Management	33	33	34	-

Deferred mining capital is distributed uniformly over all of the operating years except the last two.

In addition to its initial entry, working capital is entered as a negative value (capital recovery item) for the last operating year.

Land costs and salvage value of plants are disregarded.

Output Sheet 2 (See Appendix Table 5)

Annual Revenue = Σ (Daily Production Rate x Product Value) x 365, \$/year.

Output Sheet 3 (See Appendix Table 6)

Annual Royalty = (Daily Syncrude Production Rate) x (Royalty Rate) x 365/100, \$/year.

Royalty is added to the annual mining operating cost.

Debt Committed (on annual basis) = (Annual Initial Capital + Working Capital) x (Initial Debt Percent)/100, \$/year.

Debt is assumed to be retired at a uniform annual rate over the life of the project.

Outstanding Debt = Debt remaining at beginning of each year.

Annual Interest - (Outstanding Debt) x (Interest Rate)/100, \$/year.

Annual interest is distributed in proportion to the initial capital investment for each operation (mining, retorting, etc.) and added to that operation's annual operating cost.

Incr Operg Cost = (Annual increment to capital, CAPINC>0.) x 0.05, \$/year.

Incremental operating cost provides for operating costs incidental to increases in capital investment (resulting, e.g., from environmental control requirements). The annual amounts are arbitrarily added to the annual retort operating costs.

<u>Output Sheet 4</u> (See Appendix Table 7)

Depreciation is calculated annually for each operating year and each of the four capital categories. The depreciation methods and lives used are discussed in the section on Input Data. Unless otherwide called for, depreciable life is 10 years for mining, crushing and ash disposal, project life for the water system, and 15 years for retorting and refining.

<u>Output Sheet 5</u> (See Appendix Table 8)

Depleted Product Revenue Ration = (Operating Costs + Depreciation, for Mining [including crushing and ash disposal] and Retorting)/(Total Operating Costs + Depreciation for the entire project.)

Depleted Product Value = (Annual Value of Syncrude) x (Revenue Ratio), \$/year.

Depletion Allowance by Value = (Depleted Product Value) x (Depletion Allowance, %)/100, \$/year.

Depletion Allowance by Margin = (Depleted Product Value - [Operating Costs + Depreciation for Mining and Retorting]) x 0.05, \$/year.

Depletion Allowance Permitted = the lesser amount (by Value) or (by Margin), \$/year.

Taxable Income = (Annual Revenue)-(Annual Operating Costs)-(Depreciation)-(Preproduction Expenses, if applicable to the year)-(Depletion Allowance Permitted), $/year.

Income Tax = (-1) x (Taxable Income) x (Income Tax Rate, %)/100, $/year.

Note that taxes charged are negative values and tax credits are positive. An income tax credit will be carried forward a maximum of 5 years, if input CODE>0.

Tax on Preferences = (-0.1) x (Depletion Allowance Permitted + Income Tax) $/year.

Note that tax on preferences may be a positive value and, therefore, a credit against income tax.

Net Cash Margin = (Revenue) - (Operating Costs) - (Preproduction Expense, if applicable) + (Income Tax, noting sign) + (Tax on Preferences, noting sign) - (Payment on Debt), $/year.

Net Cash Flow = (Net Cash Margin) - (Annual Capital Investment) - (Working Capital, if applicable that year) + (Debt Committed), $/year.

Net Profit = (Taxable Income) + (Depletion Allowance Permitted) + (Income Tax, noting sign) + (Tax on Preferences, noting sign) $/year.

Net Profit = (Net Cash Margin) - (Depreciation) + (Payment on Debt), $/year.

Discounted Cash Flow Rate of Return = discount rate required to make sum of present worth of the net cash flow equal to zero, %.

The rate of return calculation is an iterative procedure, starting at 10%, and is permitted up to 40 iterations to converge within a prescribed error.

Appendix Table 4

DISCOUNTED CASH FLOW RATE OF RETURN COMPUTATION - PROGRAM WBDCFROR

NPC ENERGY STUDY - PRODUCTION OF 100,000 BBL/CD SYNCRUDE FROM 35 GAL/TON SHALE

INPUT DATA (NOTE - ANNUAL CAPITAL AND OPERATING COSTS ARE MILLIONS OF DOLLARS PER YEAR)

NO OF CONSTRN YEARS 3 NO OF OPERG YEARS 20 WITH 3-MONTH STARTUP INCOME TAX RATE 52.0 INVEST TAX CREDIT 0.0

DEPLETION ALLOWANCE CRUDE SHALE OIL 15.0 PRODUCTION, BPD 104000.

	CAPITAL		INVESTMENT		PREPRODUCTION	EXPENSE		WORKING	TOTAL	TOTAL
YEAR	MIN-CRUSH-ASH	WATER	RETORTING	REFINING	START-UP	MINE DEV	MGMNT	CAPITAL	CAPITAL	PREPROD EXP
1	15.000	3.500	17.720	19.280	0.0	0.0	0.0	0.0	55.500	0.0
2	22.500	3.500	79.740	86.760	0.0	0.0	0.0	0.0	192.500	0.0
3	37.500	0.0	79.740	86.760	0.0	0.0	0.0	10.400	214.400	0.0
4	2.833	0.0	0.0	0.0	0.0	0.0	0.0	10.400	13.233	0.0
5	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
6	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
7	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
8	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
9	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
10	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
11	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
12	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
13	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
14	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
15	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
16	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
17	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
18	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
19	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
20	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
21	2.833	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.833	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-20.800	-20.800	0.0
TOTALS	126.000	7.000	177.200	192.800	0.0	0.0	0.0	0.0	502.998	0.0

OPERATING EXPENSE SCHEDULE

	INITIAL YR OF EXP	AMOUNT	INITIAL YR OF EXP	AMOUNT	INITIAL YR OF EXP	AMOUNT	INITIAL YR OF EXP	AMOUNT	INITIAL YR OF EXP	AMOUNT
MINE, CRUSH, ASH DIS	1	28.20	0	0.0	0	0.0	0	0.0	0	0.0
WATER SYSTEM	1	0.40	0	0.0	0	0.0	0	0.0	0	0.0
RETORTING	1	14.60	16	18.20	0	0.0	0	0.0	0	0.0
REFINING	1	16.80	16	19.40	0	0.0	0	0.0	0	0.0

PRODUCT DAILY QUANTITIES (BPD OR TONS/DAY) AND VALUES ($/UNIT)

	QUANT	INITIAL YR OF PROD	VALUE	INITIAL YR OF PROD	VALUE	INITIAL YR OF PROD	VALUE	INITIAL YR OF PROD	QUANT	INITIAL YR OF PROD	QUANT
SHALE OIL	100000.	1	4.50	0	0.0	0	0.0	0	0.0	0	0.0
COKE	1450.	1	4.00	0	0.0	0	0.0	0	0.0	0	0.0
AMMONIA	250.	1	30.00	0	0.0	0	0.0	0	0.0	0	0.0
SULFUR	100.	1	15.00	0	0.0	0	0.0	0	0.0	0	0.0
OTHER	0.	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0

Appendix Table 5

NPC ENERGY STUDY - PRODUCTION OF 100,000 BBL/CD SYNCRUDE FROM 35 GAL/TON SHALE

CALCULATED ANNUAL REVENUE (MM$/YEAR)

YEAR	SHALE OIL	COKE	AMMONIA	SULFUR	OTHER	TOTAL
1	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0
4	123.19	1.59	2.05	0.41	0.0	127.24
5	164.25	2.12	2.74	0.55	0.0	169.65
6	164.25	2.12	2.74	0.55	0.0	169.65
7	164.25	2.12	2.74	0.55	0.0	169.65
8	164.25	2.12	2.74	0.55	0.0	169.65
9	164.25	2.12	2.74	0.55	0.0	169.65
10	164.25	2.12	2.74	0.55	0.0	169.65
11	164.25	2.12	2.74	0.55	0.0	169.65
12	164.25	2.12	2.74	0.55	0.0	169.65
13	164.25	2.12	2.74	0.55	0.0	169.65
14	164.25	2.12	2.74	0.55	0.0	169.65
15	164.25	2.12	2.74	0.55	0.0	169.65
16	164.25	2.12	2.74	0.55	0.0	169.65
17	164.25	2.12	2.74	0.55	0.0	169.65
18	164.25	2.12	2.74	0.55	0.0	169.65
19	164.25	2.12	2.74	0.55	0.0	169.65
20	164.25	2.12	2.74	0.55	0.0	169.65
21	164.25	2.12	2.74	0.55	0.0	169.65
22	164.25	2.12	2.74	0.55	0.0	169.65
23	164.25	2.12	2.74	0.55	0.0	169.65
TOTALS	3243.93	41.81	54.07	10.81	0.0	3350.62

Appendix Table 6

MONDAY FEBRUARY 12, 1973

NPC ENERGY STUDY - PRODUCTION OF 100,000 BBL/CD SYNCRUDE FROM 35 GAL/TON SHALE

ROYALTY RATE IS EQUIVALENT TO 0. CENTS PER BARREL OF SYNCRUDE PRODUCED

INITIAL DEBT IS 0. PERCENT OF TOTAL CAPITAL

INTEREST ON DEBT IS 0. PERCENT

J	ANNUAL ROYALTY	DEBT COMMITTED	OUTSTANDING DEBT	ANNUAL INTEREST	INCR OPERG COST
1	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0
13	0.0	0.0	0.0	0.0	0.0
14	0.0	0.0	0.0	0.0	0.0
15	0.0	0.0	0.0	0.0	0.0
16	0.0	0.0	0.0	0.0	0.0
17	0.0	0.0	0.0	0.0	0.0
18	0.0	0.0	0.0	0.0	0.0
19	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0
TOTALS	0.0	0.0		0.0	

Appendix Table 7

NPC ENERGY STUDY - PRODUCTION OF 100,000 BBL/CD SYNCRUDE FROM 35 GAL/TON SHALE

ANNUAL DEPRECIATION AND OPERATING COSTS (MM$/YEAR)

DEPRECIABLE LIFE - 10 YRS MINING, CRUSHING & ASH DISPOSAL, PROJECT LIFE ON WATER SYSTEM 15 YRS ON RETORTING & REFINING

DEPRECIATION METHOD - COMBINATION OF DOUBLE DECLINING BALANCE AND STRAIGHT LINE

	DEPRECIATION		COSTS		DEPR	OPERATING		COSTS		OPERG	DEPR +
YEAR	MIN-CRUSH-ASH	WATER	RETORTING	REFINING	TOTAL	MIN-CRUSH-ASH	WATER	RETORTING	REFINING	TOTAL	OPERG
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	7.50	0.70	23.63	25.71	57.53	28.20	0.40	14.60	16.80	60.00	117.53
5	7.78	0.63	20.48	22.28	51.17	28.20	0.40	14.60	16.80	60.00	111.17
6	8.07	0.57	17.75	19.31	45.69	28.20	0.40	14.60	16.80	60.00	105.69
7	8.35	0.51	15.38	16.73	40.97	28.20	0.40	14.60	16.80	60.00	100.97
8	8.63	0.46	13.33	14.50	36.92	28.20	0.40	14.60	16.80	60.00	96.92
9	8.92	0.41	11.55	12.57	33.45	28.20	0.40	14.60	16.80	60.00	93.45
10	9.20	0.37	10.01	10.89	30.48	28.20	0.40	14.60	16.80	60.00	90.48
11	9.48	0.33	8.68	9.44	27.94	28.20	0.40	14.60	16.80	60.00	87.94
12	9.77	0.30	7.52	8.18	25.77	28.20	0.40	14.60	16.80	60.00	85.77
13	10.05	0.27	6.52	7.09	23.93	28.20	0.40	14.60	16.80	60.00	83.93
14	2.83	0.24	5.65	6.15	14.87	28.20	0.40	14.60	16.80	60.00	74.87
15	2.83	0.24	4.90	5.33	13.30	28.20	0.40	14.60	16.80	60.00	73.30
16	2.83	0.24	4.24	4.62	11.94	28.20	0.40	14.60	16.80	60.00	71.94
17	2.83	0.24	3.94	4.29	11.30	28.20	0.40	14.60	16.80	60.00	71.30
18	2.83	0.24	3.94	4.29	11.30	28.20	0.40	14.60	16.80	60.00	71.30
19	2.83	0.24	3.94	4.29	11.30	28.20	0.40	18.20	19.40	66.20	77.50
20	2.83	0.24	3.94	4.29	11.30	28.20	0.40	18.20	19.40	66.20	77.50
21	2.83	0.24	3.94	4.29	11.30	28.20	0.40	18.20	19.40	66.20	77.50
22	2.83	0.24	3.94	4.29	11.30	28.20	0.40	18.20	19.40	66.20	77.50
23	12.75	0.24	3.94	4.29	21.22	28.20	0.40	18.20	19.40	66.20	87.42
TOTALS	126.00	7.00	177.20	192.80	503.00	564.00	8.00	310.00	349.00	1231.00	1734.00

87

Appendix Table 8

MONDAY FEBRUARY 12, 1973

NPC ENERGY STUDY - PRODUCTION OF 100,000 BBL/CD SYNCRUDE FROM 35 GAL/TON SHALE

CALCULATED ANNUAL DEPLETION ALLOWANCE, INCOME TAX, CASH FLOW AND NET PROFIT (MM$/YEAR)

DEPLETION BASED ON VALUE OF CRUDE SHALE OIL (CALC AS PROPORTION OF TOTAL REVENUE)

DEPRECIATION METHOD - COMBINATION OF DOUBLE DECLINING BALANCE AND STRAIGHT LINE

INVESTMENT TAX CREDIT, MM$ 0.0

YEAR	DEPLETED REV RATIO	PRODUCT VALUE	DEPLETION ALLOWANCE BY VALUE	MARGIN	PERMITTED	TAXABLE INCOME	INCOME TAX	TAX ON PREFERENCE	NET CASH MARGIN	NET CASH FLOW	NET PROFIT
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-55.50	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-192.50	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-214.40	0.0
4	0.64	81.22	12.18	3.10	3.10	6.61	-3.44	0.03	63.84	50.60	6.30
5	0.65	110.01	16.50	18.96	16.50	41.98	-21.83	0.53	88.35	85.52	37.19
6	0.66	111.69	16.75	21.06	16.75	47.21	-24.55	0.78	85.88	83.05	40.19
7	0.67	113.31	17.00	22.93	17.00	51.68	-26.87	0.99	83.77	80.93	42.79
8	0.68	114.86	17.23	24.62	17.23	55.50	-28.86	1.16	81.96	79.12	45.03
9	0.69	116.33	17.45	26.13	17.45	58.75	-30.55	1.31	80.41	77.58	46.96
10	0.69	117.72	17.66	27.47	17.66	61.52	-31.99	1.43	79.10	76.26	48.62
11	0.70	119.03	17.85	28.67	17.85	63.86	-33.21	1.54	77.98	75.15	50.04
12	0.71	120.24	18.04	29.72	18.04	65.85	-34.24	1.62	77.03	74.20	51.26
13	0.72	121.36	18.20	30.66	18.20	67.52	-35.11	1.69	76.23	73.40	52.30
14	0.69	117.66	17.65	32.87	17.65	77.13	-40.11	2.25	71.79	68.96	56.92
15	0.70	118.44	17.77	33.63	17.77	78.57	-40.87	2.31	71.10	68.26	57.80
16	0.70	119.14	17.87	34.31	17.87	79.84	-41.52	2.36	70.50	67.66	58.56
17	0.70	119.48	17.92	34.63	17.92	80.43	-41.82	2.39	70.22	67.39	58.92
18	0.70	119.48	17.92	34.63	17.92	80.43	-41.82	2.39	70.22	67.39	58.92
19	0.69	117.80	17.67	31.99	17.67	74.48	-38.73	2.11	66.83	64.00	55.53
20	0.69	117.80	17.67	31.99	17.67	74.48	-38.73	2.11	66.83	64.00	55.53
21	0.69	117.80	17.67	31.99	17.67	74.48	-38.73	2.11	66.83	64.00	55.53
22	0.69	117.80	17.67	31.99	17.67	74.48	-38.73	2.11	66.83	66.83	55.53
23	0.73	123.68	18.55	29.98	18.55	63.66	-33.11	1.46	71.79	92.59	50.57
TOTALS			347.23		338.15		-664.81	32.67	1487.48	984.48	984.48

DISCOUNTED CASH FLOW RATE OF RETURN 13.5

AVERAGE OIL VALUE FOR DEPLETION, $/BBL = 3.09

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