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CURRENT PROSPECTS FOR ENTRY INTO SHALE OIL PRODUCTION—WITH OR WITHOUT LEASING OF FEDERAL OIL SHALE LANDS

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During the Hearings on the competitive aspects of oil shale development held by the Subcommittee on Antitrust and Monopoly of the Senate Judiciary Committee in April and May of 1967, Senator Hart and his colleagues repeatedly sought the answer to one question which was highly pertinent to their investigation.[1] Why do private firms, currently holding oil shale lands with physical reserves amounting to tens of billions of barrels, insist that this is an insufficient basis for undertaking production, and that a favorable decision on production must await the announcement of an acceptable set of policy decisions on public oil shale land leasing, import controls, conservation regulation, and depletion allowances? A variety of answers were given by various witnesses, but Senator Hart was unconvinced by them and indicated his suspicion that major oil firms only wanted access to public lands in order to control oil shale reserves and defer production until some future period when exploitation of these resources would be consistent with long run profit maximization in the total energy market.

In this paper an attempt is made to answer Senator Hart's question. The principal contentions may be summarized as follows: (1) shale oil production technology is already well advanced, and exploitation through one or more developed methods "conventional" mining and retorting can accomplish large scale production at sufficiently low cost to yield profit rates after taxes which, while absolutely high, are not excessive in relation to the risks of pioneering a new industry. (2) Major oil firms, however, are more interested in developing *in situ* processes, the considerable length of time required to perfect them being regarded as one of their advantages. (3) The crucial concern of prospective investors in shale oil operations is not that current costs are too high, but that current domestic prices for crude oil may be "too high" in the sense that they are well above world price levels and might be subject to downward pressures if import and conservation policies were altered. (4) Another factor giving rise to concern over future price declines is

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1. Competitive Aspects of Oil Shale Development, *Hearings on S. 26 Before the Subcomm. on Antitrust and Monopoly of the Senate Comm. on the Judiciary*, 90th Cong., 1st Sess., pt. 1 (1967).

the possibility that shale oil production may increase much more rapidly than is generally expected once the industry gets underway. (5) Decisions on federal shale land leasing policies are certainly of interest to potential entrants, but other decisions, such as the enunciation of an official policy for "phasing in" oil shale production into the total energy market, are of much greater importance. (6) An increase in the depletion allowance for oil shale, while helpful in reducing the tax disadvantage of shale relative to crude oil, would be less beneficial than is generally supposed; furthermore, the oil industry seems reluctant to make a major issue of the 27.5% depletion allowance for shale oil since this would open the depletion controversy to another agonizing reappraisal at the federal level. (7) The federal oil shale land leasing regulations proposed by the Department of the Interior in 1967 seem to be based in large part upon false analogies between crude oil and shale oil and will not promote desirable efforts toward entry by private firms, particularly the anomalous "research and development lease" arrangement. (8) Industry reluctance to exploit shale oil and, in the long run, to convert the industry largely from a crude oil to a shale oil basis may also be due to the greatly decreased political influence of a shale oil industry which would have production in only one to three states, no lobby of ten thousand or more small producers, and no support from several million royalty recipients.

These observations suggest several tentative conclusions. First, the enunciation of any reasonable leasing policy for federal oil shale lands will not, by itself, have any great influence on the willingness of most major oil firms to engage in shale oil production in the next ten or more years. A liberal policy would probably result in more shale land acquisition but would not accelerate the rate of industry development. A strict policy involving high costs for speculative holding of idle lands would limit acquisitions. Second, in the absence of any leasing of public lands, one or more firms will probably undertake successful commercial scale operations on private lands. Colony has announced its plan to produce 58,000 barrels per day by 1970, and the demonstration of successful plant operations on this scale would probably induce the entry of one or more large oil companies having shortages of crude oil reserves. Third, the entry of any major oil firms during the years prior to the perfection of an *in situ* technique for retorting will be a reluctant entry, although some firms may enter shale oil production in order to protect themselves competitively. Fourth, the implications for government policy seem clearer on the negative than on the positive side. The government should be extremely careful about adopting any explicit policies re-

garding the "phasing in" of shale oil, particularly with respect to the effect on price levels of such a policy in the context of other arrangements supporting prices. Research and development "leases" should not be used. It is highly desirable that public decisions on shale oil issues be an integrated program and not a series of isolated pronouncements. Thus, ideally, a simultaneous resolution of all policy issue uncertainty should be achieved by means of explicit decisions on leasing, depletion, imports, state conservation regulation, and federal offshore crude oil production policies.[2] These decisions, of course, must remain flexible and to some extent tentative. It is clear that much more study is needed before an appropriate oil shale leasing policy can be adopted—study comprising not only a more adequate appraisal of the resource itself, but also, among other things, a comprehensive investigation of the effect of the existing complex of policy measures on crude oil price levels, and the relationship of prices to foreign and domestic costs, supplies, and the various dimensions of the nation's security posture.

I
ESTIMATED CURRENT COSTS OF PRODUCING SHALE OIL AND SHALE OIL PRODUCTS

How much are the oil shale deposits worth? A handsome range of estimates was presented before the Hart Subcommittee. Former Senator Douglas suggested a maximum of $7 trillion,[3] and Bruce Netschert indicated a preference for a zero valuation.[4] Narrowly considered, the value to a firm contemplating production from such resources logically would be the present discounted value of the future stream of net receipts obtainable from the exploitation of the resource. Everything depends upon expected production costs relative to revenues. But, in view of the crucial importance of the level of production costs to the entire shale oil debate, it is remarkable that so little insistence has been placed upon the presentation of comprehensive and authoritative production cost estimates.

If the demand for authoritative cost data is surprisingly weak, the available supply is virtually zero. This is not the result of an actual absence of detailed engineering evaluations—more than two dozen firms are likely to be conducting such studies at present—but to the

2. The limited scope of this paper does not permit consideration of other facets of shale oil policy which do not bear quite as directly on oil industry prices and economics, such as scenic conservation, water policy, elaborate waste disposal methods, and conservation of minerals other than shale oil.

3. *Competitive Aspects, supra* note 1, at 107.

4. *Id.* at 131.

virtually quasi-military secrecy imposed on any information secured by the investigators. The approaches to the Colony plant are said to bristle with armed guards, and visitors to the Anvil Points research center (where 26 firms are doing joint research on *in situ* methods) are stopped by guards about a mile from the entrance.[5] If nothing else, this would lead one to believe that what has been learned is well worth guarding. Still, until private firms can be persuaded to share their closely-guarded cost data, only a few sources are available from which to draw inferences regarding actual present cost levels: (1) the author's 1962 study based on engineering cost data for the production of crude shale oil;[6] (2) a 1966 study done by the Bureau of Mines using similar cost data and including refined shale oil products as well as crude shale oil;[7] and (3) the existence of the fact that Colony believes it worthwhile to invest $130 million in a commercial scale plant.[8] Each of these three sources will be examined in turn.

In 1962, the author made conservative estimates of the costs of mining, crushing and retorting 25,000 barrels per day of crude shale oil and the costs of conveying it by a small-diameter pipeline to the Four Corners area. These estimates were made with the aid of the engineering firm of Cameron and Jones of Denver, Colorado, and the study was financed by a grant from Resources For the Future, Inc. Mining methods were by room-and-pillar techniques from cliff-face sites to produce 41,000 tons per day of 30 gallon per ton shale. Retorting was by the Bureau of Mines gas-combustion method, as modified by Cameron and Jones, and the process facilities consisted of a bank of 12 cylindrical retorts each 36 feet in diameter. As of 1962, total cost per barrel after leaving the retort was estimated at $1.46, of which 98 cents was mining cost, 9 cents shale preparation cost, 27 cents retorting cost, and 12 cents viscosity breaking cost. Transportation to the Los Angeles market would have increased the cost to $1.99 per barrel for crude oil selling at about $2.90 at the time, resulting in a gross margin of 91 cents per barrel which is sufficient to allow a rate of return on average invested capital of 14.7 per cent. Economies of large scale pipeline transportation are so great, however, that the cost per barrel in Los

5. *Id.* at 395.

6. Steele, *The Prospects For the Development of a Shale Oil Industry,* 3 Western Econ. J. 60-82 (1963).

7. *A Cost Analysis of An Oil Shale Installation in Colorado* (1966), Exhibit G-667 presented by the Project Evaluation Group of the United States Bureau of Mines, Morgantown, West Virginia, in behalf of the United States Department of Land Management in the two contests, United States v. Winegar, and United States v. D. A. Shale Inc., in Denver, Colo., July 1967. [Hereinafter cited as *Cost Analysis*]

8. *Competitive Aspects, supra* note 1, at 334.

Angeles of a 250,000 barrel per day operation would be only $1.76, permitting a rate of return of 20.4 per cent.[9] The author referred to these cost estimates as conservative since he was aware, at the time they were made, that a major mining company had expressed willingness to contract for mining oil shale at a price equivalent to about 68 cents per barrel of shale oil derived from 30 gallon per ton shale. Hence cost estimates 30 cents per barrel lower than the author's 1962 estimates might have been appropriate.

The author has no precise way of updating his 1962 cost data. Pipeline tariffs to Los Angeles apparently have increased by about 18 cents per barrel. Retorting costs may have dropped about 6 cents per barrel between 1962 and 1965, but may have increased for reasons of price inflation since 1965. The author has been advised that, on the whole, technological advances, in this particular complex of processes, have just about kept pace with price inflation since 1962, so that the cost per barrel in Los Angeles might be from $1.87 to $2.17 for a 50,000 barrel per day operation and $1.64 to $1.94 for a 250,000 barrel per day operation, if the lower limit is computed to include 68 cents per barrel mining costs. Using the lower cost estimate one might project a profit rate of 16.5 per cent on the 25,000 barrel per day operation, and 22.2 per cent on the 250,000 barrel per day operation, if profits are computed on average invested capital, after taxes, with no depletion allowance.

In the past students of shale oil costs have become accustomed to more or less complete reliance on government sources for detailed studies on process costs such as those done in the late 1940's by the Bureau of Mines or in the 1950's for the Corps of Engineers or the Department of the Interior. The most recent complete study also has been prepared under government sponsorship, but it differs from the others in that its immediate function is forensic rather than purely informational. The Project Evaluation Group of the Bureau of Mines at Morgantown, West Virginia has prepared a study of the costs of producing 40,290 barrels per day of crude shale oil and 32,990 barrels of refined shale oil products as of 1966.[10] This study was prepared at the request of the Bureau of Land Management in order to contribute to the successful prosecution of litigation in which the Bureau of Land Management is claiming forfeiture of rights by the holders of certain oil shale land mining claims because of their failure of discovery. One element of proof of failure of discovery would consist, the Bureau contends, of demonstration that the deposits were not capable of sufficiently profitable exploita-

9. Steele, *supra* note 6, at 72 (table), 74 & 75.
10. *Cost Analysis, supra* note 7, at 1-20.

tion to induce investors to risk their capital in such an enterprise. Since the legal proceeding is adversary, it is to be expected that each party will attempt in accordance with established legal procedures to make the best possible case in his own behalf. Hence the possibility exists that there may be an upward bias in the costs presented in the Morgantown study, in that any decisions involving a choice between a higher-cost and a lower-cost alternative might be resolved in favor of the former. Hence the costs reported might most wisely be regarded as representing the upper limit of the probable range of costs actually to be encountered.

The processing complex can be briefly described. It consists of a mine and a retorting plant in Garfield County, Colorado, a preliminary refinery at DeBeque, Colorado, a pipeline from DeBeque to Fort Laramie, Wyoming, the use of existing pipeline facilities from Fort Laramie to Saint Louis, Missouri, and a final refining installation at Saint Louis. 60,300 tons of 30 gallon per ton shale is mined daily by the room and pillar method from cliff-face sites with a mining thickness of 61 feet (33-foot heading round and 28-foot bench round). 68.7 per cent of the shale rock will be recovered. The mined shale is crushed and fed to the retorting phase. Dust losses are 600 tons per day. Of the 59,700 tons of crushed shale conveyed daily to the retorts, 57,020 tons come directly from the crushers, and 2,680 tons of shale fines are briquetted before being fed to the retorts.

The crushed shale and shale briquets are conveyed to the seven cylindrical modified gas combustion retorts, each 45 feet in diameter. The output from the retorts is 40,290 barrels per day of crude shale oil, 359 million cubic feet of excess low-BTU retort gas, and 44,370 tons of shale ash. The ash is discharged into an adjoining canyon and is periodically compacted. The shale oil is fed by pipeline to the preliminary refinery at DeBeque where it is subjected to delayed coking and hydrogenation, yielding 35,020 barrels per day of semi-finished liquid products (hydrogenated distillate) as well as substantial amounts of by-product coke, ammonia, sulfur, and salable high-BTU excess refinery gas.

The hydrogenated distillate is shipped 400 miles to Fort Laramie, Wyoming through a ten inch pipeline, and is then transported through an existing commercial pipeline a distance of 800 miles to Saint Louis, where final refining occurs, yielding about 16,000 barrels per day of premium gasoline, 14,000 barrels of high-quality diesel fuel, and 3,000 barrels of liquefied petroleum gas, as well as some 6 million cubic feet of marketable high-BTU excess refinery gas.

Table I shows the total capital requirements, annual operating costs, and average cost per ton of shale mined and per barrel of crude shale oil and refined products produced. Costs of mining and retorting the crude shale oil are $1.23 per barrel; Colorado refining increases the cost to $1.82 per barrel. Transportation costs are 34 cents per barrel of crude shale oil produced by the retort, but since the volume of liquid products is reduced by about one-seventh in the Colorado refinery, transportation costs per barrel of hydrogenated distillate actually shipped through the pipeline are 39 cents per barrel. Costs per barrel of crude shale oil for refining in Saint Louis amount to 55 cents, but costs per barrel of hydrogenated distillate actually processed are about 63 cents. Total costs per barrel of crude shale oil are $2.71, but costs per barrel of hydrogenated distillate are $3.10. Finally, total costs per barrel of gasoline and diesel oil produced are $3.65, the volume of these two fuels being only about 86 per cent of the volume of the hydrogenated distillate input to the Saint Louis refinery.

Unfortunately, none of these per barrel cost figures can be compared directly with prices per barrel to compute unit profits in any satisfactory manner. First, the presence of by-products and joint products prevents definitive cost analysis. Second, there are no market prices available for any of the liquid products at any stage except for the gasoline and diesel fuel finished products. The best sort of unit profit computation which could be made would consist of comparing the cost per barrel of gasoline and diesel oil with the composite market price of the two fuels in the ratio they are produced, after adjusting either costs or revenues for by-products and joint products. The usual method of treating by-products is to deduct revenues of their sale from the total cost of producing all products, and then to simply charge the remaining costs against the principal product. This procedure has well-known drawbacks, which increase as the ratio of by-product revenues to total cost increases. But if we subtract all by-product revenues ($10,414,180 per year) from total annual operating cost ($40,003,500) and divide the difference by total annual production of gasoline and diesel fuel, the computed cost per barrel for the composite of these two fuels is $2.70. The weighted average price for the composite of these fuels is $4.99, so that a constructive unit profit of $2.29 per barrel is realized, which would be applied to an annual production of some 10.95 million barrels of these products. If one were to include liquified petroleum gas with gasoline and diesel fuel in order to compute average cost per barrel of total liquid fuel products, the cost per barrel would be $2.65 and the composite price

TABLE I

TOTAL CAPITAL REQUIREMENTS, ANNUAL OPERATING COSTS, AND AVERAGE COSTS PER TON OF SHALE MINED AND PER BARREL OF CRUDE SHALE OIL AND REFINED PRODUCTS PRODUCED, FOR 1966 INTEGRATED OIL SHALE OPERATION PROCESSING 60,300 TONS OF COLORADO OIL SHALE PER DAY

Unit	*Mine*	*Retorting plant*	*Colorado refinery*	*Pipeline to Fort Laramie*	*Commercial pipeline*	*St. Louis refinery*	*TOTAL*
CAPITAL INVESTMENT:							
Equipment capital	$17,585,200	$32,688,400	$39,141,600	$9,341,600	—	$14,584,300	$113,341,100
Facilities & utilities	—	7,360,000	14,222,400	—	—	6,114,600	27,697,000
Initial catalyst	—	—	3,124,000	—	—	2,309,100	5,433,100
Interest during construction and startup expense	1,480,000	3,369,300	4,752,000	786,200	—	1,936,000	12,323,600
Working capital	15,889,700	3,445,400	3,949,700	304,200	—	3,098,400	25,687,400
TOTAL CAPITAL REQ.	34,955,000	46,863,100	65,189,700	10,432,000	—	28,042,400	185,482,200
ANNUAL OPERATING COST:							
Pump station power	—	—	—	210,200	—	—	210,200
Raw water (St. Louis)	—	—	—	—	—	47,500	47,500
Water use charge (Colo)	3,700	1,000	29,500	—	—	—	34,200
Power (St. Louis)	—	—	—	—	—	554,400	554,400
Annual catalyst and chemicals	—	2,000	1,132,700	—	—	3,395,200	4,529,900
Pipeline charge	—	—	—	—	3,962,500	—	3,962,500
Direct labor & supv	3,008,500	748,300	984,600	111,700	—	338,400	5,191,500
Maint. labor & supv	774,400	372,900	377,700	—	—	485,000	2,010,000
Maintenance material	736,600	335,100	339,900	—	—	434,200	1,845,800
Payroll overhead	945,700	280,300	340,600	27,900	—	205,900	1,800,400
Mine supplies	3,960,000	—	—	—	—	—	3,960,000
Operating supplies	—	194,800	234,200	14,300	—	142,900	586,200
Administration and general overhead	624,100	240,200	184,700	10,500	—	483,000	1,542,500
Taxes & insurance	409,000	891,800	1,257,800	208,000	—	536,900	3,303,500
Depreciation	1,851,000	2,713,600	3,827,600	473,700	—	1,559,000	10,424,900
TOTAL OPERATING COSTS	12,313,000	5,780,000	8,709,300	1,056,300	3,962,500	8,182,400	40,003,500
TOTAL UNIT COSTS:							
Cost, dollars per ton of shale mined	$ .56	$ .26	$ .40	$ .05	$ .18	$ .37	$1.82
Cost, dollars per barrel of crude shale oil	.84	.39	.59	.07	.27	.55	2.71
Cost, dollars per barrel of hydrogenated distillate	.96	.45	.67	.08	.31	.63	3.10
Cost, dollars per barrel of gasoline and diesel fuel	1.12	.53	.79	.10	.36	.75	3.65

would be $4.72, yielding a computed per barrel profit of $2.07, which would be applied to an annual output of some 12.04 million barrels of the three products. In either case the ultimate arbitrary nature of the method may be misleading because of the relatively high ratio of by-product receipts to total operating costs: 26.0 per cent in the first instance and 20.3 per cent in the second.

A less misleading approach is simply to compute annual profits on all operations in total and compare after-tax profits with average invested capital. Table II shows daily receipts per product and total

TABLE II

PRODUCT SELLING PRICES AND ANNUAL RECEIPTS, FOR 1966 INTEGRATED OIL SHALE OPERATION PROCESSING 60,300 TONS OF COLORADO OIL SHALE PER DAY

Product	*Volume produced per day*	*Unit value*	*Daily receipts*
Excess refinery Gas—Colorado	3.144 Million cu. ft. (1266 Btu/cf)	$.40/mm Btu	$ 1,592
Excess refinery Gas—Missouri	5.964 Million cu. ft. (431 Btu/cf)	$.40/mm Btu	1,028
Diesel fuel	14,008 Barrels	$.1025/gal.	60,304
Liquefied Petroleum gas	2,974 Barrels	$.05/gal.	6,245
Premium gasoline	16,007 Barrels	$.1325/gal.	89,079
Coke	1053.5 Tons	$9.50/ton	10,008
Ammonia	93.1 Tons	$92/ton	8,565
Sulfur	43.75 Tons	$25/ton	1,094
Total receipts per day			$177,915
Total receipts per year			$64,939,000

annual receipts, and Table III shows annual gross and net income and cash flow. Net income after taxes is $12.0 million per year and annual cash flow is $24.3 million. This implies a rate of return of

TABLE III

FINANCIAL ANALYSIS FOR 1966 INTEGRATED OIL SHALE OPERATION PROCESSING 60,300 TONS OF COLORADO OIL SHALE PER DAY

Total Capital Investment	$185,482,200
Annual Sales Receipts	64,939,000
Annual Operating Costs	40,003,500
Gross Income	24,935,500
Depletion Allowance	1,848,800
Taxable Income	23,086,700
Federal Income Tax	11,081,616
Net Income After Taxes	12,005,084
Depreciation Allowed per Year	10,424,900
Depletion Allowance	1,848,800
Annual Cash Flow	$ 24,278,784

12.9 per cent per year after taxes on average invested capital, which can be interpreted as a probable minimum estimate in view of the likely bias in the data toward the overestimation of costs and the necessary investment for those items which require assignment of a cost estimate involving questions of judgment. The most apparent instance of cost overestimation occurs in the case of working capital, which could defensibly be reduced by some $18 million. If this single adjustment is made, the rate of return after taxes on average invested capital increases to 15.5 per cent. Other adjustments which might be made would operate to improve further the rate of return, chiefly by reducing taxes. Some items, such as initial catalysts and chemicals, interest during construction, and start-up expenses would be expensed rather than capitalized, with a resulting reduction in book investment. The depletion allowance which is taken appears to be well below that which could probably be obtained under present law. And although a substantial credit against the income tax liability itself was available at the time of the 1966 study no investment credit was taken.

The only other basis of inference about present estimated costs is from Colony's statements regarding its own plans. These data can readily be summarized in view of their sparsity. Colony intends to have in operation by 1970 an oil shale complex mining 66,000 tons of oil shale daily and producing 58,000 barrels per day of hydrotreated shale oil, with a total plant cost of under $130 million. Furthermore, it has been stated that in computing expected profitability, Colony has been "burdened by the need to assume, against ourselves, a number of very severe economic penalties in calculating the rate of return."[11] Can one take a wholesome crumb of data—a capital cost of about $2,240 per daily barrel of production—and reconstruct the dinosaur skeleton of projected total costs, revenues, and profits? One does not know how to allocate the capital costs, quite apart from the complete ignorance regarding estimates or forecasts for any other elements of total cost. One is similarly in ignorance of estimated future prices and by-product operations, and does not know the rate of return the firm considers necessary. What is interesting, however, is the statement that Colony has deliberately made the worst possible case for future rate of return in its profitability calculations and, nevertheless, has decided to undertake full-scale production. Again, one does not know the assumptions constituting the worst of all profitable worlds, but they would no doubt include denial of recognition of shale oil as a refinery input for computing import quotas, and obtaining of only the minimum per-

11. *Competitive Aspects*, *supra* note 1, at 318.

centage depletion tax deduction allowable under present law, which although it might not be literally zero, might still be less than cost depletion.

If one assumes that an investor desires a rate of return of at least 15 per cent for such an investment and then discounts entirely the tax advantages of percentage depletion and reduces expected prices by the six to eleven cents per barrel penalty shale oil would incur if not eligible as refinery input source in computing import quotas, it becomes apparent that costs must be quite low relative to expected prices and that the company would be in a good position to make very attractive profits if their deliberately pessimistic expectations proved unfounded. If, in addition, the firm has predicted a long run decline in crude oil prices, such as might result if policy decisions were made which would increase imports and impair the effectiveness of state production controls, then the enterprise's future would indeed appear bright.

Even so, it is not a profitable exercise to try to compute a range of expected unit costs per barrel by assuming a minimal 15 per cent rate of return, no percentage depletion allowance, a maximal per-barrel price penalty for adverse import-quota treatment, and future prices which are constant or declining. Even without the presence of too many unknowns, the resulting data would not compare with the information from the earlier cost studies, if only because Colony will be achieving much higher shale oil yields per ton of oil shale mined than the earlier studies contemplated.

The author's 1962 study involved operations resulting in a ratio of 25.6 gallons of crude shale oil recovered from every gross ton of oil shale mined. The 1966 study contemplates a recovery of 28.1 gallons per ton—some 10 per cent higher; the Colony operation projects 37 gallons per ton—45 per cent higher. At least three factors can account for these differences. There may be variation in crushing losses. The chief difference between the 1962 and 1966 studies is probably that recovery in 1966 was greater because of the briquetting of the smallest crushed shale particles, although this procedure naturally involves some additional costs. There may also be variations in the percentage recovery of oil from the shale rock. Here the Colony process would appear to be superior, reportedly yielding 103-104 per cent recovery of the modified Fischer essay. Here, too, however, it is likely that higher recoveries may in part be counterbalanced by higher process costs, although this is not necessarily true over a period of time or when comparing two different methods. Finally, the oil content of the shale rock may vary, and it would appear that Colony is planning to mine much

richer shales than were contemplated in the other studies. This is to Colony's advantage, provided that the acquisition costs of the shale were not correspondingly higher, which is possible since the market for oil shale lands at present is quite imperfect.

One last difficulty which deserves mentioning is the unknown ratio of debt to equity capital in Colony's prospective shale oil venture. In order to penalize their economics with the most adverse projections, they would assume a zero debt to equity ratio. But several of the earlier shale oil studies have assumed unusually high ratios. It is always possible to make an enterprise with a rate of profit greater than bond interest rates appear to display any desired level of returns by obtaining sufficiently high leverage through extreme debt to equity ratios. However the shale oil industry is not yet a public utility.

In summary, available evidence relating to probable production costs, while it cannot be regarded as conclusive, suggests strongly that the relationship of shale oil production costs to current crude oil prices is sufficiently favorable from the point of view of profitability that it cannot be regarded as a factor discouraging entry. Accordingly, other factors must be examined, particularly those which relate to possible future downward pressures on crude oil prices.

II

CURRENT PUBLIC POLICY ISSUES—THEIR IMPACT ON SHALE OIL INDUSTRY INVESTMENT CLIMATE

A. Leasing Policies for Federal Oil Shale Lands

One argument made by firms holding private shale lands but still hesitating to enter the industry relates to their uncertainty over the market impact of various policies on the future status of federal oil shale lands. The typical contention is that since the richest lands are federally held and since an industry should logically begin by using the richest resources in the interest of cost minimization, federal leasing of these lands, on sufficiently favorable terms, is essential for the development of the industry. Resource richness in the physical sense, however, cannot be divorced from costs of gaining access to them, and it appears that the richest resources are also the most difficult to reach by existing mining methods. Certain privately held sites provide exceptions. The public lands will be more amenable to *in situ* methods which will probably not be perfected for ten or twenty years; hence, those firms which are actually deterred from entry by the present non-availability of federal lands would not be

planning to undertake production for a decade or more even after acquiring suitable lands. A variant argument is that firms would not enter production now on higher-cost private lands if, in the near future, the government awarded leases on very liberal terms to lower-cost public lands. This argument has some plausibility, but the plausibility depends upon how much lower the costs would prove to be on such public lands, how much longer it would take to develop the lands by lower-cost methods, and how liberal the terms of leasing would be. The alleged fear that the government might enter the shale oil business itself is a further reason for hesitation. If such fears are genuine, it is surprising that the firms whch entertain them have acquired, and continue to hold, shale lands. Actually, it is improbable that government will enter the market as a producer, and it is also doubtful that shale lands will ever be leased on extremely liberal terms. Firms holding private shale lands are concerned over uncertainty regarding various policy decisions relating to shale oil, but other decisions are more important than leasing policy *per se*.

The proposed regulations for leasing shale lands, which were issued in May 1967, did not strike the industry as being liberal and do not seem conducive to any very rapid or even logical development of the industry. The notion of the research and development lease seems particularly anomalous, and those who made statements before Senator Hart's Subcommittee unanimously criticized it. If the government wishes to have research and development done on oil shale, the logical approach is to have it done under contract. If it wishes to lease shale lands, the logical approach is to devise an appropriate form of production lease. Those elements in the proposed regulations which do have a bearing upon production leasing seem to be somehow inappropriate or irrelevant in relationship to the optimal requirements for shale oil production leases. It would seem that those on the Department of the Interior staff who drafted the proposed regulations followed, as guides, certain features of contracts which exist between American oil companies and Middle Eastern governments.[12] If this is the case, it is not surprising that many of the proposals seem inapplicable: there is no basis for analogy between appropriate Colorado oil shales leasing procedures and current procedures existing in the Middle East.

The assumptions behind Interior's oil shale leasing policy seem to

12. Secretary Udall stated before Senator Hart's Subcommittee that "[M]any of the oil producing countries in the Middle East and else where have, through the use of different types of performance contracts, developed techniques for assuring performance . . .", and also that "[s]ome of the foreign countries that have gotten smart lawyers are even better than we are in terms of how you protect the interests of a nation that owns a resource." *Id.* at 281 & 293.

include the following: (1) Existing shale oil technology is not sufficiently developed to form the basis for a commercial industry. (2) The logical first site of industry development will be in the richest federal lands.[13] (3) *In situ* methods are regarded as the most promising retorting techniques. (4) An industry will not begin to develop for at least ten years. These assumptions might be more or less mutually consistent if all shale lands were federally owned. The first two assumptions are doubtful; the last two may be made to appear correct if a leasing policy is adopted which strongly favors the development of *in situ* methods. If all shale lands were federally owned, and only the richest were offered for lease, these lands, with their substantial overburdens, might appeal only to those firms interested in doing long term research on *in situ* methods. The Interior Department's program would be much more understandable if the four above assumptions were valid. If conventional techniques were unavailing and, hence, if private shale lands were at a great disadvantage relative to public lands, it would be in the interest of proper disposition policy for public resources that the government take steps to increase its resource value by developing low-cost utilization and by leasing the lands on competitive terms. If the government can induce firms to develop the necessary methods at their own expense and then to make the methods available to all, the direct costs to the government may be minimized, and leasing revenues may still be satisfactory. Such results will follow only if the firms operating under the research and development leases receive only production leases on modest sized tracts, as reward and only if other firms may then bid on additional tracts on the basis of information made available by the original lessee.

There are flaws in the plan. Firms are not fond of entering into agreements which sacrifice patent monopoly privileges. The research and development lease is likely to be unworkable because of too much uncertainty on both sides. Furthermore, it is highly probable that economical methods of shale oil production now exist, and the government does not have a monopoly even on lands suitable for *in situ* retorting. In view of these considerations, it is more logical for the government to adopt a different program involving the contracting out of research and development and the granting of production leases to those firms which are now, or which will be later in a position to undertake production on federal lands. The terms of these production leases should be carefully drawn; some of the problems involved in such leasing arrangements are briefly discussed below.

13. Udall's explicit contention. *Id.* at 298.

Competitive bidding for leases, with the submission of sealed bids, appears to be the best approach economically—there is little argument on this point. However, more discussion of the object of the bidding—bonus, royalty, rentals, tract size, and the like—is needed. In order to evaluate rival bids unambiguously, only one of the lease conditions should be variable, and the others should be held constant. If there were no uncertainty of the future profitability of shale oil operations, bonus bidding by itself might suffice since the present discounted value of the lands could be computed, and competition among bidders would insure that the lessor would realize, as the lease bonus, all of the economic rent in excess of the competitive supply price of the bidder's services. If uncertainty exists, royalty bidding is preferable to the bidder since it results in some sharing of the risk of failure between lessor and lessee. Lease rental rates and tract size would not ordinarily be appropriate key variables for competitive lease bidding.

If bonuses were to be the sole object of bidding and if costs are low and prices are predicted to remain stable per-acre bids might be quite high. While bonuses cannot be predicted with any precision, order-of-magnitude comparisons might be instructive. For high quality onshore crude oil prospects, bonuses might be in the range of $1000 per acre; for similarly promising offshore crude oil prospects, $10,000 per acre, and for high-quality shale lands, $100,000 per acre. Bonus bidding alone, however, would not be appropriate since considerable uncertainty exists regarding future profitability, although the physical extent of deposits being bid upon would be subject to less uncertainty. Furthermore, the requirement that bonus be paid in full at the time of awarding the lease would further increase barriers to entry in a situation already characterized by high barriers. Also, the risk of initial investment would lead firms to use a high interest rate in discounting future net receipts so the total lease bonuses received by the government might be much smaller than the value of a subsequent stream of royalties, if the industry proves profitable. If a high discount rate is employed, reserves to be produced 20 or more years in the future will be valued at very low levels so that a firm currently might bid very little more for a 10 billion barrel tract than for a 5 billion barrel tract. This possibility would limit the size of tracts to be leased. Thus, although sole reliance on lease bonus bidding would have the advantage that the bonus would be a sunk cost without influence on subsequent production rates through influence on marginal costs, its disadvantages, in terms of inherent uncertainties, high discount factors, and increas-

ing barriers to entry, would effectively rule out this simple method of lease bidding.

Royalties could be made the leasing variable by specifying fixed per-acre bonuses and rentals. Much depends upon the type of royalty —whether applicable to crude shale oil or refined products, whether specific, ad valorem, or expressed as a share in net profits. If an ad valorem royalty on crude shale oil were to be adopted, there is a possibility that the 12.5 per cent rate traditional in crude petroleum would be too high, at least initially. Interior's 3 per cent figure seems more appropriate at present. Per barrel royalties are preferable to per-ton royalties because of variations in the richness of deposits, and ad valorem royalties generally are preferable to specific royalties if only because of the likelihood of price changes. Royalties are preferable to bonuses in that they are paid in relation to production rather than in an initial lump sum and, hence, pose less of a barrier to entry. In addition they are more flexible because periodic renegotiation of rates is possible. Per-unit royalties have a conservation disadvantage because they constitute an addition to marginal production cost which may induce premature abandonment of properties when incremental production costs increase beyond a certain point. The use of net income royalties avoids this inefficiency, but it can cause conflict between lessor and lessee over the method used to compute net income.

Relatively high lease rentals would seem appropriate to prevent speculative holding of idle lands. The preferable policy for production leases probably would depend upon the workability of net income royalties. If workable, leases should be awarded on the basis of net income royalty bidding coupled with relatively low fixed bonuses and relatively high annual rental requirements. If net income royalties are not workable, Professor Walter Mead's proposal would be preferable—bonus bidding with low fixed royalties and a high annual rental requirement.[14]

B. Depletion Policy for Oil Shale

Although there has been some agitation for obtaining 27.5 percent depletion on crude shale oil, it is likely that most industry participants in the debate are resigned to the impossibility of achieving this rate, and would be glad to settle for the present 15 percent if it could be applied to the crude shale oil rather than to the mined shale. The present law provides for a maximum 15 percent on the

14. *Id.* at 389.

value of the mined shale; this percentage applied to crude shale oil would probably amount to a tax deduction equivalent to no more than about 5 percent on the value of the shale oil. Prospects for obtaining 15 percent on the value of the shale oil are doubtful, since it would require a judicial decision in favor of the change.

It is at least conceivable that political action might bring about a change in the depletion law, but this is unlikely since the shale oil industry has no established lobby, and the petroleum industry seems divided on the question of whether to support higher shale oil depletion. Those who see shale as a threat to market stability would be opposed, and the others will probably want to avoid the issue of raising the depletion rate to 27.5 per cent because of the necessary re-opening of the entire depletion debate to fresh examination at the legislative level in an atmosphere of treasury department criticism, and widespread taxpayer suspicion or hostility toward the allowance. Those fearful of re-opening debate may assume that not only are the prospects for increasing the depletion allowance for shale oil rather small, but that there is some increased risk that depletion rates for crude oil may be reduced.

Even if 27.5 per cent depletion were to be achieved for shale oil, it would by no means imply that crude petroleum's tax advantage over shale had been negated. Since percentage depletion is always limited to no more than 50 percent of net income, a shale oil industry would not obtain the benefit of 27.5 percent depletion unless its ratio of net income to gross receipts was 55 percent or more. The author's studies indicate that in shale oil the same ratio would be about 32 percent, so that the effective net rate of percentage depletion would be 16 percent no matter how high the gross rate. In addition, if rate of return is computed on a discounted cash flow basis, the petroleum industry's ability to expense intangible drilling and development costs is at least as important as percentage depletion in improving the calculated rate of return. In crude oil the ratio of such costs to total costs is high because of exploration risk and because most drillings result in dry wells rather than in successful wells. In shale oil, such a high ratio is not needed, and almost all investment costs must be capitalized and depreciated instead of being subject to immediate expensing. (The gross tax advantage of crude oil over shale is, however, not necessarily the same as the net economic advantage since shale oil investment is in part desirable precisely because there is no need for continual exploration efforts.)

With regard to public lands, decisions on depletion and on leasing policy are intertwined in such a way that the value of a highly effective rate may be competed away through the medium of bonus-

bidding. Assume that lease bidding is on a bonus basis only, that royalties and rents are fixed at relatively low levels, and that the government has made firm policy commitments on imports, depletion, and the phasing-in of shale oil so that firms can compute the present discounted value of oil shale lands with a good deal of confidence. If a shale tract is worth $50 million with a zero depletion rate, and a 15 percent rate will increase the value by $10 million to $60 million, perfectly competitive bidding among firms will increase the bonus on such a tract by the same $10 million. Under these circumstances, granting depletion on public lands would increase current leasing revenues at the expense of later tax revenues but would not permit the firms themselves to realize any net advantage from any particular depletion rate. The principle remains the same even if the assumptions regarding government policies are relaxed so as to increase uncertainty about future earnings. Only by relaxing the assumption that the bidding is perfectly competitive will the principle be compromised. (If the treasury's opportunity cost of funds is lower than the rate at which bidders discount the future, such a means of raising revenue is inappropriate from the federal government's standpoint, regardless of the many other facets of the problem.) Raising depletion rates would therefore be of limited value to shale oil producers, and it would be of greater value to holders of private lands than to leasers of public shale lands.[15]

C. *Petroleum Import Policies*

It is scarcely necessary to state that the prospects for the development of a shale oil industry depend critically upon the future level of domestic crude oil prices, which in turn are dependent upon limitation of supply by import controls and domestic production regulation. The import control program is based exclusively on the national security argument that "excessive" imports would destroy incentives in the domestic industry and reduce its scale of operations below some critical level necessary for minimal security. The entire import control program should be subjected to renewed study in the light of the probable degree of existence of a domestic shale oil industry at various crude oil price levels. The impact on security of such additional domestic supplies obtained by import control relative to the costs of such control, and the impact of alternative methods of achieving an equivalent degree of security must also be considered. Since such a study would require considerable time, it is

15. One alleged advantage of *in situ* methods of retorting is that the oil produced would qualify for 27.5 per cent depletion. But this is not explicitly provided for in present tax law, and prospects for amending the law are problematical.

unwise to insist that immediate action be taken to "clarify" future import controls policy.

As long as the present system is in effect, however, it is clear that there is no reason why shale oil should not qualify as a refinery input for purposes of computing a refiner's import quota. This appears to be the only shale oil policy issue which could be resolved quickly and without likelihood of serious error. There is no reason why the Oil Import Regulation should not be amended to include shale oil in addition to crude petroleum as a qualified "refinery input." (At any rate, one would be suspicious that those opposing such an amendment were motivated by considerations other than those of national security, the explicit basis for the import control program.) If the import control program is later changed, this amendment may become irrelevant to the new program, but as long as the present program is in effect there is every reason for expanding the definition of refinery input by such an amendment.

D. Domestic Crude Oil Production Controls: State Conservation Regulation Policy

The system of domestic crude oil production controls through state conservation commission activity is similarly overdue for a comprehensive reappraisal of costs and benefits of existing and alternative programs, although the effectiveness of state control depends ultimately upon federal legislation—such as the Connally Act of 1935, prohibiting interstate shipment of violative production.

The federal government has no direct jurisdiction over state commissions, but it has considerable potential influence in crude oil production because of increasing output from federal offshore lands. The federal government in managing production from its lands should resist any effort to introduce conservation regulation in shale oil on any basis remotely resembling the crude oil industry model. Conservation regulation in crude oil has been widely and justifiably criticized for its inefficiencies and the burdens it has placed upon both consumers and efficient producers. Moreover, unless *in situ* methods of production are perfected, there will not be the slightest analogy between the genuine conservation problems in crude petroleum and similar problems which may arise in shale oil. In fact, there should be no conservation problems in shale oil except those relating to rather different matters such as the conservation of the scenic appeal of the landscape and the avoidance of air and water pollution.

The question of whether the government could prevent proration of production from federal shale lands on a market demand basis was explicitly considered during the Hart hearings. When asked by Coun-

sel for the Subcommittee majority whether or not the federal shale lands could be made exempt from state production quotas, Assistant Attorney General Donald Turner replied: "We could certainly so provide. And I think the consequences would be clear. The successful development of shale oil would put an end to the state prorationing program."[16] While the latter statement might need some qualification, the implication is evident that any very rapid expansion of shale oil output might put very great pressures on state commissions. If after study it appears desirable to limit the expansion rate of shale oil output, it would be vastly preferable to limit expansion under an explicit phasing-in program instead of through a production control program in the disguise of a physical conservation measure. Some aspects of such a phasing-in program are discussed below.

E. The Possibility of an Explicit Federal Policy on the "Phasing-in" of Shale Oil Production into the National Energy Market

It is likely that a major factor impeding entry into shale oil is the failure of the government even to adumbrate any conscious policy for the phasing of shale oil into the national energy market. Although both petroleum industry and shale oil spokesmen in their public statements have discounted the idea of a rapidly growing shale oil industry exerting downward pressure on prices, it would appear possible that output might increase more rapidly than total market demand if early production experience leads to rapid process innovation and cost reductions. The processes involved—very large scale materials handling in mining and continuous-flow fluids processing in retorting—seem to lend themselves to cost-reducing breakthroughs in technology. In particular, the development of extremely large scale continuous mining equipment is probable once the industry begins to develop and a sizable market for such equipment is created. While it is arguable that capacity is unlikely to expand as rapidly as total demand, much depends upon profit rates and inducement to entry. The private sector of our economy is justly noted for its rapid response to new profit opportunities, and as Professor Walter Mead noted during the Hart hearings: " . . . the industry right now is profitable, and not just a little bit—it is very profitable . . . if this industry consequently gets started in a big way, we are talking then about a large increase in the supply of oil in the American market. And given that, any further price increase for crude seems to me to be out of the question. Prices are likely to go down."[17]

16. *Competitive Aspects, supra* note 1, at 363.
17. *Id.* at 400.

Mr. Morton Winston of the Oil Shale Corporation states that in his view shale oil will probably supply no more than one-fifth of the market growth between now and 1980, but he also made some remarks which support the adoption of a phasing-in program or its equivalent: " . . . this industry will not grow in an orderly manner into the role it can play in meeting a portion, a significant or small one, of the nation's petroleum needs, unless the federal acreage is planned and opened, and unless it is done within a reasonably short time . . ."[18]

Of greater interest and significance were certain statements by Secretary Udall indicating that his thinking was proceeding along parallel lines. The following quotations merit close study:

> " . . . if we handle the development of this resource wisely, if the Government maintains control, as it must—oil shale ultimately, when you look on down the road, will be the dominant factor in this larger picture. The Federal Government, by controlling the rate of development of oil shale can in effect much more wisely determine what its energy policies should be."[19]
>
> "We will decide that in terms of a national energy policy that we want to bring in a certain amount of production, and we will put it out for leases, and on a competitive basis of some kind, perhaps. This is probably what we would do *if we had the process perfected today*."[20]
>
> "[the Canadians] limited their production [of tar sands oil] . . . in order to phase it into their whole energy economy, in order to not disrupt it. Now, this is the type of problem that we are going to have down the road when we start talking about how oil shale development would fit into the total national energy problem . . . [The Canadians] can control it, just as we would be able to control oil shale—so as to produce the minimum disruptive effect on their energy economy."[21]

From this one may safely infer that the government is considering taking a very definite role in the phasing of shale oil production into the energy market. If high priority is given to producing the "minimum disruptive effect" in the manner of the apparently admired, but highly restrictive, production control policy of the Alberta Oil and Gas Conservation Commission, then the price effects of shale oil will be quite minimal indeed. One suspects that many potential entrants into the shale oil industry are awaiting govern-

18. *Id.* at 320.
19. *Id.* at 284.
20. *Id.* at 294 (emphasis supplied).
21. *Id.* at 306-307.

ment assurance, in the form of explicit and detailed policies, that the advent of shale oil on the scene will not be allowed to depress crude oil prices. Such assurances would probably have a much greater impact on willingness to enter the industry than would even the announcement of a quite liberal shale leasing policy.

The government should exercise the utmost caution before adoption of any explicit policies regarding the phasing of shale oil into the market, and no steps should be taken without making studies of the effects of such a policy on crude oil price levels, relative costs of different energy sources, and national security, in the context of the other policies supporting crude oil prices.

F. Policies to Promote Competition in the Shale Oil Industry

During the Hart Subcommittee hearings, justified concern was continually expressed regarding the probable inability of the small firm to gain a foothold in the shale oil industry. No one was able to propose a feasible plan to allow the entry of genuinely small firms, and it seems that for reasons of economies of scale and because of capital requirements, there is simply no place whatsoever in the industry for the firm which is small in absolute size. This fact, and its implications for competitive behavior in the shale oil industry, must be fully assessed.

While it may be possible to increase the number of entrants into the industry by encouraging consortia of many smaller interests, the fact remains that the resulting consortia must have large absolute size. Atomistic competition will never prevail in shale oil, but after all, relative rather than absolute size is the crucial determinant of a firm's market power. If the shale oil industry can ultimately attract as many as 20 major firms with diverse interests in various phases of the energy market so that the imperfect alignment of interest existing in the crude petroleum industry is reproduced in the shale oil industry, the latter industry should not be extremely concentrated as major industries go, and competitive rivalry will exist. However, it is probable that the shale industry is going to be more concentrated than the crude oil industry and that almost all of the firms will be fully integrated. Since the asymmetrical organizational structure of crude oil companies has been a large factor in the historical dynamics of crude oil competition, it is to be expected that the degree of homogeneity of interests among shale oil producers will tend to reduce competition. Therefore, to the extent that it may prove possible, public policy should seek to promote the entry of organizationally and technologically diverse firms into the industry:

firms using different retorting methods; firms with varying degrees of vertical integration; firms with and without investments in oil, coal, and electric power.

Nevertheless, the industry will in all likelihood be substantially if not extremely concentrated, and without any fringe of numerous small "independents." Hence antitrust in the industry will be present. Thus, the absence of any constellation of small operators presents insight into a little-publicized reason for the reluctance of major firms to start the process which will increase the role of shale oil in the liquid fuels market. And not only will the lack of numerous small firms expose the industry to more searching antitrust scrutiny, but it will contribute, among other factors, to a serious weakening in the political power of the industry. Political influence does not depend nearly as much upon the financial power of the few major firms, as it does upon the large number of small producers, the great number of royalty recipients, and the widespread geographical incidence of oil production among the states. Moreover, while crude oil is currently produced in over thirty states, shale oil will be produced in at most three states, and possibly in only one for quite a while. A state's position on oil industry legislation is curiously affected by the circumstance of its having some crude oil production, even though it may consume vastly more than it produces. If for no other reason this is because producer lobbies are much more active and effective than consumer lobbies. In the crude oil industry, producing states are not only numerous, but include almost all of the politically most influential states; in the shale oil industry, producing states are not only few but without much political influence at the national level.

Since shale oil production will inevitably be the preserve of the large firm, there will be no fringe of small "independents" like the ten thousand and more miniscule participants in the petroleum industry whose political efforts (chiefly effective at the state level, but very influential nationally because of the key role of state regulatory commissions) are probably more vital to the present status of the industry than are their economic contributions. And since private shale lands are seldom encumbered by a network of numerous small royalty interests, and federal lands are entirely free from such complications, there will be no lobby of several million royalty recipients with the political power to influence the legislative fortunes of the shale oil industry. Shale oil production will therefore be more vulnerable to shifts in administrative and legislative climates than the crude oil industry has been.

III

CONCLUSIONS REGARDING PROBABLE INDUSTRY REACTION TO VARIOUS ALTERNATIVE SHALE OIL POLICY POSITIONS

No discussion of shale oil policy issues can be conclusive in the present fragmentary state of basic information. Under these circumstances, conclusions must be limited to two classes of observations. First, there is great need for additional data, particularly on the part of government policy makers. Many comprehensive studies are needed upon which to base difficult policy decisions. These studies cannot be made quickly; hence there is no prospect for immediate clarification of existing uncertainties. But there is no need for hasty decisions. Those firms having developed the most efficient processes will be able to enter the industry in due course, producing from private shale holdings. Energy supplies are not currently so short that it is necessary to accelerate the rate of production from public lands by putting a premium on favorable lease terms and on an otherwise artificially stimulated climate for shale development.

The second class of observations comprises those relating to probable industry reaction to alternative shale oil policy positions, if and when such positions are announced. Four major alternatives may be selected for brief discussion: (1) the preservation of the status quo; (2) the adoption of very strict leasing policies; (3) the adoption of quite liberal leasing policies; and (4) the adoption of a unified program which would encourage entry by promising greater stability in future energy markets.

A. Maintenance of the Status Quo on Shale Oil Policy Issues

If the status quo is maintained for the indefinite future through continued postponement of positive decisions on shale leasing or depletion allowances, and through maintenance of the present degree of protection of domestic crude oil prices; then, it may be predicted that entry will be slow unless and until major technical breakthroughs are achieved which will unambiguously demonstrate that shale oil costs are much lower than crude oil costs. Until that time the growth of the industry will be slow. Assuming that Colony does achieve production by 1970, one or more additional firms will probably enter the market soon after, the most likely entrants being major oil companies short of crude oil which are now doing research in "conventional" shale mining and retorting techniques. Most of the major oil firms, however, will probably continue to devote much of their efforts to long term research on *in situ* methods.

B. *The Adoption of Very Restrictive Leasing Policies for Federal Oil Shale Lands*

If very restrictive leasing policies are adopted for federal oil shale lands, the situation will be little different from the status quo projection. If bonuses, royalties, rentals, and other lease terms are too restrictive, there will be no successful applicants for leases, and major firms may lose interest in *in situ* research, to the extent that the methods investigated would be applicable only to federal lands. Consequently, there may be increased interest on the part of the large firms in more conventional techniques.

C. *The Adoption of Very Liberal Leasing Policies for Federal Oil Shale Lands*

If very liberal leasing policies are adopted so that bonuses, rentals, and royalties are low and the amount of lands leased relatively large, more interest in shale development will be stimulated. More firms will enter the industry, but there will probably be much semi-speculative or defensive holding of reserves, as major firms obtain lands and keep them idle, pending the development of methods to exploit them. There will be more research by major firms, particularly in *in situ* techniques. If governmentally subsidized research is undertaken as part of a highly liberal program, and the results made available to all, technical breakthroughs may occur sooner, and more major firms may enter the industry on a large scale at an earlier stage in the industry's development.

D. *The Adoption of a Unified Program Encouraging Entry by Promising Greater Stability in Future Energy Markets*

The last alternative is presented to provide a marked contrast with the first and not necessarily as the preferred alternative. Here it is assumed that a unified program is adopted by the government which maximally guarantees future price stability in the domestic energy market. Leasing policy will be liberal, subject to an overall strategy of phasing in shale oil at the maximum level consistent with crude oil stability. Import controls and conservation regulation will be employed to serve this goal in much the same manner as they do at present. Production from federal oil shale lands will be made subject to market demand quotas. The depletion controversy will be resolved by allowing 15 percent depletion on the value of crude shale oil. Assuming this model, much entry on the part of major firms should occur and considerable research on both *in situ* and conven-

tional methods should be undertaken. Although Colony and the crude-short majors would still be the first likely entrants, they would soon be joined by the great majority of the major firms. New entry through the medium of consortia of smaller firms might materialize, and major pipeline projects would probably come about reasonably early through joint ventures among major producers seeking to achieve economies of large scale pipeline transportation. New technology should develop more rapidly, and a greater number of competitors, or at least rival firms, should enter the market earlier in the history of the industry. On the debit side, the favorable climate thus created by government policy would rest upon a level of oil prices well above world price levels.