Oil Shale: Prospects on the Upswing . . . Again

The borders of Utah, Wyoming, and Colorado come together on a windswept plateau more than 3 kilometers above sea level. The summer sun regularly heats the arid plains to more than 40°C, and only the hardiest desert plants survive. Spring comes late on the plateau, fall comes early, and, in the middle of winter, icy winds sweep between the buttes and chill the bones of those few individuals who choose to brave the −30°C temperature. Probably fewer than 5000 people live within a radius of 200 kilometers of this juncture. Yet this inhospitable land is wealthy. Within that same radius lies the equivalent of nearly 2 trillion barrels of oil locked tightly in shale formations—more than 50 times the total U.S. reserves of petroleum. For most of this century, this oil shale has been considered a major potential source of energy.

But exploitation of that treasure has proved elusive. The potential oil shale industry has been riding a dizzying roller coaster as its prospects have swept alternately from Olympian heights to Stygian depths. Every 2 or 3 years, it seems, this embryonic industry reaches a peak where the need for oil from shale seems imperative, the economics viable, and the problems minimal. And then the cost of petroleum comes down. Or the cost of construction skyrockets. Or water resources appear too meager. Or air pollution standards appear too strict. Or Congress backs off from incentives that the industry thinks necessary. And every time the roller coaster comes downhill, one or two more companies bail out, and the ever fewer hardy survivors cinch their seatbelts a little tighter and look forward to that next glorious high, hoping that this time the ride will stop at the top, that this time they will reach that seductively beckoning goal of commercial production.

This time they might be right.

There is no one overwhelming factor that says this time will be different from the others. But many small factors have all come together at one time to produce a new round of confidence that this time shale oil will be produced. These factors include: successes in the development of underground (in situ) conversion techniques; federal encouragement, including financing and tax incentives; lessening of water requirements for both conversion and disposal of spent shale; easing of air pollution standards; the need for safe sources of military fuels; recognition that, apart from tertiary recovery of petroleum, oil from shale is the cheapest alternative source of liquid fuels; and recognition that eastern shales are a more exploitable resource than they had appeared to be (see box).

Perhaps the most important of these elements is the refinement of techniques for converting kerogen—the organic component of oil shale (*Science*, 21 June 1974, p. 1271)—into crude oil in situ. These techniques seem particularly promising because they should reduce the cost of the shale oil, the amount of water required, and the problem of disposal of spent shale.

This is the first of three articles exploring unconventional approaches to fossil fuels.

The problem with in situ conversion is that oil shale is fairly impermeable to the passage of liquids or gases. In a true in situ process, therefore, the shale bed must be fractured hydraulically or with explosives so that a flame front can pass through the bed and release the oil. Several companies are developing this fracturing technology, which is much the same as that used for releasing natural gas locked into other types of rock, but the technology is still at a formative stage. More rapid advances have been made with a technique known as modified in situ conversion. One type of modified in situ process was refined by Occidental Petroleum Company from technology originally developed at the Department of Energy's (DOE) Laramie Energy Research Center (LERC).

In a modified in situ process (Fig. 1), the difficulties of fracturing the shale are alleviated by first mining out about 20 percent of the volume of the shale that is to be tapped; the shale that is removed can be retorted on the surface by means of any one of several well-developed conversion techniques. The remaining 80 percent of the shale is then fractured with explosives ("rubblized"), a process that is greatly simplified by the presence of the 20 percent void volume. The initial chamber is then sealed and ignited and, as the flame front advances through the rubble, kerogen is converted to oil that flows to a sump in the chamber from which it is pumped to the surface. In this manner, between 60 and 70 percent of the organic material in the rubblized area can be recovered. If all energy inputs are considered, this is about the same conversion efficiency as is achieved by surface retorting.

The primary difficulty with this approach, according to Harry McCarthy of Science Applications Inc., is in rubblizing the shale. If the voids created by rublization are not fairly regular, the flame front will not advance evenly and much of the kerogen will be left unconverted. At the other extreme, creation of too many fine particles will have a similar effect. Occidental has thus spent much of the past 5 years refining rubblizing techniques in chambers as large as half the size required for a commerical retort. In October, the company signed a contract with DOE to evaluate the two best rublizing techniques in two commercial-size chambers, each about 40 meters square and 90 meters high, at Logan Wash, Colorado.

Occidental and its partner, Ashland Oil Inc., will then use the more successful technique in a 2500-bpd (barrel per day) demonstration plant in Rio Blanco County, Colorado. Some 71 percent of

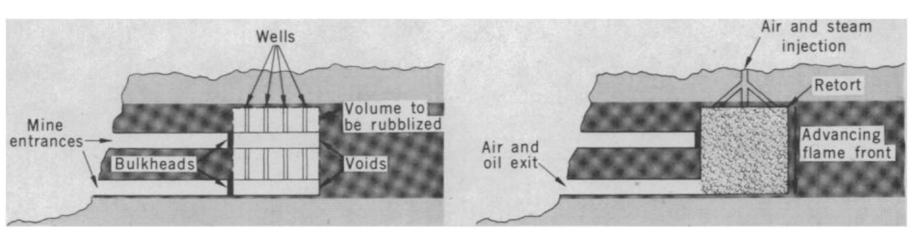

Fig. 1. A scheme for rubblizing shale in situ. Two or more shafts are dug to the shale and horizontal slots or voids, accounting for about 20 percent of the volume of the shale, are excavated; pillars of shale are left in place to support the roofs. Vertical wells are then drilled through the shale and packed with explosives; explosives are also placed in the pillars. The mine shafts are then sealed off, the explosives are detonated, and the shale ruble expands to fill the voids. The shale is ignited, and air and steam are injected at the ceiling; the oil flows downward ahead of the flame front and collects in a sump from which it is pumped. Alternatively, vertical slots can be mined out. Occidental will evaluate each of these approaches in full-size chambers to determine which is better.

the $60.5 million cost of these projects will be provided by DOE. Meanwhile, Occidental and Ashland have begun work on a $440 million, 57,000-bpd commercial facility that is to be completed late in 1983. Independent observers estimate that production costs for that facility will be between $8 and $11 per barrel. Since shale oil can now be sold at the prevailing world price for petroleum, currently about $14 per barrel, the plant should be economically viable.

Somewhat less advanced is a similar project undertaken by Rio Blanco Oil Shale Project, a joint venture of Standard Oil Company of Indiana and Gulf Oil Corporation. Their process is similar to Occidental's, but they use a slightly different rubblizing technique and they will pressurize the chamber so that the flame front will advance faster. Rio Blanco received government approval in September to begin work at a site in Rio Blanco County, and the company plans to conduct its first burn in a small chamber about the middle of 1979. They plan to conduct experiments in four larger chambers and to have the rubblizing techniques refined by the end of 1981. They would then begin construction of commercial scale facilities if the experiments are successful.

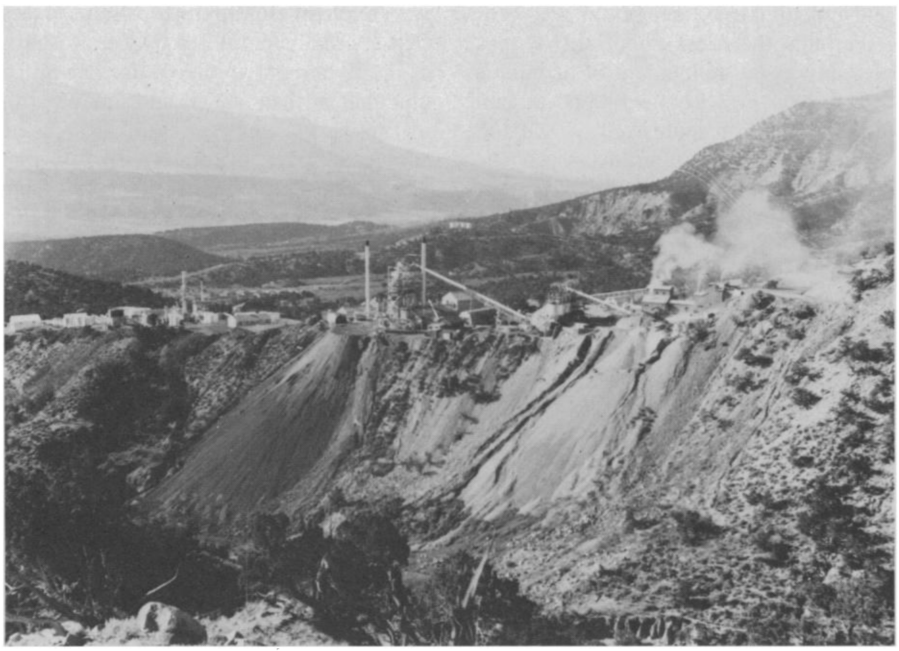

Fig. 2. The Department of Energy's surface retorting facility at Anvil Points, Colorado. The facility is currently leased to Paraho Development Corporation, which is using it to produce 100,000 barrels of shale oil for a major refining study sponsored by the United States Navy. [Source: U.S. Department of Energy]

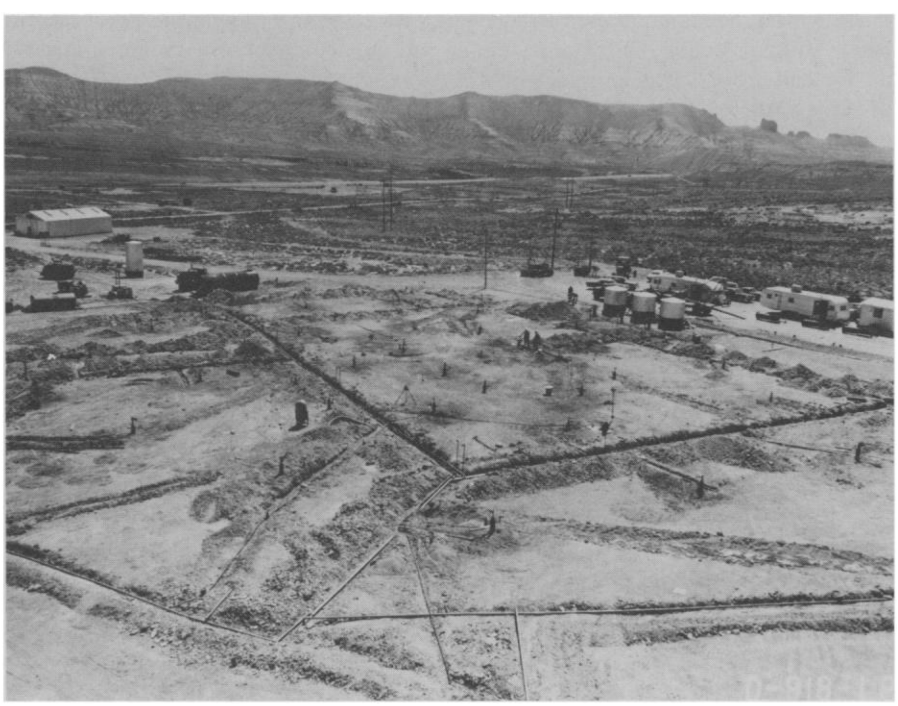

Fig. 3. The Laramie Energy Research Center's experimental in situ oil shale conversion site near Rock Springs, Wyoming. Each of the black pipes in the foreground is a well used for monitoring subterranean temperatures and water quality. [Source: U.S. Department of Energy]

This modified in situ approach, however, may be useful only for certain types of shale deposits, notably those that are thick and close to the surface. Therefore DOE is supporting research on other approaches. Talley-Frac Corporation of Mesa, Arizona, for instance, is studying true in situ conversion in deep shale beds with hydraulic and explosive fracturing. Geokinetics Inc. of Concord, California, is studying an approach similar to Occidental's in very thin shale beds close to the surface. And Equity Oil Company of Salt Lake City is studying the injection of hot fluids into certain types of deep shale beds that have some natural permeability. Equity has, in fact, already produced some oil from a site in the Piceance Creek Basin in Colorado. At least one of these approaches, says LERC director Andrew W. Decora, should be applicable to any type of western shale.

The rapid advances being made in the in situ technology are forcing federal energy officials to rethink some of their positions on shale oil. In the mid-1960's, federal energy authorities concluded that surface retorting of oil shale was well developed, or "on the shelf," and awaited only the proper economic situation—a position that has been roundly criticized by the congressional Office of Technology Assessment. Because of this view, the majority of research funding was shifted to the development of in situ processes. The two sites in Rio Blanco County where Occidental and Rio Blanco Oil Shale Project are now working were, in fact, originally committed by the government to shale mining and surface retorting. But surface retorting has never gotten off the ground and very rapid progress has been made in the refinement of in situ techniques. About 2 years ago, therefore, the two groups requested that the two lease sites (for which they have so far paid more than $200 million) be redesignated for in situ development.

In light of these developments, according to Philip C. White of DOE, the department has come full circle and concluded that in situ processes are near commercialization and that greater support must be given to surface retorting. White thus announced at an oil shale conference in September that DOE is requesting funds in 1979 for engineering designs of a full-scale surface module, and that the department may finance construction of the plant itself. This project, he says, would be the minimum needed to advance surface technology at a rate commensurate with in situ development. Advances in both areas, he concludes, would provide the technology base for commercial expansion by various techniques in the 1990's. For his part, Decora thinks that the surface techniques will be the stronger of the two and that, within 15 years, there will be many surface facilities.

If the government should decide to provide all or some funding for a surface retorting operation, several companies will almost certainly be interested. Among those who have well-developed retorting processes are: Colony Development Corporation, which once had five partners, but is now operated jointly by Atlantic Richfield Company and The Oil Shale Corporation (TOSCO); TOSCO itself; Union Oil Company of California; and Paraho Development Corporation. Each of these groups has already announced plans to construct a commercial surface retorting facility, and then suspended the plans for one reason or another. One of those reasons is escalation in construction costs.

In 1973, for example, Colony estimated that a 45,000-bpd surface plant would cost about $250 million (although some observers think that initial estimate was optimistically low). Today, that same plant would cost close to $1.2 billion. Inflation in construction costs has slowed substantially; but even at present costs, DOE secretary James Schlesinger has told Congress, the cost of shale oil

Eastern Oil Shales: An Undervalued Resource

The oil shales of Colorado, Utah, and Wyoming, which date from the Eocene era, are not the only oil shales in this country. The rest of the country, particularly the East, has resources equivalent to as much as 2 trillion barrels of petroleum locked in older shales dating from the Devonian and Mississippian eras. The eastern shales have generally been considered inferior to the western shales because they yield much less oil in the standard test for oil shale quality, the Fischer assay. In this assay, a given weight of shale is pulverized and heated at 500°C for a short time; the quantities of oil, gas, and water that result are measured and used to estimate the quality of the shale. By this assay, most western shales yield from 30 to as much as 50 gallons of oil per ton of shale, whereas the eastern shales generally yield less than 15 gallons, a quantity that is generally considered to be insufficient for an economically viable commercial process. New evidence, however, indicates that the Fischer assay is probably not the appropriate yardstick with which to measure the eastern shales, and that the eastern shales are not inferior, only different.

The key factor, according to John P. Humphrey of the Dow Chemical Company, is that the organic carbon contents of both types of shale are comparable, but the eastern shales contain less hydrogen. When heated in the Fischer assay (or in conventional retorting processes), the hydrogen-rich kerogen in western shale turns into oil. Under the same conditions, much of the hydrogen-poor kerogen in eastern shale turns to coke that remains locked in the rock matrix. The trick, then, is to find some way to use this coke or to prevent its formation.

Dow has worked with the so-called Antrim shales in lower Michigan for more than 20 years. It would like to use this shale, which is located near its manufacturing facilities, as a source of both energy and raw materials. They think that the appropriate procedure is partial combustion of the coke to produce industrial quality boiler gas.

The cheapest, most efficient way to utilize the relatively thin shale beds, Humphrey says, is in situ conversion of the kerogen by the injection of air. In cooperation with the Department of Energy (DOE), Dow has simulated its in situ process in surface retorts. The company has also done considerable work on explosive and hydraulic fracturing of the shale beds and is now conducting combustion experiments in shale beds about 400 meters underground. Although the results from these studies are considered preliminary, it appears that the shale yields oil and boiler gas with a total energy content approaching that yielded by western shales. The evidence to date, Humphrey says, is that the process is economically feasible, but that more development of fracturing techniques will be necessary. DOE has funded much of the current Dow work because the results should be applicable to many types of eastern shale.

Much of the eastern shale is in thick beds that are suitable for strip mining. For these deposits, an alternative approach might be surface retorting by means of a new process developed by Frank C. Schora and his associates at the Institute of Gas Technology (IGT). The IGT process is similar to other retorting processes, except that the conversion is achieved in a hydrogen atmosphere. The hydrogen—which is obtained by catalytic reforming of a small part of the product—not only reduces coking substantially, but also increases the yield of medium-boiling components so that the oil requires less subsequent refining. Tests with Devonian shales in IGT's experimental hydroretort show that the process can produce as much as 250 percent of the amount of oil predicted by the Fischer assay. Increases in yield can also be obtained with western shales.

IGT is trying to obtain as much as $50 million from DOE and other sources to build a 30-ton-per-hour pilot plant to demonstrate the process on a more realistic scale. If that is successful, Schora says, a commercial plant could be completed within 12 years. Schora guesses that the cost of oil from the process might range from $15 to $20 per barrel at today's construction costs.

Strip mining of course, is not without its problems; but those problems are much smaller in the East and Midwest than in the arid western regions. Water is much more freely available, transportation costs would be much lower, virgin land would not be disturbed, and there would not be the problem of settling an unpopulated region. Combining these factors and the potential of the new technology, eastern shales are looking more attractive every day.—T.H.M.

would be about \$18 to \$20 per barrel. At this level, most observers feel, a pilot plant will not be built without some government financial participation and assistance.

TOSCO seems to have put its retorting plans on the back burner and is now concentrating on the development of technology for the gasification of kerogen. Union and Paraho, however, would each like to construct prototype facilities to get more information about costs and operating factors. Union is considering the investment of \$123 million to build a 7200-bpd pilot plant in Garfield County, Colorado. Paraho is awaiting approval of its environmental impact statement to begin design and engineering work on a \$65 million, 4000- to 5000-bpd module to be located near Anvil Points, Colorado. Either of these could be in operation within 3 years if the companies made a firm commitment. Paraho is the most optimistic of the surface retorters, arguing that oil could be produced for as little as \$11.50 per barrel.

One incentive that might speed the plans of Union and other companies was recently approved by the Senate as part of the Administration's energy program. Largely at the instigation of Senator Herman Talmadge (D-Ga.), the Senate authorized a \$3 tax credit for each barrel of oil produced from shale. The House's version of the energy bill does not contain this provision, however, and therefore it will be up to the conference committee whether it stays in the final bill. Knowledgeable observers think it will. This incentive, says a Union spokesman, could launch a national oil shale industry.

Government encouragement for shale oil production is also coming from, of all places, the Navy. Concerned that some of its dedicated petroleum reserves in California have been given over to civilian production, the Navy has been seeking alternative domestic sources of liquid fuels. Shale oil contains a high percentage of medium boiling range components suitable for fuels—more even than petroleum—and the Navy possesses large oil shale properties in the West. The Office of Naval Research is therefore sponsoring a large-scale refining test in which 100,000 barrels of shale oil will be converted into fuel for military vehicles.

The oil for this test, like that for a 10,000-barrel preliminary test 3 years ago, is being produced at a pilot plant operated by Paraho at Anvil Points. This facility produces only about 160 to 200 bpd, but the plant has operated with high reliability, and Paraho has so far accumulated about 50,000 barrels. The rest of the oil should be accumulated within a year so that the refinery test should begin about this time next year. It should then take about 1.5 years to complete the test, which should also provide a great deal of information about industrial civilian uses of shale oil.

The principal potential problems with refining shale oil are the presence of as much as 2.5 percent nitrogen (about ten times the amount in petroleum), as much as 1 percent sulfur, and relatively high concentrations of paraffinic waxes. The waxes foul engines, the sulfur fouls refinery catalysts and pollutes air, and the nitrogen compounds cause engine "knocking" and deterioration of the fuel during storage. Preliminary results from Standard of Ohio, Chevron Research Company, and LERC all suggest, though, that these problems can be solved by treating the oil with hydrogen. It should, in fact, even be possible to recover potentially

Shale By-products: Cutting the Cost

If shale by-products could be used commercially instead of being simply dumped into the nearest ravine, the economics of surface retorting might be improved substantially and the problem of materials handling would be alleviated. Superior Oil Company of Houston has made substantial progress toward that goal. The firm has developed a process that produces not only shale oil, but also nahcolite ($NaHCO_3$), alumina (Al_2O_3), and soda ash (Na_2CO_3), all valuable industrial chemicals. Recovery of these products could more than double the value of the materials obtained from shale.

The multimineral process is conducted in four steps, the first of which is conventional mining. The shale is then crushed so that the friable nahcolite is liberated from the oil shale. With additional crushing, screening, and photosorting, says Superior's Bernard E. Weichman, nahcolite is obtained in about 80 percent purity. That purity is sufficient for a variety of purposes, particularly for use as a scrubbing agent for removal of sulfur dioxide from stack gases.

Oil is then recovered by a process in which the shale is carried through the retort on a circular grate. By proper control of heat in the retort, dawsonite [$NaAl(OH)_2CO_3$] is converted into alumina and soda ash, which are leached out of the shale with aqueous sodium carbonate. The spent shale, which now has only about 90 percent of its orginal volume, is then disposed of in the mine from which it was taken.

Aluminum trihydrate is crystallized from the alkaline solution, filtered, and calcined to produce alumina ready for conversion to aluminum. Soda ash is then recovered from the solution by evaporation and centrifugation. The facility would be a net producer of water, Weichman says, and strict controls would prevent emission of pollutants. A commercial plant would be built in modules capable of producing 13,000 barrels of oil per day. Using shale from Superior's 2600-hectare tract in the Piceance Creek Basin, each module would produce an estimated 220,000 tons of alumina, 550,000 tons of soda ash, and 1.6 million tons of nahcolite per year. That quantity of alumina would yield about 110,000 tons of aluminum, or about 2.5 percent of last year's primary production of aluminum in the United States. Not all western shale is suitable for the process, but deposits in the basin recoverable by the multimineral process contain more than 300 billion barrels of oil, 30 billion tons of nahcolite, and 20 billion tons of dawsonite.

Superior has financed development of the process alone. Until earlier this year, experimental work was conducted in a small pilot facility near Cleveland; the company is now operating a somewhat larger pilot plant in Colorado. Weichman says a commercial-scale module to produce about 13,000 barrels of oil per day could be in operation within 5 years if the company can obtain a land exchange with the federal government to obtain shale that is slightly richer in the minerals. Such a module would cost about \$300 million. It seems unlikely that the government will provide any financing for the project, but energy officials who are familiar with the process say it looks very promising. If the commercial module proves itself, Superior should have little trouble obtaining funds for a full-scale operation.—T.H.M.

valuable ammonia and elemental sulfur from the process.

As promising as these advances seem, they mean nothing if the environmental problems associated with shale cannot be overcome. These problems, which have been discussed more extensively in the *Science* article cited earlier, include lack of water, rigid air quality standards, and the potential impact of large numbers of workers resettling into the now sparsely populated areas. One by one, however, these problems have begun to appear less serious. The most important reason for this is the development of in situ processes.

The modified in situ processes such as that proposed by Occidental, says Decora, will require only about one-third the total number of people required for mining and surface retorting of shale. They will require only 25 to 33 percent of the water required for surface retorting. And finally, in situ processing will reduce spent shale disposal requirements by at least 80 percent, and perhaps even more. Each of these factors should substantially reduce the environmental impact of a shale oil plant.

Even in a surface retorting facility, the water requirement for spent shale disposal—which accounts for as much as 40 percent of total water requirements—may be drastically lowered. Work at Paraho has shown, according to consulting engineer Philip W. Trumbo, that spent shale can be compressed into a high strength, dense, cementlike material without the use of water or special equipment. The small amount of carbonaceous residue that remains after the oil is retorted out apparently both lubricates the shale for compression and provides the "glue" to hold it together. The compressed shale, Trumbo says, is exceptionally stable and is virtually impermeable to water. The impermeability is important because spent shale is highly alkaline, and it has been feared that alkalinity would leach out of the shale and pollute aquifers and rivers.

Trumbo suggests that the spent shale could be formed into a large basin that would trap water so it would not leach the shale. The interior of the basin would have a 2- to 3-meter deep coating of uncompressed shale. Normal rainfall would then, over a period of 4 to 8 years, leach the alkalinity out of the surface shale, but the basin would prevent it from spreading into the surrounding environment. After the alkalinity is removed from the surface, it would be suitable for growing plants that are indigenous to the area. Trumbo says that the spent shale from a 100,000-bpd plant would, over the course of 20 years, occupy an area of about 3 square kilometers to a depth of about 300 meters. In the region where the shale is located, he argues, such a geological structure would be virtually insignificant. .

A possibly more difficult problem has been air quality standards in the area. As recently as a year ago, Occidental and Ashland and the Rio Blanco group were forced to suspend their leases in Colorado because the ambient concentrations of particulates, hydrocarbons, and ozone in the area already exceeded federal guidelines and because limits on sulfur emissions from retorts were too restrictive. But this situation may not be the impediment it once seemed.

Easing of Standards

In August, the Colorado Air Pollution Commission eased the standard for sulfur emissions to 0.18 kilogram of sulfur dioxide per million Btu's of energy produced. This is the level sought by oil shale companies, but it is still much tighter than the federal standard of 0.54 kilogram per million Btu's. The federal Environmental Protection Agency also seems likely to give ground. Earlier this year EPA told Occidental and Ashland and the Rio Blanco Oil Shale Project that they would not need a so-called PSD permit—the initials stand for the rather nebulous concept of prevention of significant deterioration of air quality—until they were ready to begin retorting. Under pressure from environmental groups in Colorado, the agency last month reversed itself and said that the permits must be obtained before mine shafts to the shale can be sunk, an operation that is scheduled to begin this month for Occidental and next month for the Rio Blanco Oil Shale Project.

Despite this reversal, EPA appears likely to permit the projects to continue. The agency has found, according to Terry Thoem of EPA's Office of Energy Activities in Denver, that particulates in the region are primarily wind-blown dust, and thus are not an air pollution hazard. Similarly, the high concentrations of hydrocarbons result primarily from plants and are also not a hazard in the absence of significant concentrations of oxides of nitrogen, which must combine with the hydrocarbons before smog can be produced. The federal guidelines for hydrocarbon concentrations, furthermore, are just guidelines and not standards, and are thus not legally enforceable. And finally, the ozone problem could be solved simply by easing the standards by a few percent. The most compelling argument, Thoem adds, is that it will be impossible to determine the impact of shale oil plants precisely until one or more are built and operating. It thus seems likely that the current projects, at least, will not be delayed because of air quality problems.

There is one final hill in the path of shale oil's roller coaster: the problem of materials handling. If about 1 million bpd of shale oil were to be obtained by surface retorting (about 5 percent of projected oil requirements at the turn of the century), about 1.5 million tons of shale would have to be mined and retorted and about 1.3 million tons of spent shale would have to be disposed of each day. That amounts to about 1 billion tons of material that would have to be handled each year. Last year, in contrast, total coal production in the United States was about 600 million tons. Most engineers seem to think that, considering other mining needs, 1 billion tons is about the outer limit of the amount of shale that can be handled each year.

If a modified in situ process were used, it would be necessary to handle only about 200 million tons of material each year for the same oil production. A mix of surface, in situ, and modified in situ retorting might thus be able to produce 2 to 3 million bpd by the year 2000—if a capital investment of $20 to $30 billion can be obtained and if the necessary mining equipment and engineers can be obtained without disrupting other mining operations.

The economics of shale oil production might be improved and the materials handling problem alleviated slightly by the recovery of secondary products. Recovery of ammonia from a 1-million-bpd shale oil industry could, for example, produce about 6 percent of last year's total U.S. production of anhydrous ammonia. On the same basis, recovery of sulfur would yield about 8.6 percent of last year's output of elemental sulfur. Recovery of other minerals, as envisioned in the Superior Oil Company process (see box) would be even more dramatic.

Past experience has shown that it is very easy to be too optimistic about production of shale oil. Another sharp increase in inflation, a moderate decrease in the world price of petroleum, a faltering of government support, or perhaps some still undiscerned factor could send the roller coaster downhill again. For the moment, though, the direction is definitely up and the industry is hoping it will stay that way for a long time.

—THOMAS H. MAUGH II