Potential Small-Scale Development
of Western Oil Shale

Topical Report

V. Smith
R. Renk
J. Nordin
T. Chatwin
M. Harnsberger
L.J. Fahy
C.Y. Cha
E. Smith
R. Robertson

October 1989

MASTER

DISCLAIMER

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

SUMMARY

Several studies have been undertaken in an effort to determine ways to enhance development of western oil shale under current market conditions for energy resources. This study includes a review of the commercial potential of western oil shale products and byproducts, a review of retorting processes, an economic evaluation of a small-scale commercial operation, and a description of the environmental requirements of such an operation. Related studies, which are reported elsewhere, include an evaluation of the market potential of numerous oil shale products and byproducts, a cost analysis of several oil shale mining alternatives and unconventional uses for oil shale, an evaluation of innovative mining concepts, a process engineering study of a small-scale plant, a study of propellants for enhanced oil shale fracturing, and an evaluation of methods for economic enhancement of shale oil upgrading.

Shale oil used as a blend in conventional asphalt appears to have the most potential for entering today's market. Based on present prices for conventional petroleum, other products from oil shale do not appear competitive at this time or will require considerable marketing to establish a position in the marketplace.

Because shale oil-blended asphalt may significantly extend the life of roadway pavements, the value of the shale oil will be considerably more than that of conventional petroleum asphalt. The primary reason that shale oil improves the life of an asphalt blend is the presence of nitrogen compounds in the shale oil.

Other uses for oil shale and spent shale, such as for sulfur sorbtion, power generation, cement, aggregate, and soil stabilization, are limited economically by transportation costs. These costs restrict use to a transportation distance of 700 miles. Such uses may improve the economics for a small-scale operation by reducing spent shale disposal costs and providing some additional income.

The three-state area consisting of Colorado, Utah, and Wyoming seems reasonable for the entry of shale oil-blended asphalt into the commercial market. Assuming a 7.5% increase in pavement life cycle, the amount of shale oil material required in the area is estimated at 1,500 to 2,500 barrels per day (b/d).

From a review of retorting technologies and the product characteristics from various retorting processes it was determined that the direct heating Paraho and inclined fluidized-bed processes produce a high proportion of heavy material with a high nitrogen content. The two processes are complementary in that they are each best suited to processing different size ranges of materials.

An economic evaluation of a 2,000-b/d shale oil facility shows that the operation is potentially viable, if the price obtained for the shale

oil residue is in the top range of prices projected for this product. This evaluation is based on an estimated capital cost of $82,097,600 and an operation cost of $11,013,360 per year for the retorting facility. At $700 to $1,000 per ton of shale oil residue, the estimated discounted cash flow-return on investment (DCF-ROI) is in the range of 18 to 26%. This return on investment results in about a 4- to 5-year return of capital. The most significant parameters to affect the rate of return are the price of the asphalt blend and the plant throughput. Hence, if the production capacity or the asphalt price drops below the projected values the viability of the oil shale facility becomes tenuous. On the other hand, if the price increases above these values or the plant capacity is expanded to meet greater demand with little additional capital expenditures the facility becomes much more profitable.

Environmental requirements for building and operating an oil shale processing facility are concerned with permitting, control of emissions and discharges, and monitoring. Federal, state, and local agencies require permits to ensure protection of the air, water, and land. Prior to construction, a year of monitoring may be necessary to establish baseline conditions and provide input to an assessment of environmental impacts. Costs for permitting are estimated at approximately $500,000. Control of emissions and discharges can readily be achieved with existing technology. Monitoring costs during operation are estimated to run around $200,000 per year.

INTRODUCTION

For about the past 140 years, a relatively small amount of products from oil shale have been produced commercially. Generally, the market for shale oil products has been limited by competition with conventional petroleum. The potential for shale oil to be used as transportation fuel is obvious and, during times of high oil prices, activities related to oil shale increase significantly. This occurred most recently in the 1970s as a result of the energy crises of that decade. Activities in oil shale were curtailed drastically in the early 1980s in direct response to the drop in the price of crude oil.

It is generally recognized that oil shale presently is not economically competitive with conventional petroleum in relation to the primary product, transportation fuel. So oil shale development in the United States is nearly at a standstill. There is a natural reluctance to invest capital where the return is uncertain.

For oil shale development to go forward now without government assistance, alternative uses and markets for shale oil must be considered. This study reviews the potential for western oil shale products and evaluates the economics for such an industry. This report also includes a brief review of retorting processes and a description of the environmental requirements for a small-scale commercial plant.

Several studies were conducted in conjunction with this study. An extensive number of products and byproducts from oil shale were evaluated for their market potential in a study by Sinor (1989). An analysis of costs of several oil shale mining alternatives and an examination of some unconventional uses for oil shale were made by McCarthy and Clayson (1989). Innovative mining concepts are being evaluated in a study being completed at the Colorado School of Mines. Plant construction and operation costs were estimated in a process engineering study made by Ford, Bacon and Davis Inc. (Walker et al. 1989). The performance of propellants to enhance fracturing of oil shale was studied by Lekas et al. (1989). Methods for economic enhancement of shale oil upgrading were investigated by Bunger et al. (1989).

PRODUCT SELECTION

Primary Product

Market Assessment

There are numerous products that can be made from shale oil. The recent study by Sinor (1989) provides an extensive examination of possible products from western oil shale and evaluates the potential market for these products to fit within a suitable niche. Sinor (1989) concluded that individual chemicals are not present in sufficient

amounts to be economically produced as the primary product for a commercial shale oil operation. A broad cut of products was then considered. The products included asphalt blends, waxes, olefins, modified aromatics, synthetic gas, naphthalene, creosote, phenolics, pyridines, oil field chemicals, rubber processing oils, bunker fuel, carboxylic acids, jet fuel, high-density fuel, endothermic fuel, carbon black, coal dust suppressant, and anode coke. Asphalt blends were determined to be the most likely candidate as a primary product.

Advanced Aviation Turbine Fuels

Evaluation of crude oil as a source of advanced aviation turbine fuels depends on a knowledge of the crude oil composition, the effects of processing on composition, and on the target characteristics of the finished fuel. To be an ideal source for advanced fuels, a crude oil should require only moderate processing to give high yields of alicyclic (naphthenic) hydrocarbons, which are currently viewed as the principal components of advanced fuels.

Oils from western oil shales are highly aliphatic, with a substantial content of paraffins, straight-chain olefins, and nitrogen- or sulfur-containing compounds. Typically, sulfur contents range from 0.5 to 1.0 wt %, and nitrogen contents range from 1.5 to greater than 2 wt %. Most of the nitrogen and sulfur is found in heteroaromatic compounds and virtually all suggested processing schemes employ high-severity catalytic hydrogenation to remove heteroatoms. Several different schemes for production of conventional fuels from western shale oils are described by Sullivan et al. (1978) and Lander (1981). All these schemes employ catalytic hydrogenation as the method for denitrogenation. The high severities required for nitrogen removal saturate aromatic systems and create paraffins by saturating olefins and by cleaving rings. The resulting process intermediates are more paraffinic than the crude feedstock and are well-suited for production of conventional turbine fuels. However, paraffins are not desirable components in advanced fuels.

Advanced turbine fuels considered in this study are of two types, high-density fuel and endothermic fuel. The former is a high-density kerosene similar in boiling range to commercial Jet A-1 or Air Force JP-8. Density is increased by limiting the low-density paraffins to less than 10 vol % and by concentrating 2-ring alicyclic or alicyclic-aromatic components, such as decalins and tetralins. Aromatic components are limited to a target maximum of 30 vol %, but will preferably be less than 25 vol %. Thus, the preferred composition for high-density fuel is best described as highly naphthenic.

Endothermic fuels are hydrocarbons that decompose cleanly to light combustible products by absorbing heat. Such fuels are regarded as necessary for absorbing heat generated at leading surfaces and in engines of hypersonic aircraft of the future. The components currently most favored for endothermic fuels are alkyl-substituted cyclohexanes,

2

such as methyl- or ethylcyclohexane, which thermally decompose to hydrogen and alkylbenzene. Favorable endothermic characteristics of such compounds were described by Nixon (1986) and have been recently investigated by Eyman and Datta (1988). However, the list of candidate hydrocarbons for endothermic fuel application is growing, and a recent report assessed the endothermic cooling characteristics of decalins and other high-density naphthenes (Komar 1988). It is therefore conceivable that an endothermic fuel can be a mixture of naphthenes capable of thermally decomposing to hydrogen and light aromatic compounds.

Thus, considering the target characteristics, the suitability of a crude oil as a source of either high-density fuel or endothermic fuel depends primarily on the oil's potential as a source of naphthenes.

Western shale oil is obviously not a good source for naphthenes. The initially high paraffins content is made even higher by hydrodenitrogenation, which is the only commercially practical way to reduce nitrogen contents to the low levels that can be tolerated in downstream processing or in finished fuels. The paraffins in process intermediates are ubiquitous across the oil boiling range, so they cannot be segregated by distillation. Solvent dewaxing can remove the high-boiling paraffins but are of limited usefulness in removing paraffins boiling in the jet-fuel range. Catalytic dewaxing can destroy paraffins but only with a substantial impact on yield. Dehydrocyclization can convert some paraffins to cyclic compounds; although, the effectiveness of this process on a complex mixture boiling at temperatures above the naphtha range, that is, greater than 400°F (204°C), is doubtful. Any process scheme that can convert western shale oil to a mixture rich in naphthenes and free of nitrogen compounds and paraffins is, therefore, likely to be involved and prohibitively expensive. Other crude oils, with higher naphthene and aromatic contents, lower paraffin contents, and lower nitrogen contents are far more suitable as candidates for advanced turbine fuels.

Diluent

Shale oil can be used as a diluent for enhanced oil recovery. However, because the primary need for diluent is in California, the additional cost for transportation from the oil shale area does not appear to warrant producing shale oil for this purpose.

Rail Diesel Fuel

Another possible use for shale oil is to use the distillate product as rail diesel fuel. This requires minimal transportation because two major rail transportation corridors cross the Green River Formation, the source of raw shale, and two other main corridors are close to it. It has been demonstrated that rail diesel engines can operate using a wide variety of fuels and shale oil distillate may fit into this acceptable use range. As an example of the wide range of usable fuels for rail diesels, General Motors (1986) recently demonstrated that their EMD-

series engines can be operated with powdered coal. Very different from this, several years ago one rail carrier operated diesels with overhead distillate from a gilsonite coking process. The combined costs of fuel, operations, and engine maintenance appear to determine which are acceptable fuels. Further investigation and marketing efforts for this use may be warranted.

Asphalt Blends

According to the Road Information Program in Washington, DC, there are approximately 2 million miles of roads paved with asphalt in the United States. Annually, more than 21 million tons of asphalt and asphalt-related paving materials are used, and expenditures in excess of $10 billion are incurred in the construction and maintenance of asphalt roadways. In addition to the high cost of constructing and maintaining these roadways, rough and broken pavements represent another economic burden on the taxpayer. It is estimated that damaged roads cost the U.S. motorist more than $28 billion annually in increased operating costs for wasted fuel and vehicle repairs.

Moisture damage and asphalt embrittlement are the major causes of pavement failure. Moisture damage results when water weakens or disrupts the asphalt-aggregate bond, leading to the loss of the structural strength of the pavement. This can manifest itself as rutting, raveling, flushing, or cracking that may eventually lead to pavement failure. Binder embrittlement results when the flow properties of the asphalt binder deteriorate to such an extent that, under the influence of physical or thermal tensile stresses, the binder, and thus the pavement, fractures. Binder embrittlement is caused by aging of the pavement through the processes of atmospheric oxidation and steric hardening.

Research into the use of shale oil as a source of material for pavement construction has been conducted at Western Research Institute (WRI) and its predecessor organizations and also at other institutions for over 25 years. The earlier work focused on preparing and using shale oil materials as total replacements for petroleum asphalts. These investigations examined the properties of the binder alone, the interaction of the binder and the aggregate, and also the properties of designed pavement mixes. The results from this work suggested that shale oil asphalt alone tended to age rapidly both physically, by a substantial increase in viscosity, and chemically, by an increase in oxygen-containing molecules. This same behavior was shown in the design pavement mix work (Button et al. 1978). However, the shale oil asphalts showed an unusually high resistance to moisture damage when subjected to freeze-thaw cycling and also an unusually strong interaction with aggregates when analyzed using a nitrogen-sensitive thermal desorption method (Plancher and Petersen 1984).

Ongoing research at WRI is studying the use of shale oil residue blended with petroleum asphalt. The blending of shale oil increases

resistance of the petroleum asphalt to moisture damage and lowers the viscosity aging index of the blend lower than either the petroleum asphalt or the shale oil residue alone. In addition, not only is the aged viscosity of the blend lower, but the aged blend is also more elastic, an important property of asphaltic binder. Using from 25% to 65% of tne barrel of shale oil, only slight differences are found in the characteristics of the various distillation residues. Similar findings have been reported by Sinor (1989).

Based on the volume of asphalt used annually, it is obvious that if shale oil-blended asphalt extends the life of pavements, and even if it is used only in the Rocky Mountain region, even a small increase in the longevity of pavements could save millions of dollars.

Because shale oil-blended asphalt would be a premium product, it can be sold at a price higher than petroleum asphalt. From curves developed by Sinor (1989), the value of shale oil used for asphalt blending can range from $50 to $120 per barrel, depending on the increase in the life cycle of the pavement and on the proportion of shale oil in the blend. For example, assuming just a 7.5 percent increase in pavement life with a 10 percent blend results in a shale oil value of over $70 per barrel. Even higher values may be achieved. A shale oil-blended asphalt has been compared to rubberized asphalt (AC-20R) and a petroleum asphalt in a test strip in Utah where the cost of the AC-20R was $240 per ton and the cost of the petroleum asphalt was $140 per ton. Because the 10 percent shale oil-blended asphalt was sold for the same price as the rubberized asphalt, this is equivalent to a value of $199 per barrel for the shale oil residue [(0.90 x $140/ton + 0.10Y = $240/ton) Y = $1,140/ton shale oil residue (5.71 barrels per ton)].

Field studies are presently under way in which roadways paved with shale oil-blended asphalt are being compared to ones paved with conventional petroleum asphalt (Lukens 1989). If increased life cycles are proven, the potential for shale oil as an asphalt blend will be very substantial.

Secondary Products

Having determined that asphalt blends are the primary product, the possibilities for the products remaining after asphalt-blend production need to be considered. These secondary products can supplement income to better the economics of the facility. Table 1 is a summary of products considered first as primary products and then as products secondary to asphalt-blend production. Individual chemical,, olefins, BTX (benzene, toluene, and xylene), creosote, phenolics, pyridines, oil field chemical applications, and carboxylic acids are candidates for secondary products. Further study of these products appears warranted to determine their production feasibility and marketability. Certainly, additional capital costs would be required for separation equipment, chemicals, and product storage. In the absence of this information, it is assumed that the light-end fraction of the produced material will be

sold as fuel feedstock to a facility capable of hydrotreating the material prior to sending it through a refinery.

Table 1. Summary of Product Evaluation for Western Oil Shale

Product	A	B	C	D
Individual chemicals				X
Conventional oil stock			X	
Asphalt blend	X			
Waxes			X	
Olefins (specialty)				X
Modified aromatics (BTX)				X
Synthetic gas		X		
Naphthalene		X		
Creosote				X
Phenolics				X
Pyridines				X
Oil field chemicals				X
Rubber processing			X	
Bunker fuel			X	
Carboxylic acids				X
Carbon black		X		
Coal dust suppressant		X		
Anode coke		X		
Jet fuel			X	
High-density fuel		X		
Endothermic fuel		X		
Enhanced oil recovery			X	
Rail diesel fuel				X

A Potential primary product
B Other sources appear to be better material
C Transportation or other factors presently make oil
    shale product less competitive to other materials
D Potential secondary product

Byproducts

Other revenue that can be obtained from materials processed in an oil shale facility should be considered. Potential applications for oil shale and spent shale include sulfur sorbtion, power generation, cement, aggregates, and soil stabilization.

The carbonaceous material in western oil shale is an effective sorbent for sulfur removal in fluidized-bed coal combustion. Raw shale also contains fuel that will complement energy produced in a coal-fired

power plant. The study by McCarthy and Clayson (1989) suggests that cogeneration has significant potential. Transportation costs probably limit this potential to a 700-mile radius by rail and a 350-mile radius by road. The evaluation by Sinor (1989) concludes that the potential for this use is limited to new construction because all existing power plants but one in the region do not use fluidized-bed combustors. Currently, most power utility companies in the area have excess capacity and do not plan any expansion in the immediate future. Opportunities may arise in the next decade as new power plant projects are developed.

Spent shale is believed to be an effective sulfur sorbent, but the loss of energy value relative to raw shale will probably reduce the economical range of transport. The estimated potential use of oil shale as a sorbent is 500 tons per day per power plant (McCarthy and Clayson 1989). Although this would be but a small fraction of the production of a large commercial oil shale industry, it can be significant for a small-scale operation.

The use of oil shale for production of cement is well established in Europe, and a limited amount of such production is occurring in the United States. However, present demand for cement is readily met by existing plants, and demand is not forecast to grow significantly (Sinor 1989). The potential exists for this use with successful marketing efforts.

Spent shale can also be used as aggregate for road bases. In competition with plentiful aggregate sources in the west, the maximum economic distance for transport is from 30 to 50 miles (Sinor 1989). Thus, this market is quite limited.

Spent shale used as soil stabilizing material for road subgrades can replace more expensive materials. A laboratory testing investigation evaluated engineering properties of spent shales mixed with soil (Suryavanshi 1989). This study showed that adding spent shale significantly increases unconfined compressive strength, particularly for granular soil; the plasticity index decreases for a clay soil; the method of mixing soil, spent shale, and water significantly affects strength; and the thickness of roadway subgrade can be decreased using spent shale mixed with soil, compared to unstabilized material, resulting in cost savings for road construction.

Transportation costs will limit the area in which spent shale used for soil stabilization can compete with other materials. McCarthy and Clayson (1989) determined a 500-mile radius to be the limiting distance for economic competition with cement. A market demand of 374 tons per day was then derived for roads requiring stabilization in the area. Consideration of other recreational and secondary roads can double this estimated demand. The beneficial use of this amount of material will help significantly in the waste disposal at a small oil shale facility.

With the penetration of certain markets, alternative uses of spent shale can benefit the economics for a small-scale oil shale operation by reducing spent shale disposal cost and providing some income from byproducts. However, for the purposes of this study, no economic benefits are assumed from solid waste byproducts

PROCESS SELECTION

Retorting Technology

Background

Over the last 150 years, the technology for conversion of oil shale into saleable products has evolved as ideas and concepts are developed and tested. As of 1981, there were more than twenty individual retorting processes in use or under development around the world for the production of shale oil (Piper 1981). Literally hundreds of patents have been issued in the United States concerning various aspects of oil shale processing. Despite an intensive effort in the 1970s and early 1980s, no single process or patent has been universally accepted or demonstrated as the best method for processing oil shale.

Retorting processes are typically divided into two categories: surface and in situ. The following descriptions of conventional processes and processes being developed contain further divisions within each category.

Surface Processes

Surface processes are generally categorized by the method used to heat the oil shale. Direct heating provides the required heat for retorting by combustion of residual carbon and hydrocarbon compounds within a retort vessel. Indirect heating processes use a hot solid material or hot gas to supply the heat required for retorting. Currently, fluidized-bed and cascading-bed processes are being studied that use both direct and indirect heating to retort the oil shale.

The surface processes that are considered in this study fall into the following categories, and they are described in subsequent sections.

- Direct Heating--internal combustion

    N-T-U (batch)
    USBM gas combustion
    Paraho direct heating

- Indirect Heating--external heat source

    Gas-solid heat transport (coarse feed)
        Paraho indirect heating

Petrosix
                    Superior
                    Rundle
                    Union B

              Solid-solid heat transport (fines feed)
                    TOSCO II
                    Lurgi-Ruhrgas

        • Fluidized-Bed Retorting
                    LLNL fluid bed
                    LLNL gravity bed
                    KENTORT II
                    WRI inclined fluidized bed

     N-T-U Process. The name N-T-U was given to this process when such a
plant was built by the N-T-U (Nevada-Texas-Utah) Company near Santa
Maria, California in the early 1920s. The N-T-U process is a batch,
internal-combustion method of retorting (Ruark et al. 1956). The heat
required for kerogen thermal decomposition is mainly supplied by
residual carbon combustion.

     USBM Gas Combustion Retorting Process. Encouraging results of the
N-T-U process tests led the U.S. Bureau of Mines (USBM) to build three
experimental gas combustion retorting plants at Anvil Points, near
Rifle, Colorado (Cameron Engineers 1975b).

     In the gas combustion retorting process, oil shale flows by gravity
downward through a vertical kiln retort as in a moving bed. The shale
bed flow rate is controlled by a grate discharge mechanism located in
the lower part of the retort.

     The retort is divided into four functional zones, the shale
preheating zone, the shale retorting zone, the combustion zone, and the
spent shale cooling zone. Combustion air plus recycle gas are injected
into the bed of oil shale in the combustion zone. Fuel in the recycle
gas and some residual carbon in the spent shale are burned to provide
the heat required for retorting. The flow of gases in the retort is
upward, counter to the downward flow of solids. Matzick and Dannenberg
(1960) reported data on all of the USBM gas combustion retorting tests.

     Paraho Process. In 1972, the Anvil Points facility was leased to
Development Engineering Inc. for demonstration of the Paraho process
(Jones 1976). The Paraho process is a fixed, vertical kiln. Raw shale
is fed into the top of the retort and distributed evenly across the top
of the bed. The downward flow of shale is controlled by a hydraulically
operated grate located at the bottom of the retort. As the shale moves
downward it is contacted countercurrently with an upward flow of hot
gas. This hot gas preheats the shale. Simultaneously, the gas is
cooled; oil vapor is condensed in the gas; and the oil, as an entrained

mist, exits with the gas from the top of the retort. The preheated shale then moves downward through the retort into the retorting zone, where it is heated to retorting temperatures by the ascending hot gases. After retorting is complete, the shale moves into the combustion zone. Here, a small portion of the coke residue is burned in direct mode of operation. After the shale is combusted, it continues downward and is cooled by the incoming gases before exiting the retort. In the indirect mode, the Paraho process does not have a combustion zone but uses that part of the retort for heat exchange.

Petrosix Process. The Petrosix process was specifically developed for processing Irati oil shale in Brazil (Cameron Engineers 1975a). The Petrosix retorting process uses a vertical kiln retort, which is heated by a recycled gas from an externally fired gas furnace. Shale flows downward by gravity in the kiln as in the Paraho process. Hot recycle gases are introduced in the middle of the kiln in the retorting zone. An upward flow of unheated gas condenses and carries an oil mist toward the top of the kiln and out of the retort. The Petrosix process yields a high-Btu product gas because hot recycle gas instead of air is used for retorting.

Superior Process. The Superior retorting process uses a traveling grate enclosed in a large, circular, doughnut-shaped tunnel (Knight and Fischback 1979). Raw shale is fed onto this grate and passes progressively through a retort zone, a carbon recovery zone, and an overlap zone at a controlled temperature for a controlled residence time. Energy for retorting results from (1) burning process fuel in an indirect heater to heat recycle gas, (2) recovering sensible heat from spent shale with recycle gas, and (3) burning residual carbon.

Rundle Process. The Rundle process is an adaptation of the Superior process technology to retorting of the Rundle shale deposit in Queensland, Australia (Fischback 1979).

Union B Process. Union Oil Company began development of the Union process during the 1940s (Snyder and Pownall 1978). The Union B process uses an upward flow of oil shale solids in an expanding cone vessel with a downward countercurrent flow of heated gas. Oil liberated in the retorting process is forced downward by the gas flow contacting the cooler shale and exchanging its sensible heat with the upward moving shale. The retorting configuration is designed to minimize agglomeration caused by coking of the product oil or by pressure between particles. The upward flow of shale is controlled by a solids pump immersed in product oil.

TOSCO II Process. The TOSCO II process was selected for development in the mid-1950s because of its potential for overcoming the disadvantages of gas combustion-type processes (Whitcombe and Vawter 1982). In the TOSCO II process, crushed oil shale is heated to approximately 900°F (480°C) by direct contact with heated ceramic balls. At that temperature, the organic material in oil shale rapidly

decomposes to produce hydrocarbon vapor. Cooling of the vapor produces crude shale oil, water, and light hydrocarbon gases.

The thermal decomposition reaction takes place in an inert atmosphere in a rotating kiln, where heated ceramic balls are mixed with the crushed shale. The rotation of the retort mixes the materials and causes a high rate of heat transfer from the ceramic balls to the shale. At the discharge end of the retort, the ceramic balls and shale are at essentially the same temperature, and the shale is fully retorted. The ceramic balls and the spent shale flow from the retort into a cylindrical trommel screen, and the shale passes through the screen openings. The ceramic balls flow across the screen into a bucket elevator that transports the balls to a heater prior to recycling to the retort.

Lurgi-Ruhrgas Process. The Lurgi-Ruhrgas process was developed in the 1950s to produce a high-Btu gas by the devolatilization of coal fines. However, it was realized at an early stage that the process could be applied to the cracking of hydrocarbons to produce olefins (Weis 1981). In this process, crushed raw shale is mixed with three to four times as much hot spent shale at 1200-1290°F (650-700°C). The raw shale is flash-heated to about 930-990°F (500-530°C) and retorted within a few seconds.

The shale mixture leaving the mixer passes through a surge drum where retorting is completed and is then transferred to the lower section of a lift pipe. Combustion air is preheated to about 840°F (450°C) and introduced at the bottom of the lift pipe. The air simultaneously conveys the shale to the top of the lift pipe, while it burns the residual carbon from the spent shale.

The combustion gas and spent shale are separated in a collecting bin at about 1200-1290°F (650-700°C), and the spent shale is returned to the screw mixer to be used for heating incoming raw shale.

LLNL Fluidized-Bed Process. The Lawrence Livermore National Laboratory (LLNL) two-stage fluidized-bed retort is a circular cylinder with a flat vertical plate or baffle that extends from near the top to the bottom of the retort (Cena and Mallon 1986). Fine raw shale and hot retorted shale enter the retort, mix, and travel downward in the first stage. The hot, retorted shale is the heat-carrying medium that pyrolyzes the raw shale. Passing the center baffle plate, the solids travel upward in the second stage and exit at the discharge port.

In concept, hot solid retorting represents an alternative to hot gas retorts because gas pumping costs can be reduced, rapid shale throughput can be attained, all shale can be processed, nonuniform gas flow is not a problem, and the gas cleanup required is reduced to a minimum.

LLNL Gravity Bed Process. The LLNL gravity bed retort consists of three components: a cascading mixer, a solid dispenser and a gravity bed

soak tank (Cena and Mallon 1986). In the cascading mixer, hot and raw shale are combined by tumbling down a series of inclined chutes. Below the mixer, the solids fall through a funnel to a dispenser that spreads the solids horizontally onto the top of the gravity bed soak tank. In the soak tank the solids move slowly downward in plug flow, providing 1-2 minutes residence time for pyrolysis to occur.

KENTORT II Process. The KENTORT II process is a two-stage, fluidized-bed reactor system (pyrolysis followed by desulfurization and gasification) (Carter 1987). The reactor maximizes the removal of oil, gas, and sulfur from the shale using steam at atmospheric pressure as the fluidizing medium. A combustor burns undersized raw shale fines and partially gasified oil shale char to provide the energy to drive the process. Sensible heat from the processed shale is recovered through a quench from recycled process water. Following oil removal, the gas stream is sent to the sulfur recovery section.

WRI Inclined Fluidized-Bed Process. The WRI inclined fluidized-bed reactor system consists of two horizontal fluidized-bed reactors, a solids feeder, gas heater, cyclone separator, and a wet scrubber (Merriam and Cha 1987). The reactor is designed to create horizontal plug flow of solids using a vertical flow of fluidizing gas. Residence time of solids is controlled in the range of 2 to 10 minutes by varying the slope of the reactor from 0 to 6 degrees. Each reactor has four separately controlled pairs of electrical heaters for temperature control of the reactor. Solids feed rate is controlled using a variable-speed screw feeder. Fluidizing-gas flow rate and temperature are controlled with an automatic flow-control valve and an electric heater. Typically, the raw oil shale is pyrolyzed in the presence of an inert gas in the first fluidized-bed reactor. The gas and vapor are removed from the top of the reactor, and the pyrolyzed shale is removed from the end of the reactor. The pyrolyzed shale is then fed into the second fluidized-bed reactor, where the remaining carbon is burned off.

In Situ Processes

In situ processes are generally categorized by the method of enhancing the capability for fluid flow within the oil shale bed and by the direction of retorting. Most true in situ processes enhance fluid flow, primarily by explosive fracturing; although, solution mining and dielectric heating methods have been proposed and, in some cases, tested at a small scale. Modified in situ processes involve mining part of the oil shale, which provides significant void space for subsequent development of a rubble bed by explosive fracturing. If the resulting in situ retort is retorted from the top, it is a vertical modified in situ (VMIS) retort. If the retorting is in a horizontal direction, it is a horizontal modified in situ (HMIS) retort. Although proposed, HMIS retorting has not been tested in the field (Harak et al. 1984). In actual commercial operation, most modified in situ processes would be combined with a surface process to retort the mined oil shale.

VMIS. The VMIS process consists of two basic steps (Cha and McCarthy 1982): (1) forming the in situ retort by mining approximately 15-40% of the oil shale deposit and expanding by explosive fracturing the remaining material into the void and (2) retorting down the retort from the top.

Full-scale VMIS field projects have been carried out by Occidental Oil Shale Inc. (Stevens and Zahradnik 1983) and Rio Blanco Oil Shale Company (Berry et al. 1982). Large-scale simulation tests have been run in 10-ton and 150-ton retorts (Dockter et al. 1971; Turner et al. 1984; Turner and Moore 1985; Merriam et al. 1985a; Merriam et al. 1985b; Sudduth et al. 1987).

Additional simulation of the VMIS process has been conducted by WRI in the vertical low-void retort (McLendon 1985). In these tests, bricks of oil shale were cut and loaded into a vertical retort. Fine oil shale particles were placed between layers to simulate low-void volumes (8 to 18%).

HMIS. Laboratory simulations of low-void retorting in the horizontal mode have been conducted by WRI in a block reactor (Fahy 1986). Rectangular oil shale bricks were cut and placed into a steel box in staggered rows and columns. Fine oil shale particles were placed between the rows and columns to achieve a low-void volume (11%) similar to field conditions. The oil shale bed was then retorted horizontally using air.

True In Situ. The most productive field tests of true in situ retorting have been carried out by Geokinetics Inc. (Zerga 1978; Lekas 1981). The Geokinetics process consists of fracturing shallow oil shale formations, generally with less than 100 feet of overburden. The detonation is sequenced to raise the overburden at one end of the retort, thereby creating void space, and fracturing the remainder of the retort to fill the void. After creating the rubble bed, production and injection wells are installed in the retort, the retort is ignited, and an air-steam mixture is pumped in to retort the bed horizontally.

Product Characteristics

The products obtained from oil shale processes vary, depending not only on the characteristics of the raw shale, but on the retorting process and retorting conditions as well. Properties of oils produced by the described oil shale processes are summarized in Tables 2 and 3.

Processes Selected

To produce an asphalt blend, an oil with a high nitrogen content and a high proportion of heavy ends is desirable. Evaluation of the product properties from Tables 2 and 3 shows that the Paraho direct-heating process, the KENTORT II process, and the WRI inclined fluidized-bed

Table 2. Summary of Shale Oil Properties for Retorting Processes

Process	Oil Shale Source	Yield, vol % Fischer Assay	Gravity, °API	Pour Point, °F	Viscosity (SUS) 100°F	130°F	210°F
Surface							
N-T-U	Colorado	65-92	20.3	90	-	130	48
Gas combustion retorting	Colorado	83-92	21.2	85	-	92	43
Paraho direct heating	Colorado	92	21.2	80	163	94	41
Paraho indirect heating	Colorado	92	19.1	85	241	126	45
Petrosix	Irati, Brazil	98	19.6	25	21[a]	-	-
Superior	Colorado	-	20.7	90	72[a]	-	-
Rundle	Kerosene Cr.	-	24.0	95	51[a]	-	-
Union B	Colorado	-	22.7	60	98	-	-
TOSCO II	Colorado	108	21.2	25[b]	106	-	39
Lurgi condensed oil[c]	Colorado	-	18.7	64	-	10[a]	-
Lurgi noncondensed oil[c]	Colorado	-	66.7	-	-	-	-
LLNL fluid bed	Colorado	84-100	19.4	-	400+[d]	-	-
LLNL gravity bed	Colorado	76-104	28.6	-	9[d]	-	-
KENTORT II steam	Eastern	-	8.6	-	360-2680[d]	-	-
KENTORT II N$_2$	Eastern	-	7.2	-	600-1480[d]	-	-
WRI inclined fluidized bed	Eastern	-	-5.2	-	1,249,300	-	-
WRI inclined fluidized bed	Colorado	100-104	-	-	-	-	-
In Situ							
OXY VMIS	Colorado	63	24.3	65	70	-	-
WRI 10-ton	Colorado	64	22.5	62	79	-	-
WRI vertical low void	Colorado	68-80	24.3	60	-	7[a]	3[a]
Geokinetics	Utah	60	25.9	-	-	-	-
WRI horiz. block reactor	Colorado	-	26.4	24	11[a]	-	-

a Centistokes
b Heat-treated oil
c 87% condensed, 13% uncondensed
d Centipoise @ 60-100°F

14

Table 2. Summary of Shale Oil Properties for Retorting Processes (continued)

Process	Conradsen Carbon Residue, wt %	Ramsbottom Carbon Residue, wt %	Carbon, wt %	Hydrogen, wt %	Nitrogen, wt %	Sulfur, wt %	Atomic H/C Ratio
Surface							
N-T-U	4.5	–	84.61	11.40	2.10	0.79	1.61
Gas combustion retorting	1.3	–	–	–	2.11	0.68	–
Paraho direct heating	–	1.59	84.20	11.69	1.90	0.63	1.66
Paraho indirect heating	–	1.41	84.88	11.57	2.05	0.62	1.63
Petrosix	–	–	84.80	11.36	0.62	1.68	1.60
Superior	5.0	–	84.5	12.5	2.0	0.8	1.76
Rundle	3.7	–	84.7	12.5	1.0	0.4	1.76
Union B	–	–	84.80	11.61	1.74	0.81	1.63
TOSCO II	–	–	85.1	11.6	1.9	0.9	1.62
Lurgi condensed oil	5.9	–	85.16	10.68	2.16	0.90	1.50
Lurgi noncondensed oil	–	–	86.13	13.30	0.16	0.31	1.84
LLNL fluid bed	–	–	–	–	2.1	–	1.59
LLNL gravity bed	–	–	84.7	11.1	1.6	0.6	1.59
KENTORT II steam	–	–	85.20	10.10	1.39	1.68	1.42
KENTORT II N$_2$	–	–	85.20	9.76	1.83	1.56	1.37
WRI inclined fluidized bed	–	–	82.8	8.7	1.9	4.2	1.25
WRI inclined fluidized bed	–	–	84.79	11.58	2.4-2.8	0.76	1.6
In Situ							
OXY VMIS	–	–	84.86	11.80	1.50	0.71	1.66
WRI 10-ton	–	–	84.70	11.69	1.77	0.76	1.65
WRI vertical low void	–	–	84.02	11.85	1.63	1.18	1.68
Geokinetics	1.3	–	–	–	2.15	0.61	–
WRI horiz. block reactor	–	–	34.9	12.3	1.9	1.4	1.73

Table 3.   Vacuum Distillation Properties (ASTM D-1160, corrected to 760 mm, °F) for Retorting Processes

Process	IBP	5%	10%	20%	30%	40%	50%	60%	70%	80%	90%	FBP
Surface												
N-T-U	356	475	523	605	684	756	822	881	-	-	-	-
Gas combustion retorting	363	444	497	588	665	742	807	864	915	980	1066	-
Paraho direct heating	136	379	455	565	658	745	833	-	-	-	-	-
Paraho indirect heating	178	433	515	618	700	769	826	873	-	-	-	-
Petrosix	-	-	-	-	-	-	-	-	-	-	-	-
Superior	-	-	-	-	-	-	-	-	-	-	-	-
Rundle	-	-	-	-	-	-	-	-	-	-	-	-
Union B	139[a]	-	400	-	-	-	731	-	-	-	960	1077
TOSCO II	-	200	275	410	500	620	698	775	850	920	-	-
Lurgi condensed oil	205	295	337	427	500	582	656	739	820	914	-	946
Lurgi noncondensed oil	120	130	136	145	154	163	175	185	199	219	-	302
LLNL fluid bed	-	305	370	446	536	612	698	761	824	896	935	-
LLNL gravity bed	-	230	287	356	437	500	554	617	689	770	869	-
KENTORT II steam	298	384	455	564	662	768	875	990	-	-	-	-
KENTORT II N_2	377	455	507	590	672	754	846	954	-	-	-	-
WRI inclined fluidized bed	-	504	559	661	761	858	960	-	-	-	-	-
WRI inclined fluidized bed	394	475	541	655	755	843	936	-	-	-	-	-
In Situ												
OXY VMIS	-	403	443	521	600	644	689	733	778	850	950	-
WRI 10-ton	-	395	433	509	586	649	709	769	837	913	989	-
WRI vertical low void	-	322	403	490	561	627	689	748	808	873	903	-
Geokinetics	160	439	468	530	580	624	674	732	789	837	922	979
WRI horiz. block reactor	294	316	366	425	483	523	563	632	701	770	872	-

[a] Modified Engler method

process are well suited to producing the desired oil type. At this time, oil quality data for oil produced from western oil shale by the KENTORT II process is not available; consequently, the process is not considered further in this study.

The combination of the Paraho direct-heating process and the WRI inclined fluidized-bed process results in an efficient plant system. The Paraho process cannot use oil shale that has been crushed to less than 3/8 inch. However, the WRI inclined fluidized-bed process appears to operate best with oil shale crushed to 3/8 inch or less.

PROCESS DESIGN

Capacity

The three-state area consisting of Colorado, Utah, and Wyoming is considered as the area for shale oil-blended asphalt to enter the market. The key to the market is for shale oil-blended asphalt to increase pavement life. This will result in a premium price for the blended product that will be justified by life-cycle cost analysis. Using this type of analysis, the asphalt is more expensive, but less frequent repaving operations save taxpayers money overall.

A series of calculations can be made to determine the appropriate size of a shale oil production facility needed to supply the shale oil asphalt for blending in the three-state area (Sinor 1989). The three-state demand for asphalt is about 16,400 barrels per day (b/d). If 75% of the asphalt is used for highway construction and that 75% of the highway construction is life-cycle cost sensitive, then a maximum of 9,225 b/d of asphalt can be replaced using shale oil-blended asphalt. If 50 to 55% of a barrel of shale oil is used to make the shale oil asphalt for blending, then a relationship can be derived for the percentage of shale oil asphalt in the blend to the plant size.

The value of shale oil-blended asphalt can be determined using the typical costs for pavement construction, the percentage of shale oil residue in the blend, and an estimate of the increased life obtained from the blend. A plot of these results is a family of curves of percentage of life-increase related to the percentage of shale oil residue in the blend versus the value of the shale oil residue. Because the percentage in the blend has been related to the asphalt demand in the three-state region, a relationship exists between the plant size, the percent life-increase, the percent shale oil residue in the blend, and the value of the shale oil residue.

A plot of the relationship of plant size, percentage life-increase, percentage shale oil residue in the blend, and the value of the shale oil residue was developed by Sinor (1989) to determine areas of economic feasibility. If the production costs of shale oil are $60 per barrel and the minimum amount of shale oil residue in the blend is 10%, then

17

these criteria define two boundaries of the economic feasibility area. If the other boundary, in this case, is the curve representing the life-increase of 7.5%, then these three criteria result in a plant size for the area of economic feasibility of between 1,500 to 2,500 b/d. If the 10% life-increase curve is used, then a plant size of between about 1,500 to 3,500 b/d is defined. This type of plot also shows that increases in pavement life for a given blend result in greater value of the shale oil residue, and, therefore, larger differentials with production costs. On this basis, a 2,000-b/d capacity is used for the process design, although a larger production operation may be justified if greater pavement life cycles can be demonstrated.

Process System

A process engineering study was conducted by Ford, Bacon and Davis Inc. (Walker et al. 1989). The design includes systems for material handling, retorting, product handling, and environmental control.

The material-handling system includes crushing and sorting of minus 8-inch mined material to minus 3/8-inch and 3/8- to 3-inch feedstocks. The larger material is fed to a Paraho retort and the fines go to three inclined fluidized-bed (IFB) retorts. The retorted shale from the IFB retorts goes to a fluidized-bed combustor that burns product gas and carbon on the shale to heat recycle gas. Spent shale is conveyed to an offsite disposal area.

Liquid products from the system are processed to remove and separate 60 percent of the oil for asphalt blend and 40 percent as light ends. Sulfur is removed from the process gas during contact with spent shale in the fluidized-bed combustor, and particulates are removed from the exiting gas by a baghouse.

An alternate system was considered by Walker et al. (1989) in which the IFB retorts were eliminated and the fines were used for power generation. The increase in capital costs for this system were found to be greater than the benefits derived in reduced operating costs and power generated.

ECONOMIC EVALUATION

Methodology

To evaluate the economics of the small-scale commercial oil shale production facility, a series of discounted cash flow-return on investment (DCF-ROI) calculations have been made. For this evaluation the cost of mining the oil shale has been obtained from an investigation by McCarthy and Clayson (1989). The capital and operating costs of the oil shale processing facility are from a study by Walker et al. (1989). Costs related to environmental concerns are based on the environmental requirements section of this report.

The DCF-ROI method used to evaluate the concept of an oil shale market niche consists of calculating the gross income from shale oil sales. The operating costs, royalties, and property taxes are subtracted from the gross income to get the net income. The depreciation and depletion are then subtracted from the net income, resulting in the taxable income. Federal and state income taxes less tax credits are subtracted from the taxable income to arrive at the net income after taxes. To this value, depletion and depreciation are added. Any capital expenditures or working capital are then subtracted, resulting in the net cash flow for the year. The DCF-ROI is defined as the discount rate at which the sum of the net cash flow or the net present value for the project is zero. Consequently, the time-value of expenditures and income are included in this calculation. Thus, expenditures made early in the project have more impact than an equal expenditure made later.

Assumptions

In performing the DCF-ROI analysis a number of assumptions are necessary. General assumptions for the construction, start-up, and operation of the facility are:

- Project life, 30 years

- Mine and plant site located in Colorado, Utah, or Wyoming

- Processing facility operated 330 days per year

- Cash flows calculated on the basis of this project being the company's sole source of income

- Mineral royalty, $0.213 per barrel (Chazin et al. 1979)

- County mill levy, 23.83 mills (Chazin et al. 1979)

- State income tax, 5% (Chazin et al. 1979)

- Federal income tax, 34%

- No bonus bid payments

- All development expenditures are capitalized, except environmental requirements that are treated as expenses

- Double-declining balance depreciation

- All equity financing for base case

- Capital and operating costs in mid-1989 dollars

- Depletion rate, 15% of income

The primary product from the plant is shale oil to be used as an asphalt blend. It is assumed that the distillation residue (60%) will be sold to a company that will perform any required viscosity treatment and blend the material with petroleum asphalt. As discussed in the Asphalt Blends section, the value of the heavy shale oil product may range from $50 to nearly $200 per barrel ($265 to $1,060 per ton), depending on the improvement achieved in pavement life cycle. As field testing has only begun, the product value is difficult to predict; so values varying from $300 to $1,000 per ton are considered in this evaluation. It is assumed that the light-end product (40%) can be sold for $15 per barrel as a fuel feedstock. Although some income might be obtained from byproducts, it is difficult to assign any value for this with any degree of certainty. Thus, no income is assumed for byproducts.

The 2,000-b/d retorting facility is a combined Paraho retort and inclined fluidized-bed retorting system processing 3,730 tons of oil shale averaging 25.6 gallons per ton with a yield of 90%. The capital cost for the retorting facility plus auxiliaries is estimated to be $82,097,600, including engineering and management. The plant operation cost is $11,091,000 per year, or $16.80 per barrel, including administration, management, and engineering. A process royalty fee will probably be required, and it is very uncertain what this might be. For this evaluation it is assumed to be the same as that paid for the mineral royalty, $0.213 per barrel.

Because the mining cost study and plant design and cost study were done independently, some adjustments are required to eliminate some redundancies in costs and basic assumptions. The mining costs were made rather conservatively using 4,797-tons-per-day (tpd) production with a 10-mile access road, 3-mile haul road, extensive mine development at contract rates, and 15% contingency. Because mining costs in normal mining operation are considerably less than contract mining development rates, it is assumed that development can be done making the first panel only 500 feet wide rather than 850 feet. This will decrease the initial development cost by 35%. Surface maintenance labor force at the mine is reduced by about $194,000, reflecting overlap with the processing facility. The variable mine operating costs are reduced by 80% because the assumed production rate is 3,730 tpd. To integrate with the plant operation, mining administration factored costs are removed and mine indirect costs are reduced from 10 to 2% of the labor and operating supplies. The contingency of the mining, operating, and capital costs are reduced from 15 to 5% to reflect the lower mining rate and to be consistent with the contingencies for the process facility. These revisions result in a capital cost of $45,759,500 and an annual operation cost of $6,840,056 or $10.36 per barrel for mining.

It is assumed that all shale mined during development will be processed in the facility. This will result in closing the mine one year prior to closing of the processing facility.

Facility construction will occur over three years, with operations starting in the fourth year. During start-up, production is assumed to be 75% of capacity. Mine development will occur during the third year, and full production will begin at the start of the fifth year.

Permitting costs are assumed to be $500,000, and an additional $150,000 is included for internal review and project management. During the plant construction, an environmental monitoring cost of $50,000 per year is included. After commencement of operation the annual environmental monitoring costs are assumed to be $200,000.

Results

The production costs for a 2,000-b/d oil shale facility are illustrated in Figure 1. The costs include labor, utilities, supplies, miscellaneous, and depreciated capital costs for both the mine and the processing facility. These production costs total $35.30 per barrel. The depreciated capital costs are calculated assuming a 25-year life for the equipment and facility using straight-line depreciation. To calculate this value, the capital costs are divided by the 25-year life and the annual production rate in barrels, resulting in the projected cost per barrel of total throughput.
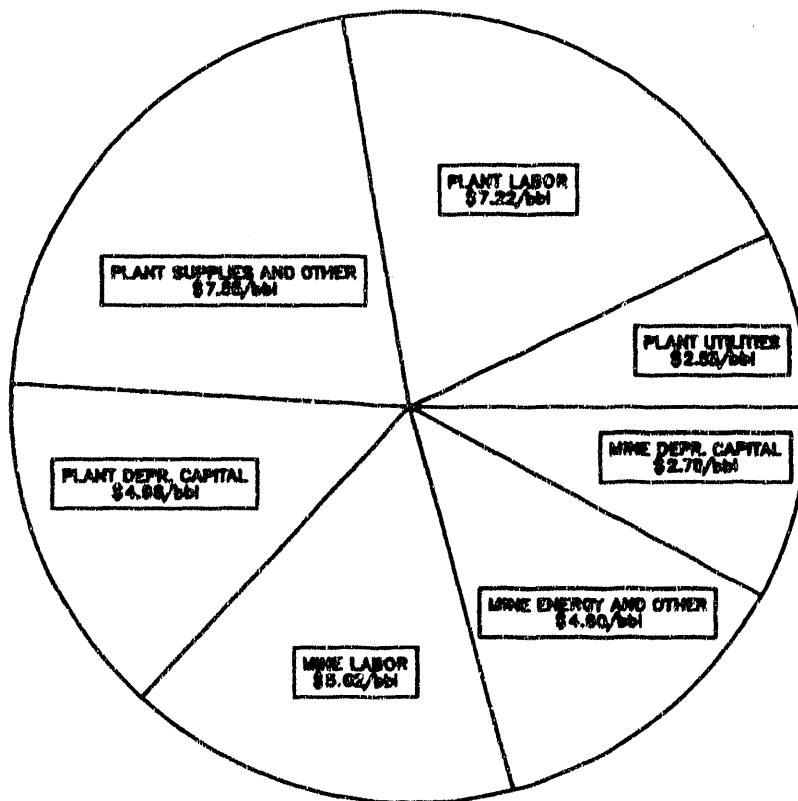

Figure 1. Cost Breakdown for 2,000-b/d Shale Oil Facility

The base case parameters for the DCF-ROI analysis are listed in Table 4. As an example of an entire computer run, results of the base case are listed in Table 5. These tables are replications of the computer printouts from the DCF-ROI computer runs.

As a technique to assess the impact of various operating and capital parameters, DCF-ROIs have been calculated for the base case with an asphalt sale price of $400 per ton and with 5% variation in the selected parameters. A 5% increase in production to 2,100 b/d, a 5% increase in shale oil residue sale price, a 5% increase in distillate product sale price, a 5% decrease in operating cost, and a 5% decrease in capital cost are used in the screening runs. The DCF-ROIs and their percentage increases are listed in Table 6. It is apparent that increasing the production rate or the price obtained for the shale oil residue (which relate to demand) have the most impact upon the ability of the operation to increase profits.

Although there is limited potential for increasing the output from a 2,000-b/d facility, there is a much greater latitude for potential increases for the residue price. The residue price has been estimated at $300 to $1,000 per ton. At 5.3 barrels per ton, the residue price ranges from $56.60 to $188.70 per barrel. To evaluate the expected return rate at various prices for the residue, $300, $400, $500, $600, $700, $800, $900, and $1,000 per ton have been used. The DCF-ROI for these cases are 1.7, 7.4, 11.7, 15.3, 18.3, 21.0, 23.5, and 25.8%, respectively. These results are shown graphically in Figure 2. Figure 3 shows the time required to return the capital investment as a function of residue price. At $1,000 per ton, the DCF-ROI of 25.8% results in a return of capital in 3.88 years. At $300 per ton, the DCF-ROI of 1.7% results in a return of capital in 58.8 years.

Sensitivities

In order to assess the impacts of uncertainties in cost estimates, process performance and market conditions, parametric sensitivity has been analyzed on three of the base case estimates ($300, $600, and $1,000 per ton). Sensitivity parameters investigated include:

- Increase or decrease in capital costs (±20%)

- Increase or decrease in operating costs (±20%)

- Increase or decrease in production (±5%)

These sensitivities are shown in Figures 4 through 6 as envelopes about the DCF-ROI as a function of residue price. Variation of capital or operating costs are quite similar in their impact. Each of them will independently vary the rate of return by about 25 to 30%. The plant production capacity has a potentially greater relative impact than the capital or operating costs. Just a 5% increase or decrease in the throughput will increase or decrease the rate of return by over 12%.

Table 4. Example of Printout of Parameters Setup for DCF-ROI Analysis

ASSUMPTIONS:

DEPRECIATION METHOD: 200% DECLINING BALANCE: MARCS 7 YEAR METHOD

VARIABLES:

Parameter	Value
PLANT PRODUCTION RATE (BBL/DAY)	2000
PLANT OPERATION (DAYS/YEAR)	330
HEAVY-END PRODUCT SALES PRICE ($/TON)	400
HEAVY-END PRODUCT (FRACTION OF OIL SHALE)	0.60
LIGHT-END PRODUCT SALES PRICE ($/BBL)	15
LIGHT-END PRODUCT (FRACTION OF OIL SHALE)	0.40
INCREASE OR (DECREASE) IN CAPITAL COSTS (%)	0.00 NOT USED
INCREASE OR (DECREASE) IN OPERATING COSTS (%)	0.00 NOT USED
RECOVERY RATE	0.90
DEPLETION RATE	0.15
OPERATING COST CONTINGENCY RATE	0.05
MINERAL ROYALTIES ($/BBL)	0.213
PROCESS ROYALTIES ($/BBL)	0.213
COUNTY MILL LEVY (MILLS)	23.83
FEDERAL INCOME TAX RATE	0.34
STATE INCOME TAX RATE	0.05
CAPITAL COSTS ($)	127857100 (PROCESSING PLANT + MINE)
VARIABLE OPERATING COSTS ($/BBL)	2.44 (PROCESSING PLANT)
FIXED OPERATING COSTS ($)	14542216 (DURING OPERATION)
COST OF MINING ($/TON)	5.10
VARIABLE OPERATING COSTS ($/BBL)	2.88 (MINE)
ENVIRONMENTAL COST-FC ($)	650000
FIXED OPERATING COSTS ($)	50000 (DURING DEVELOPMENT & START-UP)

Table 5. Example of DCF-ROI Calculations Printout

PERIOD (YEAR)	LIGHT-END GROSS INCOME	HEAVY-END GROSS INCOME	TOTAL GROSS INCOME	CAPITAL COSTS	VARIABLE OPERATING COSTS	FIXED OPERATING COSTS	OPERATING COST CONTINGENCY	COST OF MINING OIL SHALE	MINERAL ROYALTIES
0	0	0	0	0	0	650000	0	0	0
1	0	0	0	42619033	0	50000	0	0	0
2	0	0	0	42619033	0	50000	0	0	0
3	0	0	0	42619033	0	50000	0	0	0
4	2970000	22415094	25385094	0	2633400	14542215	0	0	105435
5	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
6	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
7	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
8	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
9	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
10	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
11	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
12	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
13	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
14	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
15	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
16	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
17	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
18	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
19	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
20	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
21	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
22	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
23	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
24	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
25	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
26	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
27	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
28	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
29	3960000	29886792	33846792	0	3511200	14542216	0	0	140580
30	3960000	29886792	33846792	0	1610400	9602960	0	0	140580

Table 5. Example of DCF-ROI Calculations Printout (continued)

PERIOD (YEAR)	PROCESS ROYALTIES	PROPERTY TAXES	INTEREST PAYMENTS	NET INCOME	DEPRECIATION	DEPLETION	TAXABLE INCOME TAXES	FEDERAL INCOME TAXES	STATE INCOME
0	0	0	0	-650000	0	0	-650000	0	0
1	0	0	0	-42669033	0	0	-42669033	0	0
2	0	0	0	-42669033	0	0	-42669033	0	0
3	0	0	0	-42669033	0	0	-42669033	0	0
4	105435	1090449	0	6908159	14206202	3807764	-11105807	0	0
5	140580	1090449	0	14421768	25255613	5077019	-15910864	0	0
6	140580	1090449	0	14421768	19643965	5077019	-10299216	0	0
7	140580	1090449	0	14421768	15278923	5077019	-5934175	0	0
8	140580	1090449	0	14421768	11883039	5077019	-2538290	0	0
9	140580	1090449	0	14421768	9241511	5077019	103238	35101	5162
10	140580	1090449	0	14421768	9241511	5077019	103238	35101	5162
11	140580	1090449	0	14421768	9241511	5077019	103238	35101	5162
12	140580	1090449	0	14421768	9241511	5077019	103238	35101	5162
13	140580	1090449	0	14421768	4623313	5077019	4721436	1605288	236072
14	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
15	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
16	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
17	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
18	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
19	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
20	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
21	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
22	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
23	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
24	140580	1090449	0	14421768	0	5077019	9344749	3177215	457237
25	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
26	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
27	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
28	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
29	140580	1090449	0	14421768	0	5077019	9344749	3177215	467237
30	140580	1090449	0	21261824	0	5077019	16184805	5502834	809240

Table 5. Example of DCF-ROI Calculations Printout (continued)

PERIOD (YEAR)	NET INCOME AFTER TAXES	DEPRECIATION	DEPLETION	CAPITAL EXPENDITURE	WORKING CAPITAL	BID PAYMENTS	DEBT PRINCIPAL	NET CASH FLOW	CUMULATIVE NET CASH FLOW
0	-650000	0	0	0	270833	0	0	-920833	-920833
1	-42669033	0	0	0	20833	0	0	-42689867	-43610700
2	-42669033	0	0	0	20833	0	0	-42689867	-86300567
3	-42669033	0	0	0	20833	0	0	-42689867	-128990433
4	-11105807	14206202	3807764	0	0	0	0	6908159	-122082274
5	-15910864	25255613	5077019	0	0	0	0	14421768	-107660506
6	-10299216	19643965	5077019	0	0	0	0	14421768	-93238739
7	-5934175	15278923	5077019	0	0	0	0	14421768	-78816971
8	-2538290	11883039	5077019	0	0	0	0	14421768	-64395204
9	62975	9241511	5077019	0	0	0	0	14381505	-50013699
10	62975	9241511	5077019	0	0	0	0	14381505	-35632194
11	62975	9241511	5077019	0	0	0	0	14381505	-21250689
12	62975	9241511	5077019	0	0	0	0	14381505	-6869184
13	2880070	4623313	5077019	0	0	0	0	12580408	5711224
14	5700297	0	5077019	0	0	0	0	10777316	16488539
15	5700297	0	5077019	0	0	0	0	10777316	27265855
16	5700297	0	5077019	0	0	0	0	10777316	38043170
17	5700297	0	5077019	0	0	0	0	10777316	48820486
18	5700297	0	5077019	0	0	0	0	10777316	59597802
19	5700297	0	5077019	0	0	0	0	10777316	70375117
20	5700297	0	5077019	0	0	0	0	10777316	81152433
21	5700297	0	5077019	0	0	0	0	10777316	91929748
22	5700297	0	5077019	0	0	0	0	10777316	102707064
23	5700297	0	5077019	0	0	0	0	10777316	113484379
24	5700297	0	5077019	0	0	0	0	10777316	124261695
25	5700297	0	5077019	0	0	0	0	10777316	135039011
26	5700297	0	5077019	0	0	0	0	10777316	145816326
27	5700297	0	5077019	0	0	0	0	10777316	156593642
28	5700297	0	5077019	0	0	0	0	10777316	167370957
29	5700297	0	5077019	0	0	0	0	10777316	178148273
30	9872731	0	5077019	0	0	0	0	14949750	193098023

Table 5. Example of DCF-ROI Calculations Printout (continued)

IRR = 0.07637

NPV @ 0% = 193098023
NPV @ 1% = 147585523
NPV @ 2% = 110915941
NPV @ 3% = 81202500
NPV @ 4% = 56994210
NPV @ 5% = 37169002

NPV @ 6% =   20854341
NPV @ 7% =   7367951
NPV @ 8% =   -3826630
NPV @ 9% =   -13153558
NPV @ 10% = -20950036
NPV @ 11% = -27485611

NPV @ 12% = -32976919
NPV @ 13% = -37599003
NPV @ 14% = -41494052
NPV @ 15% = -44778168
NPV @ 16% = -47546635
NPV @ 17% = -49878047

NPV @ 20% = -54848952
NPV @ 25% = -58760054
NPV @ 30% = -59684874

Figure 2. Discount Cash Flow — Return on Investment as a Function
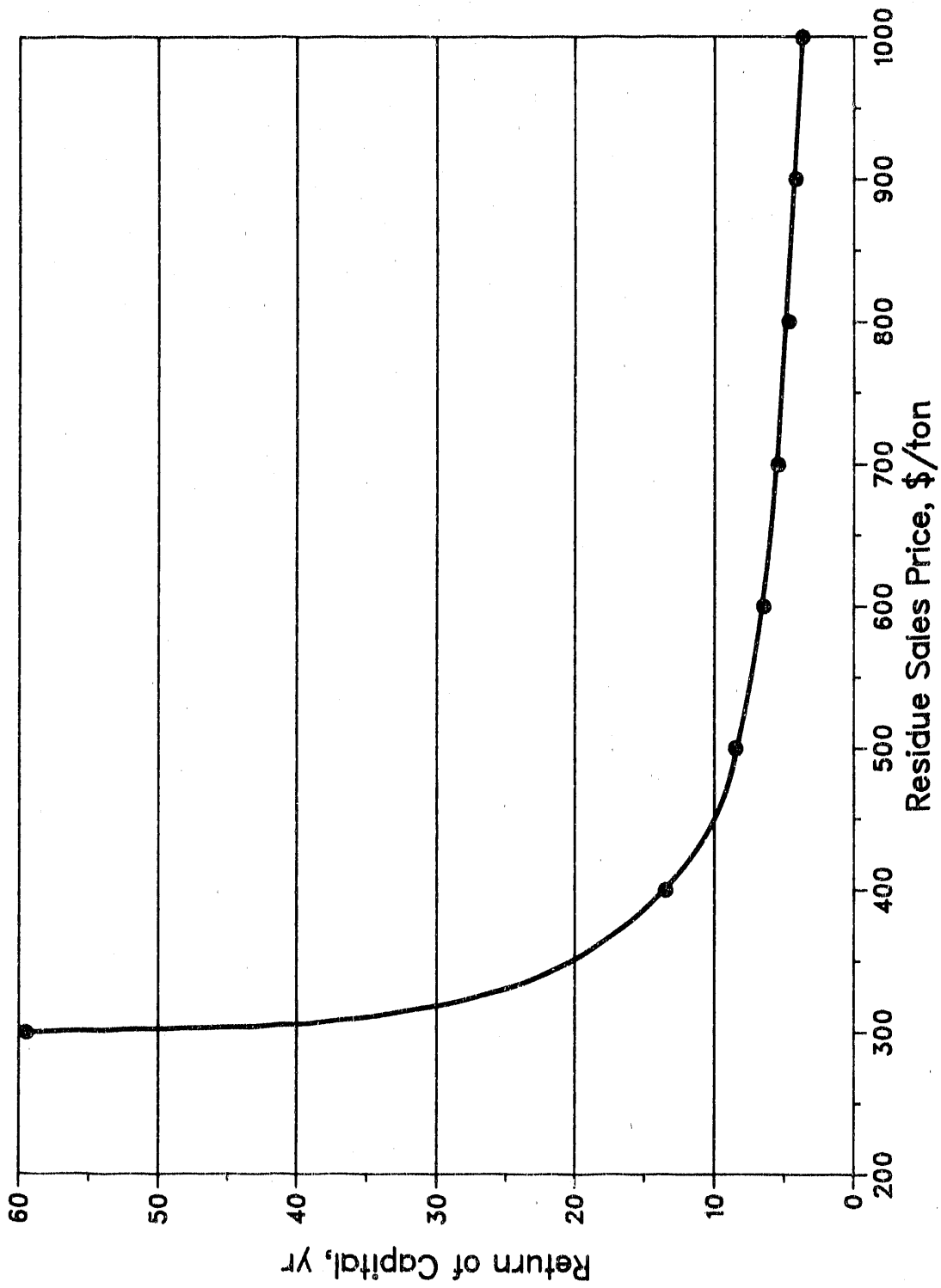of Residue Sales Price

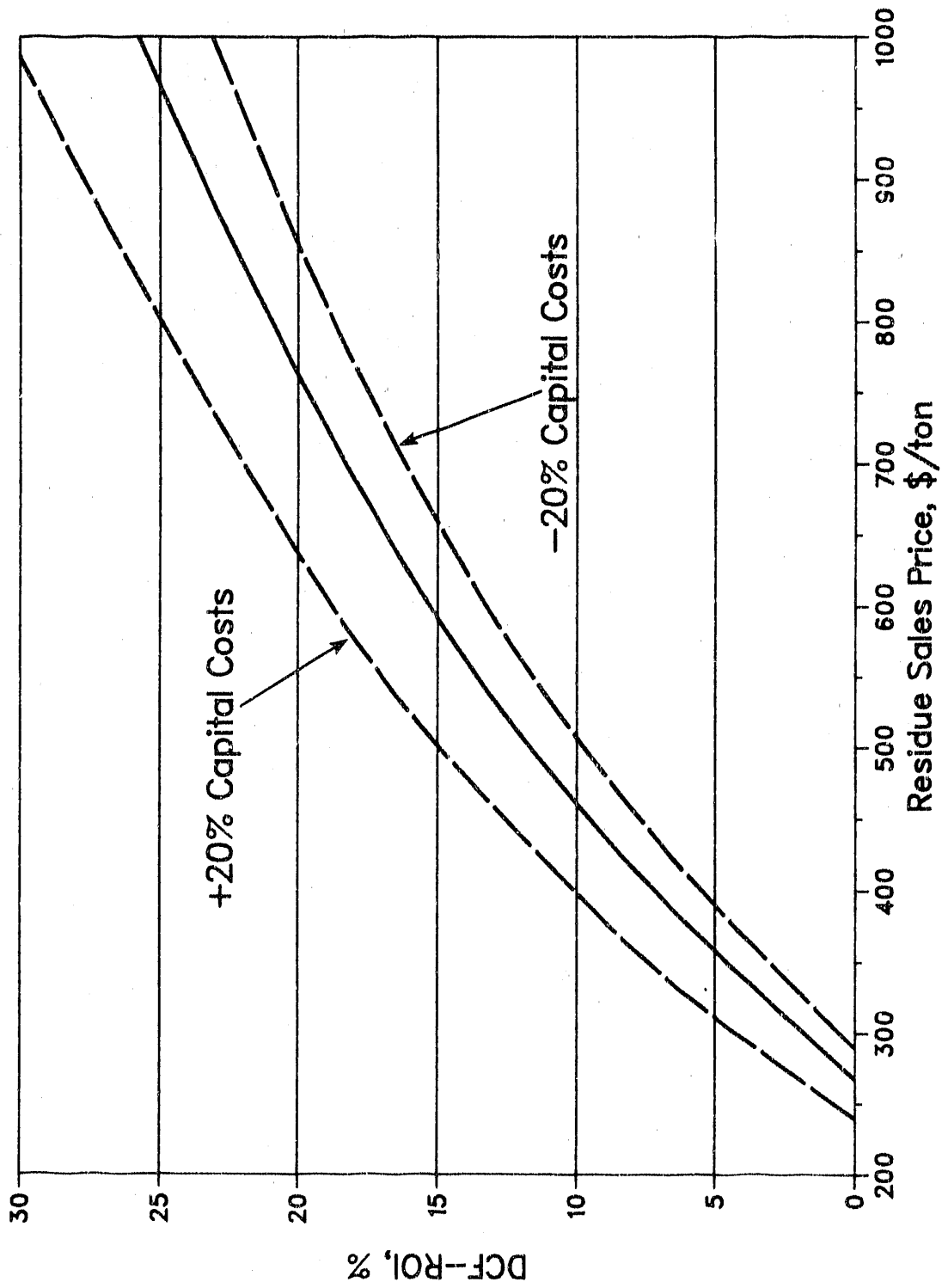Figure 3. Return of Capital as a Function of Residue Sales Price

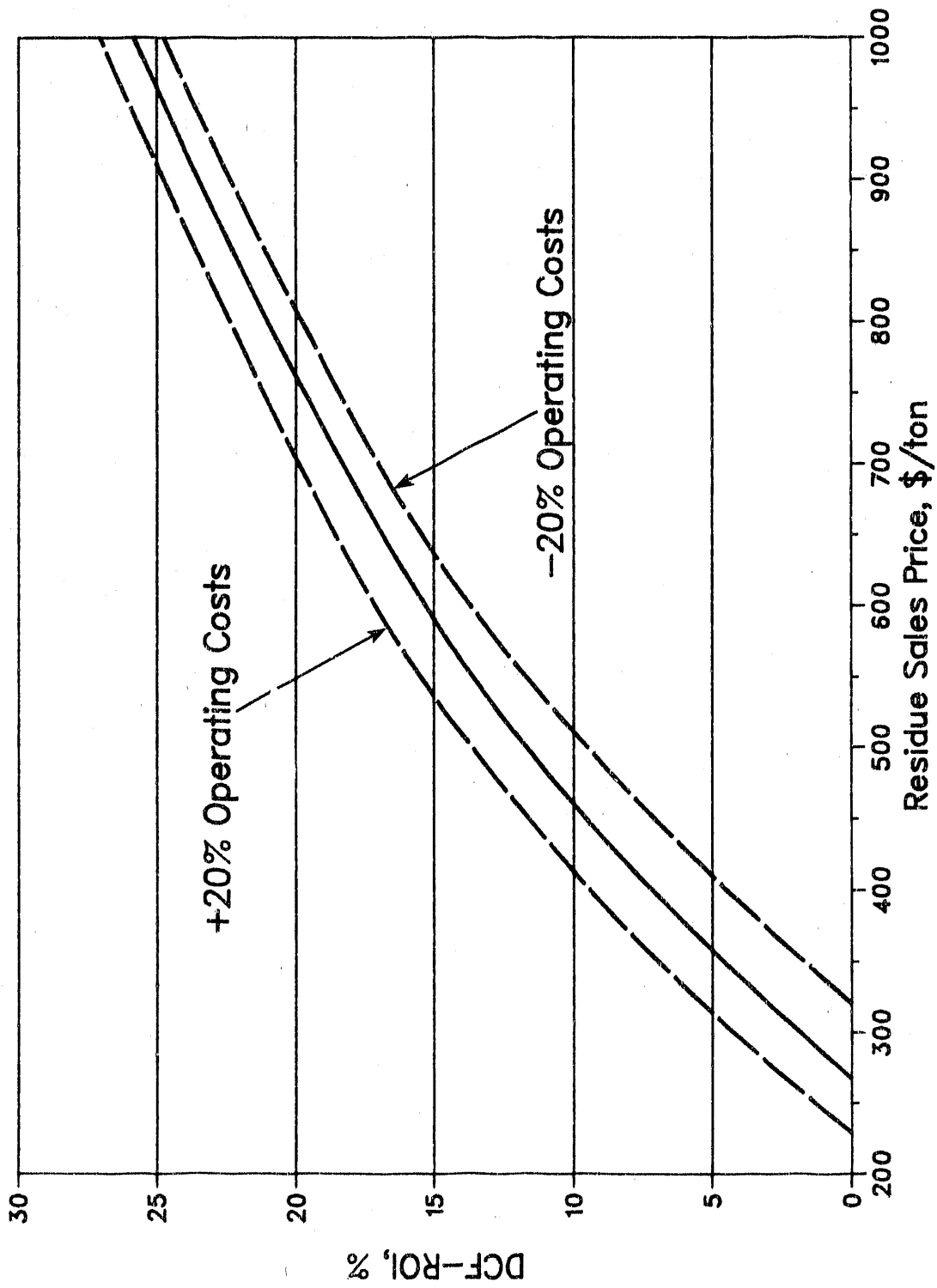Figure 4. Sensitivity of DCF–ROI to Variation in Capital Cost

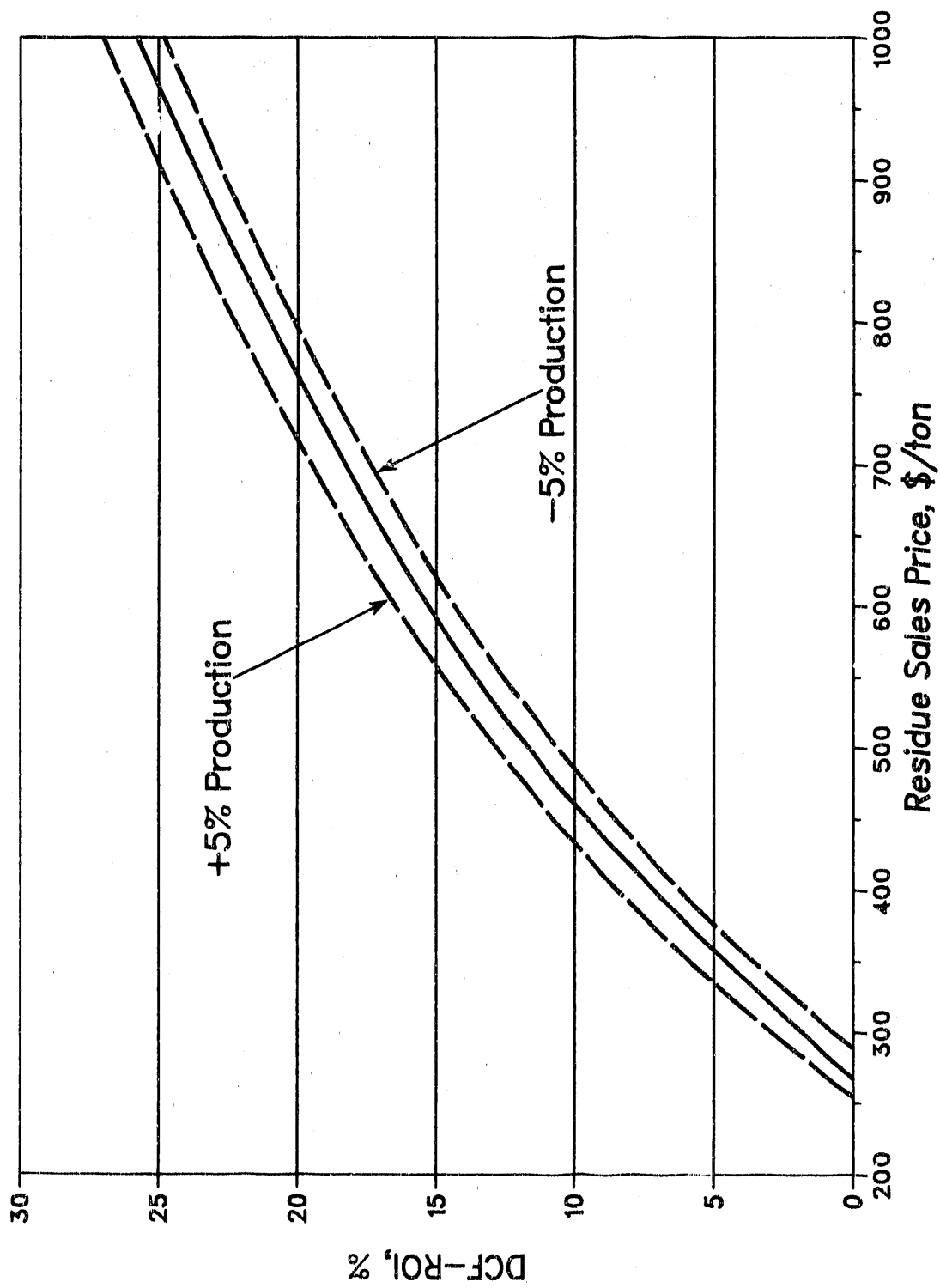Figure 5. Sensitivity of DCF–ROI to Variation in Operating Cost

The chart plots DCF–ROI, % (vertical axis, from 0 to 30) against Residue Sales Price, $/ton (horizontal axis, from 200 to 1000). Three rising curves are shown: a solid center line with dashed lines above and below it. The upper dashed curve is labeled "+20% Operating Costs" and the lower dashed curve is labeled "–20% Operating Costs".

Figure 6. Sensitivity of DCF-ROI to Variation in Production Rate

Table 6. Effect of Various Parameters on DCF-ROI

Parameter	DCF-ROI, %	Increase, %
Base case	7.421	0
+5% Production	8.350	12.52
+5% Price of residue	8.341	11.24
+5% Price of distillate	7.545	1.67
-5% Operating cost	7.976	7.48
-5% Capital cost	7.896	6.40

ENVIRONMENTAL REQUIREMENTS

Construction and operation of an oil shale mine and retorting facility requires that the environment be protected. Potential impacts must be evaluated, permits obtained, emissions and discharges controlled, and monitoring carried out to assure that impacts are mitigated and permit limits are not exceeded.

Assumptions for the retorting facility are based on the design performed by Ford, Bacon and Davis Inc. (Walker et al. 1989) and the mining study done by Synfuels Engineering and Development Inc. (McCarthy and Clayson 1989). A specific location is not selected, but it is assumed that the mine and plant will extract and process shale from the Green River Formation of central eastern Utah or northwestern Colorado.

The design basis for this study is a Paraho retorting process with an inclined fluidized-bed retort to process fines. The mined material for this operation is estimated at 3,730 tpd (Walker et al. 1989). An option that was considered by Walker et al. (1989) is to use the fines for power generation instead of retorting them in an inclined fluidized bed. In this case, about 4,700 tpd of mined material is required. However, the base case is more economical; so 3,730 tpd is used for this evaluation.

Permitting

General Requirements

Environmental permits are required by federal, state, and local agencies. Most air, water, and hazardous wastes permits are mandated by federal laws and enforced and administered by state agencies. Examples of these laws include the Clean Air Act, Clean Water Act, Safe Drinking Water Act, and the Resource Conservation and Recovery Act. The major permits are only briefly mentioned herein. A detailed description of

these laws and the required federal, state, and local permits has been prepared by Nordin et al. (1988).

The permits are designed to ensure the protection of the environment. The environment is also protected by requirements of the National Environmental Policy Act (NEPA) of 1969. This act ensures that environmental information is available to the public and private sectors before decisions are made regarding the construction of certain projects that could significantly impact the environment. The act also sets forth requirements for Environmental Assessments (EA) and Environmental Impact Statements (EIS), which analyze the impacts on air, water, land, communities, wildlife, etc. The EIS also requires year-long baseline studies, lists alternatives and mitigative actions, establishes a lead federal agency, and coordinates the environmental requirements of federal, state, and local agencies.

The decision to require an EIS rests with the U.S. Environmental Protection Agency and the federal agencies that will be affected by the proposed development, for example, the U.S. Department of Interior if the development occurs on federal-leased land or the U.S. Department of Defense (Army Corps of Engineers) if the action affects waterways. An EIS is almost certainly required for federal-leased land on which mining has not already taken place.

The agency that leases the federal land prepares the EIS. If the project is on private land, the EIS can be prepared by the U.S. Fish and Wildlife Service (if endangered or threatened species may be affected), the U.S. Department of Energy (if that agency supplies funding), or the U.S. Environmental Protection Agency, or jointly by several agencies or with state and local agencies. A lead agency is selected for the project in case multiple agencies are involved.

If an EIS is not required or if it is uncertain that an EIS is required, the lead federal agency will prepare an Environmental Assessment. An Environmental Assessment may be prepared if an EIS has been prepared previously, and the agency concludes that the new action does not significantly impact the environment. If the agency concludes that there is no impact, that agency may issue a Finding of No Significant Impact. This decision may be challenged by other agencies, and may result in an EIS having to be prepared. More information is available on the requirements of NEPA (Nordin et al. 1988) and EIS (U. S. DOE 1980; Dadiani 1983).

Air Quality

It is likely that the plant will be located in an area where the air quality is higher than the national standards established by the U.S. Environmental Protection Agency. The developer must then obtain a Prevention of Significant Deterioration of Air Quality Construction Permit. The developer must show that the lowest achievable emission rate for any air pollutant produced by the plant is achieved and that the

pollutant will be controlled so that it will not exceed a maximum allowable increase over baseline concentrations in the area. The allowable increase is determined by the nature of the area. For example, it is more restrictive for national wilderness areas than for urban settings. Other permits are required to construct and operate air pollutant control equipment.

If constructed, the oil shale facility would be classified as a major stationary source with respect to particulates and sulfur dioxide because there is the potential to emit more than 100 tons per year of pollutants in either category.

To apply for an air construction permit, the applicant must show that the project will not cause an air pollution violation of national air quality standards and will not exceed the maximum allowable increase in pollutants over baseline concentrations for a specific location. The maximum allowable increases in pollutants for class I, II, and III areas are published in 40 CFR 51.166(c). Most oil shale is located in class II areas. To implement a project in a class II area, a developer must collect one year of ambient air quality data at the location before the plant is built to establish baseline concentrations. The developer or state agency must then use applicable air quality models to determine any increase over baseline concentrations. Applicable air quality models for predicting air quality are available (U.S. EPA 1987). Computer software is also available, and the state agency may require the developer to use a particular software package to predict air quality.

In addition, federal requirements dictate that the developer must apply best available control technology for all new sources if the emission source is significant. Significant means that potential to emit pollutants equal to or in excess of those listed in Table 7.

The developer works through the state agency rather than the federal government for the purpose of obtaining the necessary permits. A public hearing is also required for major sources and for sources emitting significant pollutants. Individual states have published additional regulations to ensure that federal requirements are met. The following regulations have been adopted in Colorado:

- Fugitive emissions, including windblown particulates less than 30 μm in diameter, from oil shale piles are included as part of the particulate calculations and associated controls.

- Published emission standards from shale oil plants for sulfur dioxide are in Colorado Air Quality Control Commission (AQCC) Reg. 6-B. No more than 0.3 pounds of sulfur dioxide can be emitted per barrel of oil processed.

- Hydrogen sulfide in the ambient air cannot exceed 142 micrograms per cubic meter (AQCC Regulation #8).

35

- Open pit mining and construction activities must have a Fugitive Dust Permit for sites over 25 acres.

- Fugitive emission standards for equipment leaks of benzene are published as Colorado AQCC, Regulation #8, part VIII.

- Colorado regulation for best available technology for mining activities are published as Colorado Air Quality Control Commission, Regulation #1, part III.

Table 7. Pollutant Limits

Pollutant	Limit, tpy[a]
Carbon monoxide:	100
Nitrogen oxide:	40
Sulfur dioxide:	40
Volatile organic compounds:	40
Lead:	0.6
Mercury:	0.1
Fluorides:	3
Sulfuric acid mist:	7
Total reduced sulfur including hydrogen sulfide:	10
Particulates:	25
Particulates less than 10 μm (PM_{10}):	15
Asbestos:	0.007
Beryllium:	0.0004
Vinyl chloride:	1
Any pollutant within 10 kilometers of a class I area:	An increase of 1 microgram per cubic meter

[a] Tons per year

Regulations in Utah include:

- A single permit, called an Air Quality Approval Order that covers both construction and operation, is issued.

- The applicant must show the use of best available control technology for all sources except small sources. The definition of a small source is a judgement decision based on the interpretation of the Utah Air Conservation Regulation 3.1.1. A small source is one that has a negligible impact on air quality and does not emit objectionable odors. For small sources, the Utah Air Conservation Committee will issue an

approval letter, and no further permits, monitoring, or application of control technology are required.

* Exception to implementation of best available control technology may be granted by the state. The developer must show why an exception should be granted.

Water Quality

A one-year baseline study of the water quality of area streams may be required if an EIS must be prepared. The wastewater generated at the plant must be disposed of by (1) land application to retorted shale, roads, or through irrigation use; (2) evaporation or storage ponds; and (3) surface or subsurface disposal.

Permitting for surface discharges and deep well injections has its authority under the Federal Water Pollution Control Act, as amended by the Clean Water Act of 1977, and the Safe Drinking Water Act of 1974. Wastewater treatment or disposal is permitted either through the state or federal EPA office, whereas other methods of wastewater containment or discharge are regulated at the state level.

Besides wastewater injection or discharge permits, other permits are required for ponding, storing, treatment, or application of wastewaters to land. Permits are also required to construct and operate wastewater treatment facilities. The Clean Water Act (Section 401) also requires the state to certify that the project will not violate any state water quality standards. Additional federal and state permits are also required for construction in waterways, flood plains, and for building dams.

A permit is required from the state agency for point discharge of any wastewater to a stream or other surface water. In Colorado, the permit is obtained from the Water Quality Control Division, Colorado Department of Health. In Utah, the permit (called the Utah Pollutant Discharge Elimination System permit) is obtained from the Utah Bureau of Water Pollution Control, Division of Environmental Health. The state will impose restrictions on the discharge to ensure that water quality is protected.

Discharges to publicly owned wastewater treatment facilities in Colorado and Utah must be approved at the local and state level as well as through the regional U.S. EPA office.

Underground injection control permits are obtained from the state agency. The developer must meet criteria imposed by the state agency to ensure that potential drinking water aquifers are protected. This may include almost any aquifer containing under 10,000 ppm total dissolved solids.

All accidental spills of chemicals that may affect surface waters must be reported to the state. Plans for spill prevention must also be approved by the state. If the spill exceeds the amounts listed in 40 CFR 117 (for example, 1,000 lb for benzene), the spill must also be reported to the U.S. EPA.

All projects that affect waterways must be certified by the state and the U.S. Army Corps of Engineers.

Section 319 of the Clean Water Act protects water quality from nonpoint sources such as from mining activities. States were required to have a nonpoint-source assessment and management plan to the Environmental Protection Agency by August 1988 for approval. The state will probably require the developer to have plans to control or treat surface runoff where mining and oil shale processing take place. Runoff from undeveloped areas is expected to be unaffected by this regulation.

Land Use

Exploration, mining, and restoration plans must be filed with federal and state agencies. Federal agencies that may be involved include the U.S. Department of Labor (Mine Safety and Health Administration), Department of Interior (Bureau of Land Management, Bureau of Indian Affairs, or Geological Survey), Department of Agriculture (Forest Service), or Department of Defense (Army Corps of Engineers). State agencies may include mining, reclamation, land use, and environmental agencies. A detailed listing for Utah and Colorado has been compiled by Nordin et al. (1988).

The only solid wastes likely to leave the plant site are scrap, garbage, small quantities of laboratory chemicals, and possibly API separator bottoms and floats. All other wastes will probably be disposed on-site. API separator bottoms and floats may possibly be disposed of in the fluidized-bed combustor.

If more than 1,000 kg/month of hazardous waste is generated, the generator must certify on the manifest form that a waste minimization program is in effect. Also, a formal written contingency plan that describes how the facility will deal with fires or other unplanned releases of hazardous waste must be developed (40 CFR 265.53). In addition, a waste generation report must be filed with the U.S. EPA every two years. There are also reporting requirements for generation of less than 100 kg/month.

If hazardous waste is to be disposed on the developer's own land, a permit must be obtained from the state agency. In Colorado, application for a Certificate of Designation for Operation of a Hazardous Waste Disposal site is made to the board of county commissioners (or municipality if the site is in an incorporated area). The county or municipality forwards copies of the application to the Colorado Department of Health and Colorado Geological Survey for review. The

approval procedure includes public notification, public hearings, and judicial review. In Utah, application is made to the Utah Department of Health, Bureau of Solid and Hazardous Waste Management.

For disposal of nonhazardous wastes on site, application is made to the board of county commissioners. In Colorado, the disposal site must comply with Colorado revised statutes, solid waste disposal sites and facilities, title 30, article 20.

Before mining begins, the developer must apply for the following permits:

- Notification of Commencement of Subsurface Mining (submit to U.S. Mine Safety and Health Administration)

- Detailed Development Plan (applies to federal oil shale lease agreement, submit to U.S. Geological Survey)

- Mining Plan (applies to federal oil shale lease agreement, submit to U.S. Geological Survey)

In Colorado, the developer must apply for a permit for regular mining operations if more than 10 acres of land and more than 70,000 tons of shale including overburden are affected. Rules for preparing an application for this permit are published in CRS 1973, 34-32-12 and Rules and Regulations of the Colorado Mined Land Reclamation Board. The applicant applies to the Colorado Mined Land Reclamation Board. The developer must have an approval letter from the local government before the Mined Land Reclamation Board will consider the application for a regular operation mining permit.

In Utah, a mine is considered a large mine for permitting requirements because more than five acres of surface disturbance will occur. Surface disturbance includes buildings, roads, and oil shale processing equipment. The developer must apply for a Notice of Intention to Commence Mining Operations with the Utah Division of Oil, Gas, and Mining using forms provided by that state agency. This notice must include a reclamation plan. The operator must furnish insurance policies or post bond as evidence of financial responsibility during the proposed mining operations for any off-site public liability. After the Notice of Intention to Commence Mining Operations has been approved, that state agency must again be notified within 30 days before mining operations actually take place.

Reports and permits required during mining operations include:

- Periodic or annual reports on mining operations on federal-leased land must be filed with the U.S. Department of Interior (43 CFR 23.10).

- Annual report (Colorado). The operator must submit an annual report to the Colorado Mined Land Reclamation Board indicating phases of the reclamation plan that have been completed (CRS 1973, 34-32-116 (a)).

- Notice of borehole penetrating a coal seam (Colorado). The Colorado Oil and Gas Conservation Commission must be notified of a borehole that penetrates any workable coal seam.

- Notice of intent to revise mining operations (Utah). The Utah Division of Oil, Gas, and Mining must be notified of any change that is to take place in mining operations including a change in reclamation plans. The procedure for filing this notice is the same as that for the Notice of Intention to Commence Mining Operations (UCA 1953, 40-8-18).

- Yearly mining operations progress report (Utah). The developer files an annual operations report using forms supplied by the state agency.

- Permits for transport and use of explosives. Reporting of mining accidents.

The following notifications are required for closure of a mine:

- Notification of closure of subsurface mining. The federal Mine Safety and Health Administration must be notified if the subsurface mine is to be closed, even if temporarily.

- Notice of activity (Colorado). The Colorado Bureau of Mines must be notified when the mine is temporarily or indefinitely shut down.

- Notice of suspension of mining operations (Utah). The Utah Division of Oil, Gas, and Mining must be notified of any intention to suspend mining operations for more than six months, excluding labor disputes.

For all closure operations, the reclamation plan submitted by the developer must be followed.

The developer must submit a plan for mitigation of environmental effects due to mining as part of the Detailed Development Plan and Mining Plan submitted to the U.S. Department of Interior (applies to federal leased land). In addition, the information must also be submitted to the state as part of the mining permit application (Colorado: Permit for Regular Operation; Utah: Notice of Intention to Commence Mining Operations).

As an example of the mining permit application for Colorado, the Colorado Mined Land Reclamation Board requires the following information:

- Names and addresses of applicant and owners of the land surrounding land to be mined; legal description of land

- A mining plan, including method of mining to be employed, size of area to be worked at any one time, disposal of any overburden or other mining rejects, etc.

- Time table of operation

- How mining will affect surface and groundwater, including plans for controlling runoff water

- Description of wildlife resources, including the potential of the proposed activities on endangered or threatened species

- Climatological data

- Reclamation plan, including time table, information on suitability of top soil and other media for establishment and maintenance of plant growth as part of reclamation, final use of the area after reclamation, and information on kinds of reclamation the developer proposes to achieve and why each was chosen

- A list of air, water, and solid waste permits required

Costs

The costs associated with permitting of a facility will depend on conditions encountered at the specific site. A general estimate of the permitting costs for a 2,000-b/d plant are listed in Table 8. There is a high degree of uncertainty in these estimates and actual costs may vary by as much as three to four times these values.

Control and Mitigation

Air Quality

Emissions from a 2,000-b/d plant have been estimated and are listed in Table 9. These values are estimated without control measures. The application of control measures will reduce emissions significantly. These emission numbers are approximate and are listed for purposes of discussing permitting requirements and control only. Some of the values are derived from the Environmental Impact Statement for the Anvil Points oil shale facility (U.S. DOE 1980) prorated to a 2,000-b/d operation. Operations are considered collectively (except vehicles), and the

41

facility is assumed to operate 24 hours per day, 365 days per year, although actual operational days will be less. Estimated in annual figures, there is a potential to emit about 2,000 tons per year of particulates and about 200 tons per year of sulfur dioxide.

Table 8. Estimated Permitting Costs for a Small-Scale Shale Oil Plant

Permit	Cost in Thousand Dollars
AIR	
Baseline air quality monitoring	70
Air quality modeling	20
Air quality permit (discharge, construction, operation)	15
Compliance testing after construction, before operation	50
WATER	
Baseline groundwater quality monitoring, modeling	40
Baseline stream quality monitoring	30
On-site sewage disposal permit	10
Water quality certification (Section Y01)	10
Wastewater facility construction and operation permit	20
LAND	
Mining-reclamation permit	85
Hazardous waste generator and storage	10
OTHER	
Environmental impact study	90
Baseline plant-wildlife survey	20
Baseline culture-archaeological survey	15
Baseline socioeconomic survey	15
TOTAL	500

As part of the emission control, spent shale from the IFB retort will be combusted in a fluidized-bed combustor. Calcium carbonates and calcium oxides in the spent shale will react with and remove sulfur dioxide from the gas discharge stream. The sulfur distribution in spent shale, oil, and gas are assumed to be the same as those measured by pilot retorting tests (Merriam and Cha 1987). The calcium in the spent shale from the combustor is assumed to absorb an additional 92% of the sulfur from the retort offgas.

Table 9. Summary of Uncontrolled Daily Emission Estimates During Mine Development, Mining, Construction, and Operation of an Oil Shale Facility

Activity	Subactivity	Material Handled	Pollutant	Uncontrolled Daily Emissions, lb/day
Mining and Mine Development[a]	Mining	3730 ton/day oil shale	Particulate	33.6
	Blasting	3730 ton/day oil shale	Particulate	37.3
		2020 lb/day ANFO[b]	NO_x	3.2
			CO	42.5
	Mining Equipment	670 gal/day diesel fuel	CO	60.3
			HC	18.8
			NO_x	287
			SO_2	20.8
			Particulate	14.7
	Primary Crushing	3730 ton/day oil shale	Particulate	1865
Facility Construction	Vehicle Traffic[c]	80 VMT[c]/day	Particulate (fugitive)	368

43

Table 9. Summary of Uncontrolled Daily Emission Estimates During Mine Development, Mining, Construction, and Operation of an Oil Shale Facility (continued)

Activity	Subactivity	Material Handled	Pollutant	Uncontrolled Daily Emissions, lb/day
	Excavation, Roads, and Pipe Lines	Native earth	Particulate (fugitive)	15
Facility Operation[c]	Secondary Shale Crushing and Shale Transport	3730 ton/day oil shale	Particulate	8970
	Combustor Exhaust (combustion of retort gases)	5.4×10^6 scf/day offgas	NO_x SO_2 Particulate (after cyclones)	100 1100[d] 200
	Spent Shale Disposal Area	15 acres	Particulate (fugitive)	6.42
	Shale Storage	32,000 ton/yr	Particulate (fugitive)	20.9
	Vehicle Traffic	53 VMT/day	Particulate (fugitive)	245

a Emissions are for full-scale mining during module operation. Emissions during mine development are, at most, 20% of these.
b Ammonia nitrate fuel oil.
c Maximum capacity module operation in vehicle miles traveled.
d Emissions before reacting with spent shale.
e Gaseous emissions from vehicle traffic are not included in this table.

44

The amount of NO_x is unknown and difficult to predict. Taback et al. (1986) estimate, using the Paraho process on western shale, that 33% of the nitrogen originally present in the raw shale will be partitioned to the spent shale, another 30% to the retort gas, and the remaining 37% to the product oil. Most of the nitrogen in the retort gas is emitted as ammonia and very little as NO_x. Taback et al. (1986) estimate that the retort gas ammonia concentration is 660 ppm as NH_3. Some unpublished WRI data show the concentration of NO_x in retort gas is in the range of 20 to 30 ppm. This is equivalent to about 5 lb/day NO_x.

The NO_x formation in the fluidized-bed combustor is difficult to predict. A portion of the nitrogen in the spent shale will be converted to nitric oxide during combustion. Taback et al. (1986) estimated that 300 ppm NO_x is in the flue gas when spent shale is combusted with retort gas. However, in this situation the ammonia in the retort gas is expected to react with some of the NO_x formed in the combustor to produce nitrogen gas. Net published NO_x emissions (Taback et al. 1986) range from 75 to 500 $kg/1000 \ m^3$ of oil (52 to 350 lb per 2,000 barrels of oil per day) using a fluidized-bed combustor. For this study, it is assumed that 100 lb of NO_x will be emitted daily from the plant.

It is estimated that there will be 200 lb/day of particulates from the plant after reduction by pollution control equipment. This is based on data obtained at Colorado-Ute Electric Association's 110-MW fluidized-bed boiler system at Nucla, Colorado (Friedman et al. 1989). The particulate level after the baghouses at that plant during a compliance test period was 0.018 $lb/10^6$ Btu, or 0.35 lb/ton of coal feed. The coal used had a high ash content. This converts roughly to 200 lb per day for a 600 ton per day feed to the fluidized-bed combustor.

For control, the state will require best available control technology for removal of sulfur dioxide and particulates. For mining operations, specific mitigation methods normally considered for control of particulates include the following:

- Paving of access roads

- Treatment of major haul roads with a suitable dust suppressant

- Treatment of temporary haul roads

- Wet suppression of raw shale and spent shale pits

- Use of baghouses, wet suppression, and baffled settling during primary crushing operations

- Treatment or wet suppression of temporary shale stockpiles

- Substitution of conveyor systems for haul trucks (Colorado regulation #1, part III (D) (2) (d) (iv) (G))

- Revegetation of disturbed surface areas

- Restriction of areas to be blasted at any one time

- Haul Roads: In Colorado, regulation #1 part III (D) (2) (e) applies for best available control technology if traffic exceeds 200 total vehicle or 40 haul vehicles per day. Control measures include washing haul vehicles, covering haul vehicles, limiting load sizes, vehicle speed restrictions, road chemical stabilization, and other procedures dictated by the state.

Generally, wet suppression is expected to reduce fugitive emissions by 70%. Wet suppression and baffled settling can reduce particulate emission by 98.5% and baghouses by 99%. Spent shale can be moisturized to 20% to control fugitive dust. Usually, oil shale process (or produced) water is used to moisturize the shale. Chemical retarders can be added to surface and haul roads and to spent shale piles to control fugitive dust. Commercially available products and their effectiveness are discussed by Cross (1980). For oil shale processing, baghouses are generally considered best available control technology for removal of particulates.

If the 2,000-b/d plant is located in Colorado, the plant must meet a standard of 600 lb/day of sulfur dioxide. (See CAQCC regulation #1, page 1.78, emission standard 0.3 lb of SO_2 per barrel of oil produced for plants with production rate over 1,000 b/d). The plant design (Walker et al. 1989) includes equipment for sulfur and particulate removal to meet the requirements.

Water Quality

Water generated from a 2,000-b/d shale oil plant is estimated to range from 50,000 gallons per day (Walker et al. 1989) to as much as 84,000 gallons per day based on one barrel of water being produced per barrel of oil. If steam is used for direct heating of shale, the condensate formed will generate additional wastewater. Other wastewater sources include boiler blowdown, cooling water discharge, ion exchange or softener regeneration wastewater, surface runoff, and mine seepage.

It is likely that all of the wastewater can be reused within the plant. If the spent shale is moisturized to 20%, this will consume

about 150,000 gallons per day of wastewater. Dust control for roads and for mining operations will consume additional water. Process water requirements including cooling (no on-site power generation or steam generation for heating shale) will probably be about 100,000 gallons per day (Lewis et al. 1984, data scaled to 2,000 b/d).

Generally, a water management system can be designed such that there is no discharge of wastewater from the facility. An exception is if there is significant groundwater infiltration into a mine, and disposal of excess water is required. Depending upon the site location, it may be advantageous to dispose of noncontact cooling water to a surface stream. Treated sewage effluent can be discharged to a leach field.

The developer should prepare a site-specific water management plan that will reuse most, if not all, of the wastewater. This plan may include one or more lined ponds to contain contaminated process water or water too saline for reuse. Above-ground tanks containing shale oil products need to be diked as part of the spill prevention control and countermeasure plan. Regulations have been published for underground storage tanks. (A tank is considered underground if more than 10% of the tank, including piping, is below the surface.)

A number of studies have been published regarding materials that might leach out of spent shale that has been moisturized. Jackson and Jackson (1982) found that spent shale moisturized to 20% with process water released a leachate containing heavy metals (As, Ba, Cd, Cr, Pb, Se, and Ag) at concentrations of 10% or less than those set by the U.S. Resources Conservation and Recovery Act's Extraction Procedure Toxicity Test. The test limits are 100 times greater than those set by the Safe Drinking Water Act for certain contaminants. Sodium and potassium sulfate are the major constituents leached, and most of these salts originate in the spent shale, rather than from the moisturizing process wastewater. Fox et al. (1984) report that 92 to 97% of the base/neutral organic solutes and 85 to 96% of the hydrophobic organic solutes were removed when process water was used to moisturize combusted shale. About 90% of other organic nitrogen compounds was removed. The mechanism of removal was a combination of volatilization, sorption, and chemical reaction. Volatilization was the primary removal mechanism for organics having a boiling point less than 302°F (150°C).

The water management plan may include a leachate collection system for at least some spent shale areas where process water is used to moisturize the spent shale. Also, natural drainage areas where mining or processing activity takes place may be diked, with the excess water routed to ponds. The pond water may be used to moisturize additional spent shale and for dust control.

Oil shale process water can also be treated by biological and physical-chemical methods. Nordin et al. (1987) demonstrated that essentially 100% of the organic content can be removed by a combination of hot gas stripping and wet air oxidation. Healy et al. (1983)

47

demonstrated that 55% of the dissolved organic carbon in oil shale process water is readily removed by biotreatment (the remainder is refractory). Low levels of water soluble organic compounds can be removed from leachate or groundwater by carbon filtration.

Solid and Hazardous Wastes

Solid wastes will be produced at the facility. These wastes can include off-specification byproducts, scraps and garbage, spent flue gas desulfurization chemicals, water treatment sludges, and possibly spent catalyst. Quantities of solids, projected to a 2,000-b/d plant are listed in Table 10. The only RCRA hazardous wastes in these materials are API separator bottoms and API floats derived from process water treatment. The estimated values represent maximum amounts of waste that can be produced. Actual wastes generated in a well-managed facility may be half as much.

Table 10. Estimated Solid Waste Production[a]

	Ton/Day
Spent shale	2917
FGD sludge[b]	5.42
Off-specification oil	4.30
Oil solids	1.23
Scrap and garbage	0.15
Raw shale rejects	241
Biological sludges	1.99
Sludges and floats from waste-water treatment	25.2
API separator bottoms	0.07
API floats	0.01
Raw water treatment sludges and floats	0.26

[a] From Heistand (1985) prorated to a 2,000-b/d plant

[b] Based on 90% removal of 1,100 lb/day of SO_2 using a limestone scrubber, molar Ca/S of 1.6. FGD sludge containing 70% water, and forced oxidation of FGD sludge to $CaSO_4$

Raw shale rejects and oily solids can be used for their energy values in the fluid bed combustor. The wastes from these combustion operations can be disposed with the spent shale. Water treatment sludges can be used on site for dust control or for conditioning soils for revegetation. Off-specification oil may be collected and refined to recover most of the oil. Thus, very few of the materials need to leave the site.

If room and pillar mining is the method used for extraction, the total quantity mined would be around 1,400,000 tons per year plus a small amount of overburden and interburden material. Fifteen acres per year of land are assumed to be consumed for mining purposes, including some land lost because of roads, disposal of spent shale, and disposal of mining reject material (assuming a 60-ft-high room, and 40% of shale not mined because of pillars and walls). Generally, state laws exempt mining wastes from the rules that govern solid waste disposal facilities.

For disposal, retorted shale generally classifies as a poorly graded sandy gravel using the United Soil Classification System, with specific gravity ranging from 2.52 to 2.59. The retorted shale and mining rejects will occupy roughly 120 to 130% of the volume of the original shale mined, and will be disposed of on the surface.

Commonly, oil shale process water is used to moisturize the spent shale to 20%. Spent shale has cementitious properties and can fix most of the pollutants of the process water, particularly heavy metals and hydrophobic organic compounds. The leachate from moisturized spent shale usually passes the EP toxicity test (metal values 10% or less of RCRA limits; Jackson and Jackson 1982).

The developer will probably need to run EP toxicity tests or toxicity characteristic leaching procedure tests on retorted shale that has been moisturized with process wastewater. Some leachate tests or lysimeter studies may need to be performed simulating the environment into which the shale will be placed.

Before the start of construction, a plan will have to be prepared for disposal of retorted shale and unsuitable mining materials. If leachate from retorted shale can potentially contaminate groundwater or surface water because of organics, the developer should consider a leachate collection system with the leachate routed to a biological treatment plant. Poulson et al. (1985) have shown that hydrophobic organic solutes tend to be adsorbed by solids, whereas hydrophilic solutes tend to leach. Bell et al. (1984) report that organics leached from spent shale that had been moisturized with process water are readily biodegradable, whereas adsorbed organics tend to be refractory.

Some site-specific tests should be performed to ensure that leachate contaminants will not be a problem when the material is contacted by rain, melting snow, or runoff water. If leachate contaminants are shown to be a problem, the leachate will have to be collected and pumped to a location for treatment and discharge, pumped to evaporation ponds, or used at the facility. One possible use, if the leachate is not too saline, is the irrigation of revegetated retorted oil shale piles.

Solid waste piles will need to be covered with some soil; fertilized; seeded with a mixture of native grasses, forbs, and shrubs; mulched with a grass hay; and sprinkler-irrigated until vegetation is

established. Most likely, a concern will be the salinity of the leachate.

Kilkelly et al. (1981) completed a series of revegetation studies on retorted spent shale at sites in Rio Blanco and Garfield Counties in Colorado. They found no major differences in vegetation between leached and unleached shale or between two different types of retorted shale after seven growing seasons, with the exception of one TOSCO retorted shale plot. With time, a shift from perennial grasses to dominance by shrubs was noted, especially on south-facing slopes. Surface runoff and sediment yield was low due to satisfactory vegetative cover. During the first year of study, the leachate plots accumulated surface salts, but this was removed by subsequent precipitation.

Tuttle et al. (1985) evaluated weathering of 50-year-old retorted oil shale piles and found no detectable migration of material from the waste pile into the underlying slope wash. The mineral and chemical characteristics of the piles remained relatively unchanged by weathering. The exception was some loss in soluble salts, particularly sodium, potassium, and calcium sulfates from the retorted shale due to leaching.

Heistand and Limbach (1987) concluded that the natural invasion of native plants on exposed surfaces of retorted shale disposal sites was not significantly different from natural revegetation of disturbed soils, based on studies at the Anvil Points facility near Rifle, Colorado. Plants were well established in less than three years. Based on these studies, there should not be any major problems in revegetation of shale piles.

Costs

Costs for control of materials to meet federal and state requirements are included in the process design study (Walker et al. 1989). Other costs to be considered are land reclamation, decommissioning, and the relatively minor cost of hazardous waste disposal. Revegetation of spent shale piles can cost $250,000 to $400,000. Assuming no major problems, decommissioning costs should be under $1.5 million. The operator can expect to pay about $700 per 55 gallon barrel of hazardous waste shipped off site to a hazardous waste disposal facility located in Utah.

Monitoring

Monitoring will be required for the air, water, and land around the facility. For the air, specific pollutants to be monitored and the frequency of monitoring will be established in the permitting process. Most likely, monitoring will be required for CO, SO_2 NO_x, and particulates. The equipment to monitor these gas species can cost $50,000 to $60,000. Monitoring of current air quality around the plant may also be required, especially for SO_2 and particulates. The

equipment to monitor these pollutants can cost $50,000, depending on the site and number of plant locations to be monitored.

Surface and subsurface water quality may also require monitoring. If a surface discharge is permitted, the frequency and water quality parameters to be monitored will be listed in the permit. Use of land application fields, storage ponds, and underground disposal will all require subsurface monitoring of water quality. Area streams may require the periodic monitoring of aquatic organisms, fish and zooplankton. Water quality monitoring can cost $30,000 to $180,000 per year plus an additional $30,000 for monitoring of wells. The cost will depend on nature of waste and wastewater disposal and on the location of the plant.

CONCLUSIONS

An asphalt-blended product may have the most economic potential for development of a small-scale oil shale commercial operation. The potential for use as individual chemicals, olefins, modified aromatics, creosote, phenolics, pyridines, oil field chemicals, and rail diesel fuel may exist for the lighter fraction. There may also be a market for carboxylic acids made from oil shale.

Oil shale or spent shale may be used for power cogeneration with coal and for sulfur sorbtion. Spent shale also has a good potential for use as cement, road aggregate, or for soil stabilization. These uses can benefit a small-scale plant by providing an increment of additional income and reducing the cost of spent shale disposal. Transportation costs limit these uses to not over 700 miles for power use, 500 miles for soil stabilization, and 50 miles for aggregates.

The direct-fired Paraho retorting process and inclined fluidized-bed retorting are likely to be the best processes for production of shale oil for an asphalt blend. The Paraho retort processes 3/8- to 3-inch material and the inclined fluidized-bed retort processes material smaller than 3/8 inch. Combustion of the fine material for power rather than retorting it in an inclined fluidized-bed retort was considered by Walker et al. (1989). They found that combustion increased the overall plant cost by more than the income gained from power generation.

A 2,000-b/d facility can provide sufficient material for the assumed paving demand of Colorado, Wyoming, and Utah. The market demand may be significantly greater, depending primarily on the increase in pavement life cycle that can be achieved.

A discounted cash flow-return on investment (DCF-ROI) evaluation of a 2,000-b/d shale oil facility shows that the operation is potentially viable, if the price obtained for the asphalt-blend product is in the top range of prices projected for this product. At $700 to $1,000 per

ton of asphalt blend the estimated DCF-ROI is about 18 to 26%. This return on investment results in about a 4- to 5-year return of capital.

The environmental permitting, control and mitigation, monitoring, and restoration costs are highly variable, depending on plant location and specific process operation. For an underground mine with no significant impact on surface waters and a relatively good plant location, the cost of environmental permitting is estimated at $500,000. Equipment for air and water quality monitoring can cost $150,000, and the monitoring operation can run $200,000 per year, depending on the site location and the specific permitting, control, and monitoring requirements.

ACKNOWLEDGMENTS

DISCLAIMER

Mention of specific brand names or models of equipment is for information only and does not imply endorsement of any particular brand.

REFERENCES

Bell, P.R.F., P.F. Greenfield, M. Corney, and A.J. Moore, 1984, Evaluation of Rundle Spent Shale as an Adsorbent for the Treatment of Retort Water. 17th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 318-328.

Berry, K.L., R.L. Hutson, J.S. Sterrell, and J.C. Knepper, 1982, Modified In-Situ Retorting Results of Two Field Retorts. 15th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 385-396.

Bunger, J.W., H. Ryu, and S.-Y. Jeong, 1989, Economic Enhancement of Western Shale Oil Upgrading. Laramie, WY, WRI-89-R008.

Button, J. W., J. A. Epps, and R. M. Gallaway, 1978, Laboratory Evaluation of Selected Shale Oil Asphalts in Paving Mixtures. Laramie, WY, DOE report RF3403-1.

Cameron Engineers, 1975a, Petrobras Patents "Petrosix" Retorting Process in the U.S. Synthetic Fuels, 12(3): 2-28 - 2-29.

Cameron Engineers, 1975b, Synthetic Fuels Data Handbook, Denver, CO, 67-76.

Carter, S.D., 1987, Fluidized Bed Pyrolysis Kinetics of New Albany Oil Shale. 1986 Eastern Oil Shale Symposium Proceedings, Kentucky Energy Cabinet Laboratory, Lexington, KY, 45-52.

Cena, R.J., and R.G. Mallon, 1986, Results and Interpretation of Rapid-Pyrolysis Experiments Using the LLNL Solid-Recycle Oil Shale Retort. 19th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 102-125.

Cha, C.Y., and H.E. McCarthy, 1982, In Situ Oil Shale Retorting, in Allred, V.D., ed., Oil Shale Processing Technology. Center for Professional Advancement, East Brunswick, NJ, 189-216.

Chazin, D., G. French, K. Hanna, M. Heydari, H. McCarthy, E. Moore, R. Nelms, and E. Wing, 1979, Commercial Feasibility Evaluation of Selected Oil Shale Recovery Systems. Report to DOE, Laramie, WY, 4-26.

Cross, F.L., 1980, Control of Fugitive Dust from Bulk Loading Facilities. Pollution Engineering, 12(3): 52-53.

Dadiani, J., 1983, Environmental Baseline Characterization of the Naval Oil Shale Reserves in Colorado. 16th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 591-601.

Dockter, L., A. Long, and A.E. Harak, 1971, Retorting Ungraded Oil Shale as Related to In Situ Processing, II. _American Chemical Society Preprints_, 15(1): 2-12.

Eyman, D.T., and R. Datta, 1988, Dehydrogenation of Cycloalkanes Catalyzed by Metals in Supported Molten Salts. Air Force Wright Aeronautical Laboratories, Wright-Patterson Air Force Base, OH, AFWAL-TR-88-2029.

Fahy, L.J., 1986, Horizontal Low-Void Retorting of Eastern and Western Oil Shale. Laramie, WY, DOE Report DOE/FE/60177-2099.

Fischback, J.W., 1979, Australian Rundle Oil Shale Testing and Process Designs. The Superior Oil Company's Internal Report for Southern Pacific Petroleum.

Fox, J.P., P. Persoff, A. Newton, and R.N. Herstand, 1984, The Mobility of Organic Compounds in a Codisposal System. 17th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 339-351.

Friedman, M.A., T.J. Boyd, T.M. McKee, and R.J. Melvin, 1989, Test Program Status at Colorado-Ute Electric Association's 110-MW Circulating Fluidized-Bed Boiler, _in_ Manaker, A., ed., _10th International Conference on FBC_. ASME, New York, NY, 739-744.

General Motors Corporation, 1986, Coal-Fired Diesel Locomotive Economic Assessment. Report to DOE under contract DE-AC21-85MC22123.

Harak, A.E., T.C. Bartke, and H.C. Carpenter, 1984, A Horizontal Modified In-Situ Oil Shale Retorting Concept. Morgantown, WV, DOE/METC-84-29.

Healy, J.B., B.M. Jones, G.W. Langlois, and C.G. Daughton, 1983, Biotreatment of Oil Shale Wastewater. 16th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 498-511.

Heistand, R.N., 1985, Estimating Solid Wastes from Oil Shale Facilities. 18th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 291-297.

Heistand, R.N., and L.K. Limbach, 1987, The Natural Invasion of Native Plants on Retorted Oil Shale. 20th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 201-205.

Jackson, L.P., and K.F. Jackson, 1982, The Co-Disposal of Retorted Shale and Process Waters: Effect on Shale Leachate Composition. 15th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 505-515.

Jones, J.B., 1976, The Paraho Oil Shale Retort. Quarterly of the Colorado School of Mines, Proceedings of the Ninth Oil Shale Symposium, 71(4): 39-48.

Kilkelly, M.K., H.P. Harbert, and W.A. Berg, 1981, Revegetation Studies on TOSCO II and USBM Retorted Oil Shales. 14th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 410-421.

Knight, J.H., and J.W. Fischback, 1979, Superior's Circular Grate Oil Shale Retorting Process and Australian Rundle Oil Shale Process Design. 12th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO.

Komar, D.A., 1988, A Technical Assessment of Naphthene Dehydroisomerization for Endothermic Cooling. Air Force Wright Aeronautical Laboratories, Wright-Patterson Air Force Base, OH, AFWAL-TR-87-2096.

Lander, H.R., Jr., 1981, Jet Fuel from Shale Oil--1981 Technology Review. Air Force Wright Aeronautical Laboratories, Wright-Patterson Air Force Base, OH, AFWAL-TR-81-2135.

Lekas, M.A., 1981, The Geokinetics Horizontal In Situ Retorting Process. 14th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 146-153.

Lekas, M.A., J.M. Lekas, and F.G. Strickland, 1989, Initial Evaluation of Fracturing Oil Shale with Propellants for In Situ Retorting. Laramie, WY, DOE report DOE/MC/11076-2766.

Lewis, A.E., R.L. Braun, and J.C. Diaz, 1984, Oil Shale Retorting Processes: a Technical Overview. 17th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 1-16.

Lukens, L.A., 1989, New Paraho Shale Oil 1988 Program Results. 22nd Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 199-206.

Matzick, A., and R.O. Dannenberg, 1960, USBM Gas Combustion Retort for Oil Shale--a Study of Process Variables. USBM Report of Investigations 5545.

McCarthy, H.E., and R.L. Clayson, 1989, Oil Shale Mining Studies and Analyses of Some Potential Unconventional Uses for Oil Shale. Laramie, WY, WRI-89-R015

McLendon, T.R., 1985, Combustion Retorting of Oil Shale at Low Void Volumes. DOE/METC/85-12.

Merriam, N.W., and C.Y. Cha, 1987, Design, Testing, and Operation of a Plug-Flow, Inclined Fluidized Bed Reactor. Laramie, WY, DOE Report DOE/FE/66177-2438.

Merriam, N.W., A. Long, G.W. Gardner, and E.E. Wing, 1985a, Retorting Oil Shale with Zones of Contrasting Permeability Runs S76 and S77. Laramie, WY, DOE Report DOE/FE/60177-1885.

Merriam, N.W., A. Long, T.F. Turner, and E.E. Wing, 1985b, Retorting Oil Shale with Zones of Contrasting Permeability Tests S71-S75. Laramie, WY, DOE Report DOE/FE/60177-1886.

Nixon, A.C., 1986, A Study on Endothermic and High Energy Fuels for Air-breathing Engines. Technical Report, U.S. Air Force Contract F33615-84-C-2410.

Nordin, J.S., S.L. Hill, F.P. Barker, R.R. Renk, and J.E. Dean, 1988, Oil Shale Plant Siting Methodology: a Guide to Permits and Approvals. Laramie, WY, WRI-88-R025.

Nordin, J.S., R. Poulson, N. Niss, and C. Laya, 1987, Characterization and Treatment of By-product Waters from Selected Oil Shale Retorting Tests. Laramie, WY, DOE Report DOE/MC/11076-2638.

Piper, E.J., 1981, State of the Art: Oil Shale Process Technology. Presented at the 6th IIASA Resources Conference, World Oil Shale Resources and Their Potential Development, Golden, CO.

Plancher, H., and J.C. Petersen, 1984, Nitrogen-Containing Components from Shale Oil as Modifiers in Paving Applications. Amer. Chem. Soc. Div. of Petrol. Chemistry Preprints, 29(1): 229-237.

Poulson, R.E., J.A. Clark, and H.M. Borg, 1985, Organic Solute Profile of Water from Rio Blanco Retort 1. Laramie, WY, DOE report DOE/FE/60177-2366.

Ruark, J.R., K.L. Berry, and B. Guthrie, 1956, Description and Operation of the N-T-U Retort on Colorado Oil Shale. U. S. Bureau of Mines, Report of Investigations 5279.

Sinor, J.E., 1989, Niche Market Assessment for a Small-Scale Western Oil Shale Project. Laramie, WY, DOE report DOE/MC/11076-2759.

Snyder, G.B., and J.R. Pownall, 1978, Union Oil Company's Long Ridge Experimental Shale Oil Project. 11th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 158-168.

Stevens, A.L., and R.L. Zahradnik, 1983, Results from the Simultaneous Processing of Modified In Situ Retorts 7 & 8. 16th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 267-280.

Sudduth, B.C., N.W. Merriam, T.F. Turner, P. Vaughn, and C.Y. Cha, 1987, Retorting of Nonuniform Oil Shale Rubble. Laramie, WY, DOE Report DOE/FE/60177-2348.

Sullivan, R.F., B.E. Strangeland, C.E. Rudy, D.C. Green, and H.A. Frumkin, 1978, Refining and Upgrading of Synfuels from Coal and Oil Shales by Advanced Catalytic Processes, First Interim Report, Processing of Paraffinic Shale Oil. Richmond, CA, DOE Report HCP/T2315-25.

Suryavanshi, K.J., 1989, Pavement Subgrade Stabilization Using Oil Shale Solid Wastes, University of Wyoming Masters Thesis, Department of Civil Engineering, 156.

Taback, H., R. Goldstick, and E. Bates, 1986, The Effect of Oil Shale Recovery Processes on Air Emissions. 19th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 241-261.

Turner, T.F., and D.F. Moore, 1985, Final Report on the Use of Gaseous Tracers in WRI's 10-ton Nonuniform Oil Shale Retorting Tests. Laramie, WY, DOE Report DOE/FE/60177-1979.

Turner, T.F., D.F. Moore, N.W. Merriam, and J.R. Covell, 1984, Investigation of Tracer and Steam Tests on the Western Research Institute 150-ton Retort. Laramie, WY, DOE Report DOE/FE/60177-1624.

Tuttle, M.L., W.E. Dean, and D.J. Ackerman, 1985, An Evaluation of the Effects of Weathering on a 50-Year-Old Retorted Oil-Shale Pile, Rulison Experimental Retort Colorado. 18th Oil Shale Symposium Proceedings, Colorado School of Mines, Golden, CO, 338-346.

U.S. Department of Energy, 1980, Draft Environmental Impact Statement: Mining, Construction and Operation for a Full Size Module at the Anvil Points Oil Shale Facility, Garfield County, Rifle, Colorado. DOE/EIS-0070.

U.S. Environmental Protection Agency, 1987, Guidelines on Air Quality Models. U.S. EPA Publication 450/2-78-027R and Supplement A, U.S. Government Printing Office, Washington, DC.

Walker, W., G. Betenson, and L. Walker, 1989, Process Engineering Study for a 2000 bbl/day Shale-Oil-Production Facility. Laramie, WY, WRI-89-R010.

Weis, H.J., 1981, The Retorting of Oil Shale by the Lurgi-Ruhrgas Process. 6th IIASA Resources Conference on World Oil Shale Resources and Their Development, Golden, CO.

Whitcombe, J.A., and R.G. Vawter, 1982, In Situ Oil Shale Retorting, in
    Allred, V.D., ed., Oil Shale Processing Technology. Center for
    Professional Advancement, East Brunswick, NJ, 153-168.

Zerga, D.P., 1978, Investigation of the Geokinetics Horizontal In Situ
    Oil Shale Retorting Process. Quarterly Report to DOE, July-
    September, SAN-1787-19.

END

DATE FILMED

03 / 20 / 91