Oil Shale in the United States: Prospects for Development

By Mark Drabenstott, Marvin Duncan, and Marla Borowski

Oil shale development again is a matter of debate. For decades, developers claimed that if oil prices increased only a few dollars a barrel, the country's abundant deposits of oil shale would become a viable source of energy. The claim seemed justified when oil prices jumped sharply in 1973 and 1979. Major energy companies responded by laying plans for multibillion-dollar investments to produce oil from shale. The oil glut that developed in 1982, however, put many of these investments on hold.

The recent boom and bust cycle in oil shale development had a significant economic impact on Rocky Mountain states. Colorado's western slope, with its rich shale deposits, experienced a particularly sharp swing in both economic activity and expectations for future growth.

The Rocky Mountain region and the oil shale industry now look to the future. Will oil shale become economically viable? Or will it remain an energy resource locked away underground?

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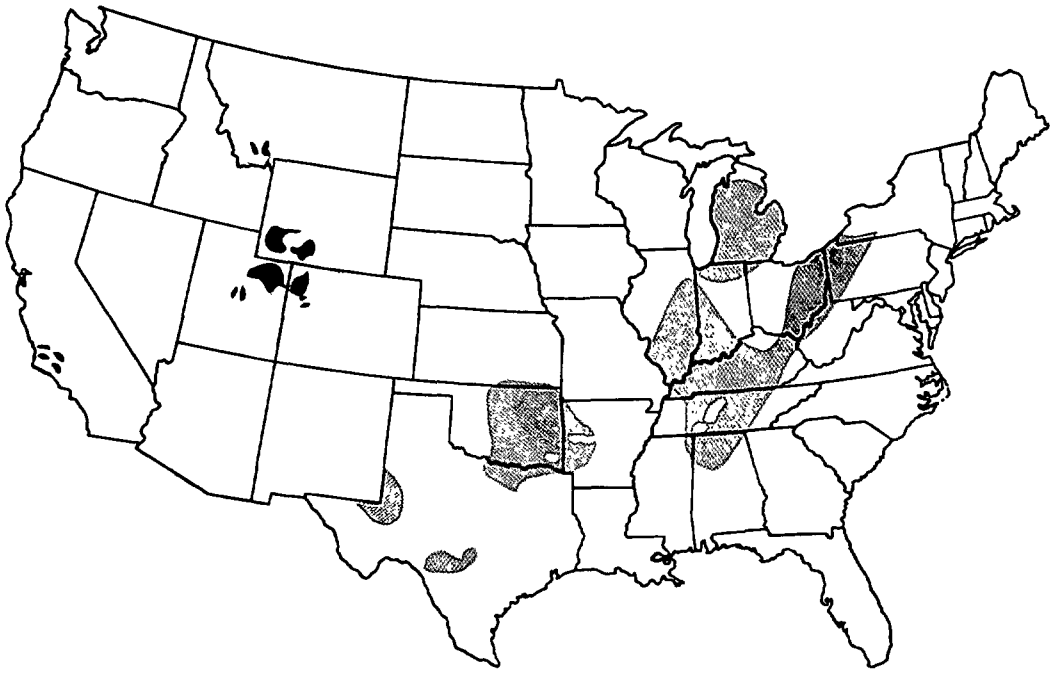
This article suggests an uncertain outlook for oil shale. The article describes oil shale resources in the United States and discusses the effects of oil shale development on Colorado's Western Slope. Finally, the article analyzes four factors that are likely to determine the future of oil shale development.

The oil shale resource

Oil shale deposits are primarily marlstone, a sedimentary rock. Oil is locked in the shale rock as a rubbery substance called kerogen. To separate the kerogen, the shale must be heated to about 900°F, a process called retorting. The raw shale oil extracted by retorting is different from conventional crude oil and must be specially treated to make syncrude, a refinery-ready substitute for crude oil.

Although oil shale deposits sometimes contain other minerals in commercially valuable quantities, the value of oil shale usually depends on its kerogen content. High-grade deposits can yield 30 or more barrels of oil per ton of rock. The United States is believed to have about 8 percent of the world's oil shale–an oil equivalent estimated at 168 trillion barrels. The deposits underlie parts of 14 states,

FIGURE 1
U.S. oil shale deposits



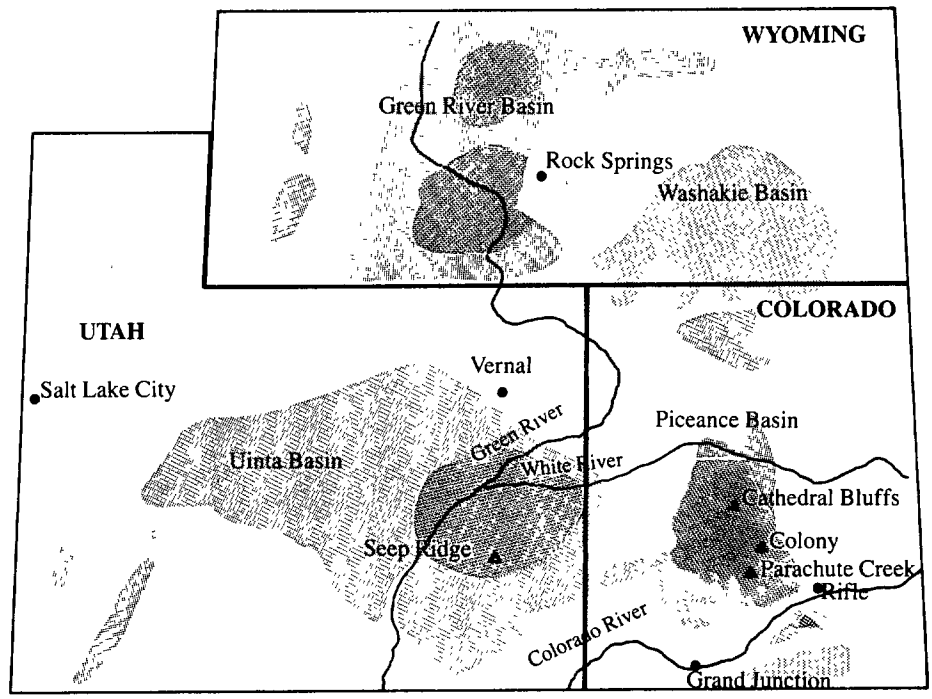
High-grade shale
Low-grade shale

Source: U.S. Geological Survey

or about a fifth of the nation's land mass (Figure 1). The richness of these deposits varies widely. Estimates of the lower quality deposits in the central and eastern United States run about 3 trillion barrels of oil equivalent. The marine shales underlying Alaska are thought to contain 450 billion barrels of oil equivalent in high-quality deposits and a large but unknown amount in lower quality deposits. Another 157 trillion barrels are in shale associated with coal and scattered deposits throughout the country. The country's richest deposits, however, are in the Green River formation underlying Colorado, Utah, and Wyoming (Figure 2).

The Green River formation contains an estimated 8 trillion barrels of oil equivalent. Sixty percent of the country's highest grade deposits are in this formation, 11 percent of its medium-grade deposits, and 3 percent of its lowest grade deposits. About 67 percent of oil shale in the Green River formation is in the Piceance Basin in Colorado, shown in Figure 2. The Uinta Basin in Utah contains about 18 percent and the Green River and Washakie Basins in Wyoming only about 15 percent. Because more than 90 percent of the richest shale is in the Piceance Basin, most of the oil

FIGURE 2
Green River Formation



Unappraised or low-grade shale
Shale yielding 25 gallons or more per foot

Source: U.S. Geological Survey

shale development has been in that area.

Industry development

Oil shale development has been associated with rapid growth in energy demand and fears of falling energy supplies. The first development began about 1850, but collapsed when oil was discovered at Titusville, Pennsylvania, in 1859. Development began again in the early 1900s, peaked during World War I, and then collapsed with the discovery of large Texas oil deposits in the late 1920s. A new surge of interest during World War II passed when Middle East oil became available in the late 1940s.

With the Arab oil embargo and rapidly rising world oil prices in the 1970s, attention turned again to oil shale. Development has been abetted more recently by loan and price guarantees by the U.S. Synthetic Fuels Corporation, a public corporation charged by Congress with spurring the development of alternative energy sources. The result of this recent attention was the largest of the recurring oil shale booms. Activity was centered mostly in northwestern Colorado but also to some extent in adjacent regions of Utah.

As recently as August 1981, at least 16 major oil shale projects were in various stages of consideration, experimentation, construction, or production (Table 1). In short, a truly spectacular oil shale boom was expected to bring permanent change to the historically weak economy of northwestern Colorado.

But even as activity began to increase, economic forces were at work that would burst the development bubble. Higher energy prices had brought greatly increased energy exploration and development, as well as greatly increased energy conservation. A deep and prolonged worldwide recession reduced world energy demand. World crude oil prices fell to about $29 a barrel in 1983 and have continued to decline in real terms. The world energy recession that began in early 1982 has not yet ended.

Thus, the economics of oil shale development changed drastically after 1981. Recognizing the change, Exxon and its partner Tosco closed down their giant Colony project in mid-1982, signaling the end of the oil shale boom. Other projects also were closed or scaled back. Only a few major projects are still moving toward commercialization in Colorado and Utah, and two of them represent different phases of the same development.

Four western oil shale projects have received federal assistance to facilitate oil shale development (Table 2). Because of the long lead times required for developing a commercial-sized plant, only these four projects are expected to produce substantial amounts of shale oil over the next several years.

Union Oil, which owns oil shale lands, started constructing Phase I of its Parachute Creek project in 1981. This project was the first commercial-size mine and retorting facility in the Piceance Basin (Figure 2). Several years had already gone into planning the project and building infrastructure. Construction was completed by late 1983, and Union Oil began final preparations for producing shale oil. The plant is expected to begin producing 10,000 barrels a day in 1984.

Development on tracts leased from the federal government is progressing slowly. The Cathedral Bluffs project, which has received Synthetic Fuels Corporation support, is in the design and engineering phase. Operations have been suspended on the Rio Blanco Oil Shale project, although research and development work continues. Partners in the White River Shale project in Utah have withdrawn their request for financial assistance from the Synthetic Fuels Corporation while they evaluate and review project plans.

Most developments on private, state-owned, or Indian land are still in the planning and research and development stages. In Utah, the Seep Ridge project is completing a seven-year research and development program and raising equity capital before beginning commercial construction. The Paraho-Ute project is still satisfying management and partnership conditions set by Synthetic Fuels and expects to sign a letter of intent by the end of the year. In Colorado, the Clear Creek development is in the pilot-plant state. Development of the large Colony project was stopped in mid-1982, and only certain construction, maintenance, and reclamation activities are still underway.

The economic impact of oil shale development

Oil shale development has long been marked by booms and busts. Moreover, each period of development has been accompanied by rapid increases in real energy prices, increased investment by energy companies, and high expectations of its economic effects. Every period of development also has col-

TABLE 1
Major oil shale projects in Colorado and Utah as of August 1981

Project	Developer	Production target (barrels per day)
Rio Blanco	Gulf and Standard Oil of Indiana	50,000 by early 1990s
Cathedral Bluffs	Occidental and Tenneco	95,000 by early 1990s
White River	Sunedco, Phillips, and Sohio	100,000
Colony	Exxon and Tosco	47,000 by 1987
Long Ridge (Parachute Creek)	Union Oil	50,000 by 1990
Pacific	Superior, Sohio, and Cleveland Cliffs	15,000 by 1987, 50,000 ultimately
Sand Wash	Tosco	50,000
Logan Wash	Occidental	500
Geokinetics	Geokinetics	2,000 by 1982
BX	Equity Oil	Unspecified
Paraho-Ute	Paraho Development and 14 industrial sponsors	8,000 by 1984, 30,000 by 1986
Horse Draw	Multi Mineral Corporation	50,000 by 1989
NOSR	DOE and DOD	Up to 200,000
Superior	Superior, Sohio, and Cleveland Cliffs	Up to 23,000
Clear Creek	Standard Oil of California	100,000 by mid-1990s
Bart In Situ	Texaco	Unspecified

Source: Colorado Energy Research Institute and Colorado School of Mines Research Institute, *Oil Shale 1982: A Technology and Policy Primer*, pp. 42-43.

lapsed with declines in real energy prices.

As recently as 1981, a panel appointed by the governor of Colorado expected that state's shale oil production to reach 200,000 barrels a day by 1990.[1] More optimistically, the U.S. Office of Technology Assessment expected production in Colorado to reach 400,000 barrels a day. Forecasts by other groups for the year 2000 ranged from 400,000 to 4 million barrels a day.

The development foreseen by all these forecasts was expected to have marked effects on the economy of Colorado's ten northwestern counties. The population of those counties, estimated at 175,000 in 1981, was expected to at least triple by the year 2000. Forecasts of spending on housing in those ten counties ranged from $1.5 billion to $18.7 billion (1979 dollars), depending on the shale oil production scenario assumed. Private sector investment in shale oil plants over the rest of the century was expected to range from $15.3 billion for the low production scenario to $200 billion for the high production scenario (1979 dollars). Public financing requirements for construction of public facilities were forecast to range from $400 million to $5.8 billion (1979 dollars).

Sharp increases were expected in the use of water, already scarce in that area. Annual

[1] *Oil Shale 1982: A Technology and Policy Primer*, Colorado Energy Research Institute and Colorado School of Mines Research Institute, Denver, November 1981, pp. 84-88.

TABLE 2
Synthetic Fuels Corporation oil shale projects

Project (developer)	Estimated authority (billions) of dollars)	Technology	Production capacity (barrels per day)	Ultimate production potential* (barrels per day)	Status
Parachute Creek, Phase I (Union Oil Co.)	$—	Union B Surface retort	10,400	—	A $0.4 billion price guarantee transferred from the DOE
Parachute Creek, Phase II (Union Oil Co.)	$2.70	Union C Surface retort	42,152	90,000	Letter of intent executed
Cathedral Bluffs (Occidental Petroleum Corp., Tenneco Oil Co.)	$2.19	Modified in-situ and Union B	14,100	100,000	Letter of intent executed
Seep Ridge (Geokenetics)	0.05	True in-situ	1,000	8,000	Letter of intent authorized
	$4.94		67,652	198,000	

*The estimates of ultimate site expansion potential are based on current Synthetic Fuels staff opinion on the land, water, and resource availability for each project and the assumption that environmental limitations can be appropriately mitigated. The estimates should not be considered as reflecting the sponsors' current planning for site development.

Source: Synthetic Fuels Corporation.

water usage for shale oil production by the year 2000 was expected to range from 72,000 to 753,000 acre feet. Shale oil production exceeding one million barrels a day was expected to require constructing new water storage facilities, purchasing water rights from current owners, and importing water from other river basins.

The recent oil shale boom has ended and the economic cost of the bust is now being assessed. Since Colony was the largest of the oil shale projects, its impact on Colorado's Western Slope economy also was large. Thus, a review of Colony's impact, both in boom and in bust, helps put oil shale development in an economic perspective.

Economic impact of the Colony project

The shutdown of the giant Colony project–after an investment of some $1 billion–raises questions about the effect of such boom and bust development on northwest Colorado. Designed to produce 47,000 barrels of shale oil a day, the Colony project would have employed more than 3,000 workers at the peak of its construction.[2] Completed, it would have taken 1,200 permanent employees. About 2,100 workers were employed in construction there when the project shut down.

In addition to direct employment associated with the Colony project, indirect employment in project-related work, such as trucking, and unrelated industries, such as banking and food service, was expected to add about 9,000 new residents to the area by 1984 or 1985.[3] Most

[2] Wayne Lee Hoffman, "Coping With Boom and Bust: The Colony Oil Shale Project," *Natural Resource Development*, Vol. 2, No 1, Center for Public-Private Sector Cooperation, University of Colorado at Denver, March 1983, pp. 29-58.

[3] Hoffman, p. 35.

of these new residents would have been in Colorado's Garfield and Mesa counties. Exxon's new town development of Battlement Mesa was planned for an eventual population of 20,000 to 25,000.

The shutdown brought rapid reductions in Colony project employment. From more than 1,900 Garfield and Mesa county people employed in early 1982, the figure fell to 239 in late 1982.[4] About one-half to two-thirds of these workers had moved into the area to work on the project. Most of them moved on to other construction projects or to other oil shale projects in the area. The shutdown also triggered layoffs at supplier and contractor firms far from Colorado.

The rapid influx of people–with further inflows expected–resulted in substantial new public investment in roads, water treatment plants, schools, and other public facilities. No new public debt was incurred, however, because the increased expenditures for capital and services were financed entirely by the firms developing oil shale, by state mineral trust funds and severance taxes, by local general fund surpluses, and by taxes collected while growth was rapid. A system of county permits allowed local jurisdictions to negotiate for substantial infrastructure and services support from the firms developing the oil shale projects. Spending on public safety also increased significantly.

On balance, because up-front investment capital was available, local jurisdictions affected by the Colony project were able to upgrade their public facilities and services substantially. These communities now have excess capacity for accommodating future growth.

With the boom over, these local jurisdictions will likely contract for several years. Sales tax revenues will decline, although the real estate tax base is larger because of new private construction. The Colony project has provided some transitional help with local budgets. Other oil shale projects, such as Union Oil's, will also help. Public budgets will, nevertheless, decline. Demand for public service will also fall, though probably not as fast as revenue.

Private interests other than energy companies also participated in the development boom, making substantial investments in rental housing and local businesses. These investments, profitable only if the rapid population growth had continued, likely will suffer losses. For example, houses at Battlement Mesa are now being offered for rent at well below previously prevailing rental rates, thus lowering rates for rental housing throughout that area. As a result, apartment investments that seemed sound at earlier rental rates may no longer be profitable. Financially weak investors could be forced out of business.

A large part of the economic effect of oil shale development on these ten counties has been borne by the energy companies themselves–through the state's share of federal payments and through payments and infrastructure investment in local jurisdictions. That means local jurisdictions have been largely protected from financial problems resulting from the oil shale boom.

Private business firms have not been as fortunate. Some firms have been adversely affected as projects phased down. But the biggest adjustment for the private sector probably has been the lowering of expectations of future economic growth. At the time of the Colony shutdown, for example, officials in Colorado's Department of Natural Resources used a computer model to forecast the effect of oil shale development on Garfield and Mesa counties. According to their forecast, if the

[4] Hoffman, p. 41.

Chevron and Colony projects were closed out and the Union project produced only 10,000 barrels a day, total employment in Garfield county in both 1985 and 1990 would be about half what it would have been if high levels of development had continued at all three projects.[5] Total personal income also would be less than half as high, reflecting the relative importance of oil shale development in mostly rural Garfield county. Population in Mesa county, more urban than Garfield county and with less oil shale development, would be about 80 percent of what it would have been in 1990. Personal income would be about 75 percent of what it would have been with rapid oil shale development.

While oil shale development had a drastic effect on the economy of northwest Colorado, the adverse aspects of both the boom and the bust that followed were substantially mitigated by the cooperation of energy developers and all levels of government. Thus, the area's public and private sectors were able to adapt to the changing level of oil shale development with much less trauma than had been initially expected. The effects were mitigated almost completely for the public sector, but less so for the private sector. Even there, however, the greatest impact of the bust was the trading down of expectations of future economic growth rates. Still, the prospect for future development holds promise for both energy firms and the communities contiguous to such development.

The future for oil shale

The future for oil shale depends on a number of economic and technological factors. Four factors will be particularly important: oil prices, technology and economies of shale oil production, energy policy, and environmental impacts.

Oil prices

To be a viable source of energy, oil shale must be competitive in price with other forms of energy. Prospects for oil shale development, therefore, hinge to a great extent on the future of oil prices.

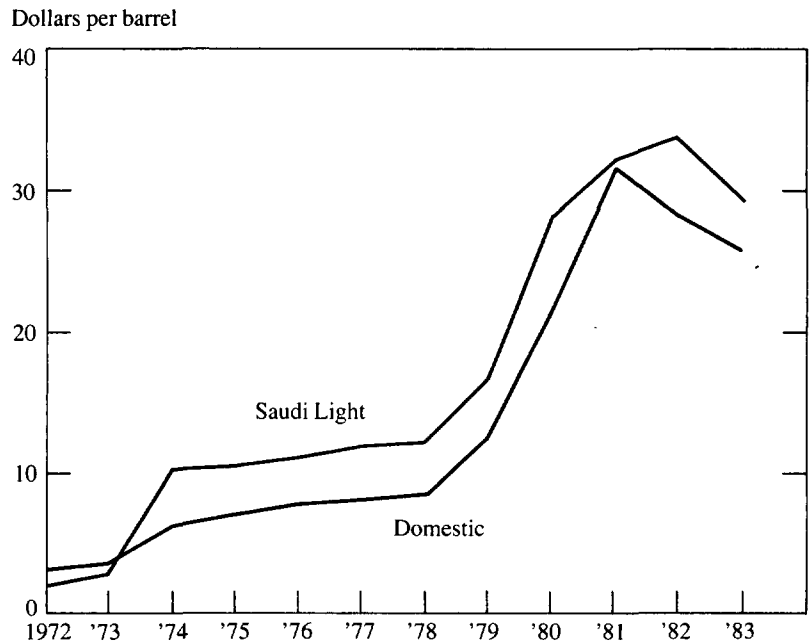
Over much of the past decade, oil prices have reflected price fixing by the Organization of Petroleum Exporting Countries (OPEC). In 1973, OPEC exercised enough control to triple prices. Crude oil prices rose from roughly $3.50 a barrel to about $10.50 (Chart 1). And in 1979, OPEC took steps that led to a near tripling in oil prices.

Although oil prices seemed headed even higher after this second round of tightening, they suddenly began declining in 1981. Two developments brought this about. One was a sharp slowing in the growth of world energy demand as industrial countries slipped into recession. Widespread efforts had already been made to improve energy efficiency. Taken together, recession and greater efficiency resulted in an 11 percent decline in total U.S. energy consumption between 1979 and 1982. The second development was that higher oil prices led to increased energy production in the United States and other non-OPEC countries. Decontrol of oil and natural gas prices spurred exploration and development. Coal production also increased substantially throughout the 1970s and early 1980s. Increased oil production in non-OPEC countries, such as Mexico and Great Britain, also raised world oil supplies.

A primary result of declining oil prices since 1981 has been the shelving of many oil

[5] Colorado Department of Natural Resources, Executive Director's Office Memorandum, May 5, 1982, Tables 2, 4, 5, and 7.

CHART 1
Price of crude oil



Source: Chase Econometrics

shale projects. The critical question for shale development now, therefore, is the future course of oil prices.

Total oil supplies will probably be fairly large for the next five years. Domestic crude oil supplies remain large compared with the 1970s. Moreover, if oil prices increase, exploration and development would also increase rapidly, adding to energy supplies. Foreign oil supplies will also continue to be large. Oil-producing countries with sizable foreign debts, such as Mexico, Venezuela, and Nigeria, will keep production high to service their debt with oil earnings. Many Middle East oil-producing countries have economic development programs that must be financed with oil revenues. Thus, total world oil supplies will probably remain ample.

U.S. energy demand, meanwhile, will likely grow slowly. Although economic expansion will lead to more energy use, continued gains in efficiency will limit the growth in demand. As one example of the improvement in efficiency, the United States now uses 15 percent less energy to produce a dollar of real GNP than it did five years ago. As a result, total energy use actually declined 1 percent in 1983, even though that was a year of strong economic growth. Thus, while total energy consumption in the United States will continue to grow, the growth will be much slower than in the 1970s.

On balance, oil prices may increase modestly in nominal terms over the next five years, but prices are expected to continue declining in real terms. This suggests, other things equal, that oil shale development will become less economical. But this near-term oil price outlook–and more especially the longer term outlook–is subject to a range of economic and political events that could force a change. A sudden disruption of world oil supplies could quickly make shale oil more attractive. But for rapid oil shale development to occur, expectations of high oil prices would have to hold for an extended period.

Economics of oil shale production

Oil shale's ability to compete with petroleum depends not only on oil prices now and in the future, but also on the relative cost of producing oil from shale. That cost depends largely on technology.

Three methods can be used to retort shale oil. In surface retorting, the shale is mined, crushed, and then heated in a retort above ground. In another, called in-situ retorting, the oil is recovered by heating the shale underground and then piping the raw shale oil to the surface for further treatment. The third method, modified in-situ retorting, combines the other two methods. Part of the shale is mined for retorting on the surface. The mine creates an underground working area where other shale can be shattered by explosives and heated to separate the kerogen. The resulting raw shale oil is then pumped to the surface and treated, along with the surface-retorted oil, to make syncrude.

Although further technological improvements or even breakthroughs lie ahead, the oil shale industry expects developments over the next decade to be based on current technologies. Of these, surface retorting processes appear most likely to succeed.

Given current technology, the critical question is how well syncrude can compete in terms of cost with conventional crude oil. The answer is not very well, at least at present.

Industry estimates made in 1981, the most recent year that such data are available, set the total cost of finding, developing, and producing a barrel of conventional crude oil at about $15 (Table 3). Production costs included in this nominal-dollar estimate–the cost of operating and maintaining wells–are the average for old and new wells. Since production costs for new wells, especially offshore, on the North Slope, or in the Overthrust Belt, are higher than for old wells, some per-barrel costs are much higher than this estimate suggests.

The Synthetic Fuels Corporation estimates that, in 1984 dollars, syncrude from Phase I of Union Oil's Parachute Creek project will cost about $35 a barrel (Table 3). After full development of Phase II, Union's syncrude costs could drop to about $29 a barrel, again in 1984 dollars. The Synthetic Fuels Corporation believes these estimates are accurate to within 20 percent. The estimates do not include an imputed return on equity capital. Inclusion of a 12 to 15 percent return would push the per-barrel costs still higher.[6]

Partly because of technical uncertainties in plant operation, costs for shale oil projects are not known exactly. Cost overruns for plant construction pose a sizable risk, given the large capital outlays required. The estimated cost of a 50,000-barrel-a-day surface retorting plant, for example, was $138 million in 1968, $450 million in 1974, and $1.7 billion in 1980.[7] When the two phases of Union Oil's

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[6] The Office of Technology Assessment estimated in 1980 that surface retorted shale oil would cost $48.20 a barrel, assuming a 12 percent rate of return on equity, and $61.70 a barrel, assuming a 15 percent rate of return on equity

TABLE 3
Comparison of syncrude and crude oil costs

	Surface retort syncrude oil (per barrel in current dollars)		
	Capital[1]	Operation[2]	Total
Parachute Creek Project			
Phase I (10,000 barrels/day)	$6.57	$28-$30	$34.57-$36.57
Phase II (42,000 barrels/day)	$7.70	$21-$22.50	$28.70-$30.20
Total (52,000 barrels/day)	$7.48	$21-$22.50	$28.48-$29.98

	Conventional crude oil (per barrel in current dollars)		
	Exploration and Development[3]	Production[4]	Total
1981	$7.78-$8.86	$7.14	$14.92-$16.00
1982	$7.29-$8.31	NA	NA
1983	$6.03-$6.87	NA	NA

[1]Source: Synthetic Fuels Corporation, Union Oil Parachute Creek Project Letter of Intent. Per-barrel costs based on 30-year plant life with 330 operating days per year.
[2]Source: Synthetic Fuels Corporation.
[3]Source: James C. Dyer, "The Cost of Reserves by Discovery vs. Acquisition," *Oil and Gas Journal*, December 19, 1983.
[4]Source: American Petroleum Institute, *Basic Petroleum Data Book*, Vol. III, No. 3, Tables V. 10, IV. 5, and XIII. 9.

project are completed in 1985, plant costs will exceed $3.85 billion.[8] Although part of the increase in cost has been due to inflation, much of it results from uncertainty about plant engineering. Operating costs are even more uncertain because the economies of scale for commercial retorting are still not fully understood. Uncertainties in forecasting total production costs translate into a high discount rate for oil shale projects that reduces the likelihood of private development without government assistance.

Although costs of production favor conventional crude oil, current cost comparisons are extremely tenuous at best. The shale oil projects now underway are the first efforts to produce shale oil on a commercial scale. No one knows for sure how well current technologies will work on a commercial scale.[9] Nor does anyone know what the final unit cost will be. Until more is known, current estimates suggest that conventional crude oil likely will

[7] Office of Technology Assessment, *An Assessment of Oil Shale Technologies*, June 1980, p. 186.

[8] Synthetic Fuels Corporation, Letter of Intent, Union Oil Parachute Creek Oil Shale Project, December 1983.

[9] Union Oil has encountered engineering problems as its Parachute Creek project scales up from pilot plant to commercial production levels. Time-consuming mechanical modifications have been required in the several months since construction was completed. For a more complete discussion, see "Shale project hits another roadblock," *Rocky Mountain News*, May 1, 1984.

remain much less expensive to produce than syncrude.

Federal energy policy

Federal energy policy has been critical to oil shale development. Although the future scope and direction of federal oil shale policy are uncertain, the infant status of the industry suggests that the government's influence on development will remain substantial.

Oil shale development is part of an overall federal energy policy that also includes other programs. Deregulation of oil and gas prices, the strategic petroleum reserve, higher gasoline taxes, research and development grants, and tax inducements are also used to achieve national energy objectives. Benefits and costs of these programs will influence future government support for oil shale.

Government involvement in stimulating oil shale development has been justified on grounds of the benefits to the country. Foremost among these benefits has been that commercial-scale plants provide critical experience with retorting technology. This experience provides a form of insurance against future disruptions in oil supplies. If shale oil ever did become economically viable, it would reduce the country's dependence on imported oil and contribute to a stronger balance of payments.

Because these benefits generally meet with approval, the real issue is whether a commercial industry would develop without any government assistance. The government's program has mitigated the significant risks private firms face in full-scale commercial development. There are technical risks in moving shale oil production from the pilot stage to a commercial operation. Largely a matter of engineering, these problems will be fully resolved only by trial and error. Examples of potential technical problems in surface retorting include handling the large amounts of shale that feed into the retort and controlling the separation of sticky kerogen from spent shale. Economic risks arise from the uncertainty of not knowing the costs of production. Finally, institutional uncertainties result from a complex set of changing government regulations. Environmental regulations are a particular concern to developers because the final scope and tenor of regulations is still in doubt.

The Office of Technology Assessment concluded in 1980 that the combination of these risks would impede the development of anything but a very small shale oil industry. The number of projects now underway suggests that federal assistance was necessary to spur development.[10]

The Synthetic Fuels Corporation provides federal assistance to oil shale development. Created in 1980 by the Energy Security Act, the corporation was intended to help develop synthetic fuels production capacity of 500,000 barrels a day by 1987 and 2 million barrels a day by 1992. To meet these targets, Synthetic Fuels was given authority to make loan and price guarantees to developers of oil shale and other synthetic fuels projects.

Synthetic Fuels committed about $5 billion in total budget authority to oil shale projects in 1982 and 1983, one-third of its total budget authority for all synthetic fuels programs. Three major projects received price guarantees, loan guarantees, or both (Table 2). The support initially committed to a project is the maximum that can be allocated over the life of the project. Once the maximum is reached, no further support is allowed. Oil shale projects were selected to achieve two basic objectives.

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[10] For a full discussion of impediments to commercial development of oil shale production, see Edward D. Merrow, "Constraints on the Commercialization of Oil Shale," Department of Energy Report R-2293-DOE, September 1978.

First, Synthetic Fuels wanted to encourage development of oil shale in its various states: deep deposits, bluff deposits, and shallow deposits. Second, recognizing that potentially significant technological breakthroughs might be made, it wanted to support various retorting technologies.[11]

Government support for oil shale development may be more limited in the future. Current support is aimed at enabling the oil shale industry to overcome the uncertainties of commercial startup. Once commercial plants are operating and more is known about the true costs of producing shale oil, developers may have to carry out additional development on their own. Nevertheless, if oil prices were to escalate sharply in the next ten years, support for public assistance could emerge again. It is much more likely, however, that any future public effort to encourage shale oil development will center on research to improve recovery techniques.

In many respects, current public support of oil shale development is a grand experiment. The public is investing substantial funds in a fledgling industry that offers potential benefits to the country. The size of the potential benefits and the number of risks facing private developers may justify this support. Conversely, oil shale development could prove too costly as an energy alternative. Once the experiment is over, the shale oil industry will very likely have to stand on its own feet.[12]

Environmental impacts

Oil shale development will bring a host of environmental problems to western mountain states. Because current technology points to an industry built on surface retorting, a range of issues involving the quality of air, water, and land will be important to the development of oil shale.

Crushing and processing mined shale will create dust and pollutants that will reduce visibility and degrade the quality of the air. Pollutants created during processing, primarily sulfur dioxide, nitrogen dioxide, and particulates, could have potentially serious effects, such as acid rain. High elevation lakes could be especially susceptible to damage from acid rain. The severity of visibility and air quality problems cannot be accurately predicted.

The processing of shale creates two potential water pollution problems. The main concern is with the discharge of contaminated process water at the surface. That problem might be reduced by treating waste water to industrial standards and reusing it. Developers are planning to discharge no surface water. They will dispose of any untreatable wastes in the spent shale.

But surface runoff and leaching from spent

[11] While the Synthetic Fuels Corporation has committed $5 billion to oil shale development, much of this could be recovered by letting Synthetic Fuels share in revenues if oil prices rise. In the Union Oil project, for example, Synthetic Fuels agreed to guarantee a price of $60 a barrel in 1983 dollars for ten years. As long as market oil prices remain below this real price, Synthetic Fuels must make up the difference, up to a maximum total subsidy of $4.25 billion. During the ten-year price guarantee period, if market oil prices rise above the $60 guaranteed real price, Synthetic Fuels receives 70 percent of the excess. Moreover, for a period of six years beyond the first ten years, Synthetic Fuels shares 50 percent of the difference between the market price and $32.55 a barrel (1983 dollars) and 70 percent of the difference between the market price and $45 a barrel (1983 dollars). Thus, if market oil prices rise sufficiently during the project's first 16 years, a large portion of the initial public subsidy could be recovered through revenue sharing. On the other hand, if market oil prices are stable or decline during the next 16 years, little if any public subsidies will be recovered. Synthetic Fuels optimistically estimates that a significant portion will be recovered and the final subsidy cost may be only about $1 a barrel, or about $350 million.

[12] That time could come sooner than previously expected. Congress currently seems to be reevaluating its earlier decision to support synfuels development with public funding. This could lead to reduced support for oil shale projects.

shale pose a more perplexing problem. Runoff of toxic wastes into mountain streams could present a serious problem. Although several methods of controlling leaching have been proposed, none have yet been proven. Significant leaching would reduce the quality of underlying aquifers. Extensive research is being done on this problem.

The availability of water could be more important to development of the oil shale industry than water quality problems. Water is a precious resource in the Colorado River Basin, and extensive processing of oil shale would substantially increase overall demand for available water supplies. If a large-scale oil shale industry becomes viable, however, water will very likely be allocated by pricing.

Another environmental issue involves reclaiming land where spent shale is deposed. The primary problems are in controlling leaching of hazardous wastes and restoring vegetation to limit erosion. The land reclamation problems appear manageable. With intensive cultivation, vegetation can be established directly on processed shale. But covering the shale with at least one foot of top soil or similar material reduces the time required for revegetation and leaves a more stable topography in the long run. Although land reclamation techniques share many common features, reclamation plans must be site-specific.

A series of federal and state regulations set environmental standards for air, water, and land. Under the Clean Air Act, the best available control technology has to be used to comply with national and state air quality standards. The Clean Water Act sets quality standards for any surface water discharge. Any toxic wastes from spent shale could be subject to the Resource Conservation and Recovery Act. Although no federal legislation has been written for managing the reclamation of spent shale, the Surface Mining and Control and Reclamation Act serves as a model for setting standards for shale projects on federal tracts.

Altogether, environmental issues have the effect of raising the cost of shale oil and slowing its development. Compliance with all the environmental regulations has been estimated as adding 10 to 20 percent to the cost of shale oil.[13] Beyond these direct costs, compliance also exacts a cost in time. More than 100 permits, many environmentally related, must be obtained to construct an oil shale plant. Obtaining these permits takes considerable time and effort.[14]

The environmental impacts of oil shale development are significant and largely unknown. Whether current environmental concerns are valid remains to be seen. But until much more is known about the effects of commercial shale oil production, environmental issues will be a factor slowing oil shale development.

Thus, oil shale's future will depend on oil prices, costs of production, energy policy, and environmental issues. Another boom and bust cycle would bring a new round of economic effects to the Western Slope. Because local governments there still have excess capacity in public infrastructure and services, they can accommodate a new development surge. The region and the oil shale industry, however, both hope for steadier growth in the years ahead.

Summary

The development of an oil shale industry has had its ups and downs throughout this century. Despite vast reserves of recoverable shale oil, energy prices usually have not been

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[13] *Oil Shale 1982: A Technology and Policy Primer*, p. 67.

high enough to make extraction of that oil commercially viable. The tripling and then tripling again of world oil prices in the 1970s gave initial promise that development had become economically feasible.

After only a few years of rapid development activity, however, the effort was brought to a near-halt by falling world oil prices. The results were a substantial reduction in economic activity for northwestern Colorado and, maybe more importantly, sharply lower expectations for the region's future economic growth. In both the upturn and the downturn, the local public sector was essentially shielded from financial stress because the energy companies helped fund public spending on infrastructure and services.

The future for oil shale remains uncertain. A few energy companies continue to pursue their development plans. To spur development of commercial scale plants, Synthetic Fuels Corporation has made loan and price guarantees to energy firms. Some projects may soon be extracting oil, providing needed technological and financial information on various techniques of oil extraction. But the future for oil shale remains clouded by uncertainties regarding the cost of producing syncrude and future oil prices. Environmental issues could also hamper oil shale development. Therefore, oil shale remains, as it has for more than a century, a technical and economic enigma that has only begun to be understood and developed.

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[14] The cost of complying with air, water, and land environmental standards differs considerably The Office of Technology Assessment concluded in 1980 that air quality controls would add 3 to 5 percent to the cost of syncrude, water quality controls would add about 1 percent, and land reclamation would add less than 1 percent.