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Oil Shale Development in the United States

Prospects and Policy Issues

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Prepared for the National Energy Technology Laboratory of the
U.S. Department of Energy

RAND INFRASTRUCTURE, SAFETY, AND ENVIRONMENT

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Cover photo: A view east, down Ryan Gulch, towards the center of Piceance Basin.
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Preface

Since the early 1980s, oil shale has not been on the U.S. energy policy agenda, and very little attention has been directed at technology or energy market developments that might change the commercial prospects for oil shale. This report presents an updated assessment of the viability of developing oil shale resources in the United States and related policy issues. The report describes the oil shale resources in the western United States; the suitability, cost, and performance of available technologies for developing the richest of those resources; and the key energy, environmental, land-use, and socioeconomic policy issues that need to be addressed by government decisionmakers in the near future.

This work was performed at the request of the National Energy Technology Laboratory of the U.S. Department of Energy. As this report was being prepared for publication, the Energy Policy Act of 2005 became law. Although we were unable to include the particulars of the Act in our analysis, this report is consistent with the Act's oil shale provisions and should be especially useful to federal officials responsible for implementing those provisions. This report should also be of interest to state, tribal, and local government decisionmakers responsible for policy development and implementation of the Energy Policy Act in the areas of energy resources, land management, and environmental protection. Technology developers, research managers, and planning organizations should find the report useful in framing information needs for future decisionmaking regarding oil shale development.

This report builds on earlier RAND Corporation studies on natural resources development in the United States. Examples of this previous work include:

- *Constraints on the Commercialization of Oil Shale*, R-2293-DOE (1978)
- *Understanding Cost Growth and Performance Shortfalls in Pioneer Process Plants*, R-2569-DOE (1981)
- *Oil Shale in the Piceance Basin: An Analysis of Land Use Issues*, R-3040-RC (1983)
- *New Forces at Work in Mining: Industry Views of Critical Technologies*, MR-1324-OSTP (2001)

- *Assessing Natural Gas and Oil Resources: An Example of A New Approach in the Greater Green River Basin*, MR-1683-WFHF (2003).

This research was conducted within RAND Infrastructure, Safety, and Environment (ISE), a division of the RAND Corporation. The mission of ISE is to improve the development, operation, use, and protection of society's essential built and natural assets and to enhance the related social assets of safety and security of individuals in transit and in their workplaces and communities. The ISE research portfolio encompasses research and analysis on a broad range of policy areas, including homeland security, criminal justice, public safety, occupational safety, the environment, energy, natural resources, climate, agriculture, economic development, transportation, information and telecommunications technologies, space exploration, and other aspects of science and technology policy.

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Summary

Since the early 1980s, oil shale has not been on the U.S. energy policy agenda, and very little attention has been directed at technology or energy market developments that might change the commercial prospects for oil shale. This report presents an updated assessment of the viability of developing oil shale resources in the United States and related policy issues. The report describes the oil shale resources in the western United States; the suitability, cost, and performance of available technologies for developing the richest of those resources; and the key energy, environmental, land-use, and socioeconomic policy issues that need to be addressed by government decisionmakers in the near future.

The U.S. Oil Shale Resource Base

The term *oil shale* generally refers to any sedimentary rock that contains solid bituminous materials that are released as petroleum-like liquids when the rock is heated. To obtain oil from oil shale, the shale must be heated and resultant liquid must be captured. This process is called *retorting*, and the vessel in which retorting takes place is known as a *retort.*

The largest known oil shale deposits in the world are in the Green River Formation, which covers portions of Colorado, Utah, and Wyoming. Estimates of the oil resource in place within the Green River Formation range from 1.5 to 1.8 trillion barrels. Not all resources in place are recoverable. For potentially recoverable oil shale resources, we roughly derive an upper bound of 1.1 trillion barrels of oil and a lower bound of about 500 billion barrels. For policy planning purposes, it is enough to know that any amount in this range is very high. For example, the midpoint in our estimate range, 800 billion barrels, is more than triple the proven oil reserves of Saudi Arabia. Present U.S. demand for petroleum products is about 20 million barrels per day. If oil shale could be used to meet a quarter of that demand, 800 billion barrels of recoverable resources would last for more than 400 years.

Oil Shale Technology Prospects

Processes for producing shale oil generally fall into one of two groups: mining followed by surface retorting and in-situ retorting.

Mining and Surface Retorting. Oil shale can be mined using one of two methods: underground mining using the room-and-pillar method or surface mining. The current state of the art in mining—both room-and-pillar and surface techniques, such as open pit mining—appears to be able to meet the requirements for the commercial development of oil shale.

The current commercial readiness of surface retorting technology is more questionable. Development of surface retorts that took place during the 1970s and 1980s produced mixed results. Technical viability has been demonstrated, but significant scale-up problems were encountered in building and designing commercial plants. Since then, major technical advances have occurred but have not been applied to surface retorts. Incorporating such advances and developing a design base for full-scale operations necessitates process testing at large but still subcommercial scales.

Cost information available from projects and design studies performed in the 1980s can be escalated to give a very rough estimate of the anticipated capital costs for mining and surface retorting plants. Using this approach, a first-of-a-kind commercial surface retorting complex (mine, retorting plant, upgrading plant, supporting utilities, and spent shale reclamation) is unlikely to be profitable unless real crude oil prices are at least $70 to $95 per barrel (2005 dollars).

In-Situ Retorting. In-situ retorting entails heating oil shale in place, extracting the liquid from the ground, and transporting it to an upgrading or refining facility. Because in-situ retorting does not involve mining or aboveground spent shale disposal, it offers an alternative that does not permanently modify land surface topography and that may be significantly less damaging to the environment.

Shell Oil Company has successfully conducted small-scale field tests of an in-situ process based on slow underground heating via thermal conduction. Larger-scale operations are required to establish technical viability, especially with regard to avoiding adverse impacts on groundwater quality. Shell anticipates that, in contrast to the cost estimates for mining and surface retorting, the petroleum products produced by their thermally conductive in-situ method will be competitive at crude oil prices in the mid-$20s per barrel. The company is still developing the process, however, and cost estimates could easily increase as more information is obtained and more detailed designs become available.

Development Timeline. Currently, no organization with the management, technical, and financial wherewithal to develop oil shale resources has announced its intent to build commercial-scale production facilities. A firm decision to commit funds to such a venture is at least six years away because that is the minimum length of time for scale-up and process confirmation work needed to obtain the technical and environmental data required for the design and permitting of a first-of-a-kind commercial operation. At least an additional six to eight years will be required to permit, design, construct, shake down, and confirm performance of that initial commercial operation. Consequently, at least 12 and possibly more years will elapse before oil shale development will reach the production growth phase. Under high growth assumptions, an oil shale production level of 1 million barrels per day is probably more than 20 years in the future, and 3 million barrels per day is probably more than 30 years into the future.

The Strategic Significance of Oil Shale

If the development of oil shale resources results in a domestic industry capable of profitably producing a crude oil substitute, the United States would benefit from the economic profits and jobs created by that industry. Additionally, oil shale production will likely benefit consumers by reducing world oil prices, and that price reduction will likely have some national security benefits for the United States. A hypothetical shale oil production rate of 3 million barrels per day was assumed for the purpose of calculating consumer benefits.

Economic Profits. If low-cost shale oil production methods can be achieved, direct economic profits in the $20 billion per year range are possible for an oil shale industry producing 3 million barrels per day. Through lease bonus payments, royalties on production, and corporate income taxes, roughly half of these profits will likely go to federal, state, and local governments and, thereby, broadly benefit the public.

Employment Benefits. A manifestation of the economic benefits of shale oil production is an increase in employment in regions where shale oil production occurs or in regions that contain industries that provide inputs to the production process. A few hundred thousand jobs will likely be associated, directly and indirectly, with a 3 million barrel per day industry. The net effect on nationwide employment is uncertain, however, because increases in employment arising from shale oil production could be partially offset by reductions in employment in other parts of the country.

Reduced World Oil Prices. Production of 3 million barrels of oil per day from oil shale in the United States would likely cause oil prices to fall by 3 to 5 percent, but considerable uncertainty surrounds any calculation on how large the effect might be, especially when trying to model the behavior of the Organization of the Petroleum Exporting Countries (OPEC) and other major suppliers far into the future. Assuming a 3 to 5 percent fall in world oil prices, the resulting benefits to consumers and business users in the United States would be roughly $15 billion to $20 billion per year.

National Security. A drop in world oil prices would reduce revenue to oil-exporting countries. A 3 to 5 percent reduction in revenue would not change the political dynamic in those countries a great deal. With regard to enhancing national security, the principal value of oil shale production would be its contribution to a portfolio of measures intended to increase oil supplies and reduce oil demand.

Other claims of the benefits of increased domestic oil production, such as a reduced trade deficits and more reliable fuel supplies for national defense purposes, are not well justified.

Critical Policy Issues for Oil Shale Development

The potential emergence of an oil shale industry in the western United States raises a number of critical policy issues.

Land Use and Ecological Impacts. Of all the environmental impacts of oil shale development, the most serious appears to be the extent to which land will be disturbed. Regardless of the technical approach to oil shale development, a portion of the land over the Green River Formation will need to be withdrawn from current uses, and there could be permanent topographic changes and impacts on flora and fauna. For surface retorting, extensive and permanent changes to surface topography will result from mining and spent shale disposal. In-situ retorting appears to be much less disruptive, but surface-based drilling and support operations will cause at least a decade-long displacement of all other land uses and of preexisting flora and fauna at each development site.

Air Quality. Oil shale operations will result in emissions that could impact regional air quality. Studies in the 1970s and 1980s suggested that air emissions from an industry producing a few hundred thousand barrels per day could probably be controlled to meet then existing regulations. No studies have been reported since, and no studies have considered output on the order of several million barrels per day. Meanwhile, so much has changed in terms of environmental regulations, mining and process technologies, and pollution control technologies that the earlier analyses are no longer relevant.

Greenhouse Gas Emissions. The production of petroleum products derived from oil shale will entail significantly higher emissions of carbon dioxide, compared with conventional crude oil production. If these emissions are to be controlled, oil shale production costs will increase.

Water Quality. All high-grade western oil shale resources lie in the Colorado River drainage basin. For mining and surface retorting, the major water quality issue is the leaching of salts and toxics from spent shale. A number of approaches are available for preventing surface water contamination from waste piles, but it is not clear whether these methods represent a permanent solution that will be effective after the site is closed and abandoned. For in-situ retorting, inadequate information is available on the fate, once extraction operations cease, of salts and other minerals that are commingled with oil shale.

Socioeconomic Impacts. Large-scale oil shale development will stimulate a significant increase in the populations of northwestern Colorado and Uintah County in Utah. Even a relatively small development effort, such as might occur during the construction of a few initial commercial plants will result in a large population influx. Rapid population growth will likely stretch the financial ability of local communities to provide necessary public services and amenities.

Leasing. The richest and most abundant deposits of oil shale are found on federal lands managed by the U.S. Department of the Interior. As such, the course of oil shale development and its environmental impacts will be shaped by federal decisions regarding how much, when, and which specific lands will be offered for lease. At present, the Department of the Interior does not have available a strategic approach for leasing oil shale–bearing federal lands. The Energy Policy Act of 2005 has liberalized the lease ownership provisions of the Minerals Leasing Act of 1920, thereby removing a major deterrent to private-sector investment in oil shale development. If mining and surface retorting turn out to be the preferred approach to oil shale development, the current lease size provisions of the Act will constrain resource recovery and increase per-barrel mining costs and land disturbance.

Production Costs. Oil shale has not been exploited in the United States because the energy industry, after some halting efforts, decided that developing oil shale was economically unviable. Over the past two decades, very little research and development effort has been directed at reducing the costs of surface retorting. For thermally conductive in-situ retorting, costs might be competitive with crude oil priced at less than $30 per barrel, but the technical viability of in-situ retorting will not be fully established for at least six years.

Market Risks. As with many commodities, crude oil prices are highly volatile. To hedge against the possibility of downward price movements, investments in projects with high capital costs, such as oil shale development, tend to be deferred until a sufficient safety cushion builds up between anticipated production costs and what the market is willing to pay. An added degree of uncertainty is associated with the potential response of OPEC nations to various market and technical developments.

Water Consumption. About three barrels of water are needed per barrel of shale oil produced. Water availability analyses for oil shale development were conducted in the early 1980s. These analyses indicated that the earliest constraining factors would be limitations in local water supply systems, such as reservoirs, pipelines, and groundwater development. A bigger issue is the impact of a strategic-scale oil shale industry on the greater Colorado River Basin. Demands for water are expected to continue to grow for the foreseeable future, making the earlier analyses regarding oil shale development outdated.

Future Development Prospects

The prospects for oil shale development are uncertain. The estimated cost of surface retorting remains high, well above the record-setting crude oil prices that occurred in the first half of 2005. For surface retorting, it therefore seems inappropriate to contemplate near-term commercial efforts. Meanwhile, the technical groundwork may be in place for a fundamental shift in oil shale economics. Advances in thermally conductive in-situ conversion may cause shale-derived oil to be competitive with crude oil at prices below $30 per barrel. If this becomes the case, oil shale development could soon occupy a very prominent position in the national energy agenda.

We are rapidly approaching a critical juncture for oil shale development. On June 9, 2005, the Bureau of Land Management released its Call for Nominations of parcels to be leased for research, development, and demonstration of oil shale recovery technologies in Colorado, Utah, and Wyoming. The response to this solicitation will provide a clear signal about whether the private sector is prepared to commit its resources to oil shale development. Government decisionmakers need to wait for that signal. When it is clear that at least one major private firm is willing to devote, without appreciable government subsidy, its technical, management, and financial resources to oil shale development, government decisionmakers should address the core policy issues listed above.

Key Recommendations

Business as Usual. The following are recommended whether or not oil shale is a candidate for early efforts toward commercial production.

- Oil shale should be part of the Department of Energy's research and development portfolio. Significant long-term research opportunities are associated with both surface retorting and in-situ retorting. A benefit of even a small federal program (i.e., a few million dollars annually) would be the continued availability of a small cadre of scientific and engineering professionals who would be deeply knowledgeable of oil shale development issues.
- Consideration should be given to establishing a national oil shale archive that would hold and preserve information on oil shale resources, technologies, and impacts of development. We fear that, with the passage of time, important information will be lost.
- Analysis should be directed at lease program implementation options, such as combining adjacent lease tracts in a lease offering and provisions for ensuring or promoting extensive recovery of resources within lease tracts.

In Support of Commercialization. Once clear indications are in hand that major firms are ready to invest in scaling up and demonstrating oil shale technologies, government attention should be directed at gathering long lead time information required to support future decisionmaking with regard to permitting and leasing. Early action is appropriate for the following:

- Development and implementation of a research plan directed at establishing options for mitigating damage to plants and wildlife and reducing uncertainties associated with ecological restoration.
- Research directed at mathematical modeling of the subsurface environment, combined with a multiyear hydrological, geochemical, and geophysical monitoring program. (This in the event that major industrial investments are directed at in-situ retorting.)
- Research directed at establishing and analyzing options for long-term spent shale disposal. (This in the event that major industrial investments are being directed at mining and surface retorting.)
- Regional air quality modeling directed at determining preferred locations for federal leasing and informing decisions on air quality permits for initial commercial plants.
- Development of a federal oil shale leasing strategy for the Green River Formation, along with appropriate analytic and procedural approaches for timing and selecting sites for lease offerings, establishing lease provisions, and avoiding measures that will constrain future development.

Development at a Measured Pace. Many uncertainties regarding technology performance and environmental and socioeconomic impacts remain unresolved. While the above "early action" recommendations will serve to narrow uncertainties and reduce the risks of making poor decisions, resolution of the most critical issues associated with strategically significant levels of production will not occur until the initial round of large-scale commercial facilities are constructed and operated—a point that is at least 12 years down the road. A particularly pressing issue is the viability of in-situ retorting because this approach may offer a more profitable and far more environmentally benign alternative to mining and surface retorting. The prevailing information shortfalls suggest that oil shale development should proceed at a measured pace.

Public Participation. Because oil shale development could profoundly affect local residents and other stakeholders, their inputs into federal decisionmaking need to be sought and valued early in the process. The same holds true of the affected state governments, tribal governments, and the wider citizenry, including nongovernmental organizations representing citizens supportive of environmental protection, wildlife conservation, and alternative land uses. An opportune time to broaden public involvement is in conjunction with the preparations for a new round of federal leasing of oil shale tracts. Toward this end, the federal government should consider fostering the creation of a regionally based organization dedicated to planning, oversight and advice, and public participation. Various venues are possible for this, including the Western Governors' Association and the Colorado and Utah state governments.

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At the Bureau of Land Management in the Department of the Interior, Nick Douglas helped us understand the bureau's oil shale leasing program. We also thank Sheri Thompson and Vern Rholl for photographs of some of the federal lands holding oil shale. From the Office of Fossil Energy in the U.S. Department of Energy, Anton R. Dammer and Jeremy M. Cusimano shared with RAND their recently completed work on oil shale development. With their cooperation, RAND was able to send a representative to a DOE-sponsored Oil Shale Development Planning Meeting held in Salt Lake City, Utah, on March 30 and 31, 2005.

At RAND, Keith Crane, Victoria Greenfield, and Michael Kennedy helped frame the analyses presented in Chapter Four on the strategic significance of oil shale development. Richard J. Hillestad helped us formulate our analytic approach.

This report benefited greatly from formal reviews conducted by Joel Darmstadter, Brian M. Harney, and our RAND colleagues, Frank Camm and Debra Knopman.

Abbreviations

BACT	Best Available Control Technology
DOE	Department of Energy
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EM	Employment multiplier
EPA	Environmental Protection Agency
MLA	Mineral Leasing Act
MACRS	Modified Accelerated Cost Recovery System
NETL	National Energy Technology Laboratory
OPEC	Organization of the Petroleum Exporting Countries
OTA	Office of Technology Assessment
PSD	Prevention of Significant Deterioration
R&D	Research and development
USC	U.S. Code
USGS	U.S. Geological Survey

CHAPTER ONE
Introduction

The United States contains massive amounts of oil held in mineral deposits known as oil shale, located primarily in the states of Colorado, Utah, and Wyoming. The recoverable energy from these high-grade deposits may be more than 800 billion barrels of crude oil equivalent—more than triple the known oil reserves of Saudi Arabia.

For nearly a century, the oil shale in the western United States has been considered as a substitute source for conventional crude oil. But the economics of shale oil production have persistently remained behind conventional oil. When crude oil prices were about $3 per barrel in the 1960s and early 1970s, estimates of the required selling price needed to make oil shale economic were about $6 per barrel. By the late 1970s, world crude oil prices had increased to about $15 per barrel, but estimates of the required selling price for oil shale had also sharply increased, ranging from a low of $20 per barrel to a high of $26 per barrel (Merrow, 1978). Crude oil prices jumped again in the winter of 1979–1980 in response to the Iranian crisis, and so did estimates of the required selling price of shale oil, which were reported at more than $45 per barrel in 1980 (OTA, Volume I, 1980).[1]

Once again, the United States is in a period during which crude oil prices have risen sharply. As in the past, concerns are being raised regarding the ability of world oil supplies to meet growing demands, especially from the developing economies of Asia. Once again, oil shale is being examined as a possible solution. In 2003, the Bureau of Land Management in the U.S. Department of the Interior established an Oil Shale Task Force to assess opportunities and prospects for oil shale development on federal lands. In early 2004, the Office of the Deputy Assistant Secretary for Petroleum Reserves, U.S. Department of Energy, released a report (Johnson, Crawford, and Bunger, Volume I, 2004) asserting

> Oil shale development holds the promise of assuring the Nation's secure access to strategically important fuels to drive the economy, meet national defense needs, and fulfill global commitments.

[1] In this paragraph, all prices are in nominal—i.e., then-year—dollars.

Most recently, and perhaps most significantly, the Bureau of Land Management announced (*Federal Register*, 2005) that the bureau has concluded that "initiating steps to help facilitate oil shale research and development (R&D) efforts is worthwhile" and that it was soliciting nominations of small parcels to be leased for oil shale technology research, development, and demonstration projects in Colorado, Utah, and Wyoming (U.S. Department of the Interior, 2005).

These developments raise the question of whether oil shale has now become a technically and economically viable energy alternative to conventional sources of crude oil. The recent increases in world oil prices, the potential leasing of federal oil shale lands for research, and certain lately achieved technology developments present a rich opportunity to consider issues and options for taking a strategic approach to oil shale development, to ensure, among other goals, that economically, technologically, and environmentally sound approaches to resource development are pursued.

About This Study

To answer this question, the RAND Corporation examined the opportunities and challenges associated with developing oil shale resources on a strategically significant scale in the United States. By "strategically significant," we mean production of a few million barrels per day—a level sufficient to have a marked impact on energy prices and the world energy trade.

The purpose of the study was to evaluate the technological and economic viability of oil shale development and to identify those issues, such as environmental protection, resource access, and infrastructure constraints, that are critical to any successful development effort. In addition, the study sponsor, the National Energy Technology Laboratory (NETL), wanted to obtain an independent perspective as it prepared a report requested by Congress on the viability of developing oil shale reserves (U.S. House of Representatives, 2004).

To give due consideration to the broad range of technology, economic, and policy issues associated with oil shale development, RAND assembled a multidisciplinary research team with expertise and experience in policy analysis, engineering and the physical sciences, the life sciences, environmental analysis, and economics. The RAND team conducted a thorough review of the extant scientific and policy literature, conducted discussions with industry representatives and other stakeholders, and held meetings and consultations with Department of Energy and Bureau of Land Management scientists and engineers knowledgeable about oil shale processing technologies and mining methods. The RAND researchers also were provided access to an internal NETL review of the costs and performance of alternative approaches for mining and processing oil shale.

Most of the information relevant to oil shale development was generated 20–30 years ago. While of great value in a number of aspects, many of the engineering studies and environmental impact analyses are out of date. For some topics, such as the management of federal oil shale lands, the early analyses are incomplete. Therefore, to a large extent, this study can be viewed as a survey of the uncertainties associated with developing oil shale. To clear the path to development, some uncertainties need to be resolved so that the appropriate decisions can be made. In other cases, we note that resolution of uncertainties is not pertinent or should be postponed until the private sector announces its intent to move forward with a specific technology approach.

Contents of This Report

Chapter Two reviews the oil shale resource base. A key question we are concerned with is whether the resource base is sufficient in size and character to support a multimillion barrel per day industry.

Technology readiness and production costs will determine when an oil shale industry will emerge. Chapter Three examines the status of known approaches for producing fuels from oil shale, presents cost estimates, and reviews performance issues. The chapter contains a timeline for technology R&D, demonstration, and initial commercial operations required to bring fuels output from oil shale to a level equivalent to several million barrels per day of crude oil equivalent.

Chapter Four explores the strategic significance for the United States of developing a domestic oil shale industry. It examines the special benefits that accrue from putting additional oil into the marketplace.

The course of oil shale development is fraught with uncertainties for the private sector, community stakeholders, and policymakers. Chapter Five identifies a number of the most critical uncertainties surrounding the prospect of oil shale development. The issues center on environmental protection, regional socioeconomic development, infrastructure, leasing, and technology costs and performance. The chapter puts forth a number of policy recommendations for addressing these concerns in parallel with technology research and development.

Chapter Six steps back from specific issue areas and recasts our findings in terms of the pathway to development and signals of industrial intent. Here, we also put forth a few recommendations that cut across multiple issue areas.

CHAPTER TWO

The U.S. Oil Shale Resource Base

For estimating U.S. oil shale resources, two measures are commonly used: resources in place and recoverable resources. In estimates prepared by the U.S. Geological Survey (USGS), resources in place are distinguished according to their grade—specifically, the gallons of oil that can be produced from a ton of shale.[1] The rich ores that yield 25 to more than 50 gallons per ton are the most attractive for early development. Deposits with grades below 10 gallons per ton are generally not counted as resources in place because it is commonly assumed that such low yields do not justify the costs and energy expended in mining and processing. However, no standard grade is used to define oil shale resources. Different resource estimates include different minimum grades, which complicates the process of summing or comparing various estimates. Except where noted, estimates of resources in place discussed below include all shale oil present at a grade of greater than 15 gallons per ton.

Usually, estimates of recoverable resources are based on an analysis of the portion of the resources in place that can be economically exploited with available technology. Because oil shale production has not been profitable in the United States, such estimates do not yield useful information. Instead, calculations of recoverable resources have generally been based on rough estimates of the fraction of the resources in place that can be accessed and recovered, considering mining methods and processing losses (e.g., Taylor, 1987).

Oil Shale Resources in Place

The Green River Formation

The largest known oil shale deposits in the world are in the Green River Formation, which covers portions of Colorado, Utah, and Wyoming. These deposits were formed over millions of years during which two large lakes covered the area. Figure

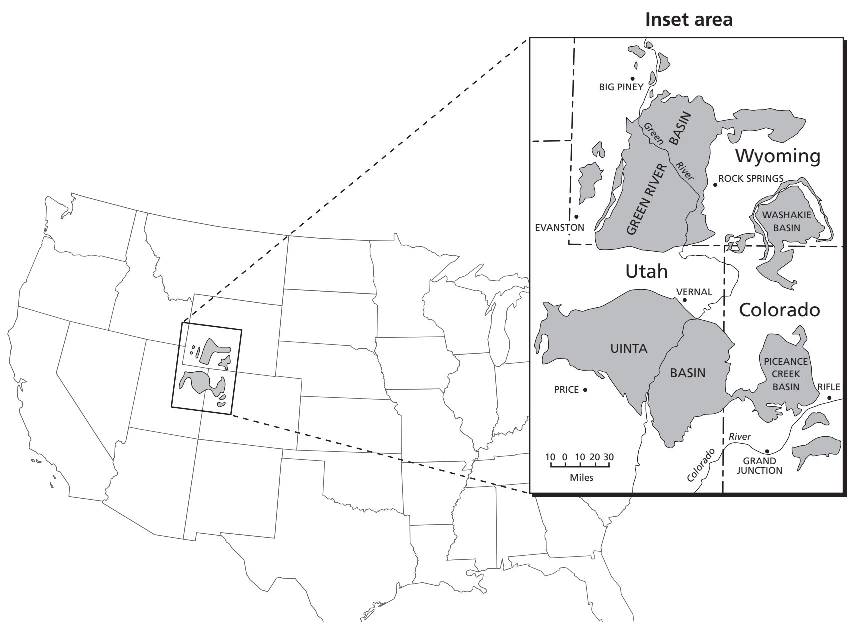
[1] The standardized test used in the United States for oil shale quality is the modified Fischer Assay method, in which a small amount of oil shale is crushed, placed in a laboratory heating vessel (a retort), and heated to 932 degrees F according to a prescribed method.

2.1 shows the location of the formation and its major oil shale–bearing basins: the Piceance, Uinta, Green River, and Washakie. The oil shale in these basins is a sedimentary rock known as marlstone and consists primarily of carbonate and silicate minerals.

Estimates of the oil resource in place within the Green River Formation range from 1.5 trillion (Smith, 1980; Dyni, 2003) to 1.8 trillion barrels (Culburtson and Pitman, 1973; Federal Energy Administration, 1974).[2] About 1 trillion barrels[3] (Smith, 1980; Pitman, Pierce, and Grundy, 1989) are located within the Piceance Basin, meaning that this 1,200 square mile area in western Colorado holds as much oil as the entire world's proven oil reserves (*BP Statistical Review*, 2005).

Within the Piceance Basin, about a half trillion barrels of oil are contained in deposits yielding more than 25 gallons per ton (Dyni, 2003). Most of the oil shale is contained in deposits more than 500 feet in thickness and located beneath 500 or

Figure 2.1
Location of the Green River Formation Oil Shale and Its Main Basins



SOURCE: Adapted from Smith, 1980.
RAND *MG414-2.1*

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[2] The oil shale deposits in Utah and Wyoming are not as well known as those of Colorado, and uncertainties regarding these deposits appear to be the principal cause of the differences in estimates.

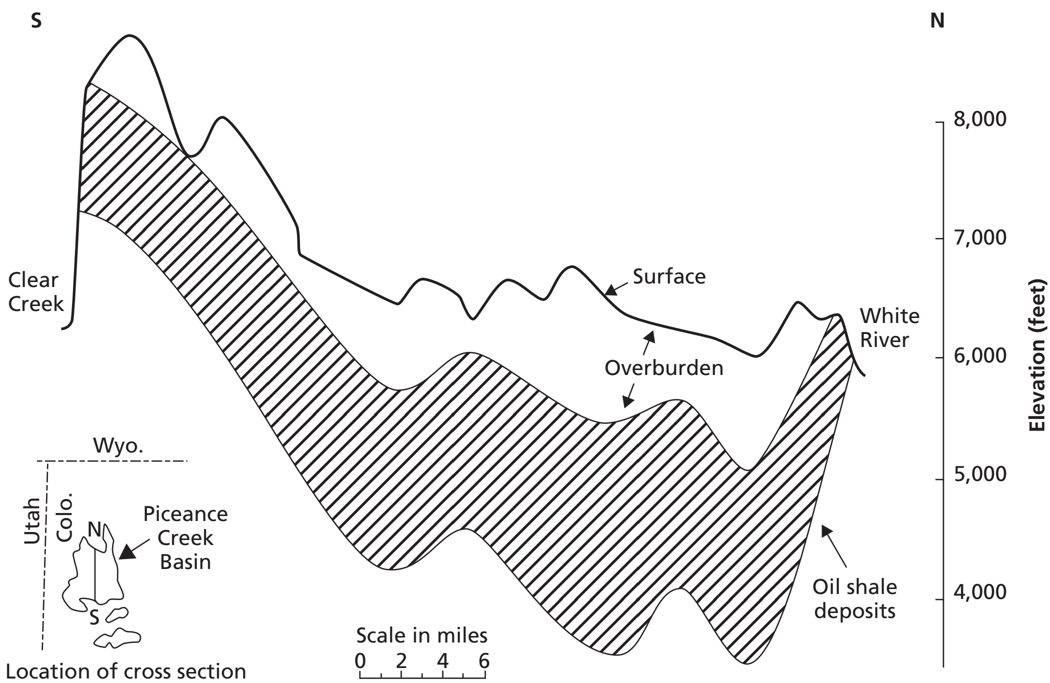
[3] Although these estimates include all oil shale regardless of richness, virtually all of the oil shale in the Piceance Basin has a richness of greater than 15 gallons per ton (Smith, 1980).

more feet of sedimentary rock, although in some cases the deposits are more than 2,000 feet in thickness and covered by more than 1,000 feet of overburden (Donnell, 1987) (see Figure 2.2). The potential yield per surface acre is enormous, with portions of the basin yielding more than 2.5 million barrels per acre (Smith, 1980; Donnell, 1987). This is well beyond the areal concentration of any known oil reserves. Worldwide, the closest we get to this energy yield are the hundred-foot-thick coal seams in Campbell County, Wyoming, which yield the oil equivalent of less than 0.5 million barrels per acre.

Less is known about shale resources in place in Utah and Wyoming. Several widely varying estimates for the Uinta Basin in Utah have been published, including 56 billion barrels (Dyni, 2003), 165 billion barrels (Smith, 1980), 214 billion barrels (Trudell et al., 1983), and 321 billion barrels (Cashion, 1964). While smaller than the Colorado resource base, much of the high-grade oil shale in Utah is close to the surface and in seams of appreciable thickness. When commercial oil shale operations begin, operations are likely in both Utah and Colorado.

The deposits in Wyoming are appreciable. The Green River Basin is estimated to contain 250 billion barrels (Culbertson, Smith, and Trudell, 1980) and the

Figure 2.2
Stratigraphic Cross Section of the Piceance Basin in Colorado



SOURCE: Adapted from Beard, Tait, and Smith, 1974.
RAND *MG414-2.2*

Washakie Basin 50 billion barrels (Trudell, Roehler, and Smith, 1973), giving a total of 300 billion barrels. About 14 billion barrels of this are in oil shale deposits holding more than 30 gallons per ton (Dyni, 2003). In general, the rich Wyoming deposits are situated in thinner, less continuous layers and represent a less favorable development target, compared with the Colorado and Utah deposits (Smith, 1980).

Other Oil Shale Deposits in the United States

The oil shale deposits of the Green River Formation have been extensively studied and overshadow all other deposits based on considerations of both abundance and richness. Once oil shale technology becomes commercial, a few operations may occur outside the Green River Formation. In particular, an early target for development might be the estimated 200 million barrels of fairly high-grade oil shale located in deposits near Elko, Nevada (Schmitt, 1987).

Black, organic-rich shales, produced during the Devonian period, underlie a large portion of the eastern United States, where they are known primarily as a potential source of natural gas. The richest and most accessible deposits are found in Kentucky, Ohio, Indiana, and Tennessee. When heated, these Devonian shales produce oil, but the organic matter yields only about half as much oil as the organic matter in the Green River shales (Dyni, 2003). Because of considerations of grade, yield, and processing costs, eastern oil shale deposits are not likely candidates for development for the foreseeable future and are not further discussed in this report.

Recoverable Resources in the Green River Formation

Not all resources in place are recoverable. Some fraction of the in-place oil shale will not be accessed because it lies under land that is off-limits to mining or other extraction methods. Off-limit lands would include those under towns, but since the area is sparsely populated, the primary reasons for setting land aside will be ecological and environmental considerations. Assuming that low–environmental impact extraction methods can be developed over the next hundred or so years, a rough upper bound for the accessible portion of the resource base is 80 percent. At best, about 75 percent of the accessible resource can be extracted and converted to useful fuels,[4] yielding an upper bound of 60 percent (0.8×0.75) for the net recovery factor. Applying this net recovery factor to estimated resources in place of 1.5 to 1.8 trillion barrels yields an upper bound of between 900 billion and 1.1 trillion barrels of oil. The same method

[4] This high level of extraction assumes that nearly all of the shale in place will be developed using a combination of in-situ methods and large surface mines that have recovery efficiencies of about 80 percent. In particular, for surface mining, boundary effects (primarily slanted walls) and spent shale disposal requirements are assumed to limit recovery to 80 percent. For in-situ methods, energy requirements are assumed to equal 20 percent of the energy contained in the extracted resource. Resource recovery is further discussed in Chapter Three.

can be used to develop a rough estimate of the lower bound of recoverable resources. Assuming that at least 60 percent of the resource base can be accessed and at least 50 percent of the accessible resources can be extracted and converted to useful fuels, we obtain a lower bound of roughly 500 billion barrels.[5]

Whether the actual amount is 1.1 trillion barrels or 500 billion does not matter for policy deliberations over the foreseeable future. Any number in this range is very large. For example, the midpoint of this range is 800 billion barrels of recoverable oil. To better grasp the magnitude of this midpoint estimate, consider that current U.S. demand for petroleum products is 20 million barrels per day. If U.S. oil shale resources could be used to meet a quarter of that demand, 5 million barrels per day, the recoverable resource would last over 400 years! In the face of such a long recovery period, it is appropriate to recognize the futility of trying to develop accurate estimates of recoverable resources. How and how much oil shale is eventually developed depends less on today's technologies than on the performance of technologies available a hundred or more years hence.

Resource Ownership

Federal lands comprise roughly 72 percent of the total oil shale acreage in the Green River Formation (Calvert, 2005). In both the Piceance and Uinta Basins, the federal lands overlie about 80 percent of the estimated in-place oil shale resources (OTA, Volume I, 1980). Because the richest and thickest deposits are located under these federally owned and managed lands, the federal government directly controls access to the most commercially attractive portions of the oil shale resource base.

In both basins, private ownership generally derives from mining claims in areas where oil shale deposits are close to the surface and visible. The private lands in the Piceance Basin are concentrated along the Basin's southern edge and along streambeds. As of 1980, most of these private lands were in the hands of major energy companies. In the Uinta Basin, ownership of nonfederal lands is split among Indian tribes, the state of Utah, and private landowners.

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[5] This lower bound calculation is based on geological and technical factors and does not include economic or environmental considerations that could conceivably limit oil shale recovery to much lower levels.

CHAPTER THREE

Oil Shale Technologies

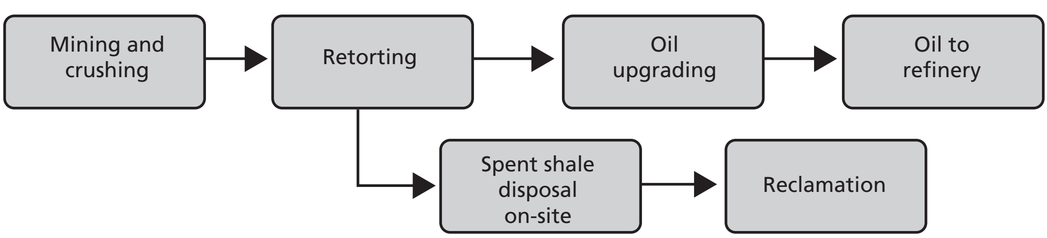
This chapter briefly describes different oil shale production methods, examines their readiness for commercial operations, and provides estimates of production costs.

Extracting oil from oil shale is more complex than conventional oil recovery. Hydrocarbons in oil shale are present in the form of solid, bituminous materials and hence cannot be pumped directly out of the geologic reservoir. The rock must be heated to a high temperature, and the resultant liquid must be separated and collected. The heating process is called *retorting*. Processes for producing shale oil generally fall into one of two groups: mining, either underground or surface, followed by surface retorting and in-situ retorting.

Mining and Surface Retorting

In this approach (Figure 3.1), oil shale is mined with conventional mining methods and transported to a retorting plant. After heating and removal of fine solid particles, the liquid product is upgraded to produce a crude oil substitute that can enter the nation's existing oil pipeline and refinery infrastructure. After retorting, the spent shale is cooled and disposed of, awaiting eventual reclamation.

Figure 3.1
Major Process Steps in Mining and Surface Retorting



RAND *MG414-3.1*

Mining Oil Shale

Oil shale can be mined using one of two methods: underground mining, most likely using the room-and-pillar method, or surface mining. In general, surface mining is the most efficient approach for mining oil shale. Room-and-pillar mining can recover about 60 percent of the oil shale in place for seams that are no more than about a hundred feet thick,[1] such as those found in the southern portion of the Piceance Basin and in portions of the Uinta Basin. However, most of the high-grade oil shale resources form more or less continuous deposits anywhere from 500 to more than 2,000 feet thick (Smith, 1980; Pitman, Pierce, and Grundy, 1989). Applying room-and-pillar mining methods to the rich, deep seams in the central Piceance Basin will result in exceptionally low levels of resource recovery—in general, less than 20 percent, and in some cases less than 10 percent (Miller, 1987).[2]

Surface mining can recover much higher percentages of in-place resources. But the thickness of oil shale deposits, the amount of overburden, and the presence of subsurface water in the Piceance Basin can make surface mining difficult. For example, oil shale sections in the center of the basin underlie more than 1,000 feet of overburden and are 2,000 feet thick. More than 80 percent of the resources within the Piceance Basin are covered by more than 500 feet of overburden.[3] Mining such thick deposits covered by so much overburden would require very large mines, comparable in size to the largest existing open-pit mines in the world.

Despite the great size of the mining operation that would be required, the relative thicknesses of overburden and oil shale (1:2) present a highly favorable stripping ratio (ratio of the mass of waste material removed to the mass of ore removed). As a point of comparison, surface coal mines with a stripping ratio as high as 10:1 are often economic (OTA, Volume I, 1980, p. 125).

Commercial oil shale plants will likely be designed to produce at least 50,000 barrels, and more likely well over 100,000 barrels, of shale oil per day.[4] At a minimum, a mine designed to serve such plants will need an annual output of more than 25 million tons. A room-and-pillar mine in that capacity range was designed and partially developed for a planned, commercial-scale Colony Oil Shale Project in the early

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[1] Additionally, geological features and rock strength limit applications of underground mining. For example, a detailed investigation of the "C-b" lease tract found that the shale was highly fractured and of insufficient strength to support efficient underground mining (OTA, Volume I, 1980, p. 127).

[2] Moreover, the use of room-and-pillar methods could cause future extraction efforts aimed at recovering the resource left behind to be expensive and dangerous.

[3] RAND estimate using the overburden thickness map of Donnell (1987) and the resource amounts by township and range of Pitman, Pierce, and Grundy (1989).

[4] This range is based on the announced production targets for potential oil shale operations in Colorado and Utah, as compiled by the Office of Technology Assessment (OTA, Volume I, 1980). As discussed in Chapter Five, the lease size provisions of the Mineral Leasing Act of 1920 may hold production levels to significantly less than 100,000 barrels per day.

1980s. The developers encountered no serious technical problems with the mine. As for surface mining, 25 million tons is about a third of the tonnage of the largest surface coal mines operating in Campbell County, Wyoming.

While mining always involves technical challenges associated with the particular characteristics of the ore body under consideration, the current state of the art in mining—both room-and-pillar and surface techniques—appears able to meet the requirements for the commercial development of oil shale.

Surface Retorting

Surface retorting involves crushing the mined oil shale and then retorting it at about 900 to 1,000 degrees F (Figure 3.1). The vessel in which this heating occurs is called a retort. The hot shale oil leaving the retort is not stable and must be sent directly to an upgrading plant for catalytic processing with hydrogen to remove impurities and produce a stable product.[5] This stable shale oil can be used as a refinery feedstock and should compete favorably with sweet, light crude oil.

An oil shale plant operating on a commercial scale—that is, producing a minimum of 50,000 barrels per day—would need to incorporate multiple retorts. Because the residence time of oil shale in the hot zone of a retort is nearly a half hour, a retort designed to produce 50,000 barrels of shale oil per day would need to be sized to contain more than 1,500 tons of oil shale, which is well beyond the state of the art.

Several surface retorting technologies were developed and underwent pilot testing in the United States during the 1970s and early 1980s. Using a combination of price supports and tax credits, Union Oil Company (now Unocal) built a single retort commercial plant with a design output of 9,000 barrels per day on private land in the Piceance Basin. This plant encountered severe performance problems, producing at an average rate of 50 percent of its design capacity. The Unocal plant terminated operations in 1991 when faced with a high-cost plant modification.

Also using private land in the Piceance Basin, a consortium led by Exxon and the TOSCO Corporation began constructing in 1980 the Colony Oil Shale Project. This plant was designed to produce 47,000 barrels of oil per day using room-and-pillar mining and the TOSCO II retort. However, the success of this system was never tested because the Colony project was canceled during construction in May 1982, in response, according to Exxon, to falling crude oil prices, continued escalation in the estimated cost of the facility, and high interest rates (Harney, 1983; Kirkland, 1984).

For many years, surface retorting of oil shale has been used to yield a crude oil substitute in Brazil, China, and Estonia. A small plant may also be operating in Russia. All of the current operating plants are small, with total world production esti-

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[5] It is possible that a single oil shale upgrading plant might serve two or more nearby, but independently operated, surface retorting plants.

mated at 10,000 to 15,000 barrels per day (Trinnaman and Clarke, 2004).[6] Given their location and size, it is highly unlikely that any of these plants approach U.S. standards for environmental protection and worker safety and health.

During the late 1980s, several small batch-testing programs were carried out to study the potential of using the Alberta-Taciuk Processor for surface retorting of U.S. oil shale. Originally developed for applications associated with tar sands, this Canadian technology has recently demonstrated oil production of 3,700 barrels per day using Australian oil shale (Corbet, 2004). U.S. oil shale has not yet been continuously tested in the Alberta-Taciuk Processor.[7]

Technical Viability and Commercial Readiness

The R&D that took place in the United States during the 1970s and 1980s, combined with the ongoing operations and recent testing abroad, supports the judgment that mining and surface retorting is a technically viable approach for producing strategically significant amounts of oil, although with potentially severe environmental impacts, as discussed in Chapter Five.

With the exception of the Alberta-Taciuk Processor, no significant development work in surface retorting has occurred for more than 20 years. During this period, major technical advances have occurred in process monitoring and control, process simulation and modeling, chemicals separation and purification, and systems and methods for reducing adverse environmental impacts. However, these advances have not yet been applied to surface retorting, and incorporating them into surface retorting processes will necessitate process testing at subcommercial scales, namely, at throughputs of 1,000 to 3,000 barrels per day. Testing at this smaller scale will enable developers to verify performance, make and test appropriate design modifications, and obtain the information needed to scale up to commercial-size units. Once testing has been completed, the follow-on scale-up to full-scale commercial retorts that can produce 10,000 barrels per day still involves considerable risks, and it is likely that the first follow-on commercial plants would consist of no more than one or two full-scale retorts.

The preceding inferences are guided by the understanding that significant performance shortfalls are typically associated with first-of-a-kind plants and especially those that process solids (see Merrow, Phillips, and Myers, 1981, and Myers and Shangraw, 1986, for documentation and further discussion of these shortfalls). The expectation of underperformance in the early stages of process development is illustrated by the performance shortfalls associated with the Union Oil Shale Plant

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[6] It is not clear whether any of this production is profitable, as opposed to being supported by government subsidies.

[7] William Taciuk, UMATAC Industrial Processes, UMA Group Ltd., personal communication, May 31, 2005.

throughout its operating life and the poor operating record of both Canadian tar sands projects during their initial operating years.[8]

Costs

While we are confident that mining followed by surface retorting is a technically viable approach to producing oil shale, we are less sanguine about projecting the costs of first-of-a-kind commercial plants that use this technology. In general, large pioneer plants involving new technologies are notorious for cost overruns. Oil shale specifically has a long history of escalating cost estimates. RAND examined this phenomenon for pioneer plants that process solids and has identified the factors that cause overruns (Merrow, Phillips, and Myers, 1981; Merrow, 1988; Myers and Shangraw, 1986). In particular, none of the early design work was based on technology that had been proven in an integrated operation of at least a few thousand tons per day. In addition, most of the designs were highly conceptual, omitting key supporting processes and site-specific requirements, such as a detailed definition of environmental performance and such infrastructure as roads, pipeline, power connections, and housing for construction workers and employees.

Cost information available from the Colony and Union projects and design studies performed in the 1980s can be escalated to give a very rough estimate of the anticipated capital costs for mining and surface retorting plants (Harney, 1983; Albulescu and Mazzella, 1987). Considering mine development, upgrading, and modest infrastructure expenditures, a 50,000 barrel per day first-of-a-kind surface retorting complex will incur capital expenditures of between \$5 billion and \$7 billion (2005 dollars) and possibly higher than that.[9] We assume operating and maintenance costs for first-of-a-kind plants to be between \$17 and \$23 (2005 dollars) per barrel (OTA, Volume I, 1980; Albulescu and Mazzella, 1987).[10] Given these capital and operating cost estimates, we project that the price of low-sulfur, light crude oil, such as West Texas Intermediate, will need to be at least \$70 to \$95 per barrel for a first-of-a-kind oil shale operation to be profitable. The assumptions underlying this projection, as well as the estimates of capital and operating costs, are reviewed in the appendix of this report.

A number of factors could make actual costs diverge from our estimates. Previous designs for commercial plants are based on compliance with environmental

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[8] During their first operating year, both plants performed at less than 10 percent of their designed capacity. In the second operating year, both performed below 40 percent of design capacity and, in the third year, below 70 percent (Merrow, 1989).

[9] When Exxon canceled the 47,000 barrel per day Colony Project in 1982, there were reports that estimated costs would exceed \$5.5 billion in then-year dollars, or about \$10 billion in 2005 dollars (Harney, 1983).

[10] Oil shale mining and spent shale disposal are major components of operating costs. Mining costs are highly site-sensitive, depending on the ease of accessing high-grade deposits. For initial commercial operations, we anticipate that underground and surface mining will yield similar operational costs.

regulations and standards out-of-date today, especially with regard to ecological concerns. Future oil shale plants will probably need to achieve much greater levels of control than plants that would have been built in the early 1980s. Environmental control systems have become significantly less expensive, and performance has significantly increased, but the net impact on costs of implementing control technologies to meet today's tighter restrictions remains uncertain. In addition, future operations may need to comply with additional environmental control requirements, such as those that might implemented to reduce carbon dioxide and other greenhouse gas emissions. These issues are further discussed in Chapter Five.

Also, over the past 20 years important technical advances have been made that may decrease the costs of oil shale mining and surface retorting. Higher-capacity mining equipment, advances in explosives placement, increased automation, and better information management have caused the real costs of mining to drop considerably. These advances should be relevant to mining oil shale, leading to similar cost reductions. In addition, new advances in materials processing (e.g., process control, simulation, comminution, and environmental controls) have not yet been applied to surface retorting. Their application will surely result in improved performance and reduced costs.

Further, our cost estimates apply only to first-generation operations. Costs should improve once the first commercial plants are operating and experience-based learning begins to take place. In the chemical process industries, for example, the expectation of rapid cost improvements often justifies an investment in marginally economic first-of-a-kind plants (Merrow, 1989).

Several earlier RAND studies have examined cost improvement expectations for oil shale mining and surface retorting (Merrow, 1989; Hess, 1985). This work indicates that after 500 million barrels have been produced with this technology, production costs could drop to about 50 percent of the costs for initial commercial plants.[11] For initial production costs between \$70 and \$95 per barrel, experienced-based learning could drop those costs to between \$35 and \$48 per barrel within 12 years of the start of commercial oil shale operations.[12]

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[11] Learning is not guaranteed and will depend on management attention to R&D, information transfer, and organizational continuity. Also, significant uncertainties exist in the estimated learning rate. For oil shale via surface retorting, the estimated cost reduction after 500 million barrels ranges from 35 to 70 percent (Merrow, 1989).

[12] The estimate of 12 years assumes that production capacity increases at an average of 25,000 barrels per day during each year after the start of initial commercial production. Continued reductions are likely as cumulative production increases. For example, after a billion barrels of cumulative production, the RAND model predicts oil shale production costs will decrease even further, to between \$30 and \$40 per barrel.

In-Situ Retorting

In-situ retorting entails heating oil shale in place, extracting the liquid from the ground, and transporting it to an upgrading facility. Various approaches to in-situ retorting were investigated during the 1970s and 1980s. The mainstream methods involved burning a portion of the oil shale underground to produce the heat needed for retorting the remaining oil shale. Much of this prior work was not successful, encountering serious problems in maintaining and controlling the underground combustion process and avoiding subsurface pollution.

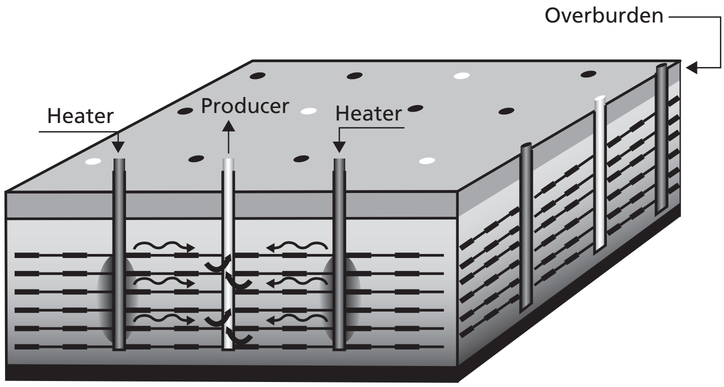
A variant on this approach—modified in-situ retorting—appears to have made progress in addressing these problems. In modified in-situ retorting, a volume beneath the retort zone is mined and the shale to be retorted is rubblized by a series of staged explosions. This process provides improved access for the air needed for combustion. The rubblized shale is retorted in place, and the mined shale is sent to surface retorts. Occidental Petroleum was the principal developer of modified in-situ retorting technology. During the early 1980s, several firms expressed interest in using Occidental's technology in commercial operations. According to the Department of Energy (DOE), no firms have recently expressed interest in pursuing any type of in-situ retorting—including modified in-situ—based on burning oil shale underground.

Thermally Conductive In-Situ Conversion

In the early 1980s, researchers at the Houston R&D center of Shell Oil envisaged an entirely different type of in-situ retorting, which they named the In-Situ Conversion Process. In Shell's approach (Figure 3.2), a volume of shale is heated by electric heaters placed in vertical holes drilled through the entire thickness (more than a thousand feet) of a section of oil shale. To obtain even heating over a reasonable time frame, between 15 and 25 heating holes will be drilled per acre. After heating for two to three years, the targeted volume of the deposit will reach a temperature of between 650 and 700 degrees F. This very slow heating to a relatively low temperature (compared with the plus-900 degrees F temperatures common in surface retorting) is sufficient to cause the chemical and physical changes required to release oil from the shale. On an energy basis, about two-thirds of the released product is liquid and one-third is a gas similar in composition to natural gas. The released product is gathered in collection wells positioned within the heated zone.

Figure 3.3 illustrates the major process steps associated with in-situ conversion via thermal conduction. As part of site preparation, Shell's current plan is to use ground-freezing technology to establish an underground barrier around the perimeter of the extraction zone. A "freeze wall" would be created by circulating a refrigerated

Figure 3.2
The Shell In-Situ Conversion Process



SOURCE: Adapted from material provided by Shell Exploration and Production Company.
RAND *MG414-3.2*

fluid through a series of wells drilled around the extraction zone. In addition to preventing groundwater from entering the extraction zone, the freeze wall is intended to keep hydrocarbons and other products generated by retorting from leaving the project perimeter during ground heating, product extraction, and postextraction ground cooling. The site preparation stage also involves the construction of power plants and power transmission lines needed to supply electricity to the underground heaters.

According to Shell, the oil produced by the In-Situ Conversion Process will be chemically stable and consist solely of distillable oil fractions (i.e., no low-value residuum content will be created). As such, the oil should be a premium feedstock that can be sent directly to refineries, without, in contrast to oil from surface retorting, the need for near-site upgrading. Postproduction cleanup involves steam flushing to remove remaining mobile hydrocarbons, ground cooling, removing the freeze wall, and site reclamation.

Technical Viability and Commercial Readiness

Shell has tested its in-situ process at a very small scale on Shell's private holdings in the Piceance Basin. The energy yield of the extracted liquid and gas is equal to that predicted by the standardized assay test.[13] The heating energy required for this process equals about one-sixth the energy value of the extracted product.[14] These tests have indicated that the process may be technically and economically viable.

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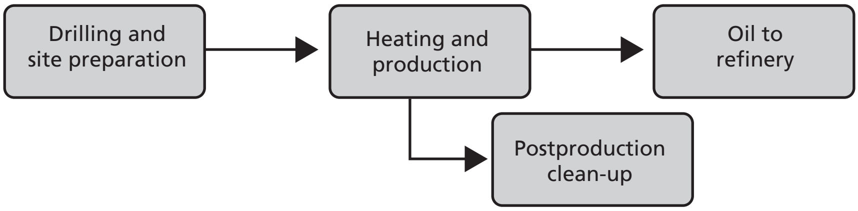
[13] The standardized assay test measures oil yield. In general, the quick heating profile typical of surface retorting and the standardized assay test yields very little natural gas.

[14] As reported by Shell and independently verified by calculation, assuming an average deposit grade of 30 gallons per ton.

Figure 3.3
Major Process Steps in Thermally Conductive In-Situ Conversion



RAND *MG414-3.3*

This approach requires no subsurface mining and thus may be capable of achieving high resource recovery in the deepest and thickest portions of the U.S. oil shale resource. Most important, the Shell in-situ process can be implemented without the massive disturbance to land that would be caused by the only other method capable of high energy/resource recovery—namely, deep surface mining combined with surface retorting. The footprint of this approach is exceptionally small. When applied to the thickest oil shale deposits of the Piceance Basin, drilling in about 150 acres per year could support sustained production of a half-million barrels of oil per day and 500 billion cubic feet per year of natural gas.

Shell reports that it has spent tens of million of dollars in developing its in-situ conversion technology.[15] Its current plan is to gain access to a small tract of federal land for a precommercial demonstration operation that would produce about 1,000 barrels per day.[16] Shell's estimate of the costs for this demonstration is between $150 million and $200 million. Other petroleum companies appear to be evaluating thermally conductive in-situ retorting concepts, although none has publicly announced ongoing efforts, if any.

Scientists from the DOE have reviewed the Shell in-situ process and report that the technology is very promising.[17] Confirmation of the technical feasibility of the concept hinges on the resolution of two major technical issues: controlling groundwater during production and preventing subsurface environmental problems.

Shell plans to use ground-freezing technology to control groundwater during production. Ground-freezing technology is a well-established method for controlling groundwater during construction and mining operations. Multikilometer barriers

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[15] Terry O'Connor, Vice President, Shell Exploration and Production Company, personal communication, March 24, 2005.

[16] According to Shell, its in-situ retorting process requires thick seams for economic reasons, and seams with a few hundred feet of overburden for environmental reasons, namely, to prevent hydrocarbon escape into the atmosphere. The oil shale on federal lands better satisfies these two criteria, compared with that on Shell's private holdings within the Piceance Basin.

[17] Lawrence Shadle and Hugh Guthrie, NETL, U.S. Department of Energy, personal communication.

have been constructed and sustained for years. Nonetheless, applying ground-freezing to in-situ conversion of oil shale requires resolving significant technical uncertainties to ensure that the frozen barrier is structurally sound.

Significant uncertainties remain regarding the impact of in-situ retorting on the quality of groundwater. Retorting and removing hydrocarbons will change aquifer properties and will likely result in an increase in hydraulic conductivity. After the removal of the freeze wall, such changes in aquifer properties could result in the leaching and transport of mineral salts and trace metals that are commingled with oil shale deposits. Questions also arise about the fate of any hydrocarbon gases that may have migrated beyond the retort zone and whether there should be any cause for concern regarding their interaction with groundwater or release into the atmosphere.

Until these critical uncertainties are satisfactorily addressed, the technical viability of Shell's method of in-situ retorting cannot be fully established. The small demonstration project envisaged by Shell could resolve operational issues in about four years, but more time may be needed for subsurface environmental monitoring and modeling required to support a decision to begin initial commercial operations.

Costs

Shell anticipates that the petroleum products produced by its in-situ method are competitive, given crude oil prices in the mid-$20s per barrel (Fletcher, 2005). The company is still developing the process, however, and cost estimates are likely to increase as more information is obtained and more detailed designs become available. No independent cost estimates are available.

This cost estimate is substantially lower than the cost estimate for mining and surface retorting. One reason for this is that the Shell approach is, in some ways, more akin to a conventional petroleum drilling process than to either mining and surface retorting or modified in-situ processes. As such, it benefits from the technical advances and accompanying cost reductions achieved by the petroleum extraction industry over the past 25 years. Other comparative benefits include lower up-front costs, reduced need for product upgrading, and lower reclamation costs. Up-front costs are lower because most capital expenditures would be made incrementally as the areal extent of drilling increases. Product upgrading costs are lower because all produced liquids are distillable (i.e., they contain no residual oil) and stable. Reclamation costs, while not insignificant, should be lower because Shell's process involves much less land disturbance than mining and does not require disposal of spent shale.

How down-hole heating is supplied affects costs. As currently configured, the Shell in-situ retorting process uses electric power as the source for down-hole heating. About 250 to 300 kilowatt-hours are required for down-hole heating per barrel of extracted product.[18] Assuming electricity at \$0.05 per kilowatt-hour, power costs for heating amount to between \$12 and \$15 per barrel (crude oil equivalent). An operation producing 100,000 barrels per day requires approximately 1.2 gigawatts of dedicated electric generating capacity.

Sources for electric power include coal, natural gas (produced from the oil shale), nuclear power, and wind energy (listed in presumed order of increasing costs in the general area of the Green River Formation). With abundant supplies nearby, coal can be used for power generation. While coal is the least expensive choice, its use will result in a significant increase in greenhouse gas emissions compared with conventional petroleum production or surface retorting. If natural gas were to be selected, roughly all the natural gas coproduced with the shale oil would be consumed in power generation.[19] In the future, however, the value of natural gas may preclude its use in stationary power generation, leaving coal or nuclear as nearer-term choices and wind as a longer-term option. Requirements to sequester carbon dioxide produced by power plants could result in power cost increases of 30 percent (Buchanan, Schoff, and White, 2002), but the net impact on shale-derived oil costs would likely be less than 15 percent.[20]

An alternative to electrical heating is to heat the shale by down-hole natural gas burning. Compared with using electric power produced by natural gas, this approach halves natural gas use. Implementing down-hole gas burning requires the development of appropriate combustion technology. Presently, the net impact on shale oil production costs is uncertain.

Timeline for Oil Shale Development

Questionable commercial readiness and high production costs pose serious problems that currently prevent oil shale development. Currently, no organization with the management, technical, and financial wherewithal to develop oil shale resources has announced its intent to build commercial-scale facilities. One petroleum company, Shell Oil, has indicated strong interest in building and operating a demonstration facility, and it is possible that a corporate-level commitment to proceed may be forthcoming shortly. We know that other major firms are investigating alternative technical options, but we are unable to confirm their level of interest and the

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[18] RAND calculation, assuming specific heat of oil shale is 0.5 and average deposit richness of 25 gallons per ton.

[19] This assumes the use of combined-cycle natural gas power plants with an operating efficiency of 60 percent (GE Energy, 2004).

[20] Here, we assume that power costs (without CO_2 sequestration) are \$12 to \$15 per barrel and that total oil production costs are \$30 per barrel, which is consistent with Shell's oil shale product carrying a premium over crude oil and being competitive with crude oil priced in the mid-\$20s per barrel.

resources that they are devoting to investigating oil shale. The corporate response to the R&D lease offering by the U.S. Bureau of Land Management will provide a useful signal of private-sector interest.

In Figure 3.4, we show the development of an oil shale industry as a four-stage process. Currently, oil shale commercialization is in the first phase, namely, *research and development.* A few firms might be prepared to enter the *scale-up and confirmation* phase.[21] We estimate the duration of this phase to be at least six years, considering the time required to obtain permits, design and construct a demonstration capable of producing 1,000 to 5,000 barrels per day, and obtain technical and environmental data required for the design and permitting of a first-of-a-kind commercial operation. Even if a few firms decide to immediately move forward with a single-module commercial plant (as did Union Oil in the early 1980s) or a small-scale commercial facility, the decision to invest in a full-scale commercial facility is at least six to eight years in the future, especially considering the additional requirements likely to be associated with permitting a longer-term operation.

Once a decision is made to go forward with a first-of-a-kind full-scale commercial operation, at least six to eight years will be required to design, construct, shakedown, and confirm performance of the operation. Here we assume a five-year construction period for the processing facilities needed no matter which technical

Figure 3.4
Stages of Oil Shale Commercial Development

Development stage	Research and development	Scale-up and confirmation	Initial commercial operations	Production growth
Facility size	Laboratory to pilot plant	1,000–5,000 bpd[a]	> 50,000 bpd	> 100,000 bpd

Years to transition[b]	0	6–8	12–16	>20	>30
Total production (million bpd)	N/A	N/A	>0.1	>1	>3

[a]bpd = barrels per day.
[b]Beginning with transition from research and development.
RAND *MG414-3.4*

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[21] In the 1980s, oil shale briefly left the R&D phase and moved into the scale-up and confirmation phase. The attempt by the Colony Project to skip the scale-up and confirmation phase and move directly to a full-scale commercial plant ran into severe technical difficulties, according to personal communications received from technical experts with firsthand knowledge of the project.

approach—surface or in-situ retorting—is pursued. The six-year estimate assumes that permitting work, land acquisition, and detailed geological analyses will commence during the prior development stage. By the end of the *initial commercial operations* stage, a few first-of-a-kind full-scale operations could be in place, collectively producing a few hundred thousand barrels per day of shale-derived oil.

Once oil shale development reaches the *production growth* stage, how fast and how large the industry grows will depend on the economic competitiveness of shale-derived oil with other liquid fuels and on how the issues raised in Chapter Five are ultimately resolved. If long lead-time activities are started in the prior stage, the first follow-on commercial operations could begin production within four years. Counting from the start of the production growth stage and assuming that 200,000 barrels per day of increased production capacity can be added each year, total production would reach 1 million barrels per day in seven years, 2 million barrels per day in 12 years, and 3 million barrels in 17 years.[22]

Given that industry is unlikely to reach the production growth phase until 12 to 16 years after the decision to pursue process scale-up and confirmation and that this initial decision has not yet occurred, an oil shale production level of 1 million barrels per day is probably more than 20 years in the future, and 3 million barrels per day is probably more than 30 years in the future.[23]

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[22] This calculation assumes that initial commercial operations will produce 200,000 barrels per day of production capacity.

[23] This analysis of production growth is technology-independent, holding for both mining and surface retorting as well as in-situ approaches. However, how the issues raised in Chapter Five are ultimately resolved will very much depend on which technology options are commercially viable.

CHAPTER FOUR

The Strategic Significance of Oil Shale

This chapter examines the strategic significance to the United States of developing oil shale. By "strategic," we mean how the development of oil shale resources may contribute to U.S. goals at home or abroad. In the case of oil shale, this is an especially important issue because commercial development will require access to government lands; involve adverse environmental impacts; displace alternative land uses; and likely involve government expenditures associated with permitting and leasing, infrastructure development, and R&D.

For the purposes of this discussion, we begin by assuming a future in which a mature oil shale industry is profitably operating without special government subsidy or other financial incentives. Further, we assume oil shale production is yielding 3 million barrels (crude oil equivalent) per day. Per Figure 3.4, this production rate will unlikely be reached until at least 30 years hence. While substantially higher levels of oil shale production might eventually be obtained, an analysis of the strategic benefits of higher production levels would place us even farther into the future.

Our analysis indicates that a domestic oil shale industry operating in a competitive environment will yield benefits by generating economic profits, some of which would be captured by governments in the form of taxes and royalty payments. A domestic oil shale industry will create new jobs in the vicinity of the oil shale operations as well as in industries nationwide that supply inputs to the oil shale operations. Some of these jobs may be offset by shifts in employment from other sectors of the economy, however, and it is very difficult to determine what the net effect would be on employment for the nation as a whole. Oil shale production will likely benefit U.S. consumers by reducing world oil prices, and the reduction in world oil prices will also offer some national security benefits for the United States.

Advocates of increased domestic production of energy supplies often raise other reasons for government support or promotion. These include reducing the trade deficit and providing U.S. military forces with a "secure" fuel supply. These arguments often confound energy policy decisionmaking, but because they are so often put forward, they are briefly reviewed in this chapter.

Direct Benefits of Domestic Oil Shale Production

A competitive oil shale industry producing 3 million barrels per day will generate about 1 billion barrels of oil per year. The value of this production will depend on where world oil prices lie 30 years hence. If by 2035 world crude oil prices are at $50 per barrel (in real 2005 dollars), the annual value of 3 million barrels per day of domestic shale oil production would be $50 billion, and larger or smaller depending on future world crude oil prices.[1] Without this level of oil shale production in the United States, this $50 billion would be dedicated, as it currently is, to paying for imported crude oil.

Economic Profits

So long as a domestic oil shale industry can produce shale-derived oil at costs, including return on capital, below the prevailing market price for oil, the industry will be generating economic profits. The $50 billion in total revenue, which includes these economic profits, would be broadly distributed among investors, workers in oil shale production facilities as well as in the industrial and service base supporting those production facilities, and the government through taxes and royalties.

If production costs, including a normal rate of return on capital, drop to $30 per barrel by the time production reaches 3 million barrels per day, the oil shale industry would annually generate $20 billion in economic profits, above and beyond revenues required to cover operating expenses and returns on capital investments.[2] Through lease bonus payments, royalties, and taxes on profits, roughly half of these profits will likely go to federal, state, and local governments, and thereby, broadly benefit the public.[3]

In particular, lease bonus payments and royalty income provide a direct means for the nation to be compensated for resource depletion, temporary diversion of land use, unavoidable environmental damages, and possibly permanent decrease in surface land value. Just as private landowners would not allow resource extraction unless they

[1] We pretend no special insight on where crude oil prices might be 30 years into the future. Our $50 per barrel estimate appears consistent with recent upward revisions by the Energy Information Administration (EIA, 2005a), namely, the "High A" and "High B" oil price cases through 2025. Much lower prices would suggest that the shortage of oil supplies has become a non-issue, while considerably higher prices would be consistent with OPEC members being unable or unwilling to meet growing global demand for petroleum.

[2] As discussed in Chapter Five, there are limits on the rate of growth and ultimate size of a domestic oil shale industry. Consequently, a strong possibility exists that oil shale will be entering the market with production costs, including return on capital, well below market clearing prices. By the time a 3 million barrel per day industry is in place, cumulative production may well be approximately 10 billion barrels, affording industry the time and experience needed to exploit cost improvement opportunities.

[3] Federal corporate tax rates top out at approximately 35 percent of profits, and state tax rates range around 5 percent. Oil production royalty payments to the federal government generally run between one-eighth and one-sixth of total revenues.

each thought that they were being adequately compensated, so too does the federal government, as part of its stewardship, "manage or influence resource use to enhance public benefit, promote responsible use, and ensure optimal value" (U.S. Department of the Interior, 2003).

Employment Benefits

The limited information on employment impacts of oil shale operations is dated, mostly being available from studies completed in the late 1970s and early 1980s, and does not reflect the significant productivity gains experienced in mining and manufacturing over the past 25 years. For purposes of estimating total employment impacts, we assume that oil shale operations producing 3 million barrels per day will directly employ roughly 50,000 persons.[4] This estimate applies solely to operations based on surface retorting and mining, because information on labor requirements for in-situ conversion methods is not publicly available.

Developing an industry with a production capacity of 3 million barrels per day will involve major construction efforts. Assuming 200,000 barrels of capacity continue to be added each year, roughly 20,000 construction workers will be employed in plant construction and mine development.[5] As before, this estimate applies only to approaches using mining and surface retorting.[6]

Considering both plant operations and construction, an estimated 70,000 workers will be directly employed in either plant operations or new plant construction. Beyond these direct employment increases, indirect increases in employment will occur, stemming from three general effects:

- Supplier effects: Jobs will be created in industries that provide equipment, materials, supplies, or services associated with construction or plant operations.
- Respending effects: Jobs will be created in those sectors where workers spend their paychecks.

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[4] Direct employment refers to persons employed by the plant operator at or near the plant site and includes plant operators; mine workers; and technical, management and administrative staff. This estimate assumes productivity gains halve the OTA estimate of 1,600 employees per 50,000 barrel per day plant (OTA, Volume I, 1980). A 1987 study estimated plant employment at 600 operators for a 50,000 barrel per day plant, but this estimate excludes all mine and maintenance workers (Albulescu and Mazzella, 1987).

[5] This estimate assumes a construction and mine development work force of 1,000 workers, averaged over an estimated five-year construction period, for each 50,000 barrels per day of capacity under construction. Annually adding 200,000 barrels per day of new production capacity requires that at any time 1 million barrels of additional capacity is under development. This is a very rough estimate, based solely on OTA's estimate of 1,200 construction workers for a plant producing 50,000 barrels per day (OTA, Volume I, 1980).

[6] Considerable construction and preproduction development work is involved in thermally conductive in-situ conversion processes. This includes extensive drilling; placement of heating elements; construction of oil storage facilities upgrading or refining facilities, oil pipelines, power plants, and cryogenic plants; and creating all the infrastructure required for power and water delivery.

- Government employment: Additional employment generates taxes that support jobs in federal, state, and local governments.

Employment multipliers have been developed for estimating the additional indirect employment associated with direct employment in various sectors of the economy. Since oil shale is not a current industrial activity, basic data required to establish an employment multiplier are not available. To obtain a rough estimate of indirect employment, we assign the collective oil shale workforce (construction and operations) an employment multiplier of between two and three, which means that for each direct job, an additional two to three indirect jobs are created, stemming primarily from supplier and respending effects.[7]

Considering both direct and indirect employment, roughly 200,000 to 300,000 jobs will be associated with an oil shale industry producing 3 million barrels per day. Using the same methodology, the total employment impact at 1 million and 2 million barrels per day would be roughly 100,000 to 150,000 and 150,000 to 200,000, respectively.

While oil shale production will clearly increase employment in areas around production facilities, the effect on employment in the economy as a whole is uncertain. National employment and unemployment levels are affected by macroeconomic factors, including tax policy the monetary policy of the Federal Reserve Bank, and the net change in national employment rates will depend on reactions in other parts of the economy. If investment in oil shale does not displace investment in other parts of the U.S. oil industry or in other sectors of the economy, the economywide employment impacts of shale oil production might approximate the estimates provided above. If, on the other hand, oil shale production results only in the reallocation within the United States of a given amount of capital to a set of slightly more productive investments, the gains in employment predicted above could be partially offset by declines in other parts of the economy. It is thus very difficult to predict what the net effects of oil shale production on employment in the U.S. economy would be.

Reductions in the World Price of Oil

Production of 3 million barrels of oil per day from oil shale in the United States would likely cause world oil prices to be lower than they would otherwise be. Oil

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[7] The estimated employment multiplier (EM) of 2.0 is based on consideration of the following sectors: mining (including petroleum and natural gas extraction), EM = 2.03; construction, EM = 1.90; fabricated metals (relevant to construction), EM = 2.23; manufacturing (overall), EM = 2.91; chemicals, EM = 4.94; and petroleum refining, EM = 11.89 (Bivens, 2003).

consumers in the United States would benefit from these lower prices, although producers of non–shale oil supplies, including those operating in the United States, would be worse off. In addition, consumers abroad would benefit from lower oil prices, which could be in the economic and political interests of the United States. These global benefits are not considered in the narrow calculations conducted by private firms when assessing the profitability of shale oil production.

How large are the price reductions likely to be? The answer depends on how OPEC and other oil suppliers respond to the increase in U.S. domestic oil production and the sensitivity of the world oil demand to price. The simplest assumption is that world oil production from nonshale sources does not react, even though prices fall, so that 3 million barrels per day of shale oil production results in a 3 million barrel per day increase in world oil production. Under the additional assumption that total world oil production, excluding shale oil, will be 110 million barrels per day,[8] oil prices are likely to fall approximately 5 to 10 percent.[9] Worldwide, such a price decline would yield an annual consumer surplus of between \$90 billion and \$180 billion. The benefit to consumers and business users in the United States of such a price decline would be quite large, yielding a consumer surplus of roughly \$25 billion to \$45 billion per year.[10]

These calculations assume that OPEC and other oil producers do not respond to increased production from oil shale by reducing their own production. At the extreme, OPEC members might be able to cut back on their own production so that world oil prices remain unchanged. Absorbing a production cut of 3 million barrels per day, however, would significantly reduce OPEC revenues and would unlikely be in the economic interests of OPEC's member countries. Economic models of OPEC behavior often assume that OPEC sets production levels taking into account anticipated production of non-OPEC producers (Garber and Nagin, 1981; Pindyck and Rubenfeld, 1998). These more sophisticated models still imply price effects of 3 to 5 percent, but uncertainty remains on how large the effect might be.[11] If a 3 million

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[8] Consistent with the "high B world oil price" forecast for 2025 by the Energy Information Administration (EIA, 2005a), which is based on a 2025 world oil price of \$50 per barrel (2005 dollars).

[9] Under these assumptions, the price decline is determined solely by the price elasticity of the world demand for oil. Recent estimates of the long-run demand elasticity range from –0.3 (Adelman, 1995, p. 190) to –0.6 (Gately and Huntington, 2002). Using these elasticity estimates and assuming world oil production at 110 million barrels per day, without oil shale production, an increase in production to 113 million barrels per day would reduce prices 5 to 9 percent.

[10] The U.S. share of the consumer surplus is calculated assuming future U.S. consumption will be 26 million barrels per day (EIA, 2005a, high B world oil price forecast) at a world oil price of \$50 per barrel, excluding the availability of oil shale.

[11] A careful analysis by Garber and Nagin (1981) modeled OPEC as a price-leading, profit-maximizing cartel with competitive fringe producers and examined the effects of establishing an oil shale industry that produced 2 million barrels per day (3.3 percent of 1978 world oil production). They simulated the impact of price for a number of different values for the elasticity of world oil demand and other parameters. For the highest demand

barrel per day increase in shale oil production caused world oil prices to fall 3 to 5 percent, the benefits to U.S. consumers would be roughly $15 billion to $20 billion per year.

In summary, the extent to which oil shale production would reduce oil prices depends on OPEC's behavior far into the future. The benefits to oil consumers of domestic shale oil production are greater when OPEC maintains its oil production in spite of increased shale oil production. The benefits to oil consumers roughly halve when OPEC acts to optimize the profits of its member countries.

Enhanced National Security

Some oil-exporting nations are governed by regimes that do not support and in some cases oppose U.S. policies encouraging the observance of human rights, the development of democracy, and suppression of terrorism. When petroleum prices are high, these nations have more resources to pursue their own policy goals. Globally, about $2.2 billion dollars per day is transferred from oil importers to oil exporters.[12] Unless oil prices break, net oil export revenues to the Persian Gulf members of OPEC will be about $330 billion in 2005.[13]

Income from petroleum exports has been used by unfriendly nations, such as Iran and Iraq under Saddam Hussein, to support weapons purchases or the development of their own industrial base for munitions manufacture. Also, the higher prices rise, the more oil-importing countries are likely to pursue "special" relationships with oil exporters and defer joining the United States in multilateral diplomatic efforts.[14]

Oil revenue can also affect the internal politics of oil-exporting regimes. Research suggests that some regimes with large oil revenue have been able to resist democratization or have become more authoritarian, spawning moves by rival elites or popular organizations to attempt to overthrow the existing government (Klare,

elasticity examined in the study (–0.4), they found that 2 million barrels per day capacity would reduce price by 4 to 5 percent (p. 241). This percentage is nearly identical to one predicted by a simple supply and demand model using a price elasticity of demand between –0.3 and –0.6 and a price elasticity of supply of 0.4. (The supply elasticity was estimated to be 0.4 by Huntington, 1992).

[12] In 2004, about 45 million barrels per day of petroleum (crude plus refined products) moved from petroleum-exporting countries to petroleum-importing countries (*BP Statistical Review*, 2005). The $2.2 billion estimate assumes average receipts (spot plus contract oil) of $40 per barrel.

[13] For 2004, net exports from the Persian Gulf members of OPEC add up to about 18 million barrels per day (*BP Statistical Review*, 2005) of crude oil and refined oil products. The $350 billion forecast assumes average receipts (spot plus contract) of $40 per barrel for OPEC exports during 2005. For reference, the average spot quotation for OPEC's reference basket for the first five months of 2005 was $45.74 (OPEC, 2005).

[14] A recent example is the 2004 agreement between Japan and Iran for the development of Iran's Azadegan oil fields. Japan's negotiations with the Iranian government came into conflict with the U.S. government's efforts to compel Iran to abide by its International Atomic Energy Agency obligations. In spite of strong pressure from the U.S. government, Japan, in the name of energy security, concluded the Azadegan agreement.

2002). Perceptions that the United States, or the West more broadly, is supporting the authoritarian regime can lead to anti-U.S. sentiment and terrorism, decreasing the U.S. national security. Reducing the oil revenues of such regimes may thus reduce escalation of anti-American sentiment.

While increased domestic oil production may improve national security, it is difficult to assess how large an impact 3 million barrels per day from oil shale would be. As discussed above, world oil prices could conceivably drop 5 to 10 percent, reducing revenue to oil-exporting countries by a similar percentage. While a 5 to 10 percent reduction in revenue would not change the political dynamic in oil-exporting countries a great deal, oil shale production combined with other new petroleum sources[15] or petroleum demand reductions could conceivably accumulate to cause oil-exporting countries to experience an appreciable loss of economic power and international political influence.

Confounding or Inconclusive Arguments

As noted above, advocates of increased domestic production of energy supplies often raise other arguments for justifying federal support or involvement. One of these arguments is that increased domestic production will reduce the trade deficit, or more accurately, the current account deficit. In 2004, the U.S. current account deficit ran at $665 billion, virtually all of it due to the merchandise trade deficit (Bureau of Economic Analysis, 2005). If high oil prices persist, the United States is likely to incur in 2005 a net deficit in petroleum trade of $222 billion (in 2005 dollars).[16]

There may be reasons to cut the current account deficit on political or security grounds. Trade deficits increase the amount of U.S. assets in foreign hands, and if foreign control of U.S. assets became large enough, foreign interests could conceivably disrupt or destabilize the U.S. economy to further their own political objectives.

However, even if it becomes a policy goal to reduce the trade deficit, no evidence exists that channeling investment into domestic oil production is more productive in reducing the trade deficit than investments in other economic endeavors. The current value of goods and services annually traded (exports and imports) with the United States is about $3 trillion (Bureau of Economic Analysis, 2005). Petroleum imports, while substantial, constitute less than 10 percent of this amount. Examining annual trade balance data covering the past 25 years shows no correlation between the costs of oil imports and the annual current account deficit.

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[15] Including production of oil shale outside the United States.

[16] Through April 2005, the trade balance for petroleum imports was 34 percent higher than the four month total for 2004. Assuming this trend continues, the $166 billion deficit in petroleum trade will grow to $222 billion (in 2005 dollars).

Here it is worth noting that Japan, Hong Kong, and Switzerland, to name a few, have absolutely no domestic oil production but each year enjoy positive surpluses in their current accounts. The primary concern should be to invest resources where they will generate greatest economic wealth, and advocating oil shale development because it might reduce the trade deficit overlooks the possibility that investments in other sectors may be more profitable.

Finally, two national security arguments are often brought up in advocating government policies directed at increasing domestic energy production and sometimes energy conservation. The first argument is that eliminating or decreasing U.S. dependence, but not that of the rest of the world, on Persian Gulf sources of petroleum will improve the national security and allow us to avoid sending U.S. troops into harm's way. This would only be the case if we could somehow isolate ourselves from the affairs of the rest of the world. If we have learned one lesson from the attacks of September 11, 2001, it is that we cannot isolate ourselves. If we are willing to pay the higher prices of alternative sources of oil on the world market, we can easily eliminate imports from the Persian Gulf, but we will have accomplished nothing except decrease the productivity of the international distribution system for petroleum. The United States would still have strategic interests in the Middle East—e.g., Israel. Our allies will still be dependent on Persian Gulf oil. Any decrease in oil supplies arising from political disruptions in the Middle East would cause world oil prices to increase, including prices charged by our alternative suppliers.

The second argument is that higher domestic oil production will increase the reliability of fuel supplies for the U.S. military. While it is true that a reliable supply of energy is vital the U.S. military, it does not necessarily follow that higher domestic production will increase this reliability. Oil is produced by many different countries in many different parts of the world. It seems highly likely that as long as this is the case, the military can buy the fuel it needs on the open market. The question is how much the military will have to pay, not whether it can find supplies. As long as prices are allowed to adjust in the face of short supplies, the military should be able to outbid others for the resources. If the world market for oil breaks down and oil cannot move to willing buyers (even through circuitous routes), the argument would be more convincing that increased U.S. production, including oil shale, might enhance the reliability of military supplies. However, given the integrated world market for oil that exists today, the argument that increased U.S. production will enhance national security by providing a more reliable energy supply for the military is not convincing.

Summary

The development of a profitable oil shale industry offers large economic benefits to investors and workers in firms associated with oil shale development, production, and supporting industries. In addition, oil consumers in the United States, as well as abroad, will likely experience lower oil prices.

Developing a quantitative estimate of these benefits is difficult, requiring assumptions far into the future regarding OPEC production and pricing behavior, the demand and price for crude oil, the costs of producing shale oil, and the nature of investments that would be taken in the absence of a domestic oil shale option. If low-cost shale oil production methods can be realized, direct economic profits in the $20 billion per year range are possible for an oil shale industry producing 3 million barrels per day. Conservative assumptions regarding supply and demand elasticities yield an additional annual benefit to American consumers of between $15 billion and $45 billion per year because of reductions in the world oil price.

A manifestation of the economic benefits of shale oil production is an increase in employment in regions where shale oil production occurs or in regions that contain industries that provide inputs to the production process. While it is difficult to predict the employment gain, it is possible to estimate that a few hundred thousand jobs will be associated, directly and indirectly, with a 3 million barrel per day industry. The net effect on nationwide employment is uncertain, however, because increases in employment caused by shale oil production could be partially offset by reductions in employment in other parts of the country.

OPEC production or lower world oil prices should also result in limited national security benefits. In this case, the principal value of oil shale production would be as a contribution to a portfolio of measures intended to decrease to reduce revenues of oil producing nations.

In deciding to provide access to federally owned lands bearing oil shale, these are the benefits that will eventually accrue from full-scale development and which offset costs associated with land use and adverse environmental impacts that cannot be mitigated.

It is relevant to note that a portion of the benefits—namely, those economic and national security benefits associated with lower oil prices—would occur whether the additional production occurs within the United States or in some other country that is not a member of or colluding with OPEC.

CHAPTER FIVE

Critical Policy Issues for Oil Shale Development

The potential emergence of an oil shale industry in the western United States raises a number of critical policy issues. One set of issues concerns environmental and socioeconomic impacts that will occur as development efforts reach the initial commercial operation phase. These issues concern land use and ecological impacts, air and water quality, and community development. For these issues, the acuteness of the impacts and how government decisionmakers address them could become a deciding (i.e., go or no-go) factor in whether there will be an oil shale industry at all in the western United States. A second set of issues entails constraints that may slow development or prevent industry from achieving strategically significant levels of production—should this be the goal of industry and government.

This chapter briefly outlines these issues and puts forth some methods for government policy to address them. Many of these issues have been raised and addressed in the past. Some of the solutions identified previously still hold, while others have been overtaken by events. While industry decisions to proceed to initial commercial operations are at least six to eight years away and the production growth phase is not expected to commence before 14–20 years from now, this time lag does not mean that consideration of these often challenging policy issues should be postponed. To the contrary, addressing these issues as soon as clear signs emerge that industry is moving forward will facilitate evaluation of the benefits and costs of proceeding to each successive phase, aid in strategic planning, and help align views and expectations among stakeholders in the process.

Environmental and Social Impacts

Land Use and Ecological Impacts

Challenges. Of all the environmental impacts of oil shale development, the most serious appears to be the extent to which land will be disturbed. The land overlying oil shale resources in the Green River Formation is currently used for numerous purposes, such as recreational hiking, fishing and hunting, fossil collecting, sheep and cattle grazing, and oil and gas drilling. The town of Rangely, Colorado

(2005), close-by and to the northwest of the Piceance Basin, reports that the region hosts approximately 28,000 hunters annually, attracted by large herds of American elk (Colorado has one of the largest elk herds in the world), mule deer, and antelope. Wild horses also roam the area.

This area also has considerable ecosystem diversity, with several different types of habitats generally corresponding to plant community types, in addition to cave and aquatic habitats (Bureau of Land Management, 2004).[1] These habitats support a variety of plants and animals, including some listed by the U.S. Fish and Wildlife Service (2005) as threatened or endangered species:

- Bald Eagle (threatened)
- Colorado Pikeminnow (fish, endangered)
- Boreal Toad (amphibian, candidate for listing)
- Dudley Bluffs bladderpod and twinpod (threatened plants)
- Parachute Beardtongue (plant, candidate for listing).

The effects of habitat loss and the potential for recovery are highly dependent on the habitat type and individual species. While some species (e.g., deer and elk) are generalists and can adapt to some habitat disruption, others (e.g., some rodents and birds) are more dependent on the existence of specific and sometimes rare habitats.

Regardless of the technical approach to oil shale development, a portion of the land over the Green River Formation will need to be withdrawn from current uses, and there could be permanent topographic changes and impacts on flora and fauna. For surface retorting, extensive and permanent changes to surface topography will result from mining and spent shale disposal. Roughly 1.2 to 1.5 tons of spent shale result from each barrel of oil produced by surface retorting (Harney, 1983; Albulescu and Mazzella, 1987). Moreover, crushing increases the volume of the spent shale by 15–25 percent compared with the raw shale prior to mining.[2] For operations based on surface mining, spent shale will likely be used to refill and reclaim the mine site, leaving the landscape elevated from its original contour. Operations based on room-and-pillar mining may seek a surface disposal option to save the costs associated with in-mine disposal. But even if in-mine disposal is selected, the volume increase over raw shale will require at least some surface disposal.[3] In-situ retorting appears to be much less disruptive to the landscape than mining, surface retorting, and spent shale disposal, but surface-based drilling and support operations will cause at least a

[1] See also Garfield County, Colorado, available at http://www.garfield-county.com/home/index.asp?page=651, accessed on June 2, 2005.

[2] The range in volume increase depends on the type of surface retort used and the method used for compaction during disposal.

[3] For oil shale operations involving multimineral recovery, the volume of the spent shale will be significantly reduced, which may make disposal within a room-and-pillar mine practical.

decade-long displacement of all other land uses and of preexisting flora and fauna at each development site.

No matter what extraction and processing methods are employed, the remote location of the western U.S. oil shale lands means that the local industrial infrastructure will need to greatly expand. Oil shale development will require surface facilities to upgrade, store, and transport intermediate and final products. Roads, power supply and distribution systems, pipelines, water storage and supply facilities, construction staging areas, hazardous materials handling facilities, and buildings (residential, commercial, and industrial) introduce additional demands on land and existing ecosystems.

In sum, while mitigation, reclamation, and compensatory measures can be implemented, some degree of long-term residual damage and disruption is likely, especially if development proceeds using mining and surface retorting.

Opportunities for Action. Oil shale development will entail use of federal lands (this issue is discussed in greater detail below). The process by which federal lands are leased and managed provides an important means for government decisionmakers and the public to weigh the land-use and ecological consequences of oil shale development. A programmatic Environmental Impact Statement (EIS) for leasing federal oil shale lands would provide an important opportunity to address the impact of oil shale development on land use and regional ecosystems, as well as on air and water quality and socioeconomic factors, which are discussed in subsequent sections. The initial phase of a programmatic EIS effort should be directed at determining critical information needs so appropriate research programs can be formulated and carried out. In particular, additional information must be collected and analyzed to understand the response of local flora and fauna to ecosystem loss or damage—especially because the knowledge base and management practices have evolved since these issues were addressed 25 years ago. To avoid delaying pilot, leasing, and initial commercial operations, federal planning should include early development and implementation of an ecological research plan.

Leasing decisions should be based on a strategic approach in which the costs and benefits of alternative options can be compared. Toward this end, the Departments of Energy and the Interior should consider developing an analytic framework that allows consideration and weighing of multiple attributes and uses of specific lease sites and the relative benefits and costs of developing them. This would provide a more comprehensive and strategic approach to regional leasing and land-use practices.[4]

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[4] A example is an approach recently developed by RAND for assessing natural gas and oil resources (LaTourrette et al., 2003)

Air Quality

Challenges. All candidate areas for oil shale development in Colorado and Utah enjoy high-quality air and accordingly are classified as Class II areas under the Prevention of Significant Deterioration (PSD) provisions of the federal Clean Air Act (Utah Administrative Code, 2005; Colorado, 2005). For PSD Class II areas, only moderate increases in ambient air pollutant levels are allowed. In addition, a few high-value, specially protected areas are within close range of the Piceance and Uinta Basins. For example, the Flat Tops Wilderness Area lies within the White River National Forest and is only 50 miles downwind of the Piceance Basin. Flat Tops is designated as PSD Class I, whereby the air quality is to remain extremely high and additional loadings of criteria pollutants are strictly limited. For at least one project proposed in the early 1980s, a deciding factor in the permitting decision was the preservation of air quality in Flat Tops (U.S. Forest Service, 1998).

Oil shale operations will result in emissions of current Environmental Protection Agency (EPA)–designated criteria pollutants (sulfur oxides, nitrogen oxides, particulates, ozone precursors, carbon monoxide) as well as small amounts of noncriteria pollutants currently on the list of air toxics covered by the Clean Air Act. Reviews of potential emissions and control options were conducted in the late 1970s and early 1980s (Harney, 1983; OTA, Volume I, 1980). This work was based on design information from oil shale processes being considered for initial commercial production facilities or large-scale demonstration plants at that time.

Air quality modeling also was conducted in support of permit applications. The EPA supported a number of analyses and modeling studies directed at understanding the broad area air quality impacts of multiple commercial operations (OTA, Volume I, 1980).[5] The general conclusion of these studies was that air emissions from shale oil production on the scale of a few hundred thousand barrels per day could probably be controlled to meet then existing air quality regulations under the PSD provisions of the Clean Air Act.

No studies on the cumulative impacts of oil shale development on air quality have been reported since the 1980s. Meanwhile, so much has changed in terms of air quality regulations, mining and process technologies, and pollution-control technologies that the earlier air quality analyses are no longer relevant. For example, much deeper levels of pollutant control can now be reliably and affordably achieved, but there are no publicly available analyses regarding how modern pollution control systems would be incorporated in oil shale production facilities. Additional research is also needed to understand the extent to which nonpoint-source air emissions (including dust and off-gassing) from both surface and in-situ operations can be prevented or controlled.

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[5] This areawide assessment work appears to have been directed solely at criteria pollutants and did not address toxics.

On the regulatory side, the National Ambient Air Quality Standards now include separate criteria for particles based on size. The Clean Air Act Amendments of 1990 also put greater emphasis on improving and protecting visibility, especially in PSD Class I areas (U.S. EPA, 2001). They also call for controlling toxic air pollutants, such as arsenic, mercury, cadmium, and selenium compounds—all of which may be released during oil shale retorting and processing (Harney, 1983).

Finally, the ability of scientists to model and evaluate pollutant dispersion in complex terrains has significantly improved, in large part because of the tremendous advances in computational capabilities that occurred during the past 20 years.

Because the available studies on air quality effects of oil shale development are so out of date, it is not possible to provide an analytically based estimate of the extent to which air quality considerations will constrain the technology profile, pace of development, and ultimate size of an oil shale industry.

Opportunities for Action. With regard to air quality, oil shale development raises several major questions:

- How can air quality be protected without unduly constraining the growth of a commercial industry?
- Is an industry producing a few million barrels per day possible under the federal Clean Air Act?
- What technology and operations profile is best suited to maintaining compliance with a strategic-scale industry?

None of these questions can be fully addressed until modern plant designs are made available so that anticipated pollutant loadings can be used in regional air quality modeling studies. However, an early start to regional air quality modeling based on hypothetical emissions may provide useful information for preparing a programmatic EIS for federal land management and leasing decisions and for establishing a framework for permitting initial commercial plants.

Specifically, an important permitting issue that warrants attention by government decisionmakers is whether permitting, should industry reach that stage, will be based on the application of Best Available Control Technology (BACT). If early oil shale facilities are allowed a PSD emissions increment based solely on application of BACT, the first few facilities may exhaust the total available PSD increment for the region.[6] In addition, technical advances in pollution-control systems have caused BACT to become a poorly defined concept because higher control levels can generally be achieved at additional costs. Without a larger framework that considers longer-term energy development objectives and impacts, a conventional first-come,

[6] This problem was noted by OTA (Volume I, 1980).

first-served, BACT-based permitting process may become lengthy and highly contentious, and this could result in a less competitive and extremely small oil shale industry.

For air quality permits, consideration should be given to developing an alternative approach in which emission limits for initial plants are established so that future production growth can occur within the allowable PSD Class II and Class I increments. Advances in regional air quality modeling make feasible multiple case studies involving alternative geographic locations and hypothetical emission levels. If timed to yield early results, regional air quality modeling will also serve as useful input to work on a Programmatic EIS conducted to inform government decisions regarding the environmental impacts of alternative strategies for leasing public lands.

Greenhouse Gas Emissions

Challenges. Heating oil shale for retorting, whether aboveground or in situ, requires significant energy inputs. Over at least the next few decades, this energy will be supplied by fossil fuels, as discussed in Chapter Three. As a result, the production of petroleum products derived from oil shale will entail significantly higher emissions of carbon dioxide, compared with conventional crude oil production and refining. In addition, the high temperatures associated with surface retorting can cause a release of carbon dioxide from mineral carbonates contained in oil shale.

A significant number of individuals, nongovernmental organizations, and firms in the United States have expressed their concerns with the adverse consequences of continued levels of greenhouse gas emissions. It is not unreasonable to anticipate that individuals and organizations concerned with the lack of progress by the U.S. government in addressing global warming will oppose oil shale development.

Opportunities for Action. The U.S. government has not yet adopted a strategy directed at significantly reducing emissions of greenhouse gases. The prospect of oil shale development provides an additional motivation for consideration of market-based approaches, such as carbon taxes or "cap and trade" programs, so that greenhouse gas reductions can be achieved in an economically efficient way. If a market-based approach is adopted for the United States, the costs of minimizing, controlling, or trading greenhouse gas emissions in oil shale production will be shifted to the producers and consumers of shale oil and shale oil–derived petroleum products. Under such a framework, the decision, at least with regard to greenhouse gas emissions, about whether to go forward with oil shale development, and how, will be industry's and not the government's.

Water Quality

Challenges. All of the Green River Formation oil shale deposits lie within the Colorado River drainage basin. Degradation in water quality stemming from oil shale development could have adverse consequences not only to the Colorado River Basin ecosystems but also to local and downstream municipal, industrial, agricultural, and recreational users.

Water quality threats associated with oil shale operations depend on the technical approach employed (mining and surface retorting or in-situ retorting) as well as the location of such operations. For mining and surface retorting, potential sources of water pollution include mine drainage; point-source discharges from surface operations associated with solids handling, retorting, upgrading, and plant utilities; and leachate from spent (i.e., retorted) oil shale. For mine drainage and point-source discharges, state-of-the-art waste treatment technology available for mining operations and petrochemical processing can be applied to eliminate or control emissions. The primary threat to water quality is generally considered to be spent shale leachate (Harney, 1983). Laboratory and field tests have shown that the salt content of leachate from freshly processed shale (derived from surface retorting) is significantly higher than that of raw shale. The spent shale leachate will also contain small amounts of the soluble forms of the same toxic substances that are of concern with regard to air pollution, such as arsenic and selenium.

The salinity of the spent shale leachate is a significant issue because of the importance of salinity management in the Colorado River and the sheer magnitude of spent shale that would be generated by an oil shale industry producing a few millions of barrels of shale oil per day. Damage in the U.S. portion of the Colorado River Basin arising from elevated salinity is estimated at between \$500 million and \$750 million annually (Bureau of Reclamation, 2005). Salinity control in the Colorado River is one of the "four key water goals" stated in the bureau's 2004 Annual Report. An industry producing 3 million barrels of shale oil per day would annually generate over a billion tons of spent shale per year.[7] All disposal options, whether mine refill or surface piles, leave spent shale potentially exposed to underground and surface water flows.

A number of approaches are available to minimize leaching and prevent direct or indirect contamination of surface waters. Many of these have been developed, tested, and implemented since oil shale development was last considered. However, it is not clear that these methods can be applied to mine refill and whether these methods represent a permanent (i.e., hundreds of years) solution that will be effective after the site is closed and abandoned.

As discussed in Chapter Three, establishing the technical viability of thermally conductive in-situ conversion requires understanding the impact of the retorting process on groundwater flow and quality—a process that will take a number of years. Currently available information also is not sufficient to predict the transport and fate

[7] Calculated assuming oil shale yielding 30 gallons of oil per ton, resulting in the generation of slightly over one ton of spent shale per barrel of shale oil.

of salts and other minerals once extraction operations are terminated and groundwater is allowed to reenter the site and contact the spent shale.

Opportunities for Action. While it appears highly unlikely that water quality risk is a "show-stopper" problem, there is a critical need to obtain better information on the nature and long-term environmental fate of leachate from spent shale and the water quality impacts of in-situ retorting. For spent shale produced by surface retorting, research is required to determine whether recent methods used to reclaim spent shale piles are applicable to the amount of spent shale anticipated from commercial-size retorting plants. Accordingly, once one or more firms announce plans to go forward with initial commercial-scale surface retorting, a comprehensive spent-shale assessment program, including mathematical modeling, laboratory tests, and field monitoring, should be developed and implemented so that the issue of spent shale management can be resolved before the production growth phase begins.

For in-situ retorting, confident prediction of the transport and fate of salts and other substances will only be resolved through extensive mathematical modeling of the subsurface environment combined with comprehensive hydrological monitoring. This research agenda should commence at the next level of scale-up (i.e., at the roughly 1,000 barrel per day demonstration operation). Otherwise, sufficient data will not be available to inform decisions about whether to proceed with initial commercial operations.

In both cases, a full understanding of risks and appropriate mitigation and control measures will probably not be available within six to eight years after a research program commences. Consequently, only a partial knowledge base may be available when industry decisionmakers are ready to build the initial round of commercial plants. This information shortfall provides an impetus to taking a measured approach to commercial oil shale development, as opposed to simultaneous permitting of numerous first-generation commercial operations.

Finally, to ensure that the above water quality research and assessment programs (as well as research agendas focused on land use and ecosystems and on air quality) are properly formulated and to foster public confidence in the process and eventual findings, consideration should be given to establishing an independent scientific advisory and oversight board and public engagement strategy.

Socioeconomic Impacts

Challenges. The oil shale–bearing lands and the surrounding regions currently are sparsely populated, with an average of only seven inhabitants per square mile.[8] Large-scale oil shale development will stimulate a significant increase in the popula-

[8] According to the U.S. Census Bureau, the populations of the two counties containing the Piceance and Uinta Basins—Rio Blanco County, Colorado, and Uintah County, Utah—were 5,986 and 25,224, respectively, in 2000 (U.S. Census Bureau, Colorado, 2003; Utah, 2003).

tions of northwestern Colorado and Uintah County, Utah. Even a relatively small development effort, such as might occur during the construction of a few initial commercial plants, will result in a large population influx. For example, the 1980 OTA analysis indicated that an oil shale industry producing 200,000 barrels of oil per day would be accompanied by between 41,200 and 47,200 new residents, and double these population increases for an industry producing 400,000 barrels of oil per day. For comparison, the Garfield County, Colorado, is the most populated of the counties near the Piceance Basin. In 2000, its population totaled 43,791.

During the 1970s and early 1980s, an extensive amount of research and planning work was directed at understanding the local socioeconomic consequences of various scenarios for oil shale development.[9] Rapid population growth will likely stretch the financial ability of local communities to provide necessary public services and amenities, including fire, police, water and sanitation, roads, health care, housing, schools, and recreational opportunities. Indeed, in evaluating an oil shale development scenario in which 200,000 barrels of oil per day would be reached within ten years, OTA (Volume I, 1980) concluded that "social and personal distress would occur unless active measures were taken for their prevention." With economic booms come the risks of busts, and local inhabitants remember the economic "bust" that accompanied the May 2, 1982, announcement by Exxon Corporation terminating of the Colony Oil Shale Project. Among locals, that date is known as "Black Sunday."

Since the 1970s, innovations in mining and process technologies and operations practices have resulted in lower personnel requirements per unit of output. Nevertheless, the potential for adverse economic and social impacts to local communities remains a serious concern if a strategic-scale oil shale industry is to develop. Moreover, this trend will compound local population and economic growth caused by extensive oil and gas development in much of northwest Colorado and northeast Utah in recent years (Russell, 2005; Evans, 2005).

Given the past volatility and future uncertainties associated with oil shale development, as well as evolving views in the United States toward environmental protection, open-space preservation, energy policy, and stakeholder involvement in local decisionmaking, an attempt to rush or shortcut development is likely to generate significant opposition at the local, state, and even national levels.

Opportunities for Action. Local social and fiscal impacts are likely to be most severe in the medium and long term—during the production-growth phase of oil shale development. Nonetheless, early reevaluation of these impacts is needed, especially in EIS preparations and federal government deliberations associated with future lease offerings. While there may be a federal role in enabling and fostering socioeconomic planning (e.g., promoting regionally based planning), the responsibility for

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[9] A summary of studies and planning activities conducted in the 1970s is provided in OTA (Volume I, 1980). Also, see Russell (2005).

conducting such planning should be at the state, tribal, and local levels and conducted in cooperation with the resource developers. Once leases are awarded, revenue for enhanced public services should be forthcoming from federal/state lease and royalty revenue sharing.

Because oil shale development could profoundly affect local residents and other stakeholders, their input into federal decisionmaking needs to be sought and valued early in the process. The same holds true of the governments of Colorado and Utah, tribal governments, and the wider citizenry, including nongovernmental organizations representing citizens supportive of environmental protection, wildlife conservation, and alternative land uses. An opportune time to broaden public involvement is in conjunction with the preparations for a new round of federal leasing of oil shale tracts. Toward this end, the federal government should consider fostering the creation of a regionally based organization dedicated to planning, oversight and advice, and public participation. Various venues are possible for this, including the Western Governors' Association and the Colorado and Utah state governments.

Constraints to Strategically Significant Production

Beyond the environmental and socioeconomic issues related to large-scale shale oil development discussed above are several challenges that are currently constraining commercial production and two problems that may limit ultimate production levels. The two currently constraining problems are high oil shale production costs and uncertainties in future crude oil prices. The longer-term constraints involve resource access and water availability.

Production Costs

Challenges. Oil shale has not been exploited in the United States because the energy industry has viewed developing the resource as economically unviable.

As we have indicated in Chapter Three, the production costs from first-of-a-kind commercial mining and surface retorting plants are estimated to be between $70 and $95 per barrel. Very little R&D has been directed at surface retorting since the early 1980s. For in-situ retorting, costs might be competitive with crude oil priced at less than $30 per barrel, according to information released by Shell Oil. Limited information on production costs, however, is publicly available.

Opportunities for Action. One way to make oil shale attractive for development is for government to support R&D aimed at lowering production costs. The annual societal benefits of oil shale production, as described in Chapter Four, are in the tens of billions of dollars, albeit these benefits are not realized until commercial production occurs, which would be at least 12 years in the future for first-of-a-kind commercial plants. To the extent that government-supported research reduces production costs and/or promotes earlier commercial production, the present value of societal benefits is in the billions, assuming net (after accounting for all adverse environmental and social costs) per-barrel societal benefits are as low as $5 (in 2005 dollars).[10]

Since the termination of development efforts on surface retorting, major technical advances have been made in reactor modeling, especially with regard to computer codes for hydrodynamics and process kinetics, solids transport, and multiphase flow. Applying this knowledge base to surface retorting could result in improved designs and should reduce the uncertainties and risks of process scale-up. A research program in this area will likely include laboratory research directed at obtaining critical model inputs. Although large-scale surface retorting operations occurring abroad are not suitable for application in the United States, these large reactors can provide a low-cost field-test opportunity for model verification. Besides reduced production costs, R&D could result in improved yields, reduced emissions of toxic compounds, and reduced carbon dioxide emissions.

For in-situ retorting, work on mathematical modeling for the purpose of understanding the fate of leachates also could serve as a base for improved understanding of oil formation and product flows during retorting. Successful application could result in improved liquid and overall energy yields, better resource recovery, and lower costs. Another cost-reduction research opportunity is the development of gas-fired burners that could replace the electric coils that are the only current option for down-hole heating. Success here could also lower greenhouse gas emissions.

Market Risk

Challenges. As with many other commodities, crude oil prices are extremely volatile—and this volatility has been increasing in recent years. Small fluctuations in supply or unforeseen changes in demand in global markets can translate into large swings in crude oil prices. In 1981, the average price in real 2005 dollars of imported crude oil was $69 per barrel.[11] The real price declined to about $22 per barrel in 1986, rose slightly and then slumped to $14 per barrel in 1998. Since then, real prices have moved steadily higher. Despite the intensity of the 2004 and 2005 crude oil price spikes, market forces may produce another significant drop in world oil prices, as demand eases and new supplies are brought on line.

In such a volatile, uncertain, and often punishing climate, oil industry executives in recent years have pursued more conservative investment strategies in both the

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[10] Based on application of a 4 percent discount rate for societal benefits, initial production starting 15 years versus 20 years hence, annual production growth of 200,000 barrels per day, and a production cap of 3 million barrels per day.

[11] Prices quoted reflect average refiner acquisition costs of imported crude oil (EIA, 2004a, Table 5.21), escalated to first quarter 2005 dollars using chain-type price indexes (Bureau of Economic Analysis, 2005).

upstream and downstream business areas (Peterson and Mahnovski, 2003). Firms investing in upstream projects to bring additional crude oil to market favor projects with relatively low capital costs. To hedge against the possibility of downward price movements, investments in projects with high capital (i.e., front-end) costs tend to be deferred until a sufficient safety cushion has built up between anticipated production costs and what the market is willing to pay. In other words, the threshold, or "hurdle price," of crude oil required to trigger capital investment in oil shale development is substantially higher than the crude oil market price that would otherwise be required to motivate investment.[12] Investments in natural-gas-to-liquids plants provide an example of this behavior. Even though current gas-to-liquids technologies appear to be profitable at crude oil prices in the low $20s per-barrel range, commitments to construct full commercial-scale plants were not made until crude oil prices reached a hurdle price well above $30 per barrel.[13]

Another source of market uncertainty is the potential behavior of OPEC member nations. If they perceive that world crude prices are sufficiently high to encourage large investments in alternative sources of liquids, such as coal liquefaction and oil shale retorting plants, OPEC members could purposely increase crude oil production to lower world oil prices and to prevent long-term loss of their market share and power. From a macroeconomic perspective, such a development would yield substantial economic benefits to energy consumers, but investors in oil shale development and the first few oil shale projects would suffer large losses.

Opportunities for Action. In the 1970s and again today, advocates of greater domestic production of crude oil and fuels derived from oil shale have often cited market volatility and OPEC market manipulation as reasons for the federal government to take actions directed at reducing market-based investment risk. Remedies recommended for government action include establishing minimum price guarantees or long-term purchase agreements on terms advantageous to oil shale developers. A variety of other forms of subsidies—such as tax credits, allowances for accelerated depreciation, and construction grants—have also been recommended (U.S. Senate, 1979; Forgotson and Lukens, 1980). All of these measures can result in extremely large costs to the government: A $10 per-barrel subsidy on the output of a single 100,000 barrel per day commercial production plant, for example, would involve annual expenditures of about $350 million per year.

At the current stage of oil shale technology development, we do not believe that policies to address market risk are appropriate for promoting oil shale development. Presently, surface retorting is the only known option proven to be technically viable,

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[12] A second important factor is time: Investors must have the expectation that the threshold will be exceeded for a significant period of time.

[13] For example, Shell Oil Company and Qatar Petroleum completed their development agreement in July 2004, at which time spot prices for West Texas Intermediate crude oil were approaching $40 per barrel.

but the estimated production costs of $70 to $95 per barrel are well beyond current and forecasted crude oil prices (EIA, 2005a). Given current price levels and volatility, government market intervention to make surface retorting attractive as a commercial investment would require a large and extended federal financial commitment and, as the experience of the 1980s showed, could prove futile.

In-situ methods may result in much lower costs. But this technology also is not an immediate candidate for market risk reduction because information needed to establish the technical viability and commercial readiness of thermally conductive in-situ conversion methods will require at least six additional years of development work.

In the meantime, some preparatory analysis would be worthwhile. In particular, governments, both here and abroad, have implemented a wide variety of measures to promote commercial production of domestic fuels that can substitute for crude oil imports. As such, a large base of information is available regarding the costs, benefits, and lessons learned from various approaches, and it may be appropriate to collect and analyze this information prior to considering alternative policy options for mitigating market risk and promoting early production. Appropriate topics for an objective retrospective review include the former U.S. Synthetic Fuels Corporation, the currently operating Great Plains Gasification Project in North Dakota, and the Canadian Tar Sands experience.

Analyses of market risk mitigation and early production policy options should also address various incentives, including highly targeted tax relief, already or likely to be in place to promote domestic production of crude oil or fuels that can displace crude oil, such ethanol-gasoline blends. Unclear at present is the extent to which current law, including the Energy Policy Act of 2005, may unintentionally put oil shale development at a disadvantage.

Leasing of Federal Lands

Challenges. Oil shale deposits on private land holdings in Colorado and Utah are generally close to the surface, and some of these are fairly rich and thick (OTA, Volume I, 1980). As such, some of the private holdings represent attractive sites for initial commercial operations using either room-and-pillar mining or surface mining. Considering holdings in both Colorado and Utah, private lands might be able to eventually support a sustained production of roughly a half million barrels per day.[14]

If oil shale development is to produce strategically significant volumes of output, however, resources on federal lands must be accessed. Compared with deposits on private lands, the quality of the oil shale deposits on federal lands is generally far superior, especially with regard to thickness and richness.

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[14] This is a very rough estimate, based on OTA's (Volume I, 1980) analysis of whether more federal leasing were needed.

The Mineral Leasing Act of 1920 (MLA) governs the leasing of federal oil shale lands. MLA had limited the size of a lease tract to 5,120 acres (eight square miles). Additionally, no individual or corporation was allowed more than one lease (30 USC 241).[15] These provisions were modified by the Energy Policy Act of 2005, which raised the size of the lease tract to 5,760 acres and now allows an individual or corporation to acquire up to 50,000 acres of oil shale leases in any one state. The MLA was enacted in part with the goal of fostering competition in petroleum supply and marketing. Prior to the 2005 amendments to the MLA, the lease size and one lease tract per corporation provisions would have constrained access to oil shale and limited the benefits that can accrue to firms that successfully developed extraction technologies.

The MLA acreage limitations were established well before the advent of modern mechanized mining methods that rely on large-scale operations to increase productivity. Accordingly, the acreage limitations for all other minerals covered by the MLA have been substantially increased through various amendments to facilitate industry modernization and development. For example, the original limit for coal leases was 2,560 acres per person or corporation. The current acreage limitation for federal coal leases is 75,000 acres per state, with a nationwide maximum of 150,000 acres.[16]

The severity of the lease ownership provisions depends on the technical approach to oil shale development. With mining and surface retorting, the constraints are particularly severe. Although surface mining is the most efficient approach for mining oil shale, the 5,760-acre lease size limitation prevents efficient resource recovery. A RAND study (Rubenson and Pei, 1983) examining the impact of lease size on resource recovery indicated that the limit of 5,120 acres per lease caused at least 80 percent of the oil shale within a lease tract to be unminable because of the land needs for processing facilities and roads, slanted mine walls, and spent shale disposal. As a consequence, the output from a single lease tract is unlikely to exceed 100,000 barrels per day. Based on the project plans developed in the 1970s and 1980s, a more realistic estimate of this ceiling might be 50,000 barrels per day. Because in-situ retorting methods are particularly suitable to deep and thick deposits, this approach might be able to yield much higher output rates within a 5,760-acre lease tract. For example, when applied to the central basin areas holding more than 2 million barrels per surface acre, in-situ methods, such as the one being developed by Shell Oil Company, may sustain daily production levels beyond 200,000 barrels per day for more than 50 years.

The RAND analysis of land-use issues in the Piceance Basin (Rubenson and Pei, 1983) showed that larger lease tracts significantly improve resource recovery with surface mining, improve the cumulative stripping ratio, and thereby reduce shale oil

[15] An individual or corporation is allowed to own an interest in more than one lease, so long as the sum of the fractional shares does not exceed unity.

[16] Nick Douglas of the Bureau of Land Management brought this comparison to our attention.

production costs. At lease tract sizes of about 40,000 acres, resource recovery was shown to approach 70 percent. Perhaps the most important implication of improved resource recovery is that much less land is disturbed per barrel of oil produced.

The course of oil shale development and its environmental impacts will be shaped by federal decisions regarding how much, when, and which specific lands will be offered for lease. Equally important are the lease provisions that the government will impose to prevent or mitigate environmental damage, establish royalty rates, and avoid government or industry actions that prevent efficient resource recovery. The Department of the Interior does not yet have available a strategic approach to the leasing of oil shale lands. The Energy Policy Act of 2005 requires the department to analyze issues underlying a potential leasing program for the commercial development of oil shale.

Opportunities for Action. The 2005 amendments to the MLA have addressed the most onerous of the lease ownership provisions of MLA, namely the limitation that a single corporation can lease no more than 5,120 acres.

If a major fraction of the resource base is to be developed using surface retorting, it may be appropriate to consider alternative approaches for resource access and federal land stewardship. For example, one or two very large surface mines are likely to pose much less environmental disturbance than numerous smaller mining operations. A decision to consider large surface mines should also consider the benefits and costs of decoupling mining and shale processing operations (Rubenson and Pei, 1983) and optional mining concepts, such as having different operators responsible for mining in different parts of a large mine.

The adverse impacts of the MLA acreage limitations become far less severe if in-situ retorting methods can be successfully developed. For in-situ retorting, research needs to be directed at developing and evaluating land management options for accessing deposits located along the perimeters of lease tracts.

When and how federal lands are made available to industry is another important consideration. For example, the best deposits on federal lands are very deep and may not be good candidates for initial commercial plants employing mining and surface retorting because of the higher up-front costs involved in mine development.[17] For in-situ retorting methods, federal lands are strong candidates for initial commercial operations because they offer the highest per-acre yields of shale oil.

Under the section in this chapter addressing "Land Use and Ecological Impacts," we suggested that the federal government's leasing policy and decisions should be based on a strategic approach to developing the oil shale resource in which the costs and benefits of alternative options can be compared. That strategic approach should also include consideration of long-term industrial growth, ultimate

[17] However, there are also federal lands (for example, on the west edge of the Piceance Basin) that are outstanding candidates for early development in that they contain rich, thick deposits that are close to the surface.

resource recovery, and analysis of alternative approaches for leasing that allow lower-cost and more extensive resource recovery, such as larger surface mines, the decoupling of mine operations from retorting, and centralized upgrading operations.

Water Consumption

Challenges. Oil shale extraction and processing operations can involve significant amounts of water and water availability was and continues to be viewed as a major constraint on large-scale oil shale development in the Green River Formation (OTA, Volume I, 1980; Russell, 2005; Smith, 2005).

For mining and surface retorting, water is needed for dust control during materials extraction, crushing, and transport; for cooling and reclaiming spent shale; for upgrading raw shale oil; and for various plant utilities associated with power production and environmental control. Estimates of process water needs and the extent to which water can be recycled or economically reclaimed vary considerably. For example, the U.S. Water Resources Council estimated that oil shale development will increase annual consumptive water use in the Upper Colorado Region by about 150,000 acre-feet per year for each million barrels (oil equivalent) per day of production, which is the equivalent of about three barrels of water per barrel of oil (U.S. Water Resources Council, 1981). Other estimates range from 2.1 to 5.2 barrels of water per barrel of shale oil product (OTA, Volume I, 1980).

In-situ retorting eliminates or reduces a number of these water requirements, but considerable volumes of water may be required for oil and natural gas extraction, postextraction cooling, products upgrading and refining, environmental control systems, and power production. Reliable estimates of water requirements will not be available until the technology reaches the scale-up and confirmation stage.

The gross amount of water available locally in the Piceance Basin in a typical year did not appear to be a constraining factor, according to the 1981 water assessment by the U.S. Water Resources Council. Based on hydrologic understanding at the time, the council determined that available supplies of ground and surface water resources could support production of nearly 3 million barrels of shale oil per day.

The most constraining factor appears to be the water supply infrastructure. Limitations in local water supply systems in place in the late 1970s were expected to start constraining shale oil production when levels reached 200,000–400,000 barrels per day (OTA, Volume I, 1980). The Water Resources Council also concluded that the water supply infrastructure was inadequate, especially in the White River area of the Piceance and Uinta Basins. Needed infrastructure included reservoirs, pipelines, and groundwater development. We do not know if these analyses remain valid.

A bigger issue is the impact of a strategic-scale oil shale industry on the greater Colorado River Basin. The basin's water resources are tightly regulated and in great demand. Demands placed on the basin have risen considerably since the 1970s and 1980s, with rapid population growth in the Southwest, rising demand for electric power, growing recreational use, and increased efforts to maintain and restore the river's ecosystems. In recent years, water availability has become particularly acute, stemming from an extended drought and the subsequent drawdown of reservoirs. Significant water withdrawals to supply the oil shale industry may conflict with other uses downstream and may also exacerbate salinity problems. Such demands and pressures are expected to continue to grow for the foreseeable future, thereby rendering earlier data and analyses regarding oil shale development out of date.

Opportunities for Action. Given the long lead times involved in funding and permitting water-related projects, the constraints in water availability and infrastructure need to be addressed fairly early in planning for the development of oil shale resources. Once commercial interests are clear and technology choices become better defined, water availability for oil shale resource development should be analyzed in light of current and projected demands in the upper and lower Colorado River Basins.

CHAPTER SIX

The Development Path for Oil Shale

The future prospects for oil shale remain uncertain. For more than 20 years, unfavorable economics, particularly those of surface retorting, has kept oil shale off the nation's energy agenda. The estimated cost of surface retorting remains high, well above record-setting prices for crude oil that occurred in the first half of 2005. If surface retorting were the only approach for oil shale development, this report would have a clear message: It is inappropriate to contemplate near-term commercial efforts; oil shale extracted through surface retorting belongs in the nation's R&D portfolio, not on its energy policy agenda for commercial development.

Meanwhile, the technical groundwork may be in place for a fundamental shift in oil shale economics. Advances in thermally conductive in-situ conversion may enable shale-derived oil to be competitive with crude oil at prices below $40 per barrel. If this becomes the case, oil shale development may soon occupy a very prominent position in the national energy agenda. Presently, we know that one major company, Shell Oil, has reached the point where it must decide whether to commit its resources to demonstrating and scaling up its technical approach for in-situ retorting. Other firms with the technical, management, and financial resources to develop oil shale technologies may be waiting in the wings.

Oil shale development is rapidly approaching a critical juncture. On June 9, 2005, the Bureau of Land Management released its Call for Nominations of parcels to be leased for research, development, and demonstration of oil shale recovery technologies in Colorado, Utah, and Wyoming (*Federal Register*, 2005). The response to this solicitation will provide a clear signal about whether the private sector is prepared to commit its resources to oil shale development. Government decisionmakers need to wait for that signal. When it is clear that private firms are willing to devote, *without appreciable government subsidy*, their technical, management, and financial resources to oil shale development, decisionmakers should address the policy issues that form a central element of this report.

Business as Usual

Whether we hear the signal or not, it does not make sense that oil shale is missing from the Department of Energy's R&D portfolio. In the 1970s and through the 1980s, crude oil substitutes from oil shale were considered to be less expensive than coal or biomass-derived liquids (see, for example, Schurr et al., 1979; U.S. Senate, 1979; National Research Council, 1990). Since then, the technologies for coal and biomass-derived liquids have improved considerably because of R&D undertaken through public- and private-sector support.[1] In contrast, very little progress has been made in improving the prospects for oil shale production using surface retorting.

Significant long-term high-risk/high-payoff research opportunities are associated with both surface retorting and in-situ retorting. These opportunities center on modeling and the development of improved scientific and engineering knowledge of solids transport and multiphase flows. While this research may be relevant to applications well beyond oil shale,[2] directing it specifically at oil shale provides program focus and maintains a small cadre of scientific and engineering professionals that would be deeply knowledgeable of oil shale development issues. If and when an industry "signal" is received, consideration can be given to nearer-term technology development efforts. A few examples of near- and long-term R&D opportunities are provided in Chapter Five.

Before low crude prices quelled interest in oil shale, hundreds of millions of dollars were spent by the federal government and private industry toward the development of oil shale technologies and understanding the impacts of oil shale development (National Research Council, 2001). As we searched the literature and sought expertise, we found that time has taken its toll. Senior industrial and government managers with in-depth knowledge of this prior work are already at or very close to retirement. Some of the key journals are out of print. Important books, articles, and technical reports are becoming scarce. Meanwhile, much of this prior work is still valuable, and repeating it will be costly. For these reasons, we suggest that consideration be given to establishing a national oil shale archive that would hold and preserve information on oil shale resources, technologies, and the impacts of development.

Now that the ownership limit on federal oil shale leases has been raised to 50,000 acres per state, private-sector investors in oil shale development have a much

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[1] This includes R&D directed at dual-benefit technologies. For example, commercial interest in gas-to-liquids technology has brought about advances in Fischer-Tropsch synthesis that also apply to coal and biomass-based liquids production. Likewise, interest in combined-cycle power production based on coal gasification is advancing gasification technology that is also applicable to coal and biomass-based liquids production.

[2] For long-term research directed at in-situ retorting, example applications areas beyond oil shale include hydrology in general, reservoir engineering, subsurface waste disposal, and carbon sequestration. Likewise, for long-term research directed at surface retorting, application areas include metals and materials processing, manufacturing, and coal and biomass processing.

greater opportunity to profit from technically successful efforts. With the possibility that in-situ retorting may be a technically and economically viable option, a major further revision of the Energy Policy Act to address the lease size issue may not be needed. Instead, we recommend an early analysis of implementation options associated with a leasing program, such as combining adjacent lease tracts in a lease offering and provisions for ensuring or promoting extensive recovery of the resources within lease tracts.

Toward Industrial Development

Early Actions

Once clear indications are in hand that major firms are ready to invest in scaling up and demonstrating oil shale technologies, government attention should be directed at gathering long-lead-time information required to support future decisionmaking with regard to permitting and leasing. The federal government should give high priority to the following:

- Development and implementation of a research plan directed at establishing options for mitigating damage to plants and wildlife and reducing uncertainties associated with ecological restoration.
- Research directed at mathematical modeling of the subsurface environment, combined with a multiyear hydrological, geochemical, and geophysical monitoring program. (This in the event that major industrial investments are directed at in-situ retorting.)
- Research directed at establishing and analyzing options for long-term spent shale disposal. (This in the event that major industrial investments are being directed at mining and surface retorting.)
- Regional air quality modeling directed at determining preferred locations for federal leasing and informing decisions on air quality permits for initial commercial plants.
- Development of a federal oil shale leasing strategy for the Green River Formation, along with appropriate analytic and procedural approaches for timing and selecting sites for lease offerings, establishing lease provisions, and avoiding measures that will constrain future development.

A Measured Approach to Development

As we delved deeper into the issue of oil shale development, we were struck by the large number of uncertainties regarding technology performance, costs, infrastructure requirements, and environmental and socioeconomic impacts. These uncertainties were present in the 1970s and early 1980s when many in government and industry were promoting the rapid buildup of an oil shale industry. These uncertainties remain unresolved today. While the five *early actions* listed above will serve to narrow uncertainties and the risks of making poor decisions, resolution of the most critical issues associated with strategically significant levels of production will not occur until confirmation of alternative technical options is obtained through integrated operation of large-scale commercial facilities—a point at least 14 years down the road.

Perhaps the most important issue presently before us is the technical, environmental, and economic viability of thermally conductive in-situ retorting approaches, such as the in-situ conversion process being developed by Shell Oil. If progress proceeds as anticipated by the Shell Oil development team, in-situ retorting will be available as a more profitable and far more environmentally benign alternative to mining and surface retorting. For this reason, consideration should be given to measures that foster the early confirmation of the viability of in-situ retorting methods. These measures include giving developers access to appropriate sites for process testing and evaluation as is currently being implemented by the Bureau of Land Management, conducting the *early action* research directed at understanding the environmental impacts of in-situ retorting, and performing research directed at improving the yield and environmental performance of in-situ retorting, such as the development of down-hole gas burners, reservoir modeling and analysis of alternative heating strategies, and recovery and use of waste heat once extraction operations cease.

In any case, the prevailing information shortfalls suggest that oil shale development proceed at a measured pace to enable evaluation and course correction along the way. This appears consistent with the Bureau of Land Management's announced intent to "initiate a phased or staged approach to oil shale development" (*Federal Register*, 2005).

Public Participation

In Chapter Five, we suggested establishing an independent advisory and oversight board to ensure that research programs directed at water quality, air quality, and ecology are properly formulated. These three research areas represent the core of the *early action* program suggested above. They cover the most critical potential impacts of oil shale development, and they involve complex issues. Getting early guidance from an independent scientific advisory board is an essential first step in building confidence in the public and the technical community regarding the relevance and credibility of the eventual findings of the research programs.

Because the richest oil shale deposits in the United States are within a relatively small area of Colorado and Utah, it is extremely important that government and industry work closely with stakeholders at the local, tribal, and state levels. Toward this end, we recommend in Chapter Five that the federal government foster the creation of a regionally based organization dedicated to planning, oversight and advice, and public participation. Beyond the early actions listed above, the agenda of such an organization would include socioeconomic impacts and water supply planning.

Here we suggest going one step further. Many of the issues that will arise in oil shale development closely resemble those involved in federal and private-sector attempts to site large energy-related facilities. The experience at Yucca Mountain, Nevada, and the difficulties associated with finding sites for liquefied natural gas terminals lead us to question past approaches in gaining public confidence and trust in major decisions involving federal, state, and local governments; industry; and the public. We suggest that federal and state governments, industry, and nongovernmental organizations consider working together to develop a better understanding of what drives public opposition in major siting and land-use decisions, what lessons can be learned from prior successful and unsuccessful interactions, what alternative approaches have been tried in other democracies, and what options might be available for the government-industry-public interaction through a regionally based organization focused on oil shale. Making progress in this area for oil shale could be very relevant to future decisions regarding site selection, such as decisions that might be forthcoming for new refineries, wind farms, and nuclear power-generating stations.

APPENDIX

Cost Estimation Methodology and Assumptions

This appendix summarizes the methodology and assumptions that underlie the estimated costs ($70 to $95 per barrel) of producing a crude oil substitute through mining and surface retorting of oil shale in a first-of-a-kind full-scale commercial plant. Oil production costs are calculated using a discounted cash flow model in which both capital costs and operating costs are input in first-quarter 2005 dollars. The calculated production costs are annualized costs per barrel expressed in first-quarter 2005 dollars.

Capital and Operating Cost Estimates

For our calculations, capital costs are defined as all outlays made after the decision to construct a commercial plant and prior to the production of saleable products. Capital costs do not include factors to account for either inflation or the time value of money because these effects are accounted for in the discounted cash flow calculations. Capital costs include three basic categories: plant costs, land acquisition costs, and various start-up costs. By far the largest category, plant costs include all site preparation; design and construction costs for the entire production complex, including the mine, the retort section, and product upgrading sections; all auxiliary systems required for pollution control and spent-shale handling and disposal; and such essential infrastructure as roads, housing for construction workers, access to electric power and water, and product pipelines.

Plant operating costs are the net costs associated with operating and maintaining the plant minus any income produced from the sale of by-products, such as elemental sulfur or ammonia (Albulescu and Mazzella, 1987). The operating costs include consumable chemicals, replacement parts, labor, royalties, fees, and outside services, including periodic plant overhauls. For the purpose of developing a rough estimate of production costs, all operating costs are expressed as variable costs—namely, dollars per barrel of product.

Both capital and operating cost estimates are expressed in first-quarter 2005 dollars, using the gross domestic product price index (Bureau of Economic Analysis, 2005) to adjust from original year-of-estimate dollars.

Key Financial Assumptions

Table A.1 summarizes the key parameters in the cost estimates for oil produced from surface retorting, presented in Chapter Three. The lower-bound estimate of $70 per barrel is based on the low end of the capital cost and operating cost ranges shown in Table A.1. Likewise, the upper-bound estimate of $95 per barrel is based on the high end of the capital and operating cost ranges.

In the discounted cash flow analysis, total plant costs are expended over a five-year construction period according to the expenditure schedule in Table A.1 (Albulescu and Mazzella, 1987). Land acquisition costs are assumed to be lease bonus payments. These costs are incurred in the initial year of construction and are estimated at $150 million. Initial catalyst and chemical inventory, spare parts, start-up costs, and working capital are grouped together and estimated at $150 million. It is assumed that these costs are expended during the final year of construction.

For the purposes of developing a product cost estimate, the operating life of the plant is set at 30 years. Estimates of real product cost estimates are highly insensitive

Table A.1
Product Price Calculation Assumptions

Capital investment (millions 2005 dollars)	$5,000–7,000
Total plant costs	$4,700–6,700
Land acquisition	$150
Inventory, start-up, and working capital	$150
Expenditure schedule for total plant costs	
Year 1	5 percent
Year 2	15 percent
Year 3	32 percent
Year 4	28 percent
Year 5	20 percent
Initial operating year	6
Plant financial operating life	30 years
Operating costs (2005 dollars per barrel)	$17–23
Depreciation schedule for total plant costs	MACRS (200DB)
Federal corporate tax rate	34 percent
State corporate tax rate	5 percent
Rate of return (real, after tax)	10 percent
Plant utilization rate (online factor)	
Initial two operating years	70 percent
Years 3 through 30	85 percent

to further increasing the financial time frame.[1] Total plant costs are depreciated over a seven-year recovery period, utilizing the double declining balance/straight line method allowed under the Modified Accelerated Cost Recovery System (MACRS). Land acquisition costs are amortized over the 30-year operating period of the plant. In our cost calculation, inventory, start-up, and working capital are neither depreciated nor amortized.[2]

Estimates of production costs are highly sensitive to the after-tax real rate of return and the plant online factor, especially during the initial operating years. Given recent levels of inflation and interest rates, a real after-tax rate of return of 10 percent is consistent with the level of risk and potential rewards associated with investing in a first-of-a-kind commercial plant.[3] The plant online factor for the first two operating years is consistent with the assumption that the first-of-a-kind plant design is based on technical data obtained during integrated operations at an appreciable (i.e., few thousand barrels per day) subcommercial scale.

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[1] For example, increasing the operating period to 40 years yields only a $2.00 reduction in the estimated product production cost.

[2] Detailed tax treatment of these costs does not significantly influence the estimates.

[3] Note that many of the cost estimates made in the early 1980s were based on real after-tax rates of return of 12 and 15 percent (e.g., OTA, Volume I) that are not appropriate for current economic conditions.

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