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INTRODUCTION

A British Petroleum pipeline finds its way across the sea floor from the Forties Field, comes ashore alongside a venerable Scottish golf course, and proceeds southward, broaching ancient Roman walls enroute. At the terminus, within sight of the Firth of Forth, the North Sea oil is held awaiting further shipment by tanker. The tanks are cleverly hidden from casual view by the rolling green terrain. The spoil banks of a bygone Scottish oil shale era now provide a pleasant camouflage for the resource industry that replaced it.

Mining and retorting of oil shale has been practiced for over 100 years in many different countries. However, with the discovery of petroleum reserves the industry declined rapidly in size, and shale oil was used in decreasing amounts. Ever since this development, the intriguing question has been whether shale oil can once again become a major source of liquid hydrocarbons.

One of the periodic revivals in oil shale enthusiasm appeared in the mid-1960's, but by 1969 this enthusiasm had begun to wane. The Oil Shale Corporation's (TOSCO) estimates of operating costs at $1.55 per barrel appeared bullish, but the Cabinet Task Force on Oil Import Policy was considering removal of oil import quotas and world oil was in abundant supply and selling at under $2.00 per barrel.[1] Perhaps most discouraging were the difficulties being encountered by the Sun Oil Company at its Great Canadian Oil Sands venture in Alberta.[2] Reports of Sun's continuing losses triggered caution in the board rooms of firms holding oil shale lands.

Ten more years have now passed, and imported oil now arrives at $14.49 per barrel, and new domestic crude brings an upper-tier price of $12.29.[3] Surely shale oil, which was nearly economic at $4.00 to $5.00 per barrel, must now be ready to burst upon the energy scene. Or is it?

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1. Schanz, *The Outlook for Synthetic Liquid Hydrocarbons*, 65 Q. Colo. Sch. Mines 13 (Oct. 1970).
2. New York Times, May 12, 1969, at 69.
3. CHASE MANHATTAN BANK, 2 The Petroleum Situation 4 (Table 1) (April 1978).

BOOM AND BUST IN THE SEVENTIES

Among the nation's major oil firms, not all are equally fortunate in having access to crude oil to meet their refinery needs. Thus firms such as Ashland Oil, Atlantic Richfield, or Standard Oil of Ohio have always been on the alert for any turn of events that could improve the outlook for new feedstock sources. Then embargo of the Organization of Petroleum Exporting Countries (OPEC) and the subsequent drastic change in world oil prices was certain to stimulate these firms and others to reexamine their position with regard to oil shale. Atlantic Richfield had already joined the Colony consortium and was engaged in a rigorous technical and economic inquiry into the feasibility of building a plant on private lands.[4] There was revived interest in public land leasing, and it appeared unlikely that there would be a repeat performance of the pitifully small bids that were rejected by Interior in 1968.

Things began to move forward smoothly, with Colony announcing that the first commercial-sized plant would be built at their Parachute Creek site.[5] The bids made for the first two federal tracts in early 1974 surprised the Department of the Interior once again, this time because they were on the high side. Standard Oil Company of Indiana and Gulf Oil Corporation bid $210.3 million for tract C-a in Colorado. Atlantic Richfield, TOSCO, Ashland Oil Company and Shell Oil bid $117.8 million for tract C-b.[6] It appeared that for the first time in the over fifty-year history of the Mineral Leasing Act, there would also be a commercial-sized operation on the public lands. But misfortune does not give up easily on its treatment of oil shale.

Environmental concerns continued to harass and delay the ventures. It was determined that the background levels of certain types of air pollutants exceeded federal clean air standards. There remained uncertainty about the ability to revegetate the surface after mining and the ability to deal properly with the wastes from the retorts. Questions about the adequacy of water supplies and the potential for harming aquifers or causing deterioration in regional water quality could not be answered to everyone's satisfaction.

Problems also appeared with respect to mining itself. The 5,000 acre tracts were not adequate in size for both surface mining and for the disposal of waste rock. Underground mining at the C-b lease, on the other hand, was encountering difficulties related to the strength

4. 68 Oil & Gas J. 34, 42 (1970).
5. 184 Science 4143, 1271 (1974).
6. Wall Street Journal, February 13, 1974, at 4.

or competence of the rock to protect the workings. But most alarming was the rapid escalation in the estimates of the capital costs to construct the plants.

While it appeared that higher priced world oil, which was due to OPEC decisions plus the increasing cost of domestic drilling offered an unparalleled opportunity for shale oil development, the financial environment for the capital-intensive shale oil industry was deteriorating rapidly (See Table 1). Although estimates vary among companies and between government and private analyses, there is general agreement about the approximate level of oil shale plant capital costs, operating costs, and the required price, assuming an equivalent rate of return. An examination of the statistical data from a variety of sources shown in Table 1 reveals that, from 1968 to 1973, the capital requirements for a 50,000 barrel per day plant doubled. The estimates then more than tripled between 1973 and 1976. Today on paper the cost of an oil shale plant of a size and degree of processing comparable to those proposed ten years ago has likely passed the $1 billion mark.

Operating costs, given prevailing inflationary conditions, have been somewhat better behaved than capital costs. These costs doubled between 1968 and 1976. This is in reasonable accord with the behavior of the wholesale price index for industrial commodities. Given the 277 percent increase in the value of U.S. crude oil and the 722 percent increase in the posted price of Saudi Arabian oil during this period, the oil shale industry could have improved its relative competitive position if capital costs had stayed in line with other inflationary trends. Unfortunately, the 696 percent increase in the estimated cost of building the shale oil plants totally negated this advantage. By 1976 the required price for shale oil, even at a modest 12 to 13 percent discounted cash flow rate of return, had reached $18 or more a barrel.[7] This was well over the market price of either domestic or foreign oil. So, by 1976, shale oil's competitive picture was perhaps worse than it had been in 1968.

It was already apparent by the end of 1974 that the oil shale bubble had burst once again. In rapid succession, the companies retrenched. By October 1974, Colony announced that it was suspending its plans at Parachute Creek.[8] On the federal leases development was initially delayed, then companies began to withdraw from the ventures. Activity on the leases was replaced by appeals for government assistance of one form or another for shale oil production to be feasible.

7. 198 Science 4321, 1023 (1977).
8. J. Comm., November 19, 1974, at 3.

TABLE 1

COMPARATIVE INFLATIONARY TRENDS, SELECTED YEARS

Year	*Oil shale plant capital cost (MM $)*	*Operating cost ($/bbl)*	*Required price at 12% or 12% DCF*	*Average value U.S. crude (S/bbl)*[a]	*Posted price light Saudi Arabian crude*[b]	*Wholesale price price index industrial commodities*[c]	*Nelson inflation index for refinery cost*[d]	*Index of payments to drilling contractors*[e]
1968	$138[f]	$2.12[f]	$3.60[f]	$2.94	$1.80	102.5	304.1	53.6
1970	250[g]	2.04[g]	4.50[g]	3.18	1.80	110.0	364.9	60.6
1973	280[h]	3.21[h]	5.66[h]	3.89	5.12[i]	125.9	468.0	76.9
1976	960[j]	4.16[j]	18.30[j]	8.14	13.00	182.3	615.7	124.0
% change 1968-76	696	196	508	277	722	178	202	231

Sources of data: (See References for complete citations)

[a]U.S. Bureau of Mines.

[b]American Petroleum Institute.

[c]Bureau of Labor Statistics, base year 1967.

[d]*Oil and Gas Journal*, base year 1946.

[e]Independent Petroleum Producers Association of America, base year 1974.

[f]U.S. Department of the Interior.

[g]National Petroleum Council.

[h]U.S. Bureau of Mines.

[i]As of November 1, 1973.

[j]The Oil Shale Corporation.

It was apparent to the companies involved that environmental standards were stricter than ever before, that state and local taxes would likely increase, and that the affected communities were very concerned over uncertain socioeconomic impacts rather than being impressed by new employment opportunities. Nonetheless, these problems were probably manageable. The capital costs were the root difficulty. One might be inclined to suspect the calculations themselves, but a comparable quadrupling of capital costs is also found in the estimates made by other firms involved in western coal gasification projects.[9]

There appears to have been a number of circumstances encountered between 1973 and 1976 that caused a multiplicative effect in the cost estimates. Initially, there was the general double digit inflationary trend. To this was added a somewhat faster increase in cost for constructing refineries or similar type plants. These costs were increasing as much as 40 percent per year by 1976.[10] Coupled with these inflationary trends was the fact that oil shale mines and plants had become more expensive in real terms as they were redesigned to meet new and more stringent environmental requirements. The direct and indirect costs of public investments in the communities supporting the plants became apparent and they also had to be factored into the estimates. In many early estimates the cost of the leases had not been included. Procedural and legal matters added two to three years to the time required between the beginning of a project and the time when production could be anticipated. A twenty-four month delay in production commencement is sufficient by itself to require as much as a 20 percent increase in the price required for a plant to be economically feasible. Finally, analysts were making a future inflationary adjustment for all anticipated capital and operating costs. In retrospect, given the above series of events the ratchet effect of these accumulative adjustments is not surprising.

A SHIFT IN TECHNOLOGY

Short of major governmental intervention, it has become apparent that no firm is currently prepared to risk its funds in conventional oil shale mining and surface retorting. Consequently, the search has turned to finding a process that will: reduce total capital costs, permit the project to be built and operated in a series of stages, and

9. GENERAL ACCOUNTING OFFICE, STATUS AND OBSTACLES TO COMMERCIALIZATION OF COAL LIQUEFACTION AND GASIFICATION, Report to U.S. Senate Committee on Interior and Insular Affairs, 27 (1976).

10. *Nelson Cost Indexes,* 76 Oil and Gas Journal 18, 55 (May 1978).

offer a better way to deal with the group of problems involving air and water quality, surface disturbance, and waste disposal.

Since the 1950's a number of surface retorting methods have been developed in the United States, and their technical feasibility has been proven so that there is acceptable technical risk for industry to proceed to commercial scale development. Although there have been some new processes and some refinements in old methods in the last ten years, none have been developed and tested to a point where it has been proven that they would significantly reduce the cost of the plants or the shale oil produced. Some of the more recent designs appear to offer some improvements in surface-type operations and they may actually reduce water consumption and minimize adverse environmental effects. Unfortunately, such processes and plant designs that minimize water requirements and environmental impact tend to be higher in cost than those that do not.

As a result, there has been a recent shift in near-term oil shale development. True in situ retorting (no mining is used) has received sporadic research and development (R&D) efforts by several private companies since the early 1950's. The major difficulty encountered was the inability to create sufficient permeability in the oil shale formation to permit retorting at economic rates. For true in situ mining to become economically attractive, methods must be devised to fracture the shale economically and create enough permeability to permit good contact between the shale and the retorting gases, and to prevent bypassing of unretorted shale so that high recovery of oil is possible.

In true in situ mining, wells are driven from the surface into the shale formation and the shale is then rubblized. The fractured shale is then ignited at a central production well into which air is blown, and combustion takes place underground. The products oil, water, and gas are recovered from a series of production wells driven around the injection well at 35 to 50-foot intervals.

The permeability needed to attain air flow at a reasonable pressure and in the necessary volumes into the oil shale can be attained by hydraulic fracturing, chemical explosive fracturing or a combination of both. In hydraulic fracturing, water or a water base gel containing sand is injected under high pressure into the oil shale. The water pressure fractures the shale and the sand remains in the formation to hold the fracture open in order to remove the oil. In chemical explosive fracturing one of several types of explosives are injected into the borehole and detonated.

Hydraulic fracturing tests have been made at two sites using Wyoming shale, and explosive fracturing experiments have been conducted at three Wyoming sites. On the basis of these experiences it has been concluded that hydraulic fracturing followed by explosive rubblization is relatively difficult to carry out and the bed porosity created is very low. Production efficiencies are expected to be low, and in the tests actually conducted recovery efficiency was less than 5 percent.[11] The explosive fracturing (using a technique known as "well bore springing") is a much simpler system but the dimensions of the retort that is created are limited in total volume, and it is difficult to get sufficient permeability in the shale to sustain combustion. As a result, one can only conclude that at present, true in situ technology is not yet technically proven.

To overcome the difficulties mentioned above and to try to take advantage of the potential benefits of the in situ approach, modified in situ tests have been conducted. Several different methods are being tested. In 1972, Occidental Oil Shale Corporation began a study of its modified in situ process.[12] Since then three research retorts and two commercial-sized retorts have been prepared and combustion tests on them have been conducted.

In modified in situ processing a small part of the oil shale is mined and the balance to be retorted is then fractured and rubblized in the space created by mining, and a permeable zone for retorting is formed. In the Occidental Oil Shale Corporation process approximately 15 percent of the oil shale is mined from the upper and lower levels of the planned retort. After fracturing of the shale between the mined-out areas with explosives that create a rubblized pile, vertical holes are drilled into the fractured chambers. The broken shale is ignited at the top and air is injected downward to maintain combustion. Oil and gas are recovered from the bottom of the retort and part of the gas is recirculated to control the oxygen concentration in the inlet combustion gas.

The Lawrence Livermore Laboratory is also investigating a modified in situ retorting process called Rubble In Situ Extraction (RISE) that is a variation of the Occidental process. The essential difference is in the method of stoping. Where, prior to blasting, the Occidental procedure mines a room above and below the planned retort, the RISE method mines drifts driven the width of the block at multiple levels. Development, fan drilling, and loading after blasting proceed on subsequent sublevels.[13]

In addition to the government-sponsored RISE project, the De-

11. Burwell, Sterner & Carpenter, *Shale Oil Recovery by In Situ Retorting; a Pilot Study,* 22, 12 J. Petroleum Tech. 1520 (Dec. 1970).

12. 71 Oil & Gas J. 39, 94 (1973).

13. A. LEWIS & A. ROTHMAN, *Rubble In-Situ Extraction* (1975).

partment of Energy (DOE) is supporting additional modified in situ projects with Equity Oil Company (modified in situ shale oil solution mining), with Geokinetics, Inc. (horizontal modified in situ), at the Laramie Energy Research Laboratory (horizontal modified in situ), and DOE is providing support for the Occidental process described above.[14] Another government-sponsored project that is designed to develop long-term shale deposits aimed at the production of gas from shale is being conducted by the Dow Chemical Company.

WHITHER NOW?

There has now appeared some optimism, although not universally shared, that modified in situ mining offers a way of getting an oil shale industry under way. Major attention will be focused on two Colorado federal leases. Occidental Petroleum and Ashland Oil Company will be partners using Occidental's modified in situ method at the C-b tract. Concurrently, Gulf Oil and Standard Oil of Indiana have also shifted their Rio Blanco Oil Shale Project on the C-a lease to the RISE modified in situ method (see Table 2). The Rio Blanco project, employing a different approach to preparation of the retorting chamber, is not as well advanced experimentally as Occidental's and will require further small scale investigation before commercial-sized development can be considered.[15]

Numerous advantages are now claimed for modified in situ. Operations will be developed in a series of steps. The projects will require only about one third as many people as the surface plants, minimizing the local socioeconomic adjustments to the new ventures. Water requirements will be reduced to 25 to 33 percent of normal requirements.[16] Spent shale disposal will be sharply reduced by 80 percent.

Government encouragement of commercial oil shale development is now becoming apparent. Colorado's Air Pollution Commission has eased its sulfur emission standards to a level that will make operations feasible. The Environmental Protection Agency has also given its approval for the projects to proceed. Tax credits have been proposed and there will be participation in the "entitlements" program for refinery purchases. Entitlement is a cost allocation program designed to equalize refiners' disparate oil costs from different sources.

14. 75 Oil & Gas J. 42, 65 (1977).

15. Personal communication with Dr. ARTHUR LEWIS, Lawrence Livermore Laboratory, Livermore, California.

16. CONGRESSIONAL RESEARCH SERVICE, ENERGY FROM OIL SHALE, Report to Subcommittee on Energy of the House Committee on Science and Technology, at 18 (Nov. 1973).

TABLE 2

SELECTED MAJOR OIL SHALE DEVELOPMENT ACTIVITIES*

Project and companies	*Planned technology*	*Completed by or 1st test by–*	*How much shale oil*	*Expected cost of activity*
Prototype of oil shale leasing program tract C-b; Ashland Oil, Inc., Occidental Petroleum Co.	Modified in situ	1983 completed	Planned 57,000 bbl/d	$440,000.000
Department of Energy–Occidental Petroleum Co., cooperative demonstration plant program	Modified in situ	Around 1982	2,500 bbl/d	$60,500,000
Prototype oil shale leasing program, tract C-a, Rio Blanco oil shale project; Standard Oil Co. of Indiana, Gulf Oil Corp.	Modified in situ	1979 1st test, work towards commercialization after 1981.	Intermittent production of demonstration unit	Planned expenditure of $93,000,000 over the next 5 yr.
Colony Development Operation; Atlantic Richfield Co., TOSCO–formerly Oil Shale Corp.	Above ground retorting, using TOSCO II system.	Commercial plans held in abeyance.	About 47,000 bbl/d	About $1,200,000,000
Union Oil Co. of California	Above ground retorting, using Union's process.	No recent information.	About 7,200 bbl/d pilot plant.	Considering investment of $123,000,000
Paraho Development Corp.; about 17 oil and industrial companies have participated	Above ground retorting, using Paraho process.	Pilot plant tested, semiworks projects operating and producing 180 bbl/d.	4,000 to 5,000 bbl/d modular unit.	Planned investment of $65,000,000
Superior Oil Co.	Above ground retorting, using Superior's 3 mineral process that yields shale oil, alumina, and sodium minerals.	Pilot plant tested, awaiting land exchange deal with Department of the Interior.	13,000 bbl/d	Investment of $300,000,000
Prototype of oil shale leasing program, tracts U-a and U-b, White River oil shale project; Sun Oil Co., Phillips Petroleum Co., Standard Oil Co., of Ohio.	A combination of modified in situ and above ground	Plans suspended pending outcome of legal problems.	100,000 bbld/d	$1,610,000,000

*CONGRESSIONAL RESEARCH SERVICE, LIBRARY OF CONGRESS U.S. ENERGY SUPPLY AND DEMAND 1976-1985 (March 1978).

Further government assistance has been received through the Department of Energy's investments in research on rubblizing techniques and various development projects. The Navy is also becoming involved in sponsoring tests of large scale refining of shale oil.[17]

Occidental has revealed little about the proprietary details of its process, and production costs have been estimated from various sources at anywhere from $8 to $16 per barrel at a 15 percent rate of return on investment. It is currently believed by those developing the technique that the capital costs per barrel of capacity will be significantly less than for surface retorting, but annual operating expenses may be slightly more. There are some questions about how much upgrading of the shale oil is included in these costs, and whether or not the oil can be refined by conventional methods without further processing.

Only the vertical modified in situ process of Occidental has been tested on a scale large enough to assume that it is ready to be demonstrated on a commercial scale. But even the Occidental process is at too early a stage of development to be certain that it will be commercially viable. It is quite apparent that greater technical certainty has been traded for a method of minimizing water needs, environmental problems, and socioeconomic impacts. Thus compared to aboveground retorting which has a much larger R&D history, estimates of technical and economic feasibility are markedly less certain. The estimated costs of producing oil by in situ methods may seem lower than production by surface methods, but the accuracy of the estimates must be considered questionable at this point.

It must also be remembered that the modified in situ approach is not totally free of environmental problems. The impact of a large number of retorting chimneys on water quality and on the alteration of flow through subsurface aquifers is not known. The potential impact of subsidence is another problem. Since some mining has to take place, the eventual disposal or processing of this material must be considered. For the moment, it appears that surface storage is contemplated, but this can only be a temporary answer. Finally, air pollutants are emitted into the atmosphere by in situ combustion. Eventually, if a number of projects gets underway, the question of air quality degradation will have to be faced again.

At the moment, surface retorting will receive additional R&D effort but the modified vertical in situ projects on federal leases still seem to be the "best show in town" (see table 2). However, in addition to being relatively untested, these latter methods are only

17. Science, *supra* note 7, at 1026.

usable at certain depths and thicknesses of shale. There has been some reduction in the "front-end" capital burden, but that burden remains sizeable. One must suspect that if tracts C-a and C-b are actually to arrive at production levels of 50,000-plus barrels per day, there is a need for clear-cut federal energy policies and positive financial support. So long as we have no commercially demonstrated technology, the future behavior of domestic and foreign crude oil prices is uncertain, and recalling the past undisciplined and unpredictable policy behavior of both the state and federal governments, it is unlikely that a totally private prototype venture in the $500 million to $1 billion price range will occur.

It will take two or three years before we can begin to assess the current oil shale development strategy. The kind of detailed technical, environmental, and economic information that is required to make a full appraisal apparently will not be in hand until 1983. Thus, as in the past, shale oil production continues to be a game of watchful waiting.