CHAPTER 5
Technology

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Introduction

The mining and processing technologies that can be used to convert kerogen, the organic component of oil shale, into marketable fuels are discussed in this chapter. The characteristics of these technologies will influence the effects that an oil shale industry will have on the physical environment, and their technological readiness will affect the rate at which an industry can be established. The following subjects are discussed:

- the general types of processing methods and their major unit operations;
- the mining methods that could be used to remove oil shale from the ground and prepare it for aboveground processing;
- the generic types of retorting methods that could be used to convert the oil shale to liquid and gaseous fuels;
- the upgrading and refining methods that could be used to convert crude shale oil to finished products;
- the potential markets for shale-derived fuels;
- the technological readiness of the major steps in the oil shale conversion system;
- the uncertainties and the research and development (R&D) needs that are associated with each major unit operation; and
- the policies available to the Government for dealing with the uncertainties,

Summary of Findings

Oil shale contains a solid hydrocarbon called kerogen that when heated (retorted) yields combustible gases, crude shale oil, and a solid residue called spent, retorted, or processed shale. Crude shale oil can be obtained by either aboveground or in situ (in place) processing. In aboveground retorting (AGR), the shale is mined and then heated in retorting vessels. In a true in situ (TIS) process, a deposit is first fractured by explosives and then retorted underground. In modified in situ (MIS) processing, a portion of the deposit is mined and the rest is shattered (rubbled) by explosives and retorted underground. The crude shale oil can be burned directly as boiler fuel, or it can be converted into a synthetic crude oil (syncrude) by adding hydrogen. The syncrude can also be burned as boiler fuel, or it can be converted to petrochemicals or refined to obtain finished fuels. Some of OTA's major findings concerning these mining and processing technologies are:

- Limited areas of the oil shale deposits may be amenable to open pit mining. This technique has never been tested with oil shale but it is well-advanced with other minerals. More oil shale experience has been acquired with underground mining, particularly room-and-pillar mining, and preparing MIS retorts. Although uncertainties remain, the mining technologies should advance rapidly if presently active projects continue and suspended ones resume.

- TIS is presently a very primitive process, although R&D and field tests are being conducted. The principal advantages of TIS are that mining is not needed and surface disturbance from facility siting and waste disposal is minimized. The principal disadvantages are a low level of technological readiness, low recovery of the shale oil, and a potential for surface subsidence and leaching of the spent shale by ground water.

- MIS is a more advanced in situ method. It is being further developed on two lease tracts and a privately owned site. The Department of Energy (DOE) is providing substantial R&D support. The principal advantages of MIS are that large deposits can be retorted, oil recoveries per acre affected are high, and relatively few surface facilities are required. However, some mining and some disposal of solid wastes on the surface are required, and the oil recovery per unit of ore processed is low relative to AGR methods. The burned-out MIS retorts have a potential for ground water pollution.

- AGR also has a medium level of technological readiness. Three retorts have been tested for several months at rates approaching one-tenth the capacity of commercial-size modules. Others are still at the laboratory or pilot-plant stages. The principal advantage of AGR processing is high oil recovery per unit of ore processed. However, with some mining methods, oil recoveries per acre may be lower than with MIS. Surface disturbance is highest with AGR because of the extensive surface facilities, and because large quantities of solid waste are generated.
- The physical and chemical properties of crude shale oil differ from those of many conventional crudes. However, depending on the nature of the upgrading techniques applied, the syncrude can be a premium-quality refinery feedstock, comparable with the best grades of conventional crude. Shale oil is a better source of jet fuel, diesel fuel, and distillate heating oil than it is of gasoline. Although some technical questions remain, the upgrading and refining processes are well-advanced. Refining shale oil may cost from $0.25 to $2.00 more per bbl than refining some of the poorer grades of domestic crude.
- The initial output from the pioneer oil shale industry will probably be marketed near the oil shale region. Once the industry is established, the shale oil will probably be used as boiler fuel or refined in the Rocky Mountain States. A large industry will most likely supply oil to Midwest markets. A 1-million-bbl/d industry could completely displace the quantities of jet, diesel, and distillate heating fuels that are presently obtained from foreign sources in the entire Midwest.
- With the present technical status of the critical retorting processes, deploying a major oil shale industry would entail appreciable risks of technological and economic failure. Although much R&D has been conducted, and development is proceeding, the total amount of shale oil produced to date is equivalent to only 10 days of production from a single 50,000-bbl/d plant. Because of its primitive status, much basic and applied R&D is needed for the TIS method. The MIS approach and some of the AGR processes are ready for the next stage of development—either modular retort demonstrations or pioneer commercial-scale plants. Such demonstrations would be costly, but they would substantially reduce the risks associated with the much larger capital investments needed to create an industry,

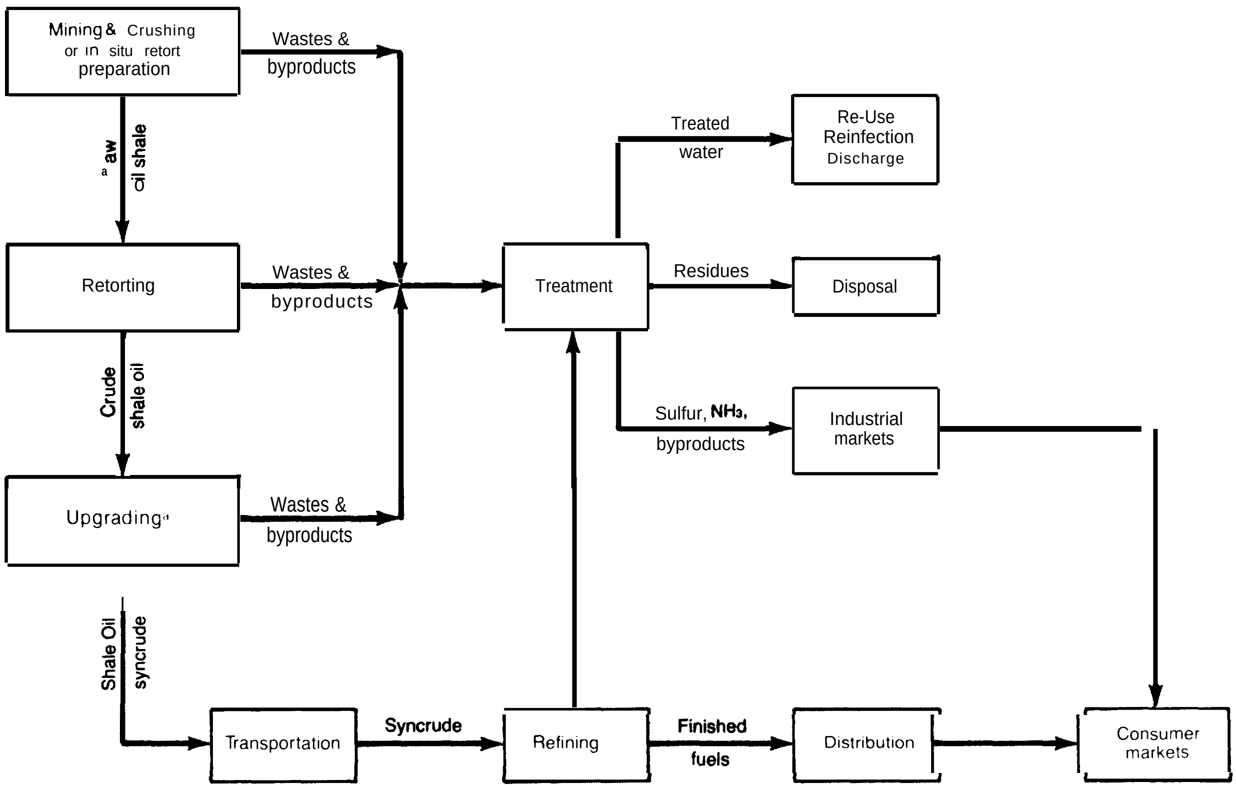
An Overview of Oil Shale Processing

Converting shale in the ground to finished fuels and other products for consumer markets involves a series of processing steps. Their number and nature are determined by the desired mix of products and byproducts and by the generic approach that is followed in developing the resource. The alternative approaches are:

- TIS processes in which the shale is left underground, and is heated by injecting hot fluids;
- MIS processes in which a portion of the shale deposit is mined out, and the rest is broken with explosives to create a highly permeable zone through which hot fluids can be circulated; and
- AGR processes in which the shale is mined, crushed, and heated in vessels near the minesite.

Figure 19 is a flow sheet for the steps common to all three options. How the steps would be integrated in an AGR facility is shown in figure 20. In the first step, the oil shale is mined and crushed for aboveground processing, or the deposit is fractured and rubbled for in situ processing. The main product is

Figure 19.– Oil Shale Utilization



[a] May not be needed for some in situ methods

SOURCE Office of Technology Assessment

raw oil shale with a particle size appropriate for rapid heat transfer. Nahcolite ore can be one of the various byproducts from this step. Dust and contaminated water are among its wastes, In the retorting step, the raw oil shale is heated to pyrolysis temperatures (about 1,000° F (535° C)) to obtain crude shale oil. Other products are the spent shale residue, pyrolysis gases, carbon dioxide, contaminated water, and in some cases additional nahcolite and dawsonite ore. The crude shale oil may be sent to an upgrading section in which it is physically and chemically modified to improve its transportation properties, to remove nitrogen and sulfur, and to increase its hydrogen content. (Crude shale oils from some in situ processes may not need upgrading before transportation.) Contaminated air and water, and in some units refinery coke, are the wastes produced along with gases that contain sulfur and nitrogen compounds. Depending on the extent of the treatment, the upgraded product—shale oil syncrude-can be a high-quality refinery feedstock, comparable with the best grades of conventional crude. In the refining step, which may be conducted either onsite or offsite, hydrogen is added to convert the syncrude to finished fuels such as gasoline, diesel fuel, and jet fuel. The syncrude, or the crude shale oil, could also be used directly as boiler fuel. After refining, the fuels are distributed to consumer markets. Refining also produces waste gases and various contaminated condensates.

To protect the environment, contaminated water must be treated for reuse in the oil shale facility, for reinfection into the ground water aquifer source, or for discharge into

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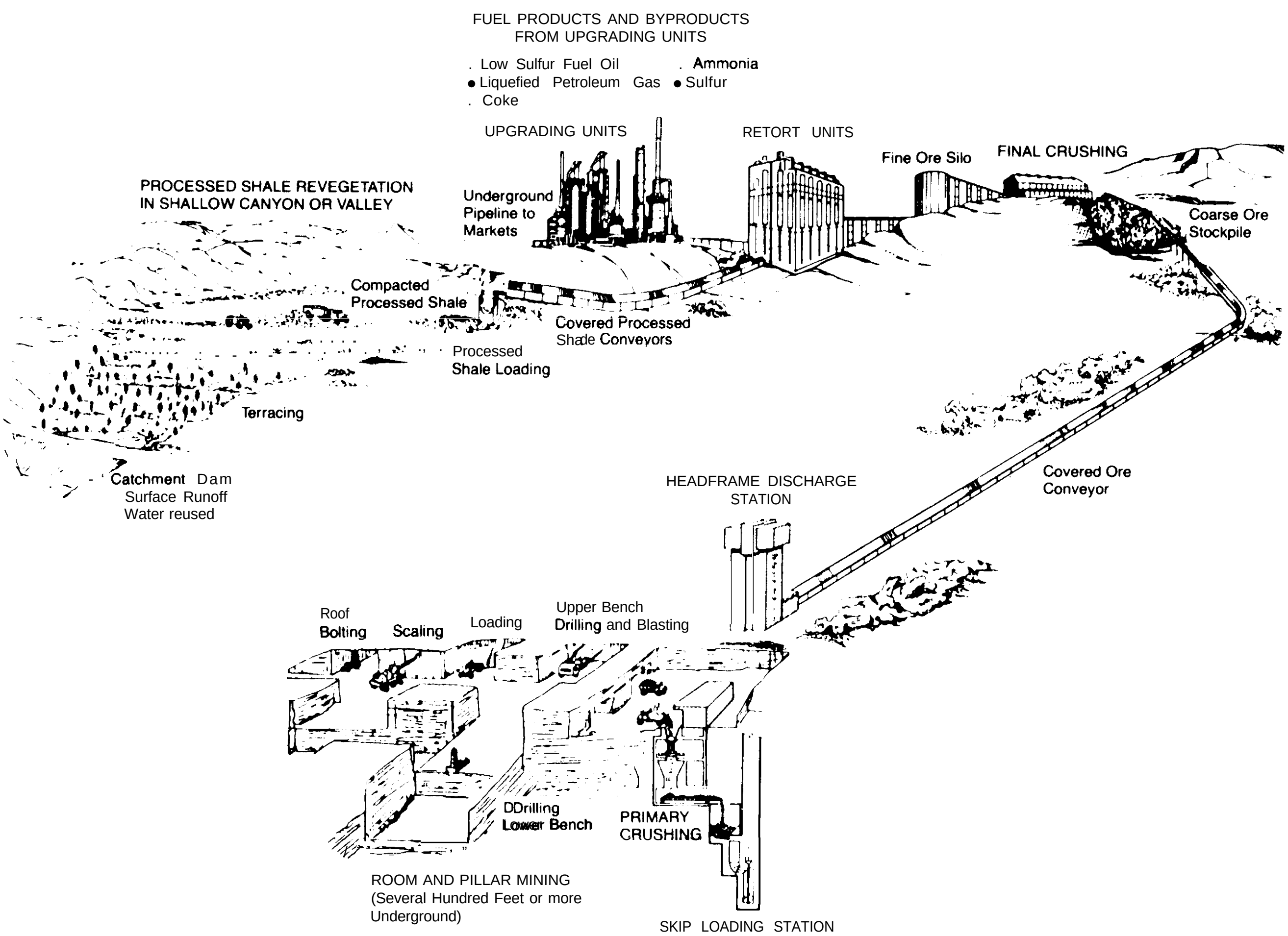
Figure 20.—The Components of an Underground Mining and Aboveground Retorting Oil Shale Complex



SOURCE C b Shale 01 IProject *Detailed Development Plan and Related Materials* Ashland 011, Inc and Shell 011 Co , February 1976, p 1-24

surface streams. Contaminated air and process gases must be purified to meet Federal and State air pollution standards before they can be discharged to the atmosphere. The waste gases from retorting, upgrading, and refining are potential sources of ammonia (for fertilizer and other uses) and sulfur (for sulfuric acid and many other materials). These can be recovered during the treatment steps and sold to industrial processors. In some portions of the Green River formation, the solid residues from mining and retorting will contain nahcolite (which can be used to produce soda ash and for stack gas scrubbing) and dawsonite (a source of aluminum metal). In any case, spent shale from above-ground processing must be moistened, compacted, and revegetated to prevent erosion and leaching. Retorted shale in in situ retorts, and spent shale from surface operations that is backfilled into underground openings, must be protected from leaching by ground water.

This chapter deals with the processing technologies used in mining, retorting, upgrading, and refining. Technologies for treating air, water, and solid wastes are discussed in chapter 8.

Oil Shale Mining

Both MIS and AGR require mining. In the case of AGR, the mined shale is conveyed to retorts where it is processed to recover shale oil. With MIS, the shale may also be retorted aboveground, or it may be discarded on the surface as a solid waste.

Green River oil shale deposits are characterized by their extreme thickness and by their extensiveness. The richer shale zones in the Piceance basin, for example, are more than a thousand feet thick, in places, and are continuous over an area of 1,200 mi^2. Deposits of this nature could be amenable to either surface mining (strip or open pit) or to underground mining methods (such as room and pillar), depending on topographical features, accessibility, overburden thickness, presence of ground water in the mining zone, and many other factors. Surface mining may be feasible for very thick oil shale zones that are not deeply buried, especially if their average oil yield is not high, Because of the thickness of the overburden, only a limited area of the Piceance basin and somewhat more of the Uinta basin and the Wyoming basins is amenable to surface mining. In other areas, streams have eroded gulleys and canyons through the shale beds, exposing some of the richer shale zones. Shale that outcrops in these areas, plus the shale in all deeply buried beds, will probably be extracted by underground mining,

Despite the high price of crude oil, oil shale is a lean ore compared with many ores that contain valuable metals. Economies of scale encourage massive mining installations, regardless of the mining method selected. A prospective developer once characterized commercial-scale oil shale mines as “prodigious, ” because it connotated a larger size than “giant.’” A sense of this can be conveyed by comparing their capacities with those of more conventional mines. At present, the largest surface mine in the United States is Kennecott Copper’s Bingham Canyon pit in Utah, which produces about 110,000 ton/d of copper ore. The largest underground mine is the San Manuel copper mine in Arizona, which yields about 50,000 ton/d of ore, About 70,000 ton/d of 30 gal/ton oil shale would have to be mined to support a single 50,000-bbl/d plant that used aboveground retorts. * This mine would be substantially larger than the San Manuel mine. A 400,000-bbl/d industry of aboveground retorts would have to mine about 560,000 ton/d—the equivalent of 5 Bingham Canyon pits or 11 San Manuel mines. If the same industry used only MIS, about 230,000 to 460,000 ton/d would have to be mined—the equivalent of four to seven San Manuel mines. ** Some of the mining techniques that could be used to achieve these levels of production are described below.

Surface Mining

The two principal types of surface mining —open pit and strip— both have been widely used to develop coal seams and deposits of many other minerals. Their technical aspects are fairly well-understood for these minerals. However, their feasibilities and effects vary with the nature of the ore body. Neither technique has yet been applied to the oil shales of the Green River formation.

Surface mining is economically attractive for large, low-grade ore deposits because it permits high recovery of the resource and allows sufficient space for very large and efficient mining equipment. An open pit mine could recover almost 90 percent of the oil shale in a very thick deposit. Strip mining could provide even higher recoveries. In contrast, underground mining would recover less than 60 percent. One of the reasons that industry’s bids on a lease for Federal tract C-a were so high was that the deposit could be

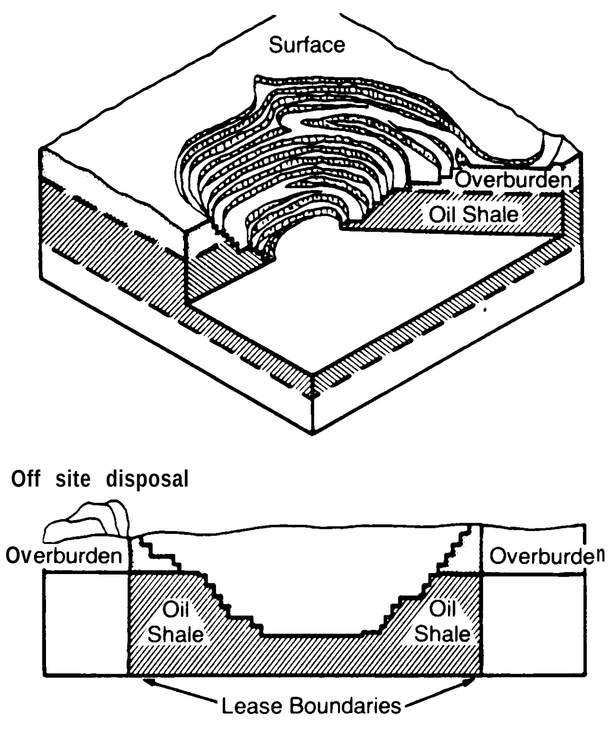
*This assumes recovery of 100 percent of Fischer assay oil, a recovery efficiency that has been achieved in tests of the TOSCO 11 technology.

**This assumes mining of 20 to 40 percent of the shale in the retort volume, and an oil recovery of 60 percent of Fischer assay.

mined by open pit methods. About five times as much shale could be recovered by open pit, which could have mined the entire deposit, than by underground room-and-pillar mining, which would have been limited to a relatively thin zone.[2]

A mature open pit mine is shown in figure 21 and the steps in its operation in figure 22. In the first step, overburden is drilled and blasted loose over a large area above the oil shale zone. The burden is carried by trucks or conveyors to an offsite disposal area. When enough burden is removed to expose the shale beds, the shale itself is drilled and blasted, and is hauled from the pit for processing in aboveground retorts. As mining proceeds, a huge hole is formed, extending from the top of the overburden to deep into the oil shale deposit. The walls of the pit are under pressure from the overburden, and must be angled outwards to transmit the pressure without collapsing.

Figure 21 .—An Open Pit Oil Shale Mine



SOURCE *Hear/rigs on Oil Shale Leasing*, Subcommittee on Minerals, Materials, and Fuels of the Senate Commitee on Interior and Insular Affairs, 94th Cong 2d sess , Mar 17, 1976, p 84

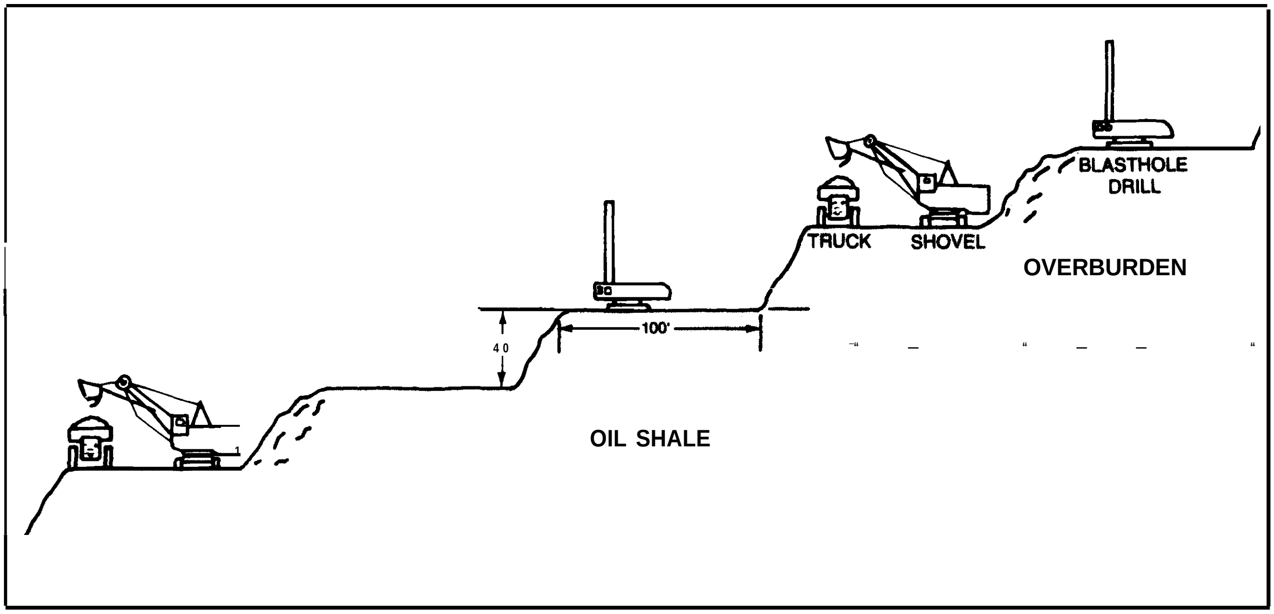
Open pit mining was originally proposed for tract C-a by the Rio Blanco Oil Shale Co., the lessee. The pit was to have started in the northwest corner of the tract, and eventually to have covered its entire surface. After a few decades, freshly removed overburden and spent shale from the aboveground retorts would have been returned to the pit as backfill. In the interim, the solid wastes would have been disposed of on a highland to the northeast of the tract boundaries. This concept was abandoned when the Department of the Interior (DOI) refused to allow offtract waste disposal. Rio Blanco later switched to MIS techniques because the alternative—underground mining—would have reduced resource recovery and threatened profitable operations. * At present, there are no plans for any open pit mines, although Rio Blanco may reconsider its original plan if offsite disposal were allowed.[3]

In strip mining, overburden is removed with a dragline—a massive type of scraper shovel. When the dragline has filled its scoop, it pivots and dumps the burden into an adjacent mined-out area. One difference between open pit and strip mines is that in strip mining, the burden is simply cast into a nearby area; in open pit, it must be moved far from the minesite to prevent interfering with the development of the pit. Strip mining has not been proposed for any of the Green River deposits.

Surface mining of most oil shale deposits is made difficult by the great thickness of the overburden that covers them. In the center of the Piceance basin, for example, the 2,000-ft-thick oil shale zones are buried under about 1,000 ft of inert rock and very lean oil shale. This does not necessarily preclude surface mining, because the deposits are generally characterized by a favorable stripping ratio—the ratio of overburden thickness to orebody thickness. The thick beds in the center of the Piceance basin have 1 ft of overburden

*This change in plans is discussed in vol. 11,

Figure 22.—Open Pit Oil Shale Mining



SOURCE *U S Energy Outlook—An Interim Report The* National Petroleum Council Washington D C 1972

for every 2 ft of oil shale—a stripping ratio of 1:2. With coal, a stripping ratio of 10:1 is often economically acceptable. A study by the National Petroleum Council indicates that open pit mining would be favored for stripping ratios between 2:1 and 5:1, strip mining for smaller ratios, and underground mining for larger ratios than 5:1.'

However, the economic principles of coal mining should be applied with caution to oil shale. Removing 1,000 ft of overburden to recover 2,000 ft of shale might be possible in theory, but the pit's boundaries would be so extensive that it would have to be located on a very large tract. Furthermore, the large "front-end" investment in removing overburden many years in advance of retorting would probably make open pit mining of deep deposits uneconomical. Also, strip mining would not be feasible in many parts of the oil shale region, even those with favorable stripping ratios, because the dragline would have to reach to the bottom of a 3,000-ft-thick layer of overburden and oil shale. It is not clear that such a machine could be built.

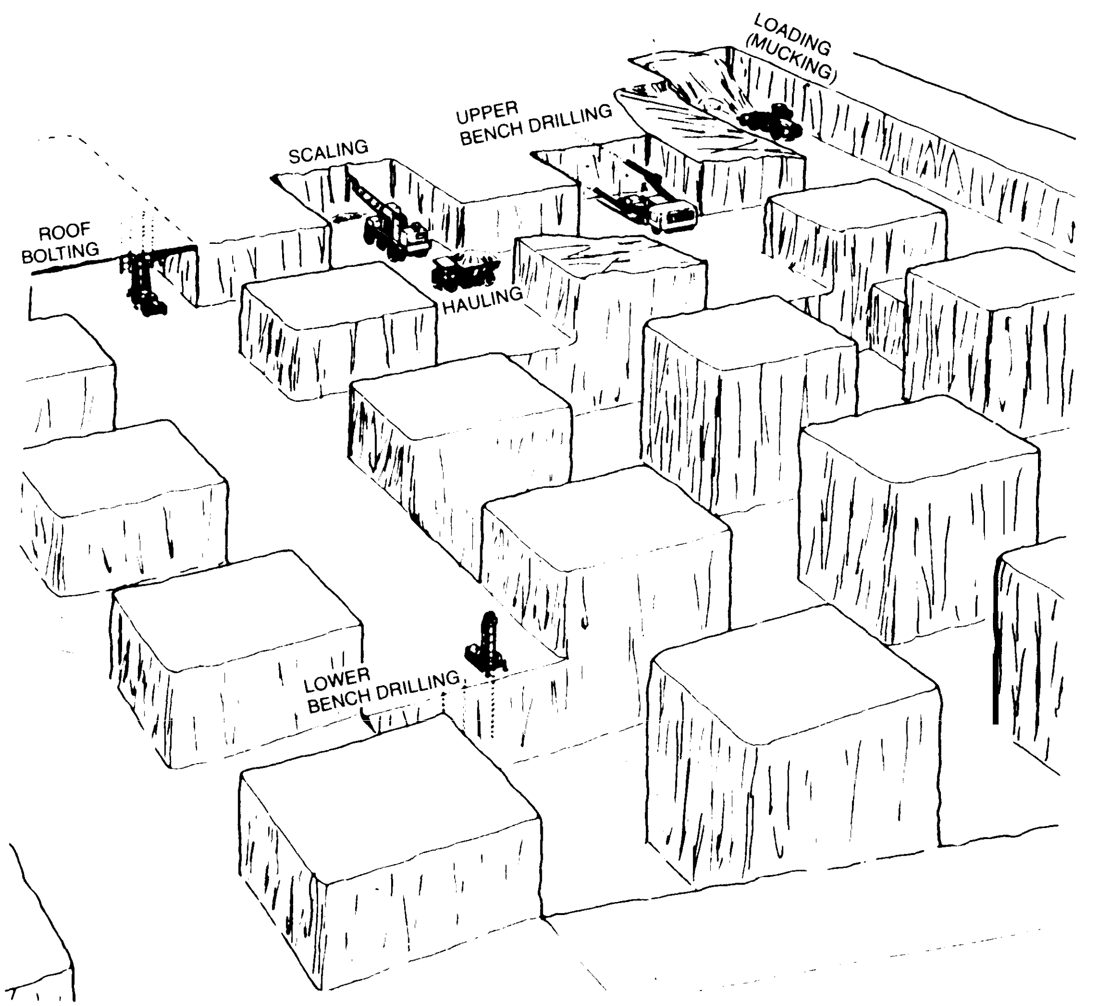
Underground Mining

Many underground mining procedures have been proposed for oil shale deposits[5-10] but to date only room-and-pillar mining and mining in support of MIS retorting have been tested at any significant scale. In room-and-pillar mining, some shale is removed to form large rooms and some is left in place, as pillars, to support the mine roof, The relative sizes of rooms and pillars are determined by the physical properties of the shale, by the thickness of the overburden, and by the height of the mine roof. Most of the deposits of commercial interest are very thick and have relatively few natural faults and fissures. The ore itself resists compression and vertical shear stresses. These properties allow the use of large rooms, and relatively little shale needs to be left as unrecoverable pillars.

The U.S. Bureau of Mines (USBM) studied underground mining of oil shale at the Anvil Points Experimental Station in the late 1940's and early 1950's. [11] The primary purpose of the mining program was to supply raw shale for the Bureau's retorting experiments, but the program was also designed to develop a safe, low-cost mining method. The room-and-pillar technique was adopted after extensive testing. From their studies, which included enlarging the rooms until the roof failed, the investigators concluded that for safe mining conditions the rooms should be 60 ft wide with pillars that are 60 ft on a side.

Many of the modern mine designs have been patterned after the USBM experimental mine. The design depicted in figure 23 is the mining plan proposed for Colony Development's 46,000-bbl/d facility in the Piceance basin. [12] The rooms are 60 ft wide; the pillars are 60 ft square; and the mine roof is 60 ft high. Mining is conducted in two 30-ft-high benches. The upper bench is mined first by drilling blastholes into the walls of a production room, and breaking the shale loose with explosives. The broken shale is carried by trucks to the crushers where it is crushed to the size range required by the TOSCO 11 aboveground retorts. The walls and the roof of the new room are then "scaled" to remove shale that was loosened by the blasting but

Figure 23.—The Colony Room-and-Pillar Mining Concept



SOURCE R W Marshall Colony Development Operation Room. and-Pillar 011 Shale Mining," *Quarterly 01 the Colorado School o/ Mines*, VOl 69, No 2 April 1974. pp 171 184 did not fall. Holes are drilled into the roof, and roof bolts are inserted to assure its integrity, thus protecting the miners from roof falls. The USBM studies indicated that roof bolts would have to be installed in the access passageways but not in areas that were actively being mined. These production rooms would be vacated long before there was any serious danger of roof falls.

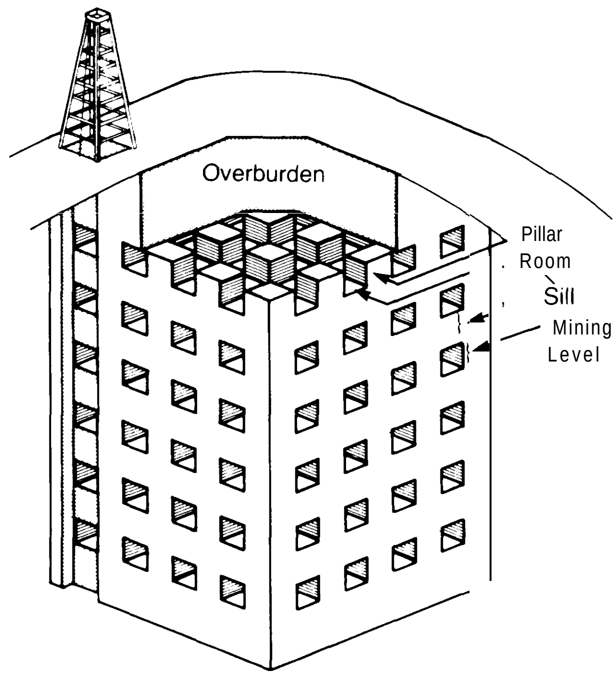
The lower bench is mined next, The sequence is similar except the blastholes are drilled into the floor of the upper bench, and additional roof bolting is not needed, The cycle of drilling, blasting, loading, scaling, and roof bolting was designed to produce about 66,000 ton/d of shale. About 60 percent of the shale in the mining zone was to be removed for processing in the aboveground retorts. The rest was to remain in the support pillars. Colony estimated that enough shale is present in the 60-ft seam to support the retorting facility for at least 20 years.

The same type of mine was proposed by the Colony partners for development of tract C-b, after considering longwall mining, long-hole blasting, continuous mining, block caving, open pit mining, in situ processing, and many other options. The major advantages of the room-and-pillar method were identified as: [13]

- it is highly flexible and can easily be modified to accommodate new conditions, new equipment, or technological advances:
- it can be highly mechanized and high overall production rates can be achieved because many areas can be mined simultaneously:
- the mine openings are relatively easy to ventilate:
- development of access passageways is also a production operation because oil shale would be removed; and
- the mine could be designed to minimize surface subsidence.

The disadvantages were the high cost of the roof support system and the relatively low recovery. In this regard, it was estimated that only 30 to 50 percent of the shale in a 75-ft-thick interval could be recovered. Higher recoveries would be possible if the pillars were subsequently mined out or if the mining were conducted on multiple levels. (See figure 24,)

Figure 24.—Room-and-Pillar Mining on Multiple Levels

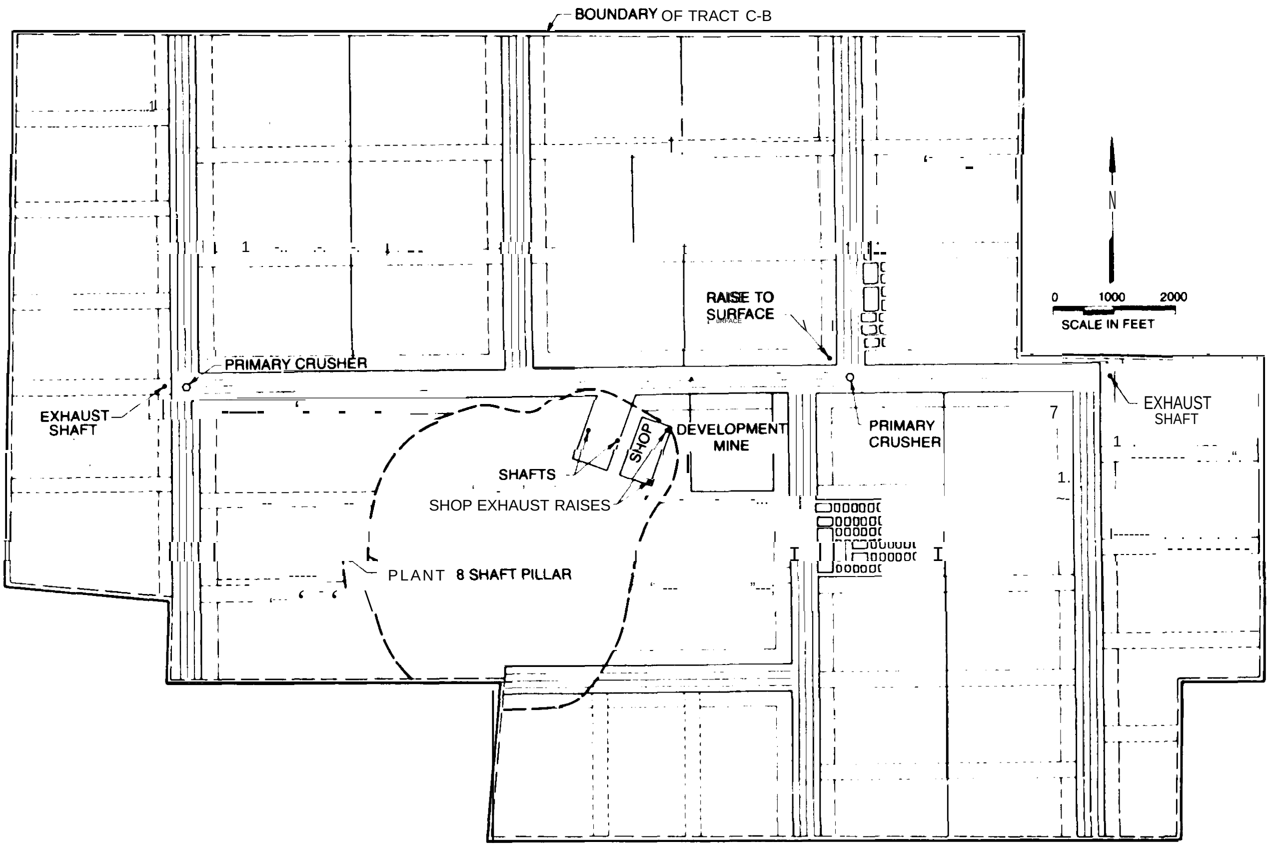


SOURCE *Hearing on Oil Shale Leas/rig* Subcommittee on Minerals Materials and Fuels of the Senate Committee on Interior and Insular Affairs 94th Cong 2d sess Mar 17 1976 p 83

The mine eventually would have extended under the entire surface of tract C-b, as shown in figure 25. However, the concept was abandoned when it was discovered that the shale in the mining zone was highly fractured—a condition that would have required large support pillars thus reducing resource recovery to uneconomic levels. All of the original partners subsequently withdrew from the tract, and it is now being developed by MIS methods by Occidental Oil Shale and Tenneco Oil Co.

Mining to prepare for MIS retorts is distinguished from room and pillar both by the volume of the deposit that is disturbed and by the configuration of the disturbed areas. As indicated, the underground mines both on the Colony property and on tract C-b would have been developed in a 60-ft-high mining zone;

Figure 25.—The Original Mine Development Plan for Tract C-b



SOURCE C-b Shale 011 Project, *Detailed Development Plan* and *Related Materials*, Ashland 011, Inc , and Shell 011 Co , February 1976, p IV-1 1

present plans for the MIS operations on tracts C-a and C-b call for recovering oil from the shale in a 750-ft-high zone. However, the actual mining required to support this development will take place in relatively confined areas. The mine will consist primarily of fairly small underground openings in the region in which the MIS retorts will be created, plus shafts from the surface for ventilation, drainage, passageways for the miners, and transportation of combustion air and retorting products. Some of the mining plans are discussed later in the section on MIS retorting methods.

Oil Shale Retorting

The three generic methods for recovering shale oil from oil shale deposits are described below. Brief discussions of some of the more significant R&D programs that have been conducted as part of their development are ineluded.

True In Situ

The sequential steps in TIS processing are:

1. dewatering, if the deposit occurs in a ground water area;

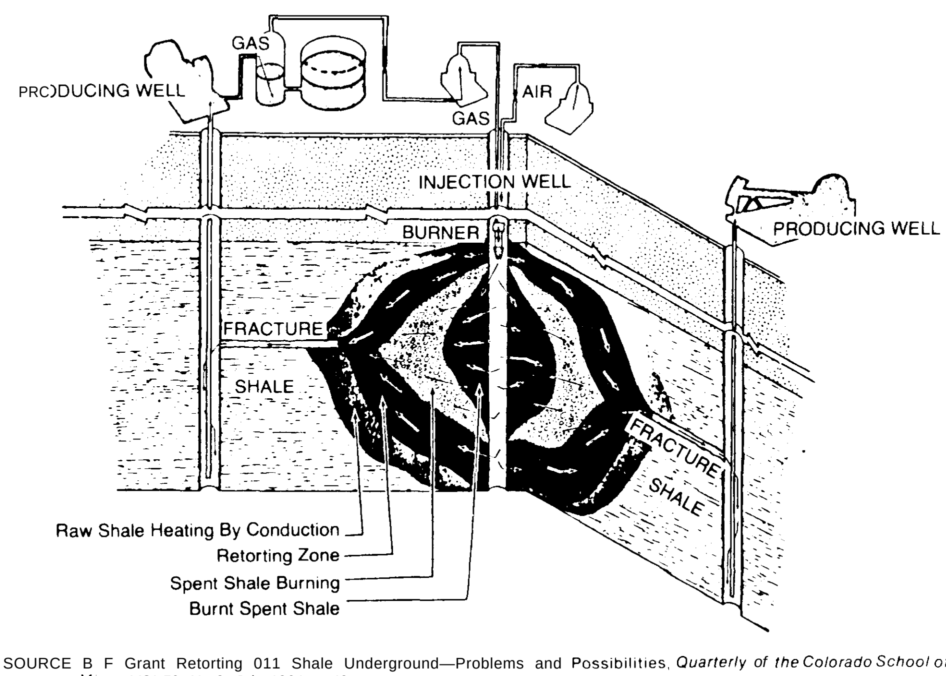
2. fracturing or rubbling if the deposit is not already permeable to fluid flow;
3. injection of a hot fluid or ignition of a portion of the bed to provide heat for pyrolysis; and
4. recovery of the oil and gases through wells.

The principles of TIS processing are illustrated in figure 26. Several types have been proposed that differ from each other with respect to the methods for preparing and heating the deposit. All use a system of injection and production wells that are drilled according to a prescribed pattern. One that is commonly used is the "five-spot" pattern in which four production wells are drilled at the corners of a square and an injection well is drilled at its center. The deposit is heated through the injection well and the products are recovered through the production wells,

For efficient TIS processing, the deposit must be highly permeable to fluid flow, which is true of portions of the Green River oil shales. A good example is the Leached Zone of the Piceance basin where ground water has dissolved salt deposits to leave large rubble-filled zones. It is estimated to contain about 550 billion bbl of shale oil in place.[14] There are interconnected fractures and voids in other areas of the formation, but these, in general, have only a very limited permeability. The permeability of most of the zones that appear to have commercial promise is essentially zero. Deposits that lie near the surface could be fractured by injecting water or explosive slurries, but mining would probably be needed to increase the permeability of deeply buried deposits. MIS or AGR processes are more appropriate for the deeper resources.

In 1961, Equity Oil Co. began developing a TIS process for the Leached Zone, which was tested in the Piceance basin between 1966 and 1968. It involved dewatering a portion of the zone followed by injecting hot natural gas. Pyrolysis gases and a small amount of oil were swept in the natural gas stream to production wells through which they were

Figure 26.—True In Situ Oil Shale Retorting



SOURCE B F Grant Retorting 011 Shale Underground—Problems and Possibilities, *Quarterly of the Colorado School of Mines VOl 59, No 3,* July 1964, p 40 pumped to the surface. The gas was separated from the oil, reheated, and reinfected into the deposit. The oil had a much lower pour point, viscosity, and nitrogen content than oils from aboveground retorts. * These favorable characteristics may have been related to the solvent properties of the natural gas, and to the absence of oxygen from the retorting zone. The quality of the retort gases was also good, partly because of their natural gas component, and partly because during retorting combustion and the decomposition of carbonate minerals were minimal. **

Process development was not pursued because too much of the natural gas was lost in the unconfined formation. In 1968, Atlantic Richfield Co. (ARCO) purchased an interest in the process and resumed its development. In 1971, a revised concept was announced in which superheated steam, rather than natural gas, was to be used to heat the deposits. In 1977, DOE contracted with Equity to test the concept in a 50()-f t-thick seam in the Leached Zone of the Piceance basin. The seam underlies about 0.7 acre of surface, and contains about 700,000 bbl of oil in place. It has been estimated that as much as 300,000 bbl could be recovered over a 2-year period, with about half of the oil produced in the first 7 months. 's Steam injection has begun at the site, and will continue through 1981. No detailed estimates have yet been released of production rates or retorting efficiency. If the process proves to be technically and economically feasible, it could be applied in portions of both the Piceance and the Uinta basins.

At present, no work is being done in slightly fractured formations, but much research is being performed to develop methods for increasing their permeability by enlarging natural fractures and creating new ones. Some of the fracturing techniques used have been chemical explosives, electricity, and injecting high-pressure air and water. These methods have been used to enhance recovery of conventional petroleum; oil shale fracturing poses a similar problem. Nuclear explosives were also proposed in the 1960's, but were not tested because of their potential for harming the environment, A nuclear test—Project Rio Blanco—was conducted in the Piceance basin to fracture sand formations containing natural gas. The test failed.

The earliest TIS work was by Sinclair Oil Co., between 1953 and 1966. A thin section of shale in the Mahogany Zone of the Piceance basin was fractured by injecting air. The bed was ignited, although with difficulty, and a small quantity of shale oil was collected before the hot shale swelled and sealed the fractures. After additional tests, Sinclair concluded that the zone's limited permeability would not permit profitable operations. *

Research on TIS processing began at USBM in the early 1960's. In 1974, the programs and personnel were transferred to the Energy Research and Development Administration, and in 1978, they moved to DOE. The R&D programs have included laboratory experiments, computer simulations, pilot-plant studies, and field tests. Among the latter were tests of electrical, hydraulic, and explosive fracturing and combustion retorting near Rock Springs, Wyo. These revealed some of the problems associated with the TIS approach. In one early test, for example, after inert gas at about 1,300° F (7050 C) was pumped into a fractured formation for a period of 2 weeks, about 1 gal of shale oil was recovered. In another experiment in a zone that contained 7,800 bbl of shale oil in place, it was estimated that only 60 bbl of the close to 1,000 bbl that were released were actually recovered.

Low oil recoveries are often associated with TIS processing because of the large im-

*These properties have economic significance. Pour point is the lowest temperature at which oil will flow. Oils with high pour points are hard to transport because they solidify at normal ambient temperatures. Viscosity is a measure of a fluid 's resistance to flow. Oils with high viscosity are expensive to pump. Reducing the high nitrogen content of most crude shale oils consumes hydrogen, which is costly.

**Both of these processes produce carbon dioxide, which is a major constituent of gases produced by some above-ground retorts.

*The results of a mathematical simulation indicated that about 18 years of continuous steam injections would be required to heat the shale to pyrolysis temperatures within a 30-ft radius of a fracture.

permeable blocks of shale in the fractured formation. These cannot be fully retorted in a reasonable length of time. Irregular fracturing patterns that can cause the heat carrier to bypass large sections of the deposit are another problem. Oil shale that is located in the bypassed regions will not be retorted, And, even if all of the shale in a fractured area were retorted, much of the oil would not reach the production wells, but would remain trapped in the pores of the spent shale or would diffuse beyond the production wells, to be lost in surrounding areas.

To develop methods for improving recovery, an extensive R&D program has been conducted at the Federal research center in Laramie, Wyo. Aboveground batch retorts with capacities of both 10 and 150 tons of shale have been used to simulate in situ retorting, but under more controlled conditions than exist underground. Oil recoveries of up to 67 percent have been achieved, and an experiment in a “controlled-state” retort achieved 95-percent oil recovery. *

In 1976 and 1977, the program was expanded to include field tests of different fracturing and retorting techniques under cost-sharing contracts with Equity Oil, Talley - Frac, Inc., and Geokinetics, Inc.** The Equity program has been described. The Talley-Frac program was terminated after the fracturing method failed. The Geokinetics process uses a fracturing technique called surface uplift in which an explosive is injected into several wells and detonated to fracture the shale and make it permeable to fluid flow, The shale is ignited by injecting air and burning fuel gas through one well. It is pyrolyzed by the heat that sweeps through the bed in the gas stream, Oil and gases are pumped to the surface through outlying production wells. It is hoped that the technical feasibility of the process can be demonstrated for thin deposits that are covered by less than 100 ft of overburden. It has been estimated that there are at least 6 billion bbl of shale oil in place in this type of deposit. It is common in the Uinta basin,[16]) and at present, would be most economically developed by strip mining.

Geokinetics has been investigating the surface uplift approach since 1973, and is presently burning its 20th retort in Utah. The largest retort prior to 1979 measured 130 ft by 180 ft by 30 ft thick. A retort about 200 ft on a side and 30 ft thick will be required to demonstrate the technical feasibility of the process. By 1982, DOE and Geokinetics hope to have developed a commercial-scale operation with a production capacity of 2,000 bbl/d.[17]

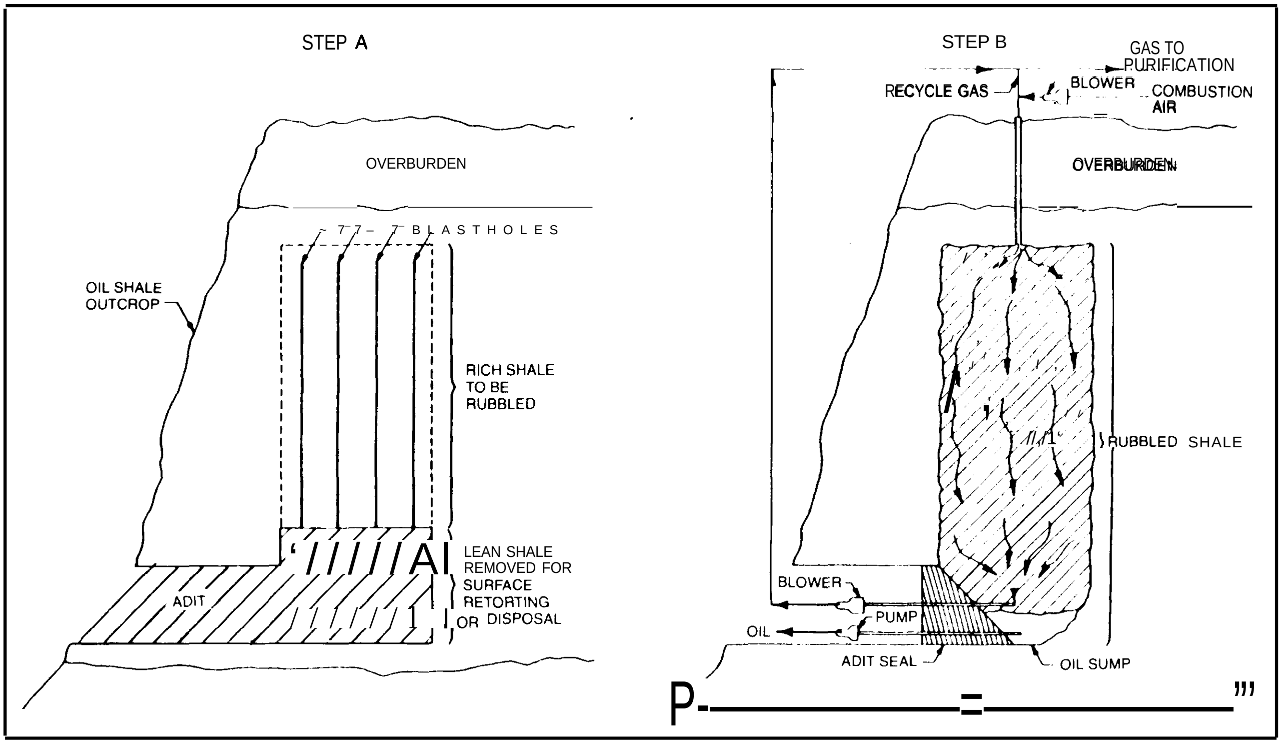
Modified In Situ

In MIS processing, the permeability of oil shale deposits is increased by mining some shale from the deposit and then blasting the remainder into the void thus created. The two-step process is depicted in figure 27. In the first step, a tunnel is dug to the bottom of an oil shale bed, and enough shale is removed to create a room with the same cross-sectional area as the future retort. Holes are drilled through the roof of the room to the desired height of the retort. They are packed with explosives that are detonated in the second step. A chimney-shaped underground retort filled with broken shale results. The access tunnel is then sealed, an injection hole is drilled from the surface (or from a higher mining level) to the top of the rubble pile. The pile is ignited by injecting air and burning fuel gas, and heat from the combustion of the top layers is carried downward in the gas stream. The lower layers are pyrolyzed, and the oil vapors are swept down the retort to a sump at the bottom from which they are pumped to the surface. The burning zone moves slowly down the retort, fueled by the residual carbon in the retorted layers. When the zone reaches the bottom of the retort, the flow of air is stopped, causing combustion to cease.

*The large retorts resemble the classic Nevada-Texas-Utah (NTU) retort that is described later in this chapter. Because of the higher percentage of void volume in the rubble, these retorts provided better simulations of MIS processing than of ‘1’1S. The controlled-state retort was much smaller and was equipped for better cent rol of retorting renditions.

**Tbe procurement also included a contract with Occidental Oil Shale, Inc., to develop its MIS process, which is discussed in the next section.

Figure 27. —Modified In Situ Retorting



SOURCE T A Sladek Recent Trends in 011 Shale — Part 2 Mining and Shale 011 Extraction Processes *Mineral Industries Bulletin* VOl 18 No 1 January 1975, p 18

Photo credit OTA staff

Head frame at tract C-a

Occidental Oil Shale, Inc., a subsidiary of Occidental Petroleum (Oxy) has demonstrated the MIS process, [18] Oxy's work began in 1972 on the D. A. Shale property along Logan Wash—a private tract on the southern fringe of the Piceance basin about 50 miles northeast of Grand Junction, Colo. To date, six retorts have been burned at the site, with varying degrees of success. The first retort was about 32 ft on each side and 70 ft high. About 60 percent (1,200 bbl) of the shale oil in place was recovered, comparable to the best results from USBM's experiments at Laramie, The next two retorts were slightly larger, and performed similarly, The fourth retort was of nearly commercial size—120 ft on each side and 270 ft high. It contained about 32 times as much shale as the first retort and yielded about 25 times as much oil. The fifth was the same size but was designed for a much lower void volume. The rubbling step did not evenly distribute the void volume, and the performance was poor. Only 40 percent of the oil was recovered. The burning of retort 6 began in 1978, but the sill pillar—the layer of unbroken shale that caps a retort—collapsed into the rubble pile. Operations were disturbed while the top was resealed, but retorting was eventually completed, and about 40 percent of the oil was recovered. DOE will share the costs of retorts 7 and 8, which are scheduled for 1980 and 1981,

The oil shale at the Logan Wash site is not considered to be of commercial quality because of its low kerogen content. In 1976, Oxy acquired access to the higher quality resources of tract C-b by exchanging its technical knowledge for a half interest in the lease. In 1978, Ashland Oil Co., Oxy's partner in the C-b Shale Oil Venture, withdrew and left Oxy in full charge. In 1979, Tenneco Oil Co. purchased a half interest in the lease for $110 million and is proceeding to develop the tract in cooperation with Oxy, If present plans are followed, Oxy's technology could be used to produce about 57,000 bbl/d by 1985.

Oxy's technique uses a vertical burn configuration— that is, the combustion zone progresses vertically through the shale bed. It is also theoretically possible to advance the burn front horizontally, in much the same way as it is done in TIS processing. A crude version of this approach was implemented in Germany during World War II, when a few MIS retorts were created by digging tunnels into oil shale deposits and then collapsing their walls into the void volume. These operations were short-lived because oil recoveries were extremely low, and they were very hard to control. [19]

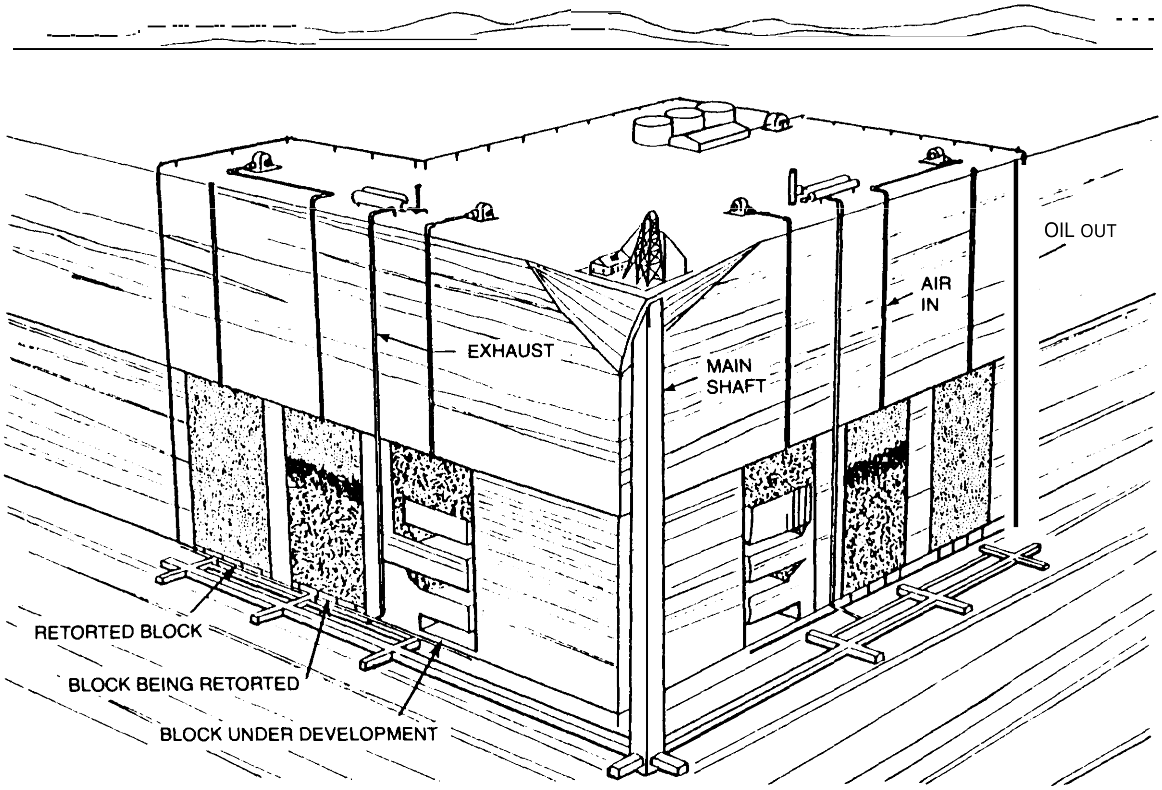
Horizontal MIS might be practical if a technique could be developed to remove large sections of oil shale strata. One possibility is to use solution mining: the injection of fluids into the formation to dissolve soluble salts from among the oil shale layers, The result would be a honeycomb pattern of voids that could then be distributed throughout the area to be retorted by injecting and detonating an explosive slurry. This method would be limited to areas like the Leached Zone or the Saline Zone that contain significant concentrations of soluble salts. Other methods, such as longwall mining or mechanical underreaming, could be used in other areas. It might be possible to operate mechanical underreaming machines by remote control from the surface, thus reducing or even eliminating the need for miners to work underground. None of these approaches has been tested in any oil shale deposit.

Other MIS techniques that use vertical-burn patterns have also been developed. For example, the firm of Fenix and Scisson designed two systems for underground mining, rubbling, and retorting in the vertical mode. [z,)] To date, they have been tested only with a computer model. DOE'S Lawrence Livermore Laboratory has also developed an MIS technique called rubble in situ extraction (RISE) with the aid of computer simulation and laboratory experiments in pilot-scale above--ground retorts.[21-23] (See figure 28.) Several levels are mined, and a portion of the deposit is removed at each. The remaining shale is broken with explosives. Sufficient broken shale is then removed so that there is a total void volume of 20 percent in the retort area. The rubble is then ignited at the top, and retorting proceeds as in the Oxy system.

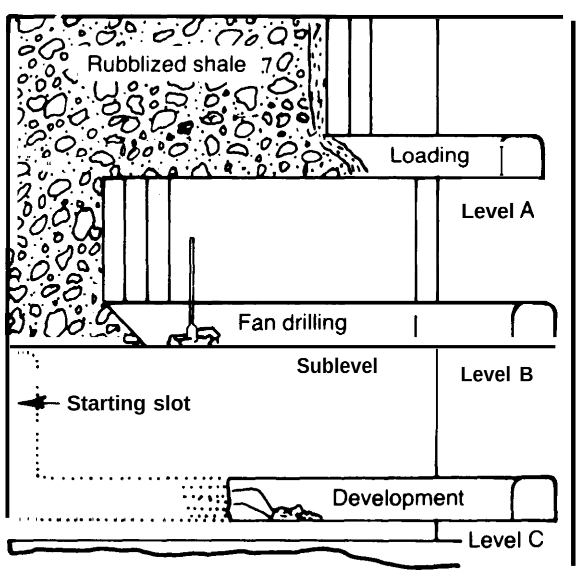
The RISE approach was originally proposed by Rio Blanco Oil Shale Co. for tract C-a, but the firm is now going ahead with its own process, which has benefited from technical information acquired under a licensing arrangement with Oxy. Livermore's modeling studies and laboratory experiments are continuing.

The initial plans for developing tract C-a by MIS methods are shown in figure 29. They would have involved five precommercial retorts of increasing size. The present plan, which was adopted after purchase of Oxy's MIS technology, is shown in figure 30. In the new development plan, a small pilot retort (retort "O") will be followed by two demonstration retorts of increasing size. The largest (retort "2") will be close to commercial scale. Several options of different size are being considered for retort 2, with one option a retort with dimensions 60 ft by 150 ft by 400 ft high, The method by which the shale is rub-

Figure 28.—The RISE Method of MIS Oil Shale Retorting



A. Isometric

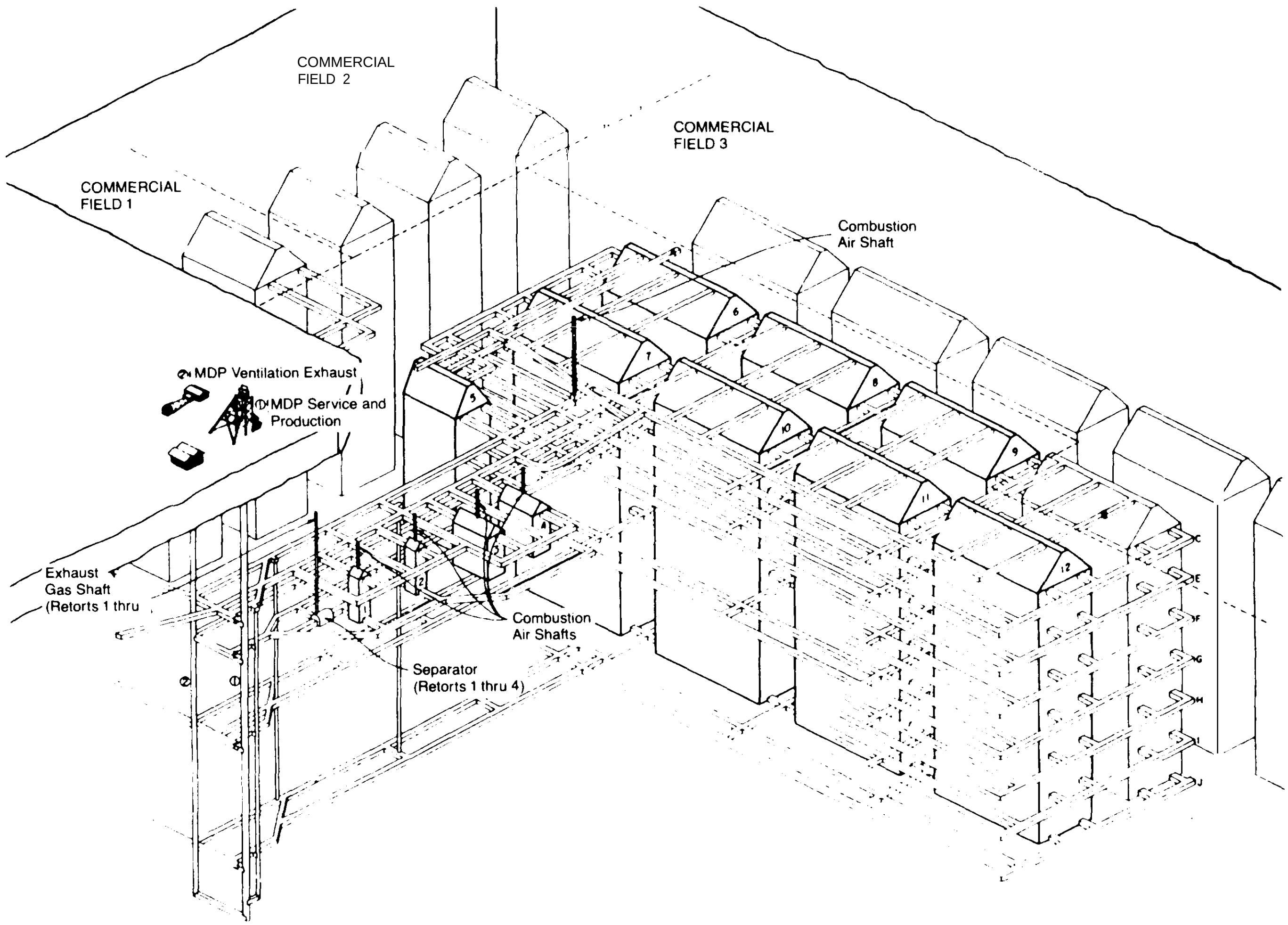


B. Elevation

Development proceeds simultaneously on several levels. At each level, horizontal drifts are driven the full width of the retort block, and a vertical slot is bored to provide void volume for blasting. About 200/. of the broken shale is removed after each blasting operation. The rest is left in the retort volume.

SOURCES: 01/ *Shale Retorting Technology,* prepared for OTA by Cameron Engineers, Inc., 1978; and C. K. Jee, et al., *Review and Analysis of Oil Shale Technology—Volume 3. Modified In Situ Technology,* report prepared for the U.S Department of Energy by Booz-Allen & Hamilton, Inc , under contract No, EX-76-C-01-2343, August 1977, p. 6.

Figure 29.— Initial Modular MIS Retort Development Plan for Tract C-a

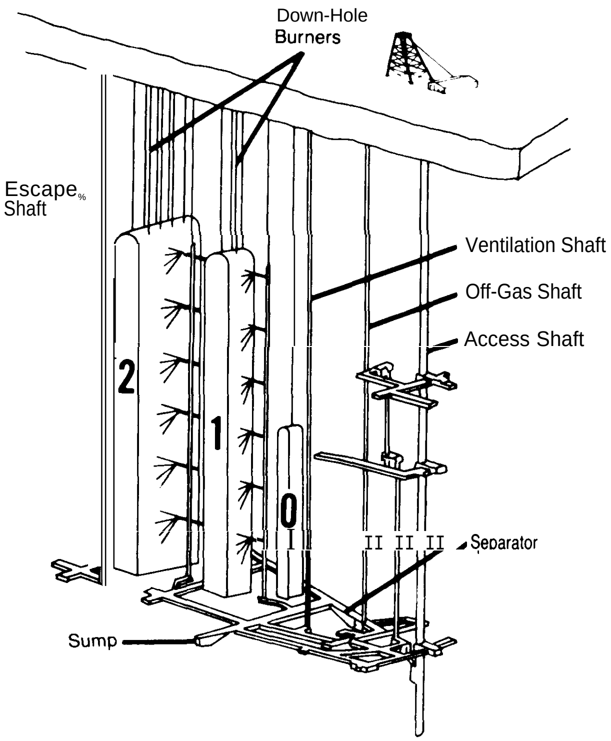


SOURCE Rio Blanco 011 Shale Project Revised *Detailed Development Plan Tract* C a Gulf 011 Corp and Standard 011 Co (Indiana), May 1977 p 1-2-5

bled, and the fraction of the shale that is mined from each retort area are two of the major differences between the Rio Blanco approach and Oxy's technique. Oxy has tested several rubbling methods, including drilling blastholes up from a room at the bottom of the retort, drilling down from the top, and boring a central shaft the full length of the retort and then blasting the surrounding shale into the shaft. In Rio Blanco's approach, a room will be created at the bottom of the future retort, blastholes will be drilled from the surface into the roof of the room, and explosives will be detonated sequentially at different levels, The shale above the room will thereby be blasted loose in layers, with each layer of rubble falling to the bottom of the retort volume before the next higher layer is blasted. Through this technique, Rio Blanco hopes to obtain uniform size distribution in the rubble. This is believed to be a key technical requirement for efficient MIS retorting. Rio Blanco also proposes to mine twice the volume (40 v. 20 percent) as is contemplated by Oxy.

Another MIS method that is still being designed is the integrated in situ technology proposed by Multi Mineral Corp. for recovering shale oil, nahcolite, alumina, and soda ash from oil shale deposits in the Saline Zone of the Piceance basin. This zone underlies the Leached Zone, is relatively free from ground

Figure 30.— Present MIS Retort Development Plan for Tract C-a

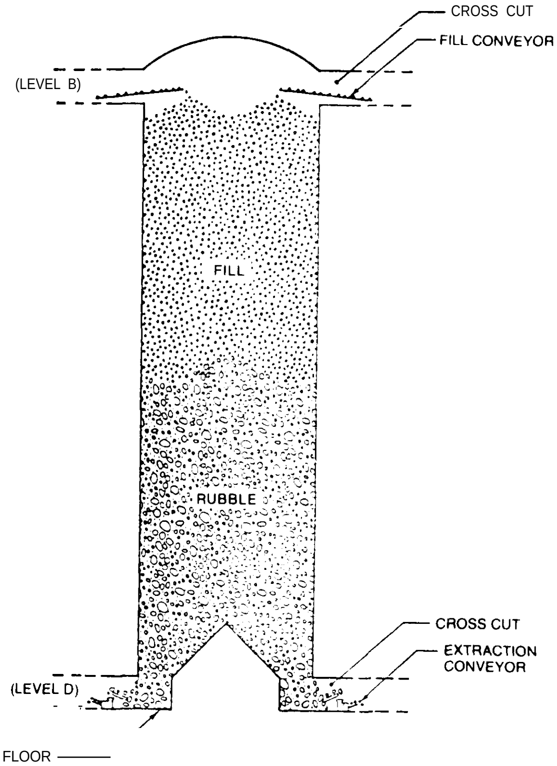


SOURCE The Pace Co Consultants and Engineers Inc *Cameron Synthetic Fuels Report* vol 16 No 3 September 1979 p 28

water, and contains extensive resources of nahcolite and dawsonite in addition to oil shale. Development is hindered because the zone is deeply buried (about 2,000 ft) below the surface of the basin. To reduce the costs of its R&D program, Multi Mineral has proposed to use an 8-ft-diameter shaft that was drilled by USBM in 1978 through the Leached Zone and into the Saline Zone. In the first phase, mining and mine safety methods will be tested, and about 8,000 tons of nahcolite and 11,000 bbl of shale oil will be produced. The nahcolite will be used for stack-gas scrubbing tests in a powerplant. In the second phase, a retorting module will be used to produce up to 3,000 ton/d of nahcolite, 10,000 bbl/d of shale oil, 200 ton/d of alumina, and 3,000 ton/d of soda ash. The modular retort and the access shafts and drifts are shown in figure 31, If technical and economic feasibility is indicated during the test program, Multi Mineral would proceed to a commercial-scale facility that would produce 50,000 bbl/d of shale oil, 10,000 ton/d of nahcolite, 1,000 ton/d of alumina, and 20,000 ton/d of soda ash.

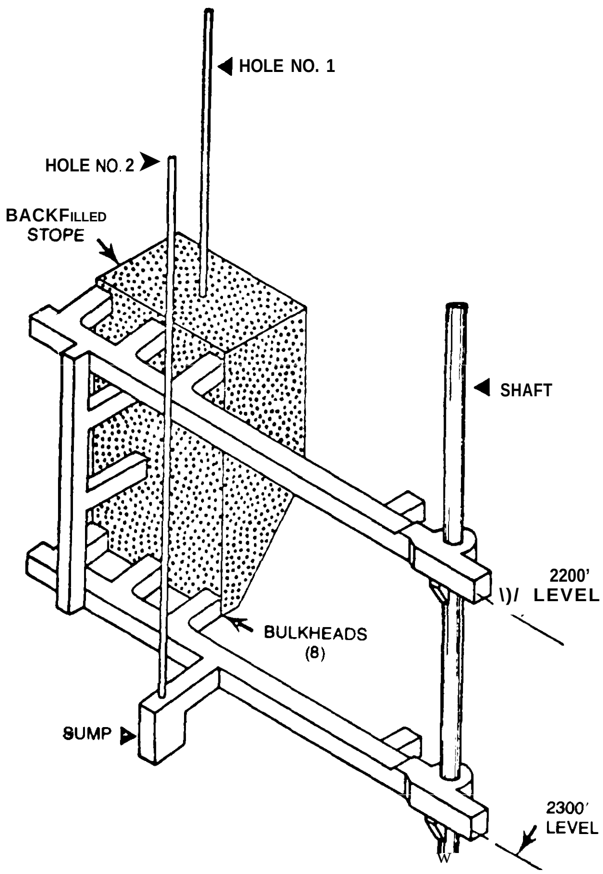
The Multi Mineral approach resembles the RISE technique in that mining and rubbling are conducted at several levels along the height of the retort, It departs from RISE in that, after rubbling, the broken shale in the retort is removed from the bottom, crushed and screened, and returned to the top in a continuous operation. This part of the retort development plan is shown in figure 32. The rubbled shale will contain free nahcolite and

Figure 31 .— Retort Development Plan for the Multi Mineral MIS Concept



SOURCE B Weichman, *Saline Zone Oil Shale Development by the Integrated In Situ Process* Multi Mineral Corp Houston Tex December 1979. p 9

Figure 32.— Preparation of a Multi Mineral MIS Retort



SOURCE B Weichman *Saline Zone Oil Shale Development by the Integrated In Situ* Process Multi Mineral Corp Houston Tex December 1979 p 15

nahcolite that is still associated with the large blocks of shale. Crushing will liberate most of the associated nahcolite, and screening will separate it from the shale particles. The shale will be backfilled to the top of the retort; the nahcolite is transported to the surface for processing. The result would be a retort that is filled with uniformly sized oil shale particles. With this configuration, Multi Mineral hopes to avoid the channeling and bypassing problems that may occur in TIS and MIS processing.

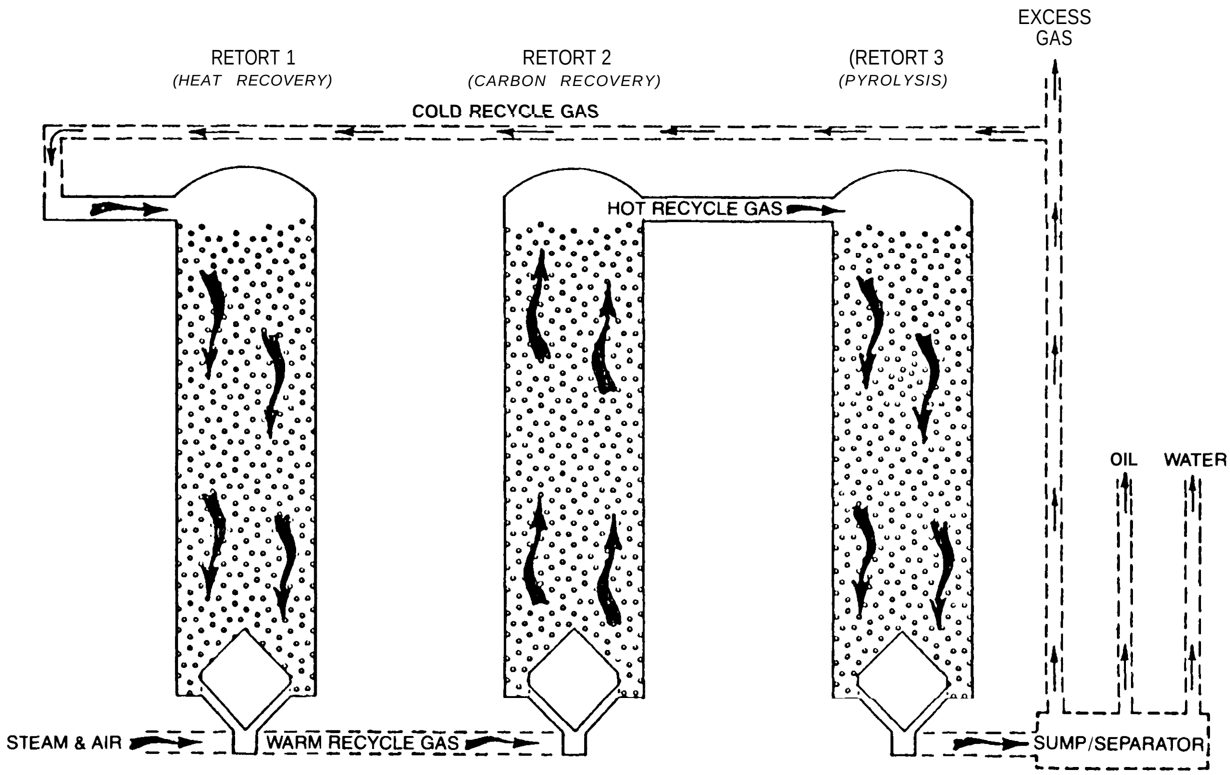
In a commercial-scale facility, the retorts would be operated in sets of three, as shown in figure 33, In retort 3, the oil shale is being pyrolyzed by injecting hot gases to produce shale oil (which is removed to the surface), residual carbon, and soda ash and aluminum oxide—the products of the thermal decomposition of dawsonite. The last three products remain in the retort rubble. In retort 2, the residual carbon is being gasified by injecting a mixture of steam and air. The heat from the gasification reaction is carried to retort 3. In retort 1, the hot gasified shale is being cooled by passage of cold recycle gas. The heat thus recovered is conveyed to retort 2. After the shale in retort 1 is cooled, the soda ash and the aluminum oxide can be leached out with water. The leachate is then pumped to the surface and processed to recover its mineral values.

Temperature control is the key to the entire operation. Oil alone could be recovered with a combustion-type method, such as Oxy's, but because of the high temperatures, the decomposition of the dawsonite would produce compounds insoluble in water. The gas-recycle heating method would avoid this problem by maintaining lower retorting temperatures. The operation also depends on the ability of explosive rubbling techniques to produce broken shale that can be fed to conventional crushing equipment. Overall, the method is very interesting because of its potential for simultaneously recovering fuel and minerals from deposits that may not be accessible with any other approach. However, too little is known about the various steps to permit a thorough evaluation at this time.

Aboveground Retorting

Hundreds of retorts have been invented in the 600-year history of oil shale development. Most were never brought to the processing stage but some were tested using laboratory-scale equipment, and a few at pilot-plant and semiworks scales. None has been tested at a scale suitable for modern commercial operations. This section summarizes the technical aspects of seven retorting systems that offer the promise of being applicable in the near future. One obsolete technology that is the basis for several of the modern systems is also discussed.

Figure 33.—A Set of Multi Mineral MIS Retorts



SOURCE B Weichman, *Saline Zone" Oil Shale Development by the Integrated In Situ Process,* Multi Mineral Corp , Houston, Tex December 1979, p 11

Although aboveground retorts differ widely with respect to many technical details and operating characteristics, they can be grouped into four classes:

- Class 1: Heat is transferred by conduction through the retort wall. The Pumpherston retorts used in Scotland, Spain, and Australia were of this class, as is the Fischer assay retort that was developed in the 1920's. It is a laboratory device for estimating potential shale oil yields. Its oil yield is the standard to which the retorting efficiencies of all other retorts are compared. Because conduction heating is very slow, no modern industrial retorts are in class 1.
- Class 2: Heat is transferred by flowing gases generated within the retort by combustion of carbonaceous retorted shale and pyrolysis gases. Retorts in this class are also called directly heated. They include the Nevada-Texas-Utah (NTU) and Paraho direct processes described below, and also USBM's gas combustion retort and the Union "A" retort. Class 2 retorts produce a spent shale low in residual carbon and low-Btu retort gas. Their thermal efficiencies are high because energy is recovered from the retorted shale. However, recovery efficiencies are relatively low—about 80 to 90 percent of Fischer assay.
- Class 3: Heat is transferred by gases that are heated outside of the retort vessel. Retorts in this class are also called indirectly heated. They include the Paraho indirect, Petrosix, Union "B," and Superior retorts discussed below, and also the Union SGR and SGR-3, the obsolete Royster design, the Soviet Kiviter, the Texaco catalytic hydrotort, and others. These retorts produce a carbonaceous

spent shale and a high-Btu gas. Thermal efficiencies are relatively low because energy is not recovered from the residual carbon, but oil recovery efficiencies are high, from 90 to over 100 percent of Fischer assay.

- Class 4: Heat is transferred by mixing hot solid particles with the oil shale. They include the TOSCO II and Lurgi-Ruhrgas retorts described below, and also the Soviet Galoter retort. Class 4 retorts achieve high oil yields (about 100 percent of Fischer assay) and produce a high-Btu gas. The spent shale may or may not contain carbon, and thermal efficiencies vary, depending on whether the spent shale is used as the heat carrier. The retorts are sometimes referred to as indirectly heated, as in class 3, because they also lack internal combustion, and produce a similar gas product.

Several other conversion methods have been developed that cannot easily be placed in these classes. These include microwave heating, bacterial degradation, gasification, and circulation of hot solids slurries. Although some of these processes have potentially valuable characteristics, they will not be discussed in this section because they have not yet been proposed for near-term commercial application.

The Nevada-Texas-Utah Retort

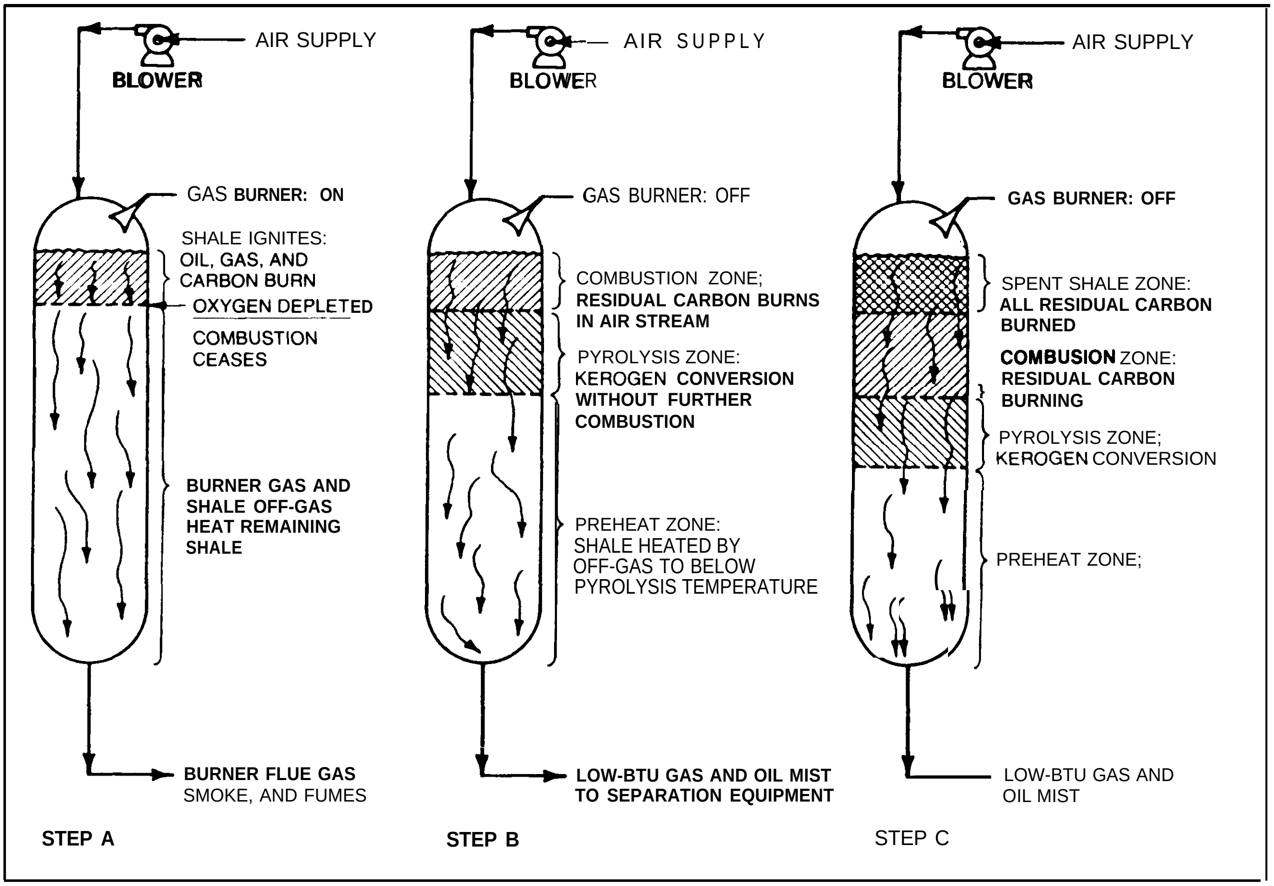
The NTU retort is a modified downdraft gas producer similar to units used in the 19th century to produce low-Btu gas from coal. It is a vertical steel cylinder, lined with refractory brick and equipped with an air supply pipe at the top and an exhaust pipe at the bottom. The top may be opened for charging a batch of shale; the bottom for discharging the spent shale after retorting. The unit was developed and tested for oil shale processing by the NTU Co. in California in 1925, and was also tested by USBM at Rifle, Colo., from 1925 to 1929. Two units with nominal capacities of 40 tons of raw shale were built and operated by USBM at Rifle between 1946 and 1951. They produced more than 12,000 bbl of shale oil. Three units that were operated in Australia during World War 11 produced nearly 500,000 bbl. As noted previously, USBM used two units to simulate in situ retorting.

The operating sequence for the NTU retort is shown in figure 34. The unit is loaded with crushed oil shale and sealed. The gas burner is lighted, and air is blown in. Once the top of the shale bed is burning (step A), the fuel gas is shut off but the air supply continues. As the air flows through the burning layer, it is heated to approximately 1,500° F (815° C). This hot gas heats the shale in the lower layers and induces the pyrolysis of the kerogen. The oil and gases produced are swept down through the cooler portions of the bed to the exhaust port (step B). The solid product from the conversion of the kerogen (residual carbon) remains on the spent shale and is consumed as the combustion zone moves down the retort, providing fuel for additional combustion and thereby heat for additional pyrolysis. When all the carbon is burned from the upper layers of the bed, the four zones shown in step C are formed. The top layer contains burned and decarbonized spent shale. The second layer is burning, releasing heat for pyrolysis in the third layer. In the bottom layer, the shale is being heated but is not yet at pyrolysis temperatures.

As time passes, the top layer expands downward and the lower three zones move uniformly down the retort. When the leading edge of the combustion zone reaches the exhaust port, oil production ceases, air injection stops, and the retort is emptied. The dumping of spent shale ash from the 40-ton NTU at Laramie is shown in figure 35. The entire cycle, from ignition to dumping, takes about 40 hours.

NTU retorts are simple to operate, and require no external fuel except for small amounts of gas to start the retorting. They can process a wide variety of shales with oil recoveries ranging from 60 to 90 percent of Fischer assay. They are unsuitable for modern commercial applications because they are batch units with high labor costs and small capacities. Over 600 150-ton retorts

Figure 34.—The Operation of an NTU Retort



SOURCE T A Sladek. Recent Trends ın 011 Shale– Part 2 Mining and Shale 011 Extract Ion Processes, *Mineral Industrial Bulletin* vol 18 No 1 January 1975 p 5

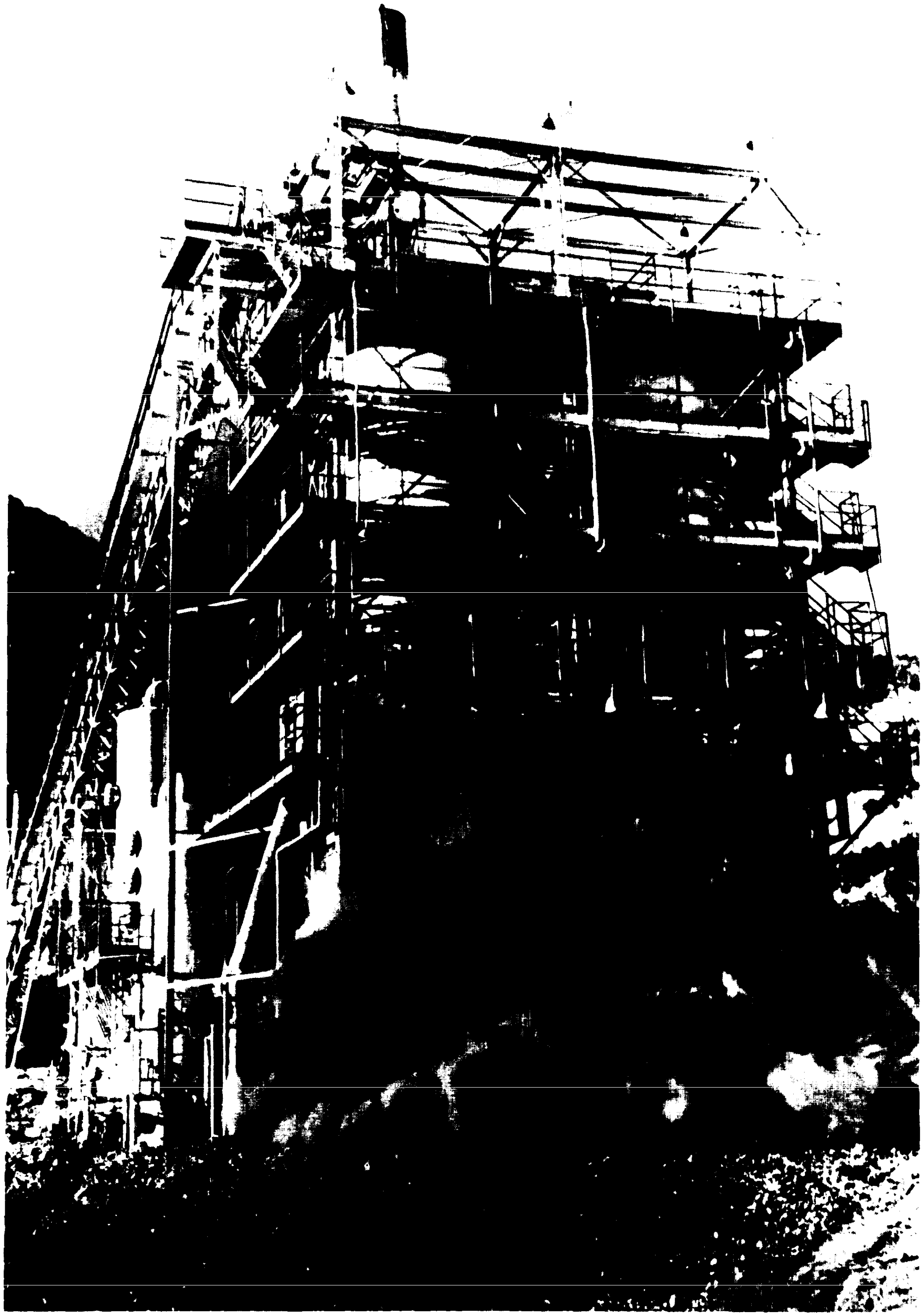
would be needed to produce 50,000 bbl/d of crude shale oil. In contrast, plants using some of the continuous technologies described below would require only about six retorts for the same production capacity.

The Paraho Direct and Indirect Retorts

An NTU retort becomes a Paraho direct retort when it is turned upside down, made continuous, and mechanically modified. The Paraho retorts are based on USBM's gas combustion retort which, in turn, evolved from the NTU retorts tested at Anvil Points in the late 1940's. The gas combustion process was tested in 6-, 10-, and 25-ton/d units by USBM between 1949 and 1955, and by a consortium of six oil companies between 1964 and 1968. The Paraho direct retort is similar in design to the gas combustion technology but it is more likely to be commercialized. It was developed by Development Engineering, Inc., (DEI) in the late 1960's, and was tested for limestone calcining in three cement kilns in South Dakota and Texas. Each kiln had a capacity of 330 ton/d and was comparable to the largest gas combustion retort tested by the six oil companies.

After verifying the solids-flow characteristics of the Paraho technology in the limestone kilns, DEI leased the Anvil Points site from the Federal Government in May 1972, and began a 5-year program to develop the technology for oil shale processing. Funding was obtained from a consortium of 17 energy companies and engineering firms. In return for a contribution of $500,000, each company

Figure 35.— Discharging Spent Shale Ash From a 40-Ton NTU Retort



SOURCE U S Department of Energy

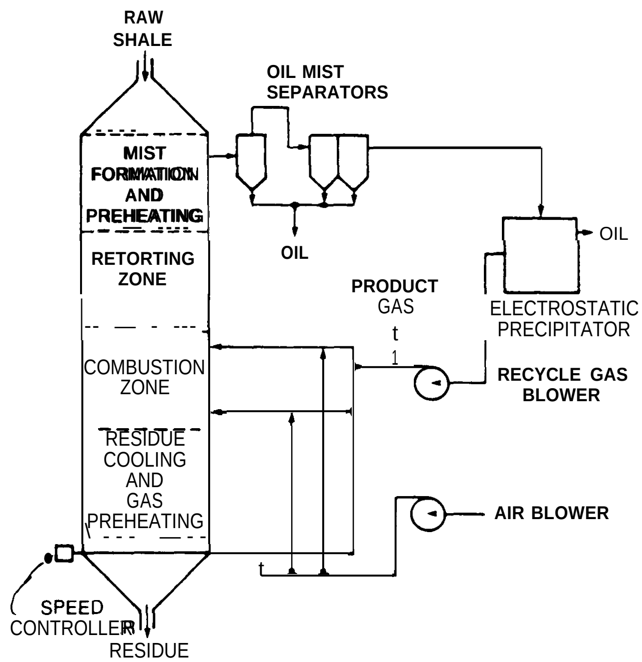
was guaranteed a favorable royalty arrangement in any subsequent commercial application of DEI's technology. The Paraho Development Corp. was formed to manage the project. * Two retorts, a pilot-scale unit 4.5 ft in diameter and 60 ft high and a semiworks unit 10.5 ft in diameter and 70 ft high, were installed and tested after August 1973. They were used to produce over 100,000 bbl of crude shale oil, some of which was used for refining and end-use experiments by DOE and the Department of Defense. Maximum throughput rates reached about 400 ton/d in the semiworks unit. Both direct and indirect heating modes were tested.

The Paraho retort is shown in figure 36, and the Anvil Points semiworks unit in figure 37. In its direct mode, the retort is very similar to the older gas combustion design. However, significant differences exist in the shale feeding mechanism, in the gas distributors, and in the discharge grate. During operation, raw shale is fed to the retort through a rotating distributor at the top. It descends as a moving bed along the vertical axis of the retort. As it moves, it is heated to pyrolysis temperatures by a rising stream of hot combustion gases. The oil and gas produced are swept up through the bed to collecting tubes and out of the retort to product separation equipment. The retorted shale retains the residual carbon. As the shale approaches the burner bars, the carbon is ignited and gives off the heat required for pyrolyzing additional raw shale. Passing beyond the burner bars, the shale is cooled in a stream of recycle gas and exits the bottom of the retort through the discharge grate. It is then moistened and sent to disposal.

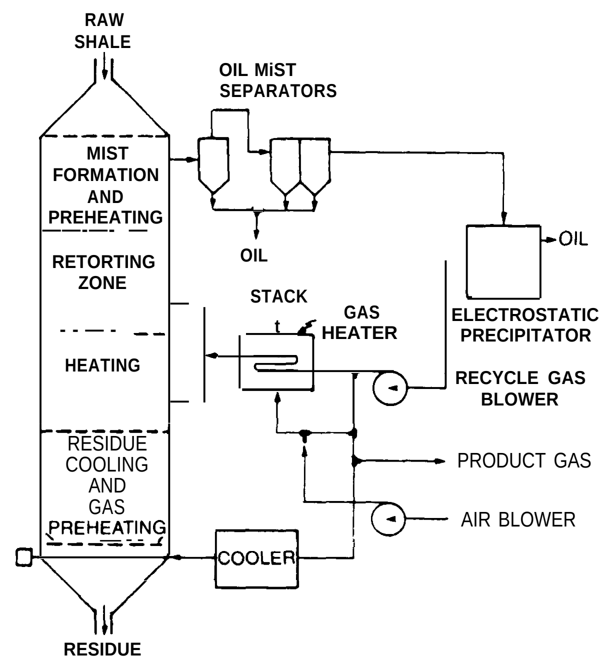
The retort may also be operated as a class 3 retort. The configuration would resemble directly heated operations except that air would not be injected and the offgas steam would be split into four parts after oil separation. One part would be the net product gas. Another would be sent through a reheating furnace and then reinfected into the middle of

*" 'Paraho" is from the Portuguese words "para homen"—for mankind.

Figure 36.—The Paraho Oil Shale Retorting System



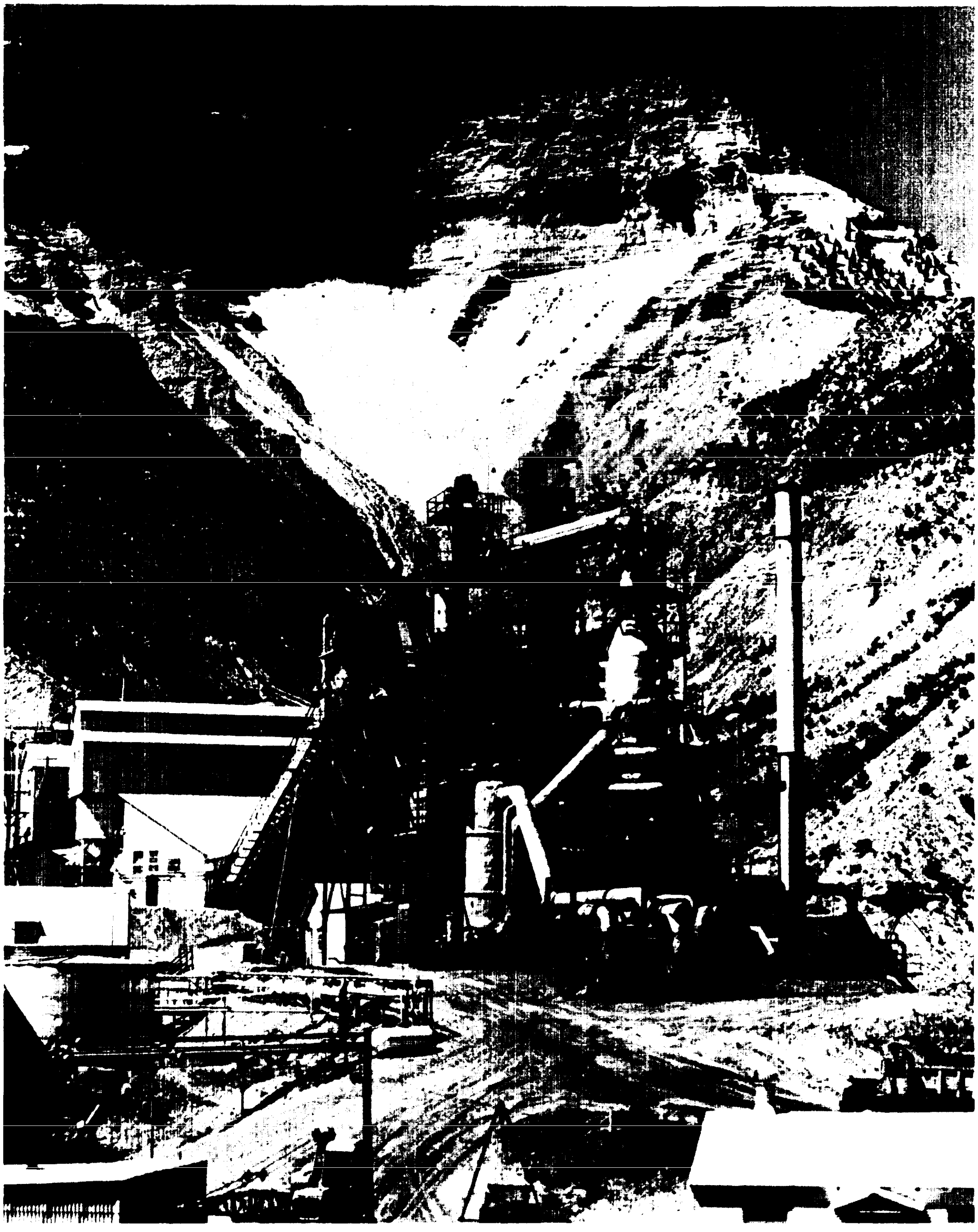
A. Direct Heating Mode



B. Indirect Heating Mode

SOURCE C C Shih, et al *Technological Overview Reports for Eight Shale Oil Recovery Processes* report prepared for the U S Environmental Protection Agency by TRW under contract No EPA-600/7-79-075 March 1979, pp 20 and 23

Figure 37.—The Paraho Semiworks Unit at Anvil Points, Colo.



SOURCE Paraho Development Corp

the retort. A third would not be reheated but would be reinfected through the bottom of the retort to cool the shale before discharge. The fourth would be used for fuel in the reheating furnace. All heat for kerogen pyrolysis would be provided by the reinfected gases, and no combustion would occur in the retort vessel itself.

To date, the Paraho retorting technology has been tested at about one-twentieth of the size that would be used in commercial plants. Paraho would like to test a full-size module producing about 7,300 bbl/d at Anvil Points, and has submitted a proposal to DOE for such a program. Both direct and indirect heating modes would be tested. Permission has been obtained from the Department of the Navy to use large quantities of shale from the Naval Oil Shale Reserves for the program. An environmental impact statement (EIS) is being prepared for the project. Paraho has responded to a DOE Program Opportunity Notice for a $15 million engineering design study of modular oil shale retorting, and would base the design of the Anvil Points module on results of the study. Outcome of the procurement has not yet been announced.

The Petrosix Indirectly Heated Retort

The Petrosix process was developed for the Brazilian Government by Petrobras, the national oil company, with the assistance of Cameron and Jones, Inc., a U.S. engineering firm, Russell Cameron, later president of Cameron Engineers, worked on the gas combustion program at Anvil Points, as did John Jones, later president of Paraho. The system is depicted in figure 38. Figure 39 is a photograph of the demonstration retort that has been built and tested in Brazil. The retort is 18 ft in diameter, and has a capacity of 2,200 ton/d of Irati oil shale. It was built in 1972, and tested intermittently until quite recently. In 1975, a U.S. patent was issued for the process, A 50,000-bbl/d plant is planned by the Brazilian Government, to be developed in a two-stage project. The first stage would involve construction of a 25,000-bbl/d facility about 5 miles from the site of the demonstration plant near the city of Sao Mateus do Sul in the State of Parana. In the second stage, the full commercial plant would be built on the same site, to include 20 Petrosix units, each about 33 ft in diameter. Brazil is not committed to either stage, but if financing is obtained in 1980, the first stage could be completed by 1983 and the second by 1985. In addition to the shale oil, the plant would also produce sulfur and liquefied petroleum gases. Preliminary plans are also being prepared for two additional commercial-scale plants south of the present demonstration plant in the State of Rio Grande do Sul.

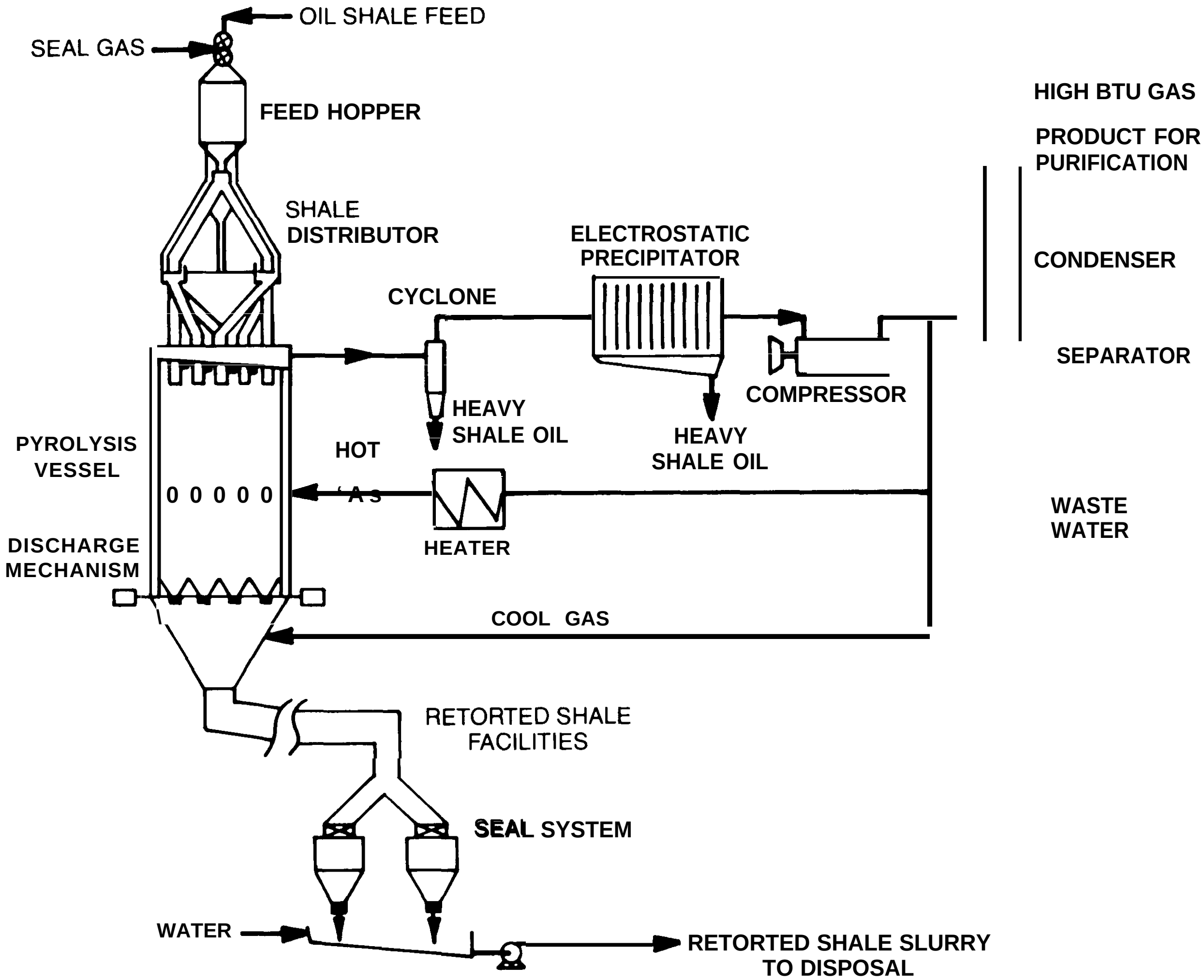
Except for mechanical differences, the Petrosix retort is very similar to the Paraho indirect retort described above. This similarity is not surprising in view of the shared engineering heritage of the two systems. One operational difference is that the Petrosix spent shale is discharged into a water bath and pumped in a slurry to a disposal pond. Paraho shale is discharged dry, with only a little water added prior to disposal.

Little information has been released about the demonstration program. Oil characteristics have been described, but these have little relevance to the processing of Green River shale. It can be predicted that the retort should have high oil recovery efficiencies and produce a retort gas with high heating value. The spent shale would be carbonaceous. In the demonstration plant, recovery of energy from the spent shale was not possible because of the slurry disposal method. In any commercial plant, it is possible that the shale would be burned in a separate unit to produce heat for pyrolysis.

The Union “B’ Indirectly Heated Retort

The Union “B” retort is a class 3 retort that evolved from the Union “A,” a class 2 retort, by the Union Oil Co. of California. Two other systems, the SGR and SGR-3, have also been proposed by Union, Union describes them all as continuous, underfeed, countercurrent retorts. The “B” has not been field tested, but the “A” was tested in Colorado in the 1950’s

Figure 38.—The Petrosix Oil Shale Retorting System



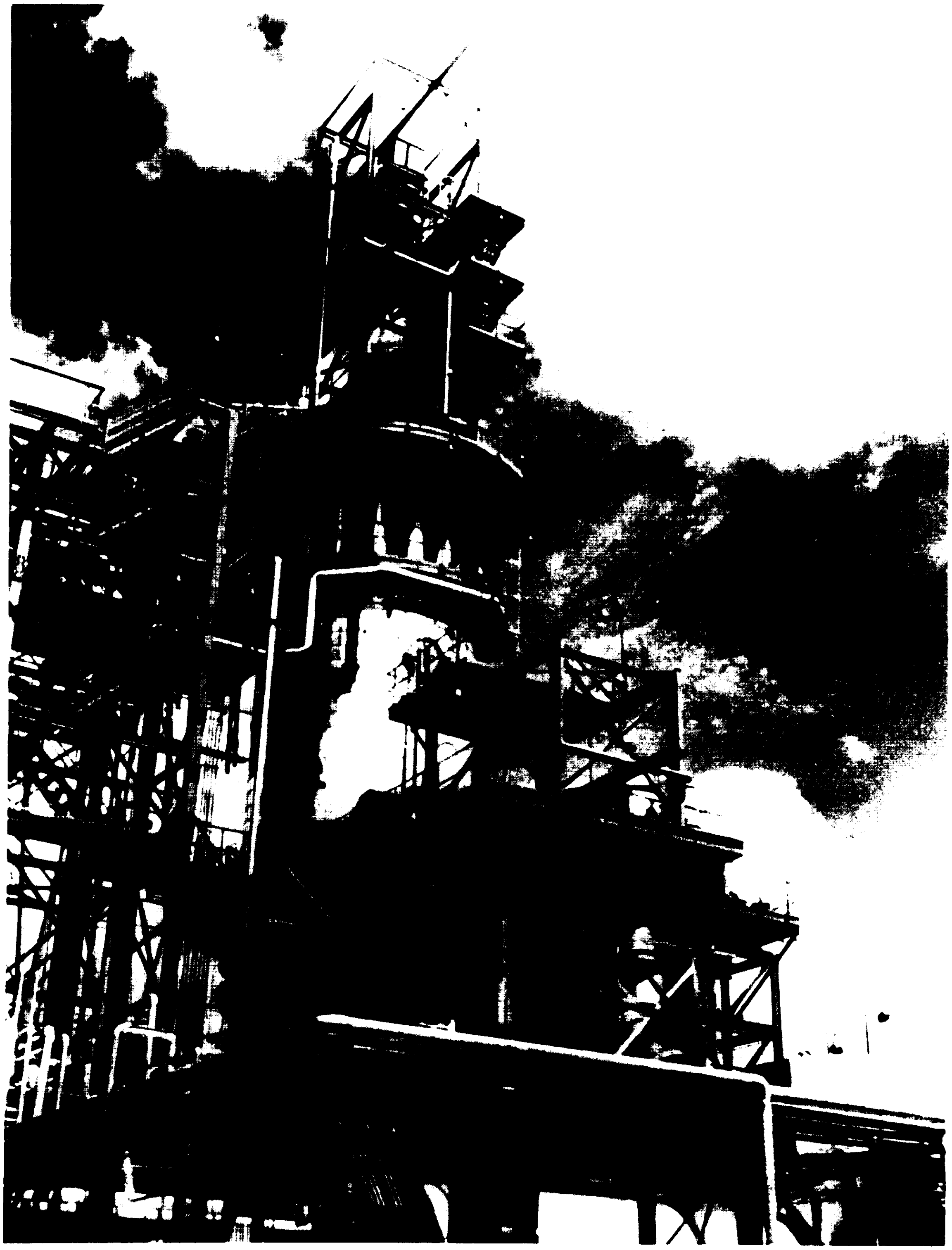
SOURCE *Oil Shale Refer//ng Technology,* prepared for OTA by Cameron Engineers, Inc , 1978

at up to 1,200 ton/d. Figure 40 is a sketch of the Union "B" design. It incorporates most of the design features of the "A."

During operation, shale is fed through the bottom of the inverted-cone vessel. The retorting process thereafter resembles that of a continuous NTU retort. Hot gases enter the top of the retort and pass down through the rising bed, causing kerogen pyrolysis. Shale oil and gas flow down through the bed. The oil accumulates in a pool at the bottom, which seals the retort and acts as a settling basin for entrained shale fines. Oil and gas are withdrawn from the top of the pool. The gases are split into three streams. One is reheated and reinfected to induce additional kerogen pyrolysis; one is used as fuel in the reheating furnace; and one is the net product. The shale is discharged from the top of the retort and falls into a water bath in the retorted shale cooler. From there it is conveyed to disposal.

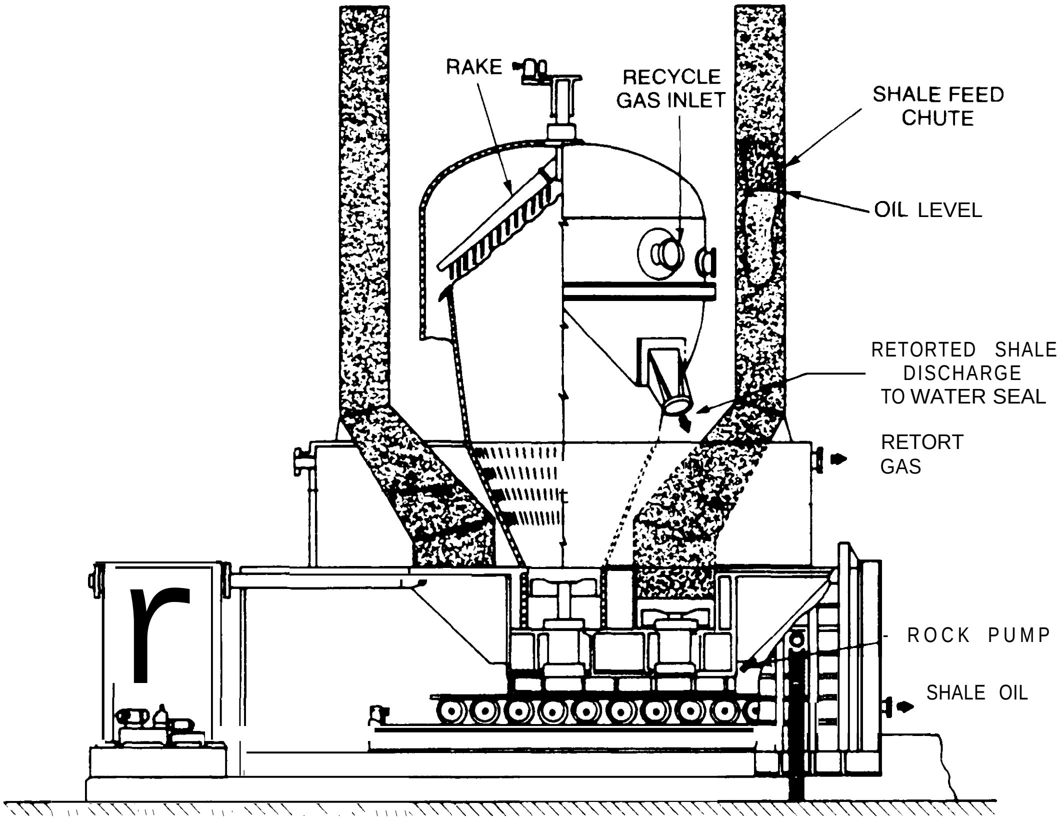
The key to all of Union's retorting systems is the solids pump that is used to move the oil shale through the retort. In the "B" design, the solids pump is mounted on a movable carriage and is immersed in the shale oil pool.

Figure 39.—The Petrosix Demonstration Plant, Sao Mateus do Sul, Brazil

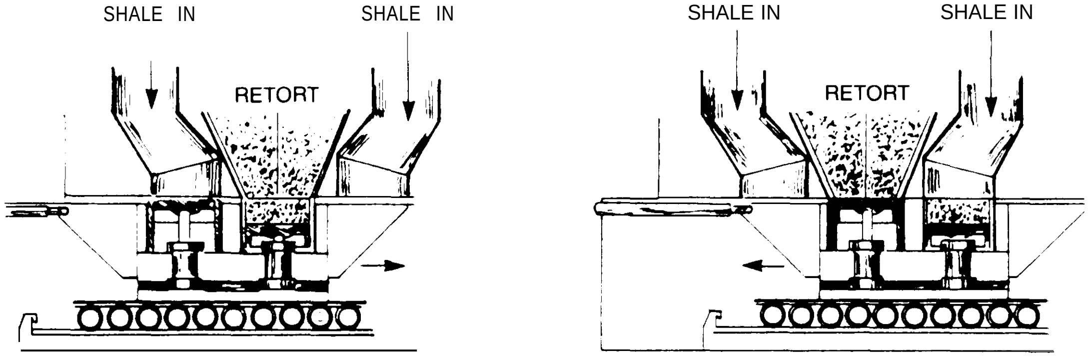


SOURCE Cameron Engineers, Inc

Figure 40.—The Union Oil “B” Retorting Process



A. The Retorting System



B. Rock Pump Detail

SOURCE *Oil Shale Retorting Technology,* prepared for OTA by Cameron Engineers Inc .1978

The pump consists of two hydraulic assemblies that act in sequence. (See figure 40.) While the cylinder of one assembly is filling with oil shale, the other is charging a batch of shale into the bottom of the retort. When this operation is completed, the carriage moves horizontally on rails until the full cylinder is under the retort entrance. A piston then moves the oil shale in this cylinder upwards into the retort, while the other fills with fresh shale from the other feed chute. The carriage then returns to its original position and the process is repeated.

The "B" achieves high oil yields, and the retort gas has a high heating value, although much of it is consumed in the reheating furnace. The mechanical nature of the rock pump is troublesome because its moving parts would be subject to wear during operation. However, the pump is immersed in the shale oil pool, which should provide adequate lubrication. Union appears to be satisfied with its reliability.

In 1976, Union announced plans to build a demonstration plant on its private land in Colorado. The "B" retort was to be used to produce 7,000 bbl/d of shale oil from 10,000 ton/d of oil shale. Later, the announced capacity was increased to 9,000 bbl/d. The demonstration plant, called the Long Ridge project, would be the first step towards a 75,000-bbl/d commercial-scale plant. Air quality permits have been obtained for the modular plant, which could be completed before 1985. Construction has not begun because Union is awaiting financial incentives from the Federal Government.

The Superior Oil Indirectly Heated Retort

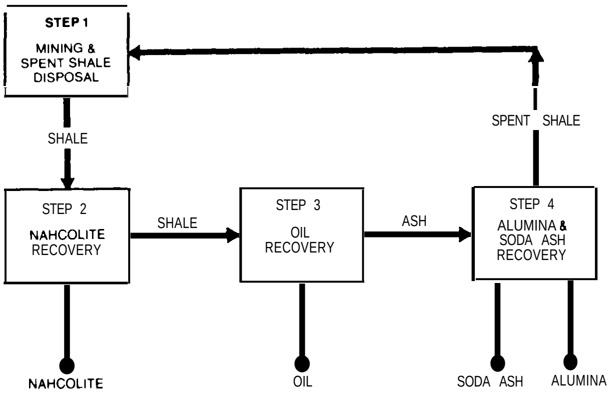
The Superior retort is unique among the aboveground retorts discussed in this section because it is designed for recovery of sodium-bearing minerals in addition to shale oil. As discussed in chapter 4, the minerals nahcolite and dawsonite occur in substantial quantities in portions of the Piceance basin. They are potential sources of sodium bicarbonate, soda ash, and aluminum.

A block diagram for the Superior approach is shown in figure 41. In step 1, the mined oil shale is crushed to pieces smaller than 8 inches and screened. About 85 to 90 percent of the nahcolite in the shale is in the form of distinct, highly friable nodular inclusions that become a fine powder during the crushing operation. This is screened from the coarser shale in step 2. The shale is then further crushed to smaller than 3 inches and is fed in step 3 to a doughnut-shaped traveling-grate retort, which includes sequential stages for heating, retorting, burning, cooling, and discharging the oil shale feed. The retort is sketched in figure 42. In the heating section, oil is recovered by passing hot gases through the moving bed. In the carbon recovery section, process heat is recovered by burning the residual carbon. In the cooling section, inert gases are blown through the bed of spent shale, cooling the shale and heating the gases for use in the heating section. After discharge, the cooled spent shale is sent to other units in which alumina is recovered from calcined dawsonite and soda ash from calcined nahcolite. The alumina is shipped to offsite aluminum refineries; the soda ash to glass plants; and the nahcolite to refineries and powerplants for use as a stack-gas scrubbing agent.

Superior chose the traveling-grate retort because it allows close temperature control, important to maintaining dawsonite's solubility during the burning stage. Similar, simpler devices have been used to sinter iron ore for steelmaking and to roast lead and zinc sulfides. Superior's process has been tested for oil shale in pilot plants in Denver and Cleveland. A commercial-scale plant would consume 20,000 ton/d of oil shale to produce 10,000 to 15,000 bbl/d of shale oil, 3,500 to 5,000 ton/d of nahcolite, 500 to 800 ton/d of alumina, and 1,200 to 1,600 ton/d of soda ash.

In the early 1970's, Superior proposed to build a commercial-size demonstration plant on its 7,000-acre tract in the northern Piceance Basin. The deposit was to be developed by deep room-and-pillar mining on several levels. The single retort was to produce

Figure 41 .— Block Diagram for the Superior Multi Mineral Concept



SOURCE 01/ *Shale Retorting Technology,* prepared for OTA by Cameron Engineers, Inc .1978

11,500 bbl/d of shale oil, plus the byproducts described above. Although the tract's resources are extensive, its L-shaped configuration does not favor large-scale development. Superior therefore proposed to exchange portions of the tract for adjacent land controlled by the Bureau of Land Management (BLM). Approval was delayed by BLM review and by preparation of an EIS, a draft of which was recently released. In February 1980, BLM denied the exchange because the two tracts involved were not considered to have equivalent value. The decision is open to review.

The TOSCO H Indirectly Heated Retort

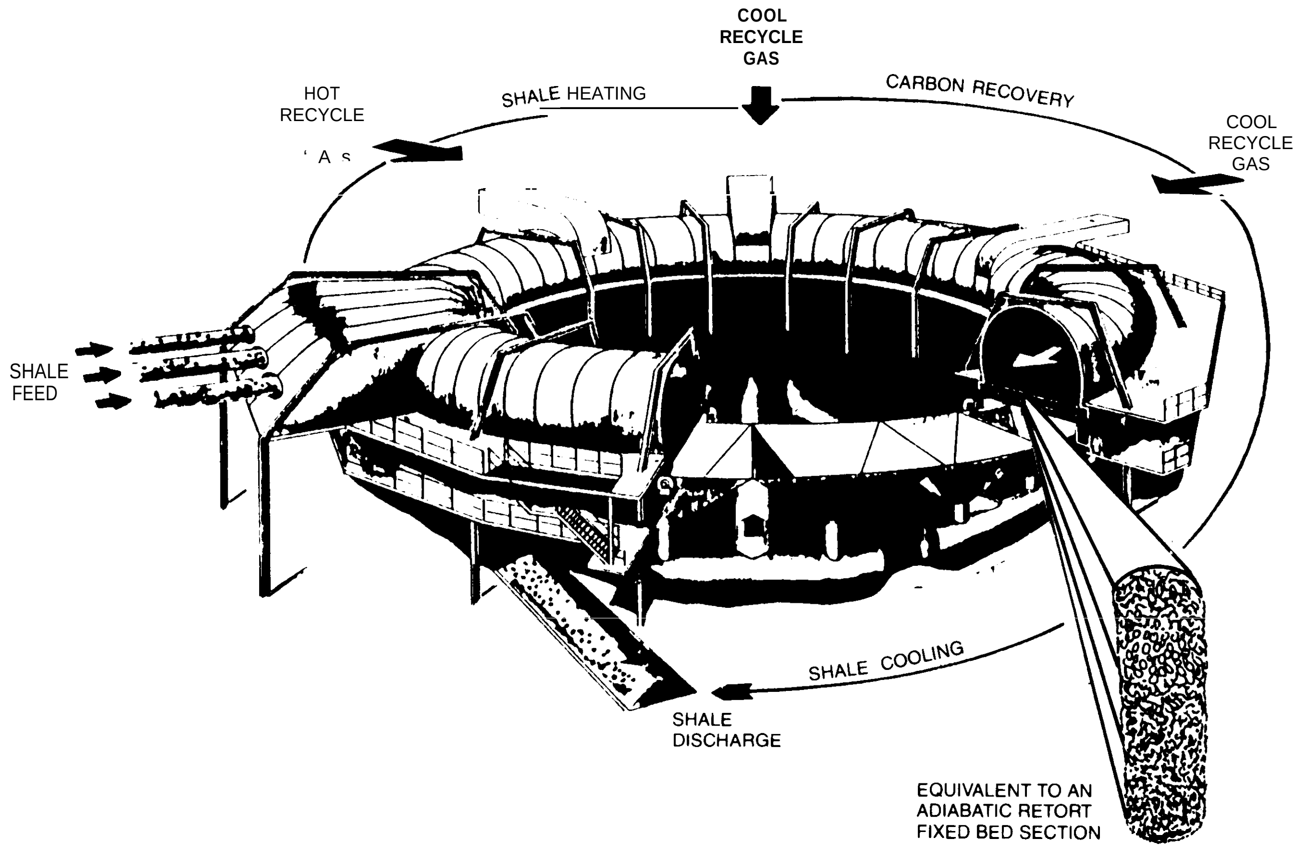
The TOSCO II is a class 4 retort in which hot ceramic balls carry heat to finely crushed oil shale, It is a refinement of the Aspeco process developed by a Swedish inventor. Patent rights were purchased by The Oil Shale Corp. (later Tosco) in 1952. Early development work was performed by the Denver Research Institute, including testing of a 24-ton/d pilot plant. In 1964 Tosco, Standard Oil Co. of Ohio (SOHIO), and Cleveland Cliffs Iron Co. formed Colony Development, a joint venture company, to commercialize the TOSCO II technology. Between 1965 and 1967, the group operated a 1,000-ton/d semiworks plant on its land near Grand Valley, Colo., next to the site of Union's semiworks operations. In 1968, Colony prepared a preliminary engineering design and cost estimate for a commercial-scale plant that would contain six TOSCO II retorts, and convert 66,000 ton/d of oil shale into about 46,000 bbl/d of shale oil. In 1969, ARCO joined Colony, and a second semiworks program began to test scaleup procedures and to evaluate environmental controls. The program continued until April 1972. Between 1965 and 1972 the semiworks plant converted 220,000 tons of oil shale into 180,000 bbl of shale oil.

In 1974, the 1968 cost estimate, which had been updated in 1971, was further revised to incorporate operating data from the latter part of the semiworks program and to account for additional pollution controls. The resulting cost estimate was about three times as large as the previous estimate. This cost escalation raised doubts about commercial feasibility, and the project was postponed indefinitely. SOHIO and Cleveland Cliffs subsequently withdrew from the Colony group.

Early in 1974, Tosco, ARCO, Ashland, and Shell purchased a lease for tract C-b from the Federal Government. Initial development plans for the tract involved a plant similar to that proposed for Colony's private tract. These plans were also affected by the cost escalations, and in 1976 suspension of operations on tract C-b was granted by the Government. In 1977 Tosco and ARCO withdrew from the tract. Shell withdrew in 1977. Ashland, the remaining partner, teamed with Oxy to develop the tract using MIS techniques.

Colony's semiworks retort, which is about one-tenth of commercial scale, is shown in figure 43. The TOSCO II retorting system is sketched in figure 44. Raw shale is crushed smaller than one-half inch and enters the system through pneumatic lift pipes in which the shale is elevated by hot gas streams and preheated to about 500" F (260° C). The shale then enters the retort, a heated ball mill, and contacts a separate stream of hot ceramic balls. As the shale and balls mix, the shale is heated to about 950° F (510° C), causing retorting to take place. Oil vapors and gases are withdrawn. The oil is condensed in a fraction-

Figure 42.—The Superior Oil Shale Retort



SOURCE. *Oil Shale Retorting Technology*, prepared for OTA by Cameron Engineers, Inc , 1978 (after Arthur G McKee & Co)

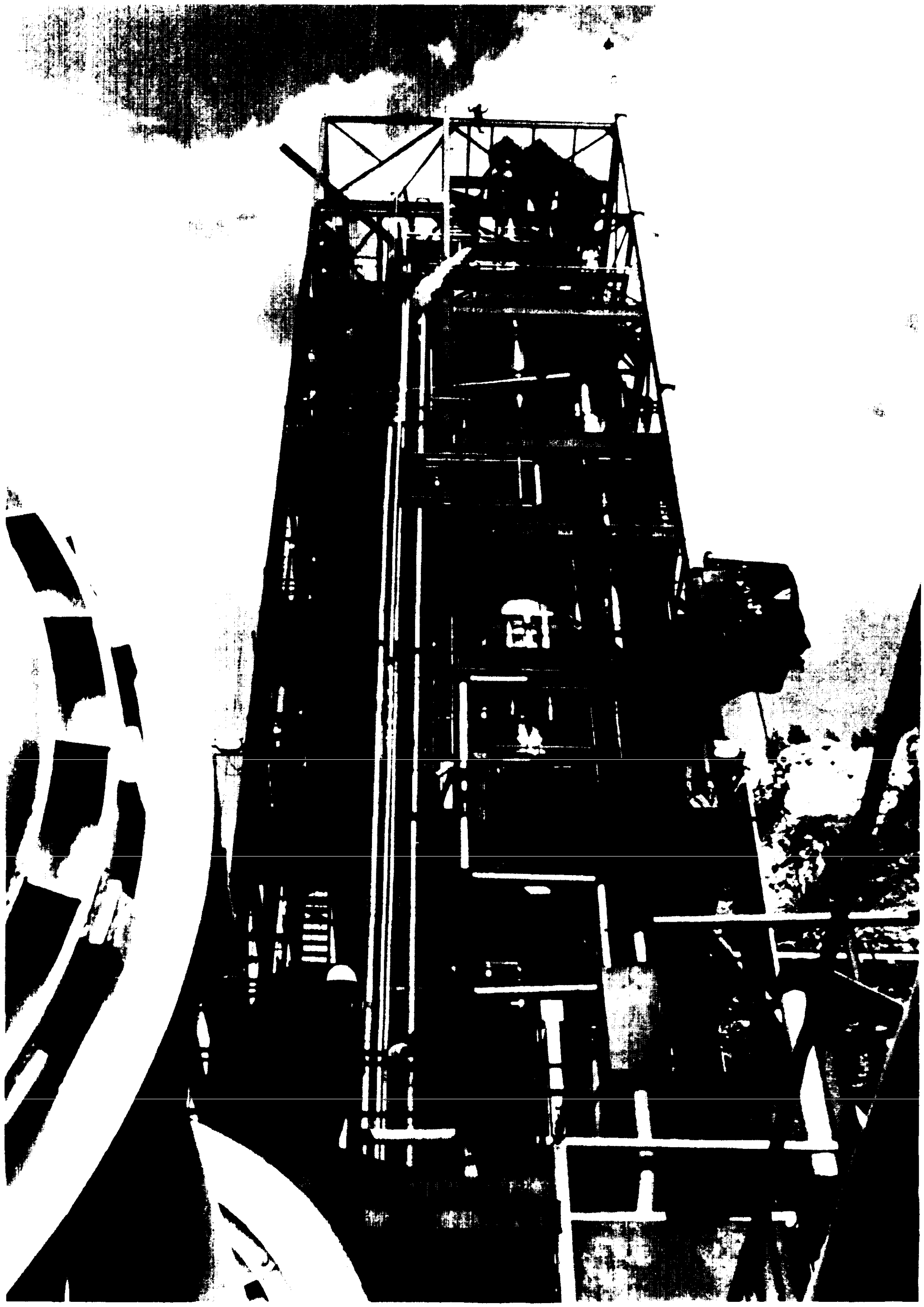
ator. Some of the gases are burned in a heater to reheat the ceramic balls to about 1,2000 F (650° C). At the retort exit, the retorted shale and the cooled ceramic balls pass over a trommel, a perforated rotating separation drum. The shale, which has been thoroughly crushed during retorting, falls through holes in the trommel. It is cooled and sent to disposal. The larger balls pass over the trommel and are sent to the ball heater.

Oil yields exceeding 100 percent of Fischer assay have been reported for the TOSCO II technology. However, overall thermal efficiencies are low because energy is not recovered from spent shale carbon, and much of the product gas is consumed in the ball heater. Tosco has patented processes to burn the retorted shale as fuel for the ball heater, thus increasing energy recovery, and freeing the valuable retort gases for other uses.

The retort's chief disadvantages are its mechanical complexity and large number of moving parts. The ceramic balls are consumed over time. The need for a fine feed size results in crushing costs that are higher than those of systems that can handle coarser feeds. On the other hand, all crushing operations produce some fine shale that could be screened from the feed to coarse-shale retorts and converted in auxiliary TOSCO II units. Disposal of TOSCO II spent shale presents some problems because it is very finely divided and contains carbon.

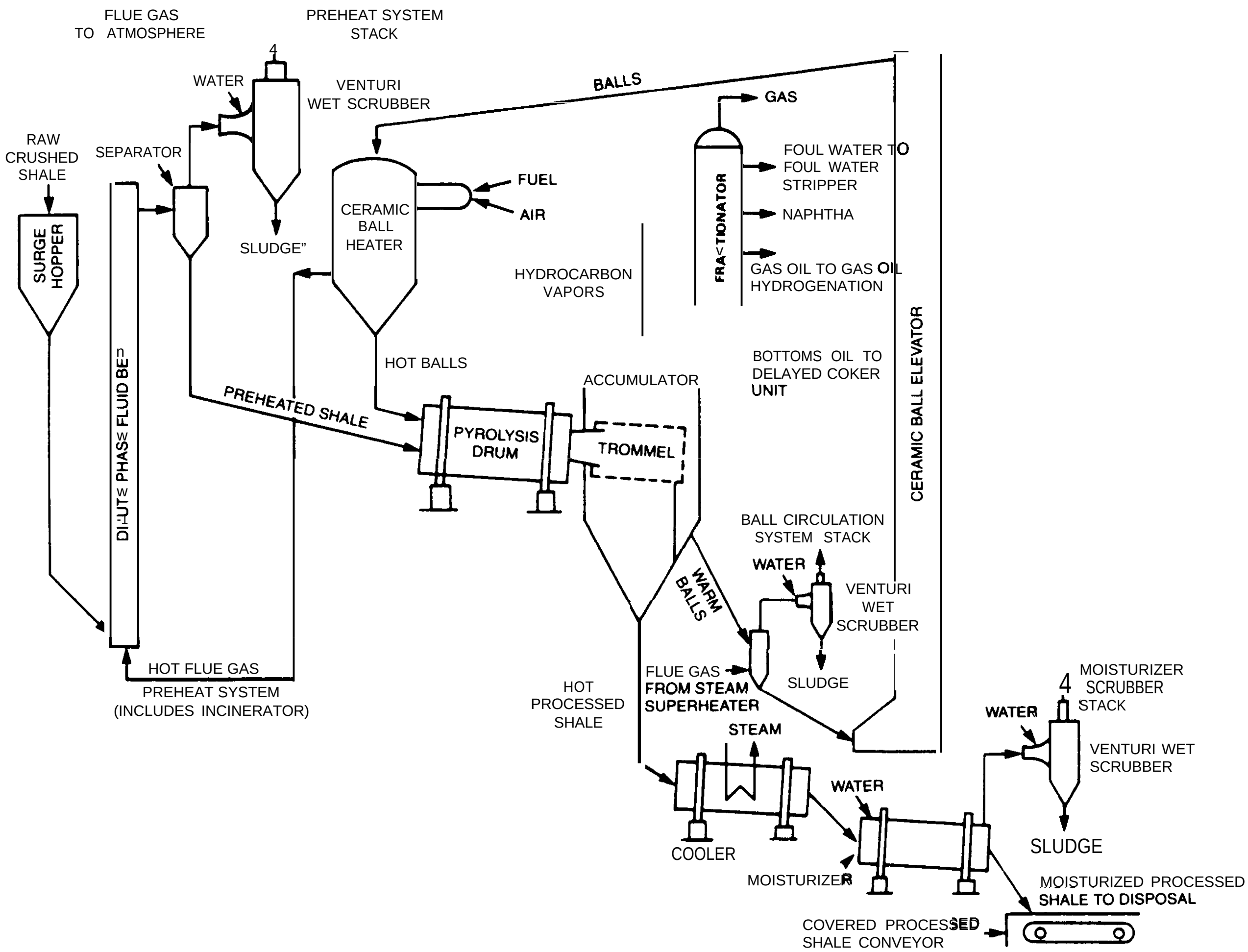
At present Tosco is participating in two projects that are committed to its proprietary

Figure 43. —The Colony Semiworks Test Facility Near Grand Valley, Colo.



SOURCE Colony Development Corp

Figure 44.—The TOSCO II Oil Shale Retorting System



SOURCE *Oil Shale Retorting Technology*, prepared for OTA by Cameron Engineers, Inc , 1978.

retorting technology. The Colony project has been mentioned previously. The other venture, the Sand Wash project, is being developed on 14,000 acres of land in the Uinta Basin leased from the State of Utah. Unlike the Colony project, which has been suspended pending resolution of economic uncertainties, Sand Wash is proceeding towards commercialization in compliance with the due diligence requirements of the State leases. A plant similar to the proposed Colony facility is contemplated, but no schedule has been announced for its construction. At present, work consists of monitoring the environment, and preparing to sink a mine shaft.

The Lurgi-Ruhrgas Indirectly Heated Retort

The Lurgi-Ruhrgas retorting system uses a class 4 retort in which hot retorted shale carries pyrolysis heat to oil shale. The process was developed jointly by Ruhrgas A. G. and Lurgi Gesellschaft fur Warmetechnik m. b. H., two West German firms that have been involved in synfuels production for decades. The process was developed in the 1950's for low-temperature coal carbonization. A 20-ton/d pilot plant was built in West Germany, to test a variety of coals, oil shales, and petroleum oils. European shales were tested in the late 1960's, and Colorado oil shale in

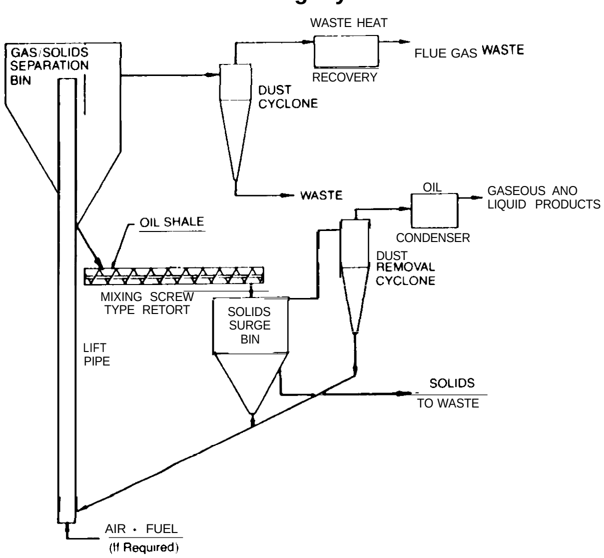
1972. The plant has since been scrapped but smaller retorts are available.

Coal processing plants using the Lurgi-Ruhrgas technique have been built in Japan, West Germany, England, and Argentina. There are also two Yugoslavian plants, each built in 1963, with a capacity of 850 ton/d of brown coal. The Japanese plant is also of commercial size, and uses the process to crack petroleum oils to olefins. No large-scale oil shale plants have yet been built.

The retorting system is shown in figure 45. Finely crushed oil shale is mixed with hot retorted oil shale in a mechanical mixer that resembles a conventional screw conveyor. Retorting takes place in the mixer, and gas and shale oil vapors are withdrawn. Dust is removed from these products in a cyclone separator and oil is separated from the gas by condensation. Retorted shale leaves the mixer and is sent to a lift pipe where it is heated to about 1, 100° F (5950 C) in a burning mixture of fuel gas and air. The hot retorted shale is then sent back to the mixer, and the process is repeated.

High oil yields have been reported for the retort, and the product gas is of high quality.

Figure 45.—The Lurgi-Ruhrgas Oil Shale Retorting System



SOURCE *Oil Shale Retorting Technology,* prepared for OTA by Cameron Engineers Inc 1978

Except for the mixer, the process is mechanically simple and has few moving parts. It should be capable of processing most oil shales, if they are crushed to a fine size. The two major problems with the system appear to be accumulation of dust in the transfer lines and dust entrainment in the oil. Dusty crude oil is not a severe problem because the dust is concentrated in the low-value residual product when the oil is subsequently refined. As with the TOSCO II process, requirements for a fine feed material will result in high crushing costs. These costs would be partially offset by the ability to process the fine fraction from any crushing process, including those used to prepare shale for coarse-shale retorts.

In 1972, Lurgi proposed to develop its retorting technologies with Colorado oil shale. The program was not funded, but Lurgi's interest in commercializing the technique has continued. In recent years Lurgi has been working with Dravo Corp. to interest U.S. firms in using the technology. At present, at least one company—Rio Blanco—has obtained a license to investigate the use of Lurgi-Ruhrgas retorts. Present plans call for constructing a modular Lurgi-Ruhrgas retort that will be close to commercial size (2,200 ton/d). It will be used to retort the shale that will be mined during the preparation of MIS retorts on tract C-a.

Advantages and Disadvantages of the Processing Options

The greatest advantage of TIS processing is that mining is not required, and spent shale is not produced on the surface. The technical, economic, and environmental problems associated with above-ground waste disposal are thereby avoided. MIS does involve mining and aboveground waste disposal, although to a lesser extent than with AGR. However, the MIS waste is either overburden or raw oil shale. Both materials are found naturally exposed on the surfaces of deeper canyons in the oil shale basins. Although raw shale has low concentrations of the soluble salts, it does contain soluble organic materials that could be leached from the disposal piles. It should be noted that the presence of spent shale underground has the potential to cause environmental problems because soluble salts could be leached by ground water. Therefore, environmental controls will also be needed for TIS and MIS methods.

Surface Facilities

TIS has another theoretical advantage in that the required surface facilities are minimal, consisting only of wells, pumps, gas cleaning and product recovery systems, oil storage, and a few other peripheral units. These facilities would probably resemble those for processing of crude oil and natural gas. MIS requires more facilities to support the mine and the waste disposal program. Aboveground processing, which uses the largest number of facilities, causes the most surface disruption.

Oil Recovery

The advantage of AGR is that the conditions within the retorts can be controlled to achieve very high oil recoveries—approaching or even in some cases exceeding the yields achieved with Fischer assay retorts. Retorting efficiencies are usually lower for MIS processing and much lower for TIS because of the difficulty in obtaining a uniform distribution of broken shale and void volume, which in turn, makes it difficult to maintain uniform burn fronts and leads to channeling and bypassing of the heat-carrier gases. The few estimates of the retorting efficiencies of TIS operations that have been published have not been encouraging. (USBM achieved recoveries of 2 to 4 percent in its field tests.) MIS retorting has not exceeded 60-percent recovery of the potential oil in the shale within the retorts. It is expected that yields from MIS retorts could be increased by injecting steam or hydrocarbon gases (as is done in Equity's TIS process), but it is doubtful that recoveries can reach those of carefully controlled above- -ground retorts. On the other hand, the present low efficiencies of MIS operations are partially compensated for by their ability to convert very large sections of an oil shale deposit, by their ability to process shale of a lower grade than would be practical for AGR, and by their lower cost of preparing the shale for retorting.

It is difficult to compare overall recoveries from MIS and AGR without making numerous assumptions about the operating characteristics of both systems. To make a rough comparison, it could be assumed that AGR (with room-and-pillar mining) and MIS were to be applied to two 30()-f t-thick deposits with identical physical characteristics. The net recoveries from several development options are summarized in table 18. The highest recovery (100 percent) is for full-subsidence mining in conjunction with AGR processing. It should be noted that full-subsidence mining, for either MIS processing or AGR, would result in extensive surface disturbance and could increase risks to the miners. Subsidence mining has never been tested in oil shale. Its potential for surface disturbance could be reduced by backfilling the mined-out areas with spent shale from surface processing, The retorted shale in burned-out MIS retorts would also reduce the severity of subsidence.

The three generic approaches to oil shale processing also have various other advantages and disadvantages with respect to water needs, environmental effects, financial requirements, and social and economic impacts. These aspects are discussed in the respective chapters of this report.

Table 18.–Overall Shale Oil Recoveries for Several Processing Options

Case	First-stage retorting technology	First-stage mining method	Second-stage processing	Overall shale oil recovery[a]
1	AGR	Conventional room-and-pillar mining on three levels 60-ft rooms, 60-ft barrier and sill pillars.	None	36%
2	MIS	Conventional MIS mining. 40% of shale left behind in barrier pillars 20% of the disturbed shale is removed to the surface to provide void volume in the retorts	None	29%
3	MIS	As in case 2	AGR processing of the mined shale	41%,
4	AGR	As in case 1	Barrier and sill pillars collapsed and retorted by MIS	74%
5	MIS	Full subsidence b	None	48%
6	MIS	Full subsidence b	AGR processing of the mined shale	68%
7	AGR	Full subsidence b	None.	100%

[a] Assuming AGR recovers 100 percent of the potential 011 in the shale retorted MIS assumed to recover 60 percent of the potential 011
[b] Entire deposit is mined

SOURCE Off Ice of Technology Assessment

Properties of Crude Shale Oil

Crude shale oil (also called raw shale oil, retort oil, or simply shale oil) is the liquid oil product recovered directly from the offgas stream of an oil shale retort. Synthetic crude oil (syncrude) results when crude shale oil is hydrogenated. In general, crude shale oil resembles conventional petroleum in that it is composed primarily of long-chain hydrocarbon molecules with boiling points that span roughly the same range as those of typical petroleum crudes. The three principal differences between crude shale oil and conventional crude are a higher olefin content (because of the high temperatures used in oil shale pyrolysis), higher concentrations of oxygen and nitrogen (derived from oil shale kerogen), and, in many cases, higher pour point and viscosity,

The physical and chemical properties of crude shale oil are affected by the conditions under which the oil was produced. Some retorting processes subject it to relatively high temperatures, which may cause thermal cracking and thus produce an oil with a lower average molecular weight. In other processes (such as directly heated retorting) some of the lighter components of the oil are incinerated during retorting. The result is a heavier final product. Others may produce lighter products because of refluxing (cyclic vaporization and condensation] of the oil within the retort. One of the most important factors is the condensing temperature within the retorting system—the temperature at which the oil product is separated from the retort gases, The lower this temperature, the higher the concentration of low molecular weight compounds in the product oil,

The properties of crude shale oil from several aboveground and MIS retorting processes are listed in table 19.[24] It is important to note that the oils that are characterized were produced in small-scale test runs under conditions that may not be representative of those that will be encountered in other areas, and with larger processing systems. The oils from commercial-scale facilities in other parts of the oil shale region may have properties that are quite different,

The properties of the oil produced by different AGR processes vary widely, but the differences between these oils and the in situ oils are much more significant. In situ oils are generally much lighter, as indicated by their higher yields of material with relatively low boiling points, and would produce more low-boiling product (such as gasoline) and less high-boiling product (such as residual oil). In general, the low yields of residuum make shale oils attractive as refinery feedstocks in comparison with many of the heavy conven-

Table 19.—Properties of Crude Shale Oil From Various Retorting Processes

Retort	Fischer assay	Aboveground processes: N U			Gas combustion		OSCO		Union Oil A'	Union Oil B'	Paraho direct		In situ processes: Occidental oil shale			USBM	
[illegible] weight percent																	
Carbon, weight %	84 59	—	84.61	84.58	83.92	—	85.1	—	84.0	84.80	84.90	—	84.86	—	—	84.60	—
Hydrogen, weight %	11.53	—	11.40	11.76	11.36	—	11.6	—	12.0	11.61	11.50	—	11.80	—	—	12.08	—
Oxygen, weight %	—	—	1.10	—	1.67	—	0.8	—	0.9	0.90	1.40	—	1.13	—	—	1.18	—
Nitrogen, weight %	1.96	2.20	2.10	1.77	2.14	2.12	1.9	1.85	2.0	1.74	2.19	2.00	1.50	—	—	1.55	1.41
Sulfur, weight %	0.61	0.92	0.79	0.76	0.70	0.68	0.9	0.67	0.9	0.81	0.61	0.71	0.71	—	—	0.59	0.72
Carbon/hydrogen ratio	7.34	—	7.42	7.19	7.39	—	7.34	—	7.0	7.30	7.38	—	7.19	—	—	7.00	—
Gravity, °API	—	19.4	20.3	25.2	9.8	2`	21.2	—	18.6	22.7	19.3	—	25	—	24.3	28.4	28.4
Specific gravity	0.92						0.93	0.93	—	0.81	0.94	0.94	0.90	—	—	0.89	—
Pour point, ° F	80	80	90	70	84	85	80	—	80	60	85	—	40	—	65	40	40
Arsenic, p/m[a]							—	—	—	—	19.6	—	—	—	—	—	—
Nickel, p/m	—	—	—	—	6.4	—	6	—	6	—	2.5	—	—	—	—	—	—
Iron, p/m	—	—	—	—	108	—	00	—	55	—	71.2	—	—	—	—	—	—
Vanadium, p/m	—	—	—	—	6.	—	3	—	1.5	—	0.37	—	—	—	—	—	—
Distillation, volume %																	
5 @ ° F	—				378	445	200	—	390	—	—	—	—	400	405	—	61
10 @ ° F	326	493	—	—	438	497	275	360	465	400	520	530	440	460	—	382	620
20 @ ° F	430	560	—	—	529	589	410	480	565	—	600	610	—	520	—	405	648
30 @ ° F	518				607	668	500	600	640	—	680	680	600	570	600	—	666
40 @ ° F	—				678	742	620	690	710	—	750	745	—	620	—	343[b]	681
50 @ ° F	655	670	—	—	743	808	700	780	775	731	810	805	700	680	—	375[b]	699
60 @ ° F	685	692	—	—	805	865	775	860	830	—	840	860	—	715	—	415[b]	732
70 @ ° F	705	—	—	—	865	918	850	935	980	—	—	910	770	765	—	464[b]	768
80 @ ° F	—	—	—	—	935	984	920	1,020	—	960	—	980	—	82	830	528[b]	809
90 @ ° F	—	—	—	—	1,030	1,065	—	—	—	—	—	1,040	920	91	—	—	867
95 @ ° F	—	—	—	—	1,099	—	—	—	—	—	—	—	—	05	1,000	—	914

[a] Parts per million. [b] Vacuum distillation at 40 mm of mercury. All other results are from atmospheric distillation.

SOURCE: Office of Technology Assessment.

tional crudes that are currently being processed in the United States. For example, in situ oil from Oxy's MIS process contains 1 to 4 percent of material with a boiling range of over 1,000° F (5350 C), compared with 20 percent for crude from Alaska's North Slope, and 18 percent for Arabian Light crude.[25 26] Other foreign crudes, such as Kuwait and Arabian Heavy, contain even larger residuum fractions. Oils from some AGR processes contain as much as 30 percent of residuum which, although higher than the contents of in situ crudes, is substantially lower than that for many conventional crudes.

Coal-derived liquids are often regarded as alternatives to shale oil feedstocks. However, syncrudes from coal have a much higher yield of gasoline and low-boiling distillates than shale oil, with little or no material boiling at temperatures above 850° to 1,000° F (4550 to 535° C), The coal liquids would be well-suited for gasoline production because their higher concentrations of lower boiling constituents when refined would yield the desired light naphtha fractions. Shale oil, on the other hand, has a much higher concentration of high-boiling compounds, and would favor production of middle distillates (such as diesel fuel and jet fuels) rather than naphtha, Shale oil and coal-derived syncrudes should, therefore, be regarded not as a competitive or substitutable feedstocks but rather as complementary feedstocks, with each yielding a different major fuel product from an equivalent amount of refining.

Among the negative characteristics of most crude shale oils are high pour point, high viscosity, and high concentrations of arsenic and other heavy metals and of nitrogen. The pour point and viscosity are of economic importance because transporting viscous oil that has a high pour point is difficult and costly, thus suggesting the need for pretreatment prior to marketing. * As shown in table 19, in situ oils with their relatively low pour points and viscosities could be marketed without pretreatment but they would retain their high nitrogen contents. This would reduce their value as refinery feedstocks and boiler fuels.

High concentrations of arsenic and other metals are a disadvantage because they poison refining catalysts, especially in hydrogenation units. They must be removed prior to catalytic processing, and a variety of physical and chemical methods have been developed for this purpose.[28 29] It should be noted that the concentrations of heavy metals in crude shale oil will vary with the location of the deposit from which the oil is recovered. Oils from some sites may be relatively free of such contaminants.

* Some conventional crudes have comparably high pour points. For example, the Altamont crude from Utah has a pour point Of about 100° F (35° C).

Shale Oil Refining

Shale oil has been successfully refined in oil shale operations in Sweden, Scotland, Australia, West Germany, the U. S. S. R., and other countries, although on a relatively small scale and under unusual economic conditions. In the United States, the initial refining research was conducted by USBM at the Petroleum and Oil Shale Experiment Station at Laramie, Wyo. It was coordinated with the early development of the gas combustion retort at Anvil Points, Colo. The results of this work, plus the findings of other investigators, allowed a preliminary assessment to be made of the economic aspects of shale oil utilization, and justified continued efforts aimed at its recovery. In recent years, refining R&D has been revived because refiners now consider the availability of shale oil to be a distinct possibility. There is also a need to perform more precise and up-to-date economic analyses.

To date, refining studies have been conducted on the upgrading of crude shale oil to a transportable product, and on the total refining of shale oil into finished fuels. The difference between these operations lies in the nature of the desired final product. As discussed previously, some crude shale oils have pour points and viscosities that make transporting them difficult and expensive. In some situations, economic considerations may dictate that the crude shale oil be partially refined (upgraded) near the retorting site to improve its transportation characteristics. In other instances, a developer may desire to obtain a complete array of finished fuels from an integrated processing facility located near the minesite. In this case, a total-refining facility would be considered rather than a more simple upgrading plant.

To date, upgrading experiments have been carried out largely at the bench scale, and in relatively small pilot plants. Theoretical studies and computer modeling have also been used to evaluate the expected performance of three types of upgrading processes: thermal, catalytic, and additive. Thermal processes include visbreaking (a relatively mild treatment) and coking (a severe treatment). Mild thermal treatment will reduce pour point and viscosity, but the oil will retain its initial amounts of nitrogen and sulfur. In contrast, severe thermal treatment reduces pour point, viscosity, and sulfur content and also causes the nitrogen compounds to concentrate in the heavier products. The properties of the lighter products will thus be considerably improved.

In catalytic processes, the shale oil is reacted with hydrogen in the presence of a catalyst. Viscosity is reduced, and the nitrogen and sulfur are converted to ammonia and hydrogen sulfide gases that can be recovered as byproducts. In additive processes, blending agents are added that reduce the pour point and allow the crude to be transported by pipeline. Such pour point depressants have been added in several instances with success, but the technique is not yet highly developed.

Total refining studies have focused either on the needs of existing refineries that would have to be modified for processing shale oil, or on those of newly built facilities that could be designed specifically for shale oil feedstocks. These studies differ in their approach to the analysis of refining requirements. Studies of existing refineries must consider the equipment that is in place, and must allow for the limited flexibility of this equipment for processing a feedstock that is different from the one for which the refinery was designed. Studies of specially built refineries, in contrast, need not be biased in this manner, and can draw upon any processing technique that is available within the refining industry. However, both types of studies must make assumptions about feedstock characteristics and desired product mixes. These will vary with the location of the refinery, the nature of the market it serves, and the type of retorting facility that supplies its feedstocks. The optimal refining conditions for one set of assumptions will probably not be applicable to another set. For example, a refining method to maximize gasoline production from TOSCO II shale oil would not maximize diesel fuel production from Oxy's in situ oil.

Numerous computer studies and bench-scale refining investigations have been conducted for a wide range of shale oil feedstocks and operating conditions. The results of these studies can be extrapolated, with some degree of caution, to predict the performance of commercial-scale refineries. However, refining tests both in pilot plants and in commercial-scale facilities, because of much higher costs, have focused on only a few feedstocks, and have been conducted for particular sets of operating constraints. In general, each large-scale study has dealt only with oil from aboveground retorts or with oil from in situ operations, but usually not with both types of feedstocks. The conclusions of all studies are highly dependent on the combination of feedstock and refining conditions assumed. Caution must be used when applying the results to different conditions.

Shale Oil Upgrading Processes

The treatment techniques that can be used to improve the transportation properties of crude shale oil are briefly described below.

Visbreaking

This technique involves heating the crude shale oil to approximately 900° to 980° F (480° to 525° C) and holding it at this temperature range for from several seconds to several minutes. The product is then cooled, and the gases evolved during the heating are removed. There is little reduction in the contents of nitrogen, sulfur, and oxygen. Therefore, the principal improvements are reductions in pour point and viscosity. This technique is simple but energy-intensive. It could reduce the pour point of crude shale oil from about 850 F to about 400 F (300 to 40 C).[30]

Coking

This process involves heating the oil to about 900° to 980° F (480° to 525° C) and then charging it into a vessel in which thermal decomposition occurs. If the vessel is a coke drum, the process is called delayed coking. The coke—the solid product from thermal decomposition—is allowed to accumulate until it fills about two-thirds of the drum's volume. The feed is then switched to another drum while the coke is cleaned out of the first one.

In the fluid coking process, hot oil is charged into a vessel that contains a fluidized bed of coke particles. The particles become coated with oil, which then decomposes to yield gases and another layer of coke. The gases are withdrawn from the vessel. The coke is also withdrawn continuously, at a rate sufficient to maintain an active stock of coke within the bed.

The flexicoking process, developed by EXXON, combines conventional fluid coking with gasification of the product coke. The advantage is that energy is recovered from the coke. The process is used in the refining industry, but tests would have to be performed to determine if it would be suitable for the coking characteristics of crude shale oil.

Catalytic Hydrogenation

In these processes, the crude shale oil is reacted with hydrogen in the presence of a catalyst. The sulfur in the oil is converted to hydrogen sulfide, the nitrogen to ammonia, the oxygen to water, the olefin hydrocarbons to their paraffin equivalents, * and long-chain molecules to smaller molecules. The hydrogenation reactions can take place in a fixed-bed reactor through which a mixture of oil vapors and hydrogen is passed, in a fluidized-bed reactor, or in an ebulliating-bed reactor. The latter technique is being promoted by Hydrocarbon Research, Inc., as the H-Oil process. Plants in several foreign nations have successfully used it for heavy petroleum feedstocks and for residuum fractions from a variety of crudes. In this process, a mixture is injected into the bottom of a reactor at a high enough velocity to cause catalyst ebulliation (a boiling motion). This movement reduces the possibility that the bed will become plugged by coke and by the liquid tars that are formed during the coking process. It also allows spent catalyst and coke to be removed, and fresh catalyst to be added, so as to keep the bed actively stocked.

Catalytic hydrogenation produces upgraded products of the highest quality, but it is relatively expensive. The use of fixed-bed reactors would probably be confined to the treatment of streams from an initial fractionation step; fluid-bed or ebulliating-bed processes could be used for either fractionator products or for the whole shale oil.

*Olefins are unsaturated (lower ratio of hydrogen to carbon) hydrocarbon compounds having at least one double bond. They are the source of synthetic polymers such as polyethylene and polypropylene used in the manufacture of fibers and other materials. Paraffins are saturated hydrocarbons (equal ratio of hydrogen to carbon) having only single bonds. Methane, ethane, propane, and butane are some of the paraffin hydrocarbons.

Additives

Chemicals may also be added to crude shale oil to improve its transportation properties. Pour point depressants have been successful in some instances, but this does not mean that they would always work. A chemical that is suitable for one type of oil may not work at all with oil from another retorting process. Furthermore, pour point depressants are disadvantageous because they only change the physical characteristics of the oil and not its chemical properties. Thus, their cost can be offset only if they save transportation costs.

Conventional petroleum crudes are other potential blending agents. Since shale oil (at least in Colorado) will be produced in an area that also contains petroleum reserves, and even active crude oilfields, the possibility exists that the light petroleum crudes could be mixed with crude shale oil to form a transportable blend. The feasibility of this concept is unclear because, in general, the blend would not be as valuable as a refinery feedstock on a per-unit basis as would the petroleum alone. However, the decrease in unit value would be offset by the increased volume. In the case of a refinery that does not have a reliable supply of crude, this could be a significant advantage.

Total Refining Processes

The three primary factors that affect the design of a refining system are:

- the characteristics of the crude shale oil feedstock;
- the desired mix of finished products; and
- the constraints imposed by the equipment and operating practices of the proposed refinery.

The first factor probably will have the lowest effect because, except for the higher nitrogen and arsenic contents, the characteristics of crude shale oil are not widely different from those of conventional petroleum. The second factor—the product mix—is much more significant. This is evidenced by the changes that have occurred in the proposed configurations of shale oil refineries since the 1950's: the earlier studies placed much more emphasis on gasoline production. For example, early designs by USBM called for the extensive use of middle-distillate cracking and reforming to yield gasoline, The ratio of gasoline to distillate yields was nearly 3 to 1.[31] Most of the refinery configurations that have been proposed more recently indicate a gasoline-to-distillate ratio of about 1 to 4."

The third factor—equipment and operating constraints—has become increasingly important in recent years. The modifications to convert a conventional refinery to shale oil feedstocks might not be economically justifiable unless the refiner could be assured of an adequate supply of shale oil. The economic desirability of building a refinery specifically for shale oil would be thoroughly scrutinized. Modular retorts, or even a few pioneer commercial plants, would not produce enough shale oil in the mid-term to justify a new refinery unless the refiner was assured that the operations would continue until his investment cost could be recovered. For this reason, the most recent studies have stressed modifying existing facilities to make them suitable for processing shale oil, rather than building new ones. In some cases, this entails only minor changes to installed equipment, in others, the adaptation of an existing facility by adding new units.

The basic unit operations in crude oil refining are:

- coking,
- hydrotreating,
- distillation,
- hydrocracking,
- catalytic cracking, and
- reforming.

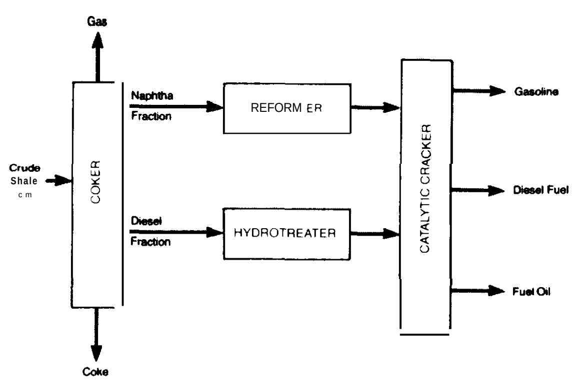
The various refining schemes that have been proposed for shale oil cannot easily be generalized because, depending on both the desired product mix and the possible operating conditions, many configurations could be designed that would achieve the same results. The one selected will largely depend on the availability of equipment and the individual economics of the particular refinery.

One significant difference among the various configurations described in the literature is the relative arrangement of distillation and thermal or catalytic treatment. Two general approaches have been investigated:

1. distillation of the whole crude into its components, then catalytic or thermal treatment; or
2. catalytic or thermal treatment of the whole crude, then distillation.

In the first approach the properties of the finished products are better controlled. In the second, the net load on successive processing units is reduced, and, in general, the overall yield of high-value hydrocarbon products is increased. Most of the refining research to date has been focused on the second approach. Three versions are shown schematically in figures 46 through **48.** The scheme in

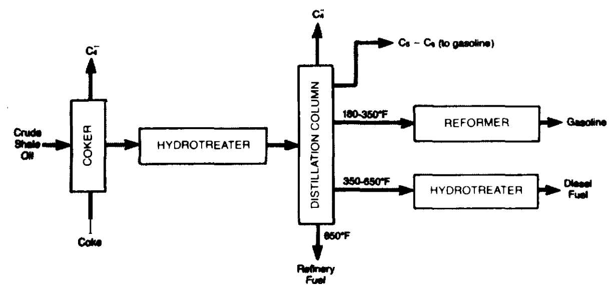
Figure 46.— Refining Scheme Used by the U.S. Bureau of Mines to Maximize Gasoline Production From Shale Oil



SOURCE G L Baughman, *The Refining and Marketing of Crude Shale Oil*

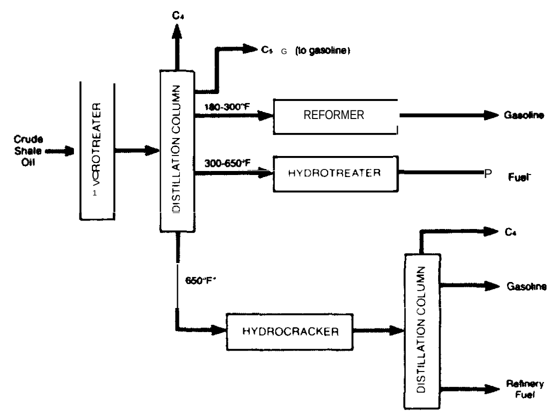
figure **46,** which was used by USBM at Anvil Points in the late 1940's,[33] had a gasoline-to-distillate ratio of 3 to 1. Figure 47, a configuration that was investigated by Chevron U.S.A. during pilot-plant runs on Paraho shale oil,[34] had a gasoline-to-distillate ratio of 1 to 4. Both of these systems used an initial coking step to upgrade the feedstock and to supply a product stream more easily refin-

Figure 47. —Refining Scheme Employing Coking Before an Initial Fractionation, Used by Chevron U.S.A. in Refining Experiments



SOURCE G L Baughman *The Refining and Marketing of Crude Shale Oil*

Figure 48.— Refining Scheme Employing Initial Hydrotreating, Used by Chevron U.S.A. in Refining Experiments



SOURCE G L Baughman, *The Refining and Marketing of Crude Shale Oil*

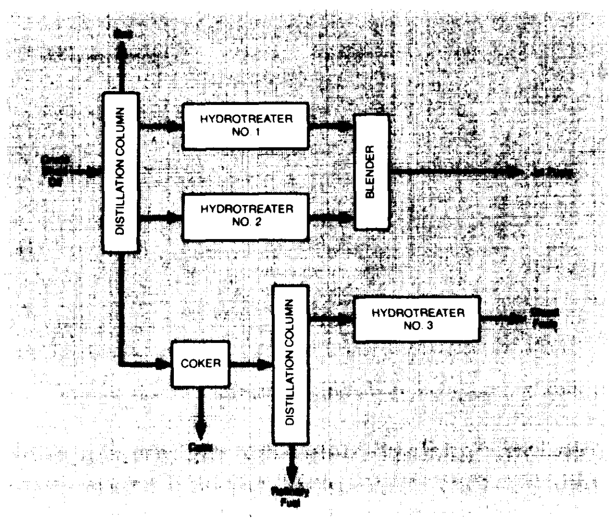
able into finished fuels. The disadvantage of coking is that there might not be a ready market for coke in the vicinity of the refinery, particularly if it were located in the oil shale region.

Another refining scheme that was investigated by Chevron is shown in figure 47. It uses a fixed-bed catalytic hydrotreater to upgrade the shale oil before distillation. No coke is produced because most of the heavier components of the crude shale oil are upgraded into lighter and more valuable liquid fuels during the hydrogenation process. This method may be more costly than the coking approach, but that can only be determined by operating experience and evaluating the economics.

Chevron also investigated the possibility of substituting a fluidized catalytic cracker for the hydrocracker in figure 48. A similar approach was used by SOHIO in processing 85,000 bbl of Paraho shale oil at its Toledo refinery.[35] The chief difference between the SOHIO runs and the Chevron experiments is that SOHIO used an acid/clay treatment to upgrade the distillation products into jet fuel and marine diesel fuel for military applications. The residuum fraction from the column was used for fuel in the refinery.

The approach in which the crude oil is fractionated before hydrogenation or other treatment is shown in figure 49. This scheme

Figure 49.— Refining Scheme Employing Initial Fractionation, Used by SOHIO in Prerefining Studies



SOURCE. G L Baughman, *The Refining and Market/rig of Crude Shale Oil*

was used by SOHIO during the prerefining studies carried out before 10,000 bbl of Paraho shale oil were refined at the Gary Western refinery in Fruita, Colo.[36] During the actual refinery run, a combination coker/fractionator was used rather than the separate units shown in the diagram.

The shale oil must also be treated to remove excess amounts of water, ash, and heavy metals such as arsenic. Water must be removed because it can cause cavitation in pumps and explosions in processing units. Ash, or particulate matter, must be removed to prevent its deposition in pipes, heat exchangers, and catalyst beds. Recent studies have shown that heating the crude oil to about 165° F (75° C) then letting it stand for about 6 hours allows the water and solid matter to separate from the oil. As noted, arsenic and other metals poison the hydrotreating catalysts. A variety of processes have been developed for their removal; consequently, their presence no longer presents a technical problem. ARCO has patented several catalytic techniques and methods for heat treating the oil in the presence of hydrogen. Recent studies by Chevron U.S.A. have shown that an alumina guard bed preceding the hydrotreater will effectively remove both arsenic and iron from shale oil.[39]

The quantity and quality of the fuels produced will be determined by both the configuration of the equipment and the operating conditions used in the refining step. The fuels produced by USBM at Anvil Points in the 1940's were quite satisfactory.'" However, some of the fuels from the Gary Western refining run in 1975 failed to meet certain military specifications, principally those for stability.[41] This has been attributed to the application of refining techniques unsuitable for shale oil feedstocks, specifically inadequate hydrogenation. Subsequent refining tests at SOHIO's Toledo refinery show that, with appropriate refining, fuels can be produced that are of superior quality and that can meet all applicable specifications.[42]

Cost of Upgrading and Refining

The most recent estimates of the cost of upgrading crude shale oil to a transportable refinery feedstock have been prepared by Chevron U.S.A.[43] The retorting complex that was considered had a capacity of 100,000 bbl/d. Conventional hydrotreating was the upgrading technique evaluated. Chevron considered two possible locations for the upgrading facility: a newly built unit at the retorting site; and a unit to be added to an existing refinery at some distance from the retorts. In both cases, the estimated cost for upgrading 1 bbl of crude shale oil was $6.50, in first-quarter 1978 dollars. The product would be a high-quality syncrude suitable as feedstock for most refineries in the United States.

It is more difficult to estimate the costs of the total-refining option for converting crude shale oil into finished fuels. This is because in addition to the properties of the crude oil consideration must be given to the location of potential refinery sites, the availability of refining equipment, the proximity and stability of potential markets, the ease of product distribution, and other factors. Chevron considered some of these in its analysis of refining costs, although in a relatively generalized manner. Three total-refining options and two refining capacities and refinery locations were considered. For a l00,000-bbl/d refinery located in an urban area in the Rocky Mountains (e.g., Denver), the refining cost was estimated to range from $8.00 to $10.00/bbl of crude shale oil. For a 50,000-bbl/d refinery located in a remote area of the Rocky Mountains (e.g., near the retorting facility), the refining cost would be approximately $10.00 to $12.00/bbl.* These are somewhat higher than the costs for refining a high-quality conventional crude oil because of the additional amounts of hydrogen that would be needed to reduce the nitrogen content of the shale oil crude.

Another study compared the cost of shale oil refining with those of refining Wyoming sour crude oil and Alaskan crude. It was assumed that a refinery in the Rocky Mountain region was modified for these feedstocks. The increased costs to refine crude shale oil, rather than the other crudes, was in the range of $0.25 to $2.00/bbl.[44 45]

*Costs are in first-quarter 1978 dollars.

Markets for Shale Oil

Crude shale oil has three major potential uses: as a boiler fuel, as a refinery feedstock, and as a feedstock for producing petrochemicals, The output from a mature oil shale industry will probably be used for all three purposes. However, the relative importance of the three markets will change with time as the industry develops. In the mid-1980's, when shale oil first becomes available in significant amounts, its most likely use will be as boiler fuel, with only a small quantity directed to nearby refineries that could be modified to accommodate the feedstock without large capital expenditures. As more shale oil becomes available, its use as a refinery feedstock will increase as conventional petroleum becomes scarcer. At a later date, when the market for boiler fuels declines, shale oil will begin to be used for petrochemical production.

Shale Oil as a Boiler Fuel

Shale oil will most likely first be used as a boiler fuel because of the relatively small capital investments and very short leadtimes that would be required. Because of Government regulation, the current trend in the utility industry is to replace oil- and gas-fired boilers with coal-fired units, thus freeing the natural gas for domestic consumers. In some areas, it will be a two-stage transition, with the gas first replaced by oil, and the oil later by coal. During the transition, there maybe a market for about 50,000 to 80,000 bbl/d of crude shale oil near the oil shale region. In addition, the refining industry has a small but significant demand for boiler fuel because refineries are also changing from natural gas to oil. Therefore, refineries located near the oil shale region are likely to be near-term shale oil customers. In the long run, the largest market for shale oil boiler fuel is likely to be in the Great Lakes States. Transportation distances will probably preclude its use in the other two major markets for boiler fuels—the east and west coasts.

Shale Oil as a Refinery Feedstock

There has been relatively little research on the refining of crude shale oil because building an oil shale plant takes about 5 to 7 years, whereas a refinery operator can evaluate a new potential feedstock in a few days, develop a feasible refining strategy within a matter of weeks, conduct the necessary pilot-plant refining studies in a few months, and modify the refinery to accommodate the new feedstock in less than 3 years. Thus, neither the developer nor the refiner has any inducement to study shale oil refining until they are sure that the oil will, in fact, be forthcoming.

Another reason is that until quite recently, shale oil was not considered a highly desirable refinery feedstock. During the 1950's and 1960's, the refining industry tended to maximize gasoline yields at the expense of middle and heavy distillates. Because shale oil is a good source of heavier distillates, not of gasoline, it was not highly regarded. However, most projections indicate that gasoline demand will peak in the early 1980's and then decline slightly, even though total demand for refined products will continue to grow.[46] This will be the result of the increasing efficiencies of gasoline engines in automobiles and of a greater use of diesel engines in automobiles and light trucks. Also, because the current supplies of conventional petroleum are becoming more like shale oil with respect to their distillate yields, the refining industry is being forced to adopt techniques that would be equally suitable for shale oil.

For these reasons, shale oil's desirability is increasing, and its potential availability as a premium feedstock has encouraged the refining studies that have been conducted by Chevron and other organizations. These studies have dealt with four general types of refining facilities:

1. a new refinery just for shale oil;
2. a new refinery for a mix of shale oil and conventional crude;
3. an existing refinery modified for, and dedicated to, shale oil; and
4. an existing refinery processing a mix of shale oil and conventional crude.

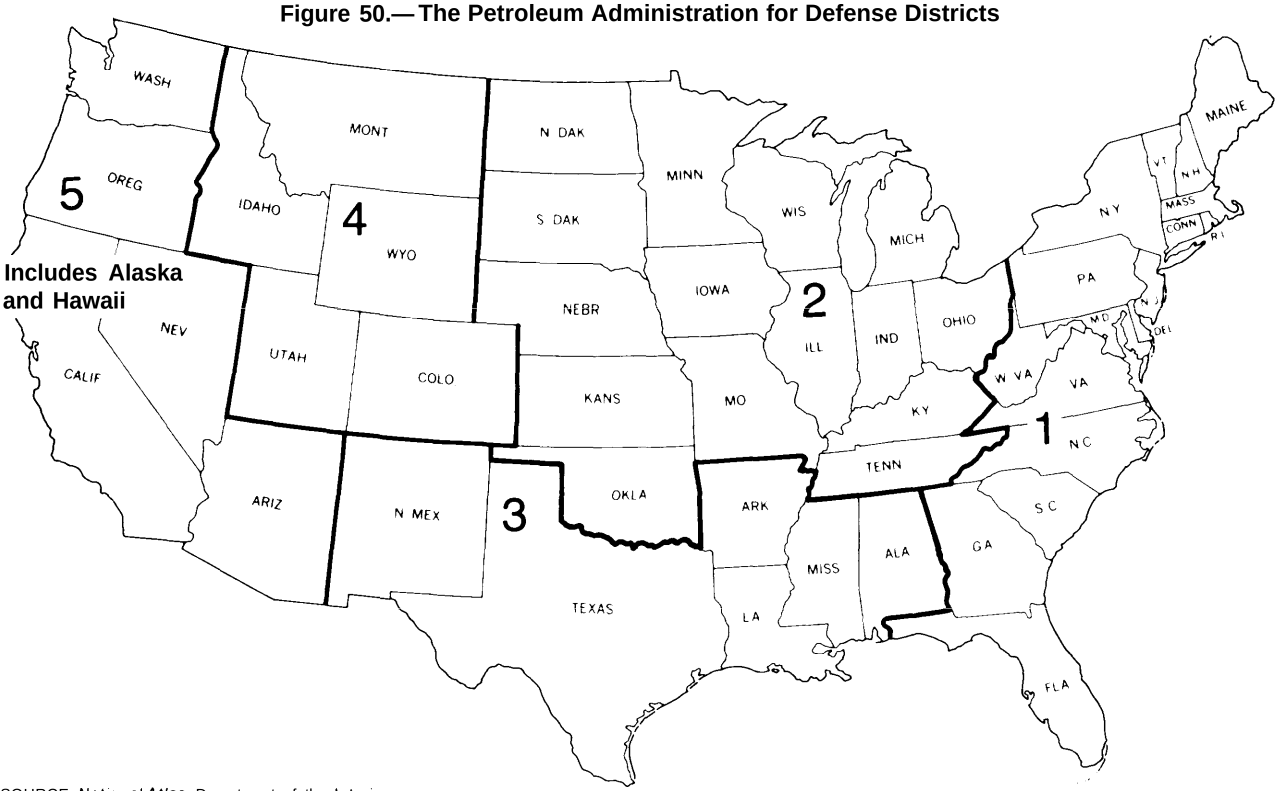
The first two approaches are precluded for the foreseeable future because, as long as refined products continue to be imported, the United States will have excess refining capacity. At least through the 1980's, shale oil will most likely be refined in existing refineries, either by itself or as a blend with conventional petroleum,

The shale oil produced by demonstration facilities will probably be processed in local refineries* or in more distant refineries owned and operated by the energy companies that participate in the oil shale programs. The much larger output from a commercialize industry will be more widely distributed; thus it will have to compete with other feedstocks, at least regionally. Recent studies have indicated that the Midwest is the most likely market area for large quantities of shale oil. This includes the States in the Petroleum Administration for Defense District 2 (PADD 2), as shown in figure 50. There will be secondary effects in other districts, as a consequence of the supplies of shale-derived fuels in PADD 2, because the conventional petroleum that it displaces will become available for use elsewhere.

The quantitative impact on the supply situation in PADD 2 can be determined by refering to table 20, which indicates how the district's supplies of finished fuels were divided among domestic and foreign sources in 1978. As shown, the district consumed about 518,000 bbl/d of medium and heavy distillates (jet fuels, diesel fuel, and distillate fuel oil) from foreign sources. According to Chevron's

*These could include the Gary Western refinery in Fruita, Colo., the Little America refinery in Rawlins, Wyo., the Chevron refinery in Salt Lake City, Utah, and others.

Figure 50.—The Petroleum Administration for Defense Districts



SOURCE *National Atlas*, Department of the Interior

Table 20.–Supply of Finished Petroleum Products in PADDs 2, 3, and 4 in 1978 (thousand bbl/d)[a]

	PADD 2 Midwest			PADD 3 Texas and New Mexico			PADD 4. Rocky Mountains		
	Foreign sources	Domestic sources	Total	Foreign sources	Domestic sources	Total	Foreign sources	Domestic sources	Total
Gasoline.	976	1,540	2,516	422	604	1,026	33	219	252
Light ends	224	236	460	276	388	664	12	25	37
Jet fuel	81	131	212	50	71	121	7	29	36
Kerosine	17	27	44	19	27	46	0	2	2
Distillate fuel oil	420	672	1,092	194	279	473	13	113	126
Residual fuel 011	150	173	323	237	340	577	4	38	42
Petrochemical feedstocks.	18	26	44	211	298	509	0	1	1
Special naphthas and still gas	60	98	158	114	165	279	2	14	16
Others	138	232	370	102	146	248	4	31	35
Total	2,084	3,135	5,219	1,625	2,318	3.943	75	472	547

[a]PADD = Petroleum Administraton for Defense District

SOURCE G L Baughman *The Refining and Marketing of Crude Shale 01/*

studies, refining will convert about 74 percent of a crude shale oil feedstock to similar distillates." A l-million-bbl/d industry would yield about 740,000 bbl/d of medium and heavy distillates. If it were marketed in PADD 2, this production would completely displace the foreign supplies and free an additional 222,000 bbl/d of the fuels for use in other districts. The same size industry would produce about 170,000 bbl/d of gasoline, which would be equivalent to about 17 percent of the district's gasoline currently obtained from foreign sources.

An alternative marketing strategy would be to sell the output from a major shale oil industry in PADD 4—the Rocky Mountain region—and to supply any surplus fuels to adjacent districts such as PADD 2 or PADD 3 (Texas and New Mexico). As shown in table 20, the Rocky Mountain district consumes relatively little distillate fuel (about 20,000 bbl/d) from foreign sources. A l-million-bbl/d shale oil industry could easily displace this entire supply. The surplus production (about 720,000 bbl/d) could displace about 95 percent of the supply of foreign-derived distillates in both PADD 2 and PADD 3. The gasoline derived from the shale oil could supply about 67 percent of the total gasoline demand in the Rocky Mountain States.

As indicated previously, the capabilities of the refineries in the Midwest and the Rocky Mountain States will strongly affect the willingness of the refiners to accept shale oil feedstocks. In some cases, shale oil could not be accommodated without significant investments of capital. However, the receptivity of refiners to shale oil will also be influenced by the reliability of other feedstocks such as foreign petroleum. The area in which the supplies of crude are most uncertain is the northern tier of States, which includes Montana, North and South Dakota, Minnesota, and Wisconsin. These States have historically depended on refinery feedstocks from Canada, but, in recent years, a significant reduction in these supplies has led the refiners in this area to look elsewhere. The result has been the present interest in building a pipeline to transport crude from Alaska and from foreign nations into the area. An alternative—a pipeline from the oil shale region—could also be built as the oil shale industry developed.

The area that covers Iowa, Missouri, Illinois, Indiana, Michigan, and Ohio also does not have an adequate indigenous supply of crude. However, unlike the northern tier, these States have good pipeline systems with adequate access to both foreign and domestic crude supplies. The feasibility of marketing shale oil in this area will largely be determined by the cost differential between it and other crude supplies and by the differences in the reliability of its supply versus that of foreign crude. Recent marketing studies have identified several large refineries in this area that, with only minor modifications would be able to handle crude shale oil. [48] Furthermore, some of the refineries only have access to the heavier petroleum crudes at present, and their production is being limited by their capacity to process the large quantities of residuum from the distillation of these fuels. Shale oil, with its relatively small yield of bottoms fractions, would help alleviate this problem.

Shale Oil as a Petrochemical Feedstock

Three principal factors must be considered in evaluating the suitability of shale oil supplies for producing petrochemicals:

- the yields of petrochemicals from shale oil feedstocks;
- the ability of existing and future petrochemical plants to process the shale oil; and
- the logistics of supplying the shale oil to the plants.

Because shale oil is produced by pyrolysis, its olefin content is approximately 12 percent, which is appreciably higher than conventional crudes. Together with its fairly high hydrogen content, these characteristics make shale oil, and its hydrogenated derivatives, appropriate feedstocks for petrochemical production.” 50 Steam pyrolysis has been used to process crude shale oil, and the yields of olefin products have been comparable with those from many conventional crudes. Shale oil syncrudes, with even higher olefin yields, are considered to be premium petrochemical feedstocks. These conclusions are based on laboratory studies under carefully controlled conditions. The feasibility of marketing shale oil to the petrochemical industry depends on the ability to replicate these conditions in commercial chemical plants.

Historically, the primary feedstock for petrochemical plants has been natural gas liquids from the gulf coast. Because crude shale oil is quite different from these liquids, it would be difficult to switch traditionally designed petrochemical plants to shale oil. However, the production of domestic natural gas and its associated liquids is declining, and the petrochemical industry is shifting to heavier feedstocks such as naphtha and gas oils. The supplies of these feedstocks are uncertain and irregular. The availability of naphtha has been affected by a growing demand for its use as a gasoline blending agent in response to the phasing out of tetraethyl lead. Gas oils are also being used more frequently for home heating fuels, which causes seasonal variations in their availability. Because of these supply uncertainties, new petrochemical plants are being designed to be highly flexible with respect to feedstocks. As using heavier feedstocks becomes more common in the industry, shale oil may become a highly regarded raw material.

The use of shale oil for petrochemical production is hampered by the distance between the oil shale region and the petrochemical plants. While refineries and oil-fired boilers are distributed fairly uniformly across the United States, the petrochemical industry is concentrated on the gulf coast. This concentration will continue into the foreseeable future. Therefore, it will be necessary to either move the shale oil to the coast, or to build a new petrochemical complex in the Rocky Mountain region. In the latter case, the half-finished products from the new plant would still have to be transported to the coast for final conversion to commercial chemicals. The former approach is more likely but is impeded by the lack of a product pipeline system between the oil shale region and the gulf coast, and by the high cost of alternative modes of transportation.

In summary, tests have shown that crude shale oil and its derivatives could be used to produce petrochemicals. However, these materials cannot be considered to be viable feedstocks in the near future because existing chemical plants are generally unable to process them and there is ‘no economical transportation link between the oil shale region and the existing petrochemical plants.

Issues and Uncertainties

The technological readiness of the major mining and processing alternatives is summarized in table 21. Estimated degrees of readiness are shown as judged by DOI in 1968,[51] and as they appear under present conditions. There are significant differences between the two evaluations because much R&D work has been conducted in the interim, and because two new processing methods—MIS retorting and concurrent recovery of associated minerals—have since entered the picture. As shown, room-and-pillar, open pit, and MIS mining methods are regarded as reasonably well-understood. Open pit mining has not been tested with Green River shales, but it is highly developed for other minerals such as copper and iron ores. It was evaluated on paper for application to the shales on tract C-a. Some highly relevent experience has been obtained from the operation of large-scale lignite (a form of coal) mines in West Germany.[52] In these operations, the lignite is covered by 900 ft of overburden, and stripping operations will soon extend to 1,600 ft. This is comparable to the oil shale deposits, which are covered by a maximum of about 1,800 ft of overburden.

Nevertheless, uncertainties remain with respect to the effects of shale stability and strength on mine design, mine safety, and resource recovery. The effects of large inflows of ground water, such as have been encountered on tract C-a, could pose severe operational difficulties, especially with underground mines. In all mines, the logistics associated with moving many thousands of tons of raw material and solid wastes could present some formidable problems. Materials-handling systems exist that could be applied, but they have yet to be tested in commercial oil shale operations.

Table 21 .–Technological Readiness of Oil Shale Mining, Retorting, and Refining Technologies

Unit operation	Technological readiness In 1968	In 1979	Developments in the Interim	Remaining areas of uncertainty
Mining				
Room and pillar	Medium	Medium	Mine design studies. Experience of Colony, Mobil, and the six-company program at Anvil Points	Rock mechanics Ground water Deep shales Logistics.
MIS	Unknown	Medium	Oxy experience at Logan Wash Mine design studies.	Rock mechanics Ground water Deep shales Logistics
Open pit	Low	Medium	Established procedure for other minerals Large-scale mines in West Germany. Mine design studies for tract C-a,	Rock mechanics Logistics Reclamation
Other	Low	Low	Mine design studies No field experience	All areas
Retorting				
Aboveground	Medium	Medium	Pilot studies for Lurgi-Ruhrgas Semiworks programs by Colony and Paraho Detailed designs by Colony and Union.	Effects of scaleup on stream factor and recovery. Characteristics of emissions streams Reliability of peripheral equipment Materials handling.
TIS	Low	Low	Field work and lab tests by USBM. Field tests by Equity, Geoknetics, and Talley-Frac. National lab support	Stream factor and recovery. Characteristics of emissions streams Rock mechanics Deep shales.
MIS	Unknown	Medium	Oxy experience, Design studies for tracts C-a and C-b. DOE and USBM design studies Modeling and lab support by national laboratories.	Effects of scaleup on stream factor and recovery Characteristics of emissions streams Reliability of peripheral equipment Use of low-Btu gas Rich shales. Mixed shales, Fracturing Rock mechanics Deep shales,
Multimineral	Unknown	Medium	Pilot plant studies by Superior USBM lab tests of product recovery methods. Nahcolite scrubbing tests.	Effects of scaleup on stream factor and recovery Characteristics of emissions streams Reliability of peripheral equipment, Materials handling Integration of recovery steps Underground waste disposal Marketability of byproduct minerals.
Upgrading and refining.	High	High	Studies and refinery runs by SOHIO/Paraho, Chevron, and others. Marketing analyses by Oxy and DOE.	Effects of retorting conditions on crude characteristics Cost effectiveness of alternate processes Use of pour point depressants Effects of metals

SOURCE Office of Technology Assessment

AGR is regarded as having a medium level of readiness, as it was in 1968. The understanding of its technical aspects has been improved since then by field tests in the Piceance basin, but the largest tests conducted to date have been at the semiworks scale—about one-tenth of commercial size. Their results do not permit accurate cost projections for commercial-scale plants. Particular problems are noted with respect to the effect of scaling up the semiworks design to commercial size. The on-stream factor—the fraction of the time that the retorts could be expected to operate at design capacity—is unknown. The reliability of some associated systems (emissions controls, product recovery devices, materials-handling equipment) is also questionable.

Although understanding has increased since 1968, TIS must still be regarded as being in the conceptual stage. Many uncertainties remain, especially with respect to economics and environmental effects.

MIS retorting, a new concept since 1968, has advanced to a medium level of technological readiness, approaching that of above-ground retorts. This progress is largely a result of Oxy's development efforts in Colorado, but additional understanding has been obtained through simulations by USBM, DOE, and the national laboratories, most notably the Lawrence Livermore and Los Alamos Laboratories. The remaining uncertainties are similar to those for aboveground retorts, except the materials-handling problems may be less substantial with MIS methods. The major uncertainties relate to the use of the large quantities of low-Btu retort gas for power generation and to the application of the technique to very rich or very deep shales.

The multimineral concept was also largely unknown in 1968, although the presence of sodium minerals was recognized. At present, the aboveground system of Superior Oil is regarded as having medium technological readiness. Its uncertainties are much the same as for other AGR methods, with the addition of the potential difficulties with integrating the systems for recovering mineral byproducts with those for recovering oil and gas. The marketability of the nahcolite, soda ash, and alumina has also not been well-established. The MIS concept proposed by Multi Mineral Corp. is not specifically evaluated in the table. It would share the same uncertainties as conventional MIS, with additional potential problems introduced by the need to evacuate a large underground retort, and because the oil shale resource is deeply buried.

Upgrading and refining systems were given a high rating in 1968, which has been improved by additional study. No major problems are anticipated, although more needs to be known about the feasibility of using pour point depressants, the effects of retorting conditions on the characteristics of the crude oil, and the effects of metals (such as arsenic) on refining catalysts. The major uncertainty in the distribution area—the existence of an adequate pipeline system to the most likely markets—is not directly related to the nature of the refining technology and is therefore not indicated.

It should be noted that mining and retorting (the major subprocesses having only medium levels of technological advancement) require only about 35 percent of the capital investment that is needed to establish an AGR complex. The remaining 65 percent is distributed among upgrading units, byproduct recovery systems, utilities, sidewalks, and other well-established items. Yet developers hesitate to commit themselves to oil shale plants. The reasons given are an uncertain regulatory climate, an uncertain future for the price of conventional petroleum, and the fact that all of the components of a facility must work as designed—not just the well-established ones. With the present state of technological knowledge, it is not clear that an oil shale plant would perform as desired, nor that the oil would be sufficiently cheap to compete with its currently designated competitor—imported petroleum. Even though the future of oil shale looks brighter, few companies are willing to build large-scale plants immediately. They prefer to follow conventional engineering practice by proceeding to an intermediate step—the so-called modular demonstration retort.

The modular retort is the smallest unit that would be used in commercial practice, A commercial-size oil shale facility would use several of these retorts in parallel to obtain the desired production rate. The capacity of a module varies with the developer. For Oxy, a modular MIS retort might have a capacity of only a few hundred barrels per day of shale oil; a commercial facility would have several dozen of these retorts operating simultaneously in modular clusters, each producing several thousand barrels per day. A modular Lurgi-Ruhrgas retort would have a capacity of about 2,200 bbl/d. One or two such units might suffice for the mined shale from an MIS operation; a facility that used only AGR might need a dozen comparable units. A commercial-sized plant that used Paraho retorting might have seven or eight individual retorts, each producing 7,300 bbl/d. A comparable plant might use seven Union "B" retorts, each producing about 9,000 bbl/d. Colony prefers to bypass the modular demonstration phase and to proceed directly to a commercial-size facility, claiming that the TOSCO 11 technology is ready to be scaled up to such a capacity for demonstration purposes.

Regardless of these differences, the several "next steps" that are proposed by the developer's have two points in common: the production units must be large enough to simulate actual commercial practice, and the equipment must be operated long enough to obtain reliable data on its performance under a complete spectrum of operating conditions.

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R&D Needs and Present Programs

R&D Needs

Mining

Room-and-pillar mining and mining in support of MIS operations have been tested with oil shale, and an extensive body of information has been assembled. To date, however, all of the field tests have been conducted in one area—the southern fringe of the Piceance basin. In each case, the deposit was reached through an outcrop along a stream course. The limited area in which mining tests have been conducted is unfortunate because the characteristics of deposits in other areas are quite different. They may be more or less favorable to mine development. For example, there is little ground water in the southern fringe. In contrast, the deposits on tracts C-a and C-b, nearer the basin's center, lie within ground water aquifers, and the inflow of water into the mine shafts has been a problem on tract C-a. Similar problems were encountered at the USBM shaft in the northern part of the basin. Work on this site was also impeded by the presence of highly fractured zones, which are not common on the southern fringe.

Similar surprises could be avoided in future projects if the suitability of the candidate mining techniques for developing deposits throughout the oil shale region were better understood, especially in these areas where near-term development is likely. This information could be obtained through coring and rock mechanics studies, mathematical simulation, and experimental mining. Field testing of mining methods would be expensive, although overall costs could be minimized through developing a single site that could be used to test many mining alternatives. A single shaft or adit, for example, could be used to test room and pillar, longwall, block caving, and other methods. It should be noted that open pit mining, because of the necessity for costly and large-scale operations, would probably not be amenable to testing in a limited field program.

TIS Retorting

TIS is the most primitive of the processing methods. It has some potentially valuable features but these cannot be evaluated because of a lack of information. The potential impacts on surface characteristics and ground water quality are especially unclear. The R&D needs include:

- development of less expensive drilling techniques;
- development of efficient and cost-effective fracturing and rubbling techniques;
- development of methods for determining the success of a rubbling program through, for example, surveys of the permeability increase that has been achieved;
- development of ignition methods and of methods for maintaining a uniform burn front;
- study of the effects of heat-carrier composition, rate of injection, and temperature on product recovery;
- study of the effects of creep* on retort stability and product recovery;
- determination of the effects of ground water infiltration on retorting; and
- evaluation of the long-term potential for surface subsidence.

Valuable information is being obtained in the Equity and Geokinetics projects, but these results are applicable only to specific types of oil shale deposits—the Equity process to shale in the Leached Zone; the Geokinetics method to thin, shallow beds. Additional field work in other types of deposits would aid in evaluating the potential of TIS methods for large-scale production. To minimize the cost and duration of these tests, they could be supplemented with initial theoretical studies and laboratory programs.

*Creep is the gradual change in the shape of a solid object induced by prolonged exposure to stress or high temperatures.

MIS Retorting

MIS is more highly developed, but more testing is needed before its potential application to other areas of the Green River formation can be determined. The R&D needs are similar to those for TIS. They are:

- the development of better rubbling techniques;
- the development of improved remote sensing procedures for permeability, fluid flow, and temperature;
- the development of methods for creating and maintaining a better burn front;
- evaluation of the effects of heat-carrier characteristics;
- evaluation of the effects of creep and subsidence; and
- examination of the effects of ground water infiltration, retort geometry, and particle-size distribution.

Many of these needs will be addressed in the MIS programs on tracts C-a and C-b and the USBM shaft.

Aboveground Retorting

Several candidate retorting processes have been tested in Colorado, but only for relatively short periods, and in small-scale facilities, More R&D is needed, and particular emphasis should be given to:

- evaluating the effects of scaleup on the flow patterns of solids and fluids within the retort vessel;
- determining the reliability and effectiveness of peripheral equipment such as solids-handling systems, pollution controls, and product separators;
- examining the effects of heat-carrier characteristics on product recovery and equipment reliability; and
- determining the reliability of mechanical components such as Union's rock pump; Tosco's retort vessel, separation trommel, and ball elevator; the Lurgi-Ruhrgas screw conveyor; and the raw shale distributors and spent shale discharge grates of all retorts that use gas as a heat carrier.

Some of these needs could be addressed by further laboratory-scale and semiworks testing. Others could be estimated by theoretical calculations and modeling. All of them and especially the need for reliability studies, will eventually have to be addressed in full-scale retorting modules, either alone or as part of a commercial-size complex.

Upgrading, Refining, and Distribution

Because crude shale oil is sufficiently similar to conventional petroleum crude, no substantial problems are anticipated in the refining area. R&D on the effects of heavy metals on refining catalysts and of retorting conditions on oil properties could be conducted in the laboratory, provided that retorts were operating that could supply a product resembling the crude oil that will be produced in commercial operations,

In the upgrading area, the major need is related to the feasibility of using chemical additives to depress the pour point of crude shale oil. The necessary R&D could be conducted in the laboratory or in a pilot refinery, again assuming the availability of a representative crude shale oil.

R&D is also needed to determine the optimum distribution pattern for the finished fuels, which will vary with the size of the industry, the location of the facilities, the need for various fuels and feedstocks, and the availability of a transportation system. R&D is needed to determine optimal plans for likely combinations of these factors. Work has begun in this area, and more work could be conducted at relatively low cost, since it is theoretical rather than experimental in nature. However, it will not be possible to define an optimum pattern for the actual future industry until the sites of the production facilities are designated.

The System

All manufacturing and processing plants potentially suffer from a lack of systems reliability. Because of the scale of operations and the need for the coordinated performance of many components, it is certainly possible that oil shale plants will have significant problems. On the other hand, they may not be more severe than in other, more conventional industries. R&D programs, such as mathematical simulations and industrial engineering studies, would help to eliminate some of the uncertainties regarding the expected performance and reliability of oil shale systems. Basic data on the lifetimes of equipment, operating characteristics, and other factors could be obtained from those minerals processing and refining plants that oil shale facilities will resemble. However, because of the unique character of oil shale operations, predictions from these studies will be tentative. It will only be possible to define performance characteristics after large-scale oil shale plants are operated at their maximum production capacities.

Present Programs

Some of the current R&D programs for individual retorting technologies were described previously. An effort that has not been discussed in detail is DOE's integrated research, development, and demonstration program for oil shale.[53] Its major objective is to provide the private sector with the technical, economic, and environmental information needed to proceed with the construction of pioneer commercial plants. Its specific goals are:

- by *mid-1981:* to provide technical designs, cost data, and environmental information for construction and operation of at least one AGR module;
- by 1982: to design at least one commercial-size MIS retort that could be used on the Federal lease tracts or in other locations; and
- by 1985 to 1990: to remove the remaining technical uncertainties that impede commercial-scale use of the alternate technologies in the various types of oil shale deposits.

In situ processing has been given the major emphasis throughout the program, and much of the technical R&D will be conducted in the "Moon Shot" project that will address the second goal. Initial support of AGR will focus on designing the retort module and on surface and underground mines to support single plants and an industry of 1 million to 3 million bbl/d. The decision to proceed with construction of AGR modules will be determined by the economic outlook for shale oil in mid-1980. DOE will consider a cost-shared program if industry has not announced firm plans to proceed without Federal participation. The program will also include resource characterization studies that will help to delineate the portions of the oil shale basins where the different types of development technologies would be most applicable. Other studies will include assessments of air, water, land, and socioeconomic impacts; of occupational safety and health; and of methods for increasing the efficiency of water use.

These efforts should substantially advance the understanding of the technological aspects of oil shale development. The budget of over $387 million for fiscal years 1980 through 1984 should be adequate to address most of the R&D needs identified in the previous section. This budget includes about $126 million for developing and operating a commercial-scale MIS retort, and half of the estimated $200 million cost of an AGR module.[54]

The demonstration facilities are especially important to the acquisition of firm engineering and economic data. Unfortunately, only one in situ technology and one aboveground retort will be tested, and it will be difficult to evaluate fully the effects of resource characteristics on the feasibility of alternate mining methods.

Policy Options

R&D

Some of the remaining technical uncertainties could be alleviated with additional small-scale R&D programs. These could be conducted by Government agencies or by the private sector, with or without Federal participation. If full or partial Federal control is desired, the programs could be implemented through the congressional budgetary process by adjusting the appropriations for DOE and other executive branch agencies, by providing additional appropriations earmarked for oil shale R&D, or by passing new legislation specifically for R&D on oil shale technologies.

Demonstration

Full-scale demonstrations will be needed to accurately determine the performance, reliability, and costs of development systems under commercial operating conditions. In general, potential developers would prefer to follow conventional engineering practice and approach commercialization through a sequence of increasingly larger production units. Union, Colony, and Paraho have progressed through this sequence to the semiworks scale of operation—about one-tenth of commercial size.

If this conservative approach were continued, the next step would be a modular demonstration facility. Although such a plant would cost several hundred million dollars, it would provide the experience and the technical and economic data needed to decide on the commitment of much larger sums to commercial-scale operation. Union has expressed its preference for this path; Rio Blanco and Cathedral Bluffs are following it. Colony regards a pioneer commercial plant as the best facility for proving the TOSCO II technology.

The two general approaches to funding such demonstration programs are discussed below. Selecting an option will depend on the desired balance between information generation and dissemination, Federal involvement, timing of development, and cost.

Private Funding

If left alone, the industry would develop in response to normal market pressures and opportunities, and the Government's expense and involvement would be minimized. However, the Government would not be assured of access to the technical, economic, and environmental information that it needs to formulate future policies and programs, although some of this information could be obtained through third-party reviewers or through licensing arrangements. Another disadvantage is that industry may not risk even the relatively modest investment of a modular program until economic and regulatory conditions clearly favor development. For example, Union and Colony have announced that they will not proceed until Federal incentives are provided and regulatory impediments removed. Industry may eventually proceed, but perhaps not in time for the resource to contribute substantially to the Nation's fuel supplies within the next decade.

Government Support

The alternatives are full Government funding of demonstration facilities, indirect funding through incentives to industry, and a sharing of the costs with industry. The options are discussed in detail in chapter 6 and summarized in chapter 3. In brief, Federal ownership would provide the Government with the maximum amount of experience and information. It would also maximize Government intervention and the commitment of public funds, and it might discourage private developers from proceeding with independent demonstrations. Also, industry and Government would design, finance, and operate a demonstration project in very dissimilar ways. The Federal experience with a Government-owned facility may have little relevance to the problems that would be encountered by a private developer with the same production goal, The Government's experience would therefore provide little guidance for evaluating oil shale as a private investment opportunity.

Incentives programs could involve tax credits, purchase agreements, price supports, or other types of support, either singly or in combination. They could be structured to encourage the participation of specific types of firms and could be combined with regulatory changes, and possibly land exchanges or additional leasing, to control both the growth and the nature of the ultimate commercial industry. They would cost less than Government ownership. They would also tend to provide the Government with less information and with no operating experience. However, disclosure requirements could be inserted into the leases or the incentives legislation as a prerequisite for project eligibility y.

The cost sharing of demonstration facilities would entail intermediate expenditures of public funds and intermediate levels of information. The receptivity of industry to such proposals would depend on how much the Government would intervene in designing and operating the projects. If industry responded, the Federal investment that would be needed for a single Government-owned plant could be spread over several projects, thereby increasing the total amount of information generated.

Program Alternatives

Demonstration will require designing, building, and operating full-size production units, either as separate modules or incorporated in pioneer plants.

A single module on a single site.—This option would provide comprehensive information about one process on one site. Either underground or surface mining experiments could be performed, but probably not both. The costs would be small overall but large on a per-barrel basis, because there would be no economies of scale. Some of the shale mined could be wasted because the single retort might not be able to process all of it economically. If the site could subsequently be developed for commercial production (e. g., a private tract, a potential lease tract, or a candidate for land exchange), the facility would have substantial resale value. Otherwise, it would be valuable only as scrap.

Several modules on a single site.—This program might consist of an MIS operation, coupled with a Union retort for the coarse portion of the mined oil shale and a TOSCO II for the fines. As with the single-module option, either surface or underground mining could be tested, depending on the site, or possibly both if the plant had a sufficiently large production capacity. The total costs would be larger than for the single-module program, but unit costs would be lower. For example, a three-module demonstration plant would cost about 2. I times as much as a single-module facility; a six-module plant about 3.7 times as much. Different technologies could be combined to maximize resource utilization, and detailed information could be obtained for each. However, all of the information would be applicable to only one site. If many modules were tested, the demonstration project would be equivalent to a pioneer commercial plant, except that a true pioneer operation would probably not use such a wide variety of technologies.

Single modules on several sites.—Several technologies might be demonstrated, each at a separate location. For example, an underground mine could be combined with a TOSCO II retort on one site; a surface mine with a Paraho retort at another. Total costs could be large, as would unit costs, which would be comparable with those of the single-module/single-site option. The principal advantage would be that different site characteristics, processing technologies, and mining methods could be studied in one comprehensive program.

Several modules on several sites.—For each site, a mix of mining and processing methods would be selected that would be most appropriate for the characteristics of the site and the nature of its oil shale deposits. The maximum amount of information would thus be acquired, in exchange for the maximum amount of investment. Each project would resemble the several-module/single-site option; the collection would constitute a pioneer commercial-scale industry.

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