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NUCLEAR IN SITU RECOVERY OF OIL FROM OIL SHALE

A. E. Lewis

September 14, 1973

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Contents

ABSTRACT	1
INTRODUCTION	1
RESOURCE DESCRIPTION	2
ROCK BREAKAGE FOR IN SITU PROCESSING	5
Mining and Collapse Method	6
Chemical Explosive Method	6
Nuclear Explosive Method	7
RUBBLIZING OIL SHALE WITH NUCLEAR EXPLOSIVES	7
OIL SHALE RETORTING	8
10-Ton Laramie Retort	11
150-Ton Laramie Retort	12
Nuclear <u>In Situ</u> Concept	12
Application of Experimental Results to the <u>In Situ</u> Process	13
UNDERGROUND PLUMBING	15
Pressure Drop in Chimney	15
Pressure Drop in Air Supply and Exhaust Gas Holes	16
Connection of Holes to Chimney	16
ENVIRONMENTAL IMPACT OF IN SITU OIL SHALE DEVELOPMENT	17
Hydrology	18
Ground Motion	18
Radioactivity	22
COST PROJECTIONS	25
PROPERTIES OF OIL PRODUCED FROM OIL SHALE AND POSSIBLE PRETREATMENT REQUIRED	31
DEVELOPMENT OF NUCLEAR IN SITU RETORTING REQUIRED FOR COMMERCIAL APPLICATION	32
Retorting Process	32
Effects of Nuclear Explosions on Oil Shale	33
Groundwater	33
History of Nuclear Development of Oil Shale	34
Government-Industry Impasse	34
CONCLUSIONS	35
ACKNOWLEDGMENTS	35
APPENDIX A - OIL SHALE RESOURCES OF THE GREEN RIVER FORMATION SUITABLE FOR NUCLEAR IN SITU PROCESSING	37
APPENDIX B - DEWATERING PLAN AND COST ESTIMATE	45
REFERENCES	51

NUCLEAR IN SITU RECOVERY OF OIL FROM OIL SHALE

Abstract

A plan is presented for production of oil by retorting oil shale in situ after breaking it with underground nuclear explosives. Reserves of oil shale of thickness and grade suitable (greater than 20 gal/ton) for this process occur in the Piceance Creek Basin of Colorado, and are estimated to contain 640 billion barrels of oil in place. Cost projections indicate that this oil could be produced at a price ranging from \$2.00 to \$3.30 at the wellhead with a 20% rate of return on investment (discounted cash flow). The price and production rate vary with oil shale thickness. At a rate of 32 nuclear chimneys per year in oil shale ranging in thickness from 1000 to 2000 ft, production varies from 28 million bbl/yr (\$3.30/bbl) to 121 million bbl/yr (\$2.00/bbl). Capital requirements for this in situ process are estimated to be 20 times less than those required by a surface retorting process.

Environmental problems such as the need to dispose of large volumes of waste rock associated with conventional mining and surface retorting of oil shale would be largely avoided. Problems of seismic ground motion and possible contamination of the oil and groundwater appear manageable.

The necessity for government action arising from federal ownership of the resource as well as the requirement for a significant government contribution to the development of the nuclear in situ retorting technology requires either government development of the resource or a policy defining how industry and government may jointly develop it. The potential contribution to the energy resources of the nation is so large that this method of recovery from oil shale must be considered.

Introduction

The oil shale of the Green River Formation in Colorado, Utah and Wyoming is the largest potential source of oil in the United States, including Alaska. Development of this resource will become a necessity in coming years as the need for oil grows.

Compared to conventional processes of mining and surface treatment, in situ oil recovery offers potential advantages including lower cost, a larger resource suitable for development and a lesser adverse effect on the environment.

In situ processes are not as well developed as conventional ones, but because of their potential advantages major attention should be devoted to their development.

Two things are essential to any in situ process. First, the rock must be broken so that most of the volume is near a fracture surface along which fluids (mostly gases) may move freely. Second, the rock must be heated to release the oil.

The most widely considered process is rubblization of the rock using either explosive or mining techniques, followed by the introduction of air to provide heat by in situ combustion of part of the organic material in the oil shale. The hot gases produced by the combustion move ahead of the combustion zone and release the bulk of the oil from the shale. The oil is then collected and pumped to the surface.

In situ processing eliminates the need to move the oil shale, the cost of processing facilities is greatly reduced, and the problem of disposal of the spent shale is eliminated. The low cost of in situ retorting makes possible the treatment of large thicknesses of low-grade oil shale provided that it can be broken economically. Therefore, the cost of breaking the rock in situ becomes important.

Conventional mining processes are expensive and must utilize the highest grade possible to be economic. An assessment of the oil shale resource suitable for in situ processing indicates that it occurs in large thicknesses of a low grade. Therefore, if a nuclear in situ technology can be developed successfully, the U.S. oil reserves can be dramatically increased.

Resource Description

The oil shale of the Green River Formation is a dolomitic marlstone rather than a shale, although it is shale-like in appearance. It was deposited in lakes of Tertiary age, and single horizons may be traced for miles in Colorado, Utah and Wyoming (see Fig. 1). The organic matter, kerogen,¹ is largely solid and insoluble, and the porosity and permeability of the rock are both low. The composition of a typical oil shale containing 25 gal/short ton (s. t.) of oil is shown in Table 1.² When heated the kerogen decomposes, releasing a major part of the organic material as a petroleum-like liquid.

Estimates of the amount of oil in place as a function of thickness and grade are

presented in Appendix A and are summarized in Table 2 and Fig. 2.

Several significant conclusions can be drawn from these summaries:

1. Almost if not all the oil shale meeting our criteria for nuclear in situ processing (more than 400 feet thick and containing 20 gal/s. t. or more oil) is in the Piceance Creek Basin of Colorado.
2. At least 720 billion barrels ($115 \times 10^9 \text{ m}^3$) of oil meeting these criteria is in place.
3. Increasing the thickness cutoff to 800 ft reduces the resource size by only 80 billion barrels.
4. Decreasing the cutoff grade to 15 gal/s. t. increases the resource by

Explanation

Area underlain by the
Green River Formation

Area underlain by oil shale
more than 800 feet thick,
which yields 20 gallons or
more oil per ton of shale

Fig. 1. Location of oil shale in Colorado, Utah and Wyoming.

Table 1. Typical composition of oil shale sections averaging 25 gal of oil per ton in the Mahogany zone of Colorado and Utah (from Ref. 2).

	Weight percent
Organic matter	
Content of raw shale	13.8
Ultimate composition	
Carbon	80.5
Hydrogen	10.3
Nitrogen	2.4
Sulfur	1.0
Oxygen	5.8
Total	100.0
Mineral matter	
Content of raw shale	86.2
Estimated mineral constituents	
Carbonates, principally dolomite	48
Feldspars	21
Quartz	13
Clays, principally illite	13
Analcite	4
Pyrite	1
Total	100

only 70 billion barrels, but increasing the grade to 25 gal/s.t. cuts the resource approximately in half.

The amount of resource available versus thickness is illustrated in Fig. 2. The estimated price of oil at each thickness is also shown, and will be discussed later.

It is significant to compare the 640 billion barrels of oil in place suitable for in situ processing at present prices

Fig. 2. Oil in place in oil shale containing more than 20 gal/ton, versus thickness - Colorado.

(>800 ft thick and containing 20 gal/s.t.) with the 160 billion barrels of oil in place in the range 30-35 gal/s.t., >25 ft thick, and <1000 ft below the surface. Of this 160 billion barrels, only 34 billion barrels is being considered at present for conventional mining and surface retorting.³ The requirement for this 34 billion barrels is that it be shallow enough for economical mining, contain more than 35 gal/s.t., and be at least 30 ft thick.

The oil shale resource is very much larger for in situ processing than it is for mining methods, assuming that the economic estimates of this paper and those of the National Petroleum Council³ are even approximately accurate.

Table 2. Estimates of oil in oil shale of Green River Formation.

Oil shale grade and thickness	Oil in place — billion barrels			
	Colo.,	Utah	Wyoming	Total
<u>This Report</u>				
<u>More than 15 gal/s.t.</u>				
>400 ft thick	790	70	0	860
>800 ft thick	700	0	0	700
<u>More than 20 gal/s.t.</u>				
>400 ft thick	720	0	0	720
>800 ft thick	640	0	0	640
<u>More than 25 gal/s.t.</u>				
>100 ft thick	490	(not estimated)		<u>>490</u>
>500 ft thick	350	0	0	350
>1000 ft thick	270	0	0	270
<u>USBM</u>				
<u>10-25 gal/s.t.^a</u>				
>10 ft thick	800	230	400	1430
<u>More than 25 gal/s.t.^a</u>				
>10 ft thick	480	90	30	600
<u>30-35 gal/s.t.^a</u>				
>25 ft thick and <1000 ft below surface				160

^aReference 2.

Rock Breakage for In Situ Processing

Results from experiments at the U. S. Bureau of Mines Energy Research Center, Laramie, Wyoming indicate that a column of rubblized oil shale can be successfully retorted by moving a combustion zone downward through it. Even large blocks have been retorted by this method.

For an in situ process, the rubblized rock must be extremely permeable,

allowing a non-channelized flow of gas to occur with a low pressure gradient. Most of the mass of material must be close enough to an exposed surface for efficient heat transfer. Also, the broken material must be enclosed by relatively unbroken rock impermeable enough to confine the fluid flow within the rubble region.

Several methods of preparing rock for this kind of in situ processing are

possible, although not all are practical with a given set of cost and environmental considerations. Three possible methods of breakage are: (1) Mining and collapse, i.e., block caving with partial removal of the broken rock; (2) Using chemical explosives to create a underground rubble; and (3) nuclear explosives to create underground rubble.

In all these methods the first requirement is to create space underground to accommodate the additional volume required by the broken rock. The minimum volume of space required relative to total volume of the broken zone is probably in the range of 5% to 10%. Because no significant free space is available underground, the only way to create it is to displace the overburden with explosives or to remove material by drilling or mining.

MINING AND COLLAPSE METHOD

Any mining and collapse method is not entirely an in situ technique unless the amount of material removed is negligible relative to the total amount broken. In the block caving method, probably 15% to 30% of the material would have to be mined and dumped, or processed in surface facilities and then dumped. After mining, the oil shale above the mined-out volume would be allowed to collapse. If the rock properties are suitable, breakage and redistribution of space as required would occur.

This hybrid method could be used, but it has many drawbacks. The oil that would have to be mined is not rich enough to justify mining and surface treatment at present prices, except as a method of

preparing for an in situ process, and the cost would be determined by balancing the profit from the in situ processing against the loss from the mining and surface processing of the material removed. Also, extensive workings would be necessary to carry out the mining operations, and gas and oil flow throughout the rubblized zone would have to be carefully controlled to assure the safety of the miners. Therefore, this hybrid process will not be considered further in this report; but perhaps it should be considered provided that mining costs are not prohibitive and practical methods can be found to control gas flow in the rubble zone and prevent gases from entering active mining areas.

CHEMICAL EXPLOSIVE METHOD

Little experience has been gained with chemical explosives that is directly applicable to preparing oil shale for in situ processing. Heaving and fracturing with chemical explosives has been limited to depths of tens of feet, although recently rubblization of rock as deep as two or three hundred feet has been accomplished.* Even so, these recent applications are directed toward leaching of copper ore in a process where breakage to the surface is not only acceptable but desirable, and where the value of copper in the ore is much higher (\$5-\$10/ton) than oil shale.†

* Approximately 2 kt of high explosives were detonated at the Old Reliable Mine (1972)⁶ and at the Zonia Mine (1973), both in Arizona.

† Oil from an oil shale containing 20 gal/s.t. (83.5 l/m.t) is worth about \$1/s.t., assuming it yields 1/3 barrel of oil on retorting and oil is priced at \$3 per barrel.

For in situ retorting, we assume that we will use the downward-moving combustion zone method developed by the USBM Laramie Energy Research Station. In this method, to control the gas flow, the rubbleized zone must be covered by a relatively unbroken, impermeable zone. To our knowledge, this kind of breakage has never been attempted with chemical explosives, and technical breakthroughs would be required. Even with these breakthroughs, costs will probably be too high by a factor of at least 2-10 to be of interest at present oil prices.

NUCLEAR EXPLOSIVE METHOD

Experience with nuclear explosives⁷ has demonstrated that they can produce

rubble with the required properties, i. e., 10-20% space distributed through a vertical rubble pile called a chimney and surrounded by rock that is relatively unbroken and low in permeability. Rock breakage costs can be low enough for this application if large enough explosive yields are used. There are questions that must be answered such as possible contamination of the oil by radioactivity, and damage and inconvenience to nearby residents caused by ground motion. Also, further information on the detailed response of this particular kind of rock (oil shale) to nuclear explosives is required. Nevertheless, enough information is available to evaluate the feasibility of using nuclear explosives to prepare oil shale for in situ processing.

Rubbleizing Oil Shale With Nuclear Explosives

When a nuclear explosive is detonated underground, some of the rock surrounding the explosive is vaporized. This gas then expands, forming a cavity that is approximately spherical. The space for the cavity is produced mainly by displacing the surface upward, although this effect is spread over a large enough area that it would not be detected except by accurate surveys (Fig. 3). When the rock gas has condensed to a liquid and begun to collect at the bottom of the cavity, the decreasing pressure can no longer support the rock above and the roof collapses. Rock continues to fall into the cavity, creating a column of broken rock called a chimney.

Methods have been developed to estimate the dimensions of chimneys as a

function of explosive yield, depth of burial (DOB) of explosive, rock properties, and other factors.⁷ Figure 4 shows the relationship between chimney height and mass of broken rock in a chimney as a function of DOB and explosive yield for a rock with properties assumed to be typical of an oil shale. This figure can be used to estimate the explosive yield required to produce a chimney of broken rock in any given thickness of oil shale for a given DOB which is determined by adding the thickness of oil shale to be broken to the overburden thickness.

Figure 5 shows histograms of the overburden thickness for various oil shale thicknesses. The figure shows the fraction of the total area in each oil shale thickness range (oil content 20 gal/s. t.)

Fig. 3. Diagram of cavity produced by an underground nuclear explosion.

that has a given overburden thickness range. Figure 5 also shows the total oil in place as well as the amount of oil in place for each combination of oil shale

thickness and overburden thickness. The amount of broken rock in a chimney is constant for a given chimney height. An estimate of the explosive yield required to produce a chimney as high as the average oil shale thickness is shown for each overburden thickness. In practice only a few "standard" yields would be used, with adjustments in the depth made as needed.

Figure 6 summarizes the amount of oil contained in oil shale that may be broken by various sizes of explosives. For example, there are approximately 240 billion barrels of oil in oil shale of combined thickness and overburden requiring an explosive yield in the range 45 to 85 kt.

Figure 7 shows examples of different sized chimneys. The variation of radius, bulking porosity, B (same as bed porosity), and mass of rock is shown for chimneys of various heights. These examples will be used throughout this paper for the purpose of illustrating the effect of the thickness of oil shale (chimney height) on the cost of retorting oil shale.

Oil Shale Retorting

In situ experiments have been limited to rock fractured enough to permit gas flow between drill holes, but not broken enough to allow contact of hot gases with the bulk of the rock between drill holes.⁸⁻¹⁰

Large experimental retorts have been constructed and operated by the USBM in Laramie, Wyoming. One of the purposes of these experiments was to obtain data on a retorting process which would be applicable to in situ processing of

rubblized material. Oil shale rubblized in situ would differ in particle size from oil shale prepared for a surface process in that it would contain a wide distribution of particle sizes, some of them possibly quite large in dimension (feet); whereas oil shale mined and crushed for introduction into a surface retort would be of a more uniform and generally finer size.

Because data are available from the USBM retorts on material similar in

Fig. 4. Chart for estimating chimney height and broken rock mass from depth of burial and explosive yield — oil shale.

Fig. 5. Fraction of area and oil in place in various oil shale thickness versus overburden thickness and required explosive yield — Colorado.

size and grade to that which must be processed underground, their results and experimental data are used in this report to extrapolate to a possible in situ process. Heat is provided in this process by burning some of the organic material in the oil shale. This consists of material which may be retorted and recovered as oil and material which remains behind as coke or carbon after retorting.

The efficiency of a combustion process depends on the extent to which the heat is provided by combustion of the carbon and not the recoverable oil. Alternatively, it is possible to supply process heat to oil shale in situ by other means, such as hot gases or liquids. The combustion process is selected here because data are available which suggest that it will work for in situ rubblized oil shale. However, other retorting methods using hot fluids to supply heat may ultimately prove to be as good or better.

10-TON LARAMIE RETORT

The first of the experimental retorts has a capacity of 10 tons. Rubble sizes up to 20 in. in two dimensions have been retorted in a shale bed of ungraded-size particles. In 18 runs, yields up to 80% of Fischer assay were obtained for a variety of operating conditions of air rate, bed temperature and recycle gas. Oil shale quality was chiefly in the range of 25-30 gal/ton for the best runs. The variables which had the largest effect on oil yields in this work were bed temperature, recycle gas rate, and assay of the charge. Heat losses from the retort shell were as high as one-third of the net heat of combustion. Such losses may well con-

Fig. 6. Amount of oil in oil shale (Colorado) that may be broken by nuclear explosives of various explosive yield range.

Fig. 7. Example chimneys used in defining retorting process requirements and costs.

tribute to a reduced oil yield compared with that obtainable from a well-insulated retort. Presumably, heat losses to the surrounding rock in underground (in situ) retorting would be much smaller.

Recent runs have been made on "lean" shale (average 15 gal/ton) using the 10-ton retort.⁴ Oil yields are lower, since a higher fraction of the organic material in the shale must be used as a fuel to heat the inert material to retorting temperature. Nevertheless, yields above 50% have been obtained.

150-TON LARAMIE RETORT

A larger retort having a capacity of 150 tons of shale was also built and operated by the Bureau of Mines.^{4,5} This retort is capable of handling pieces up to 4 ft in two dimensions, and thus can more nearly simulate the conditions in a nuclear chimney in which very large pieces of shale would be found. Combustion of shale in the retort is initiated by a natural gas burner. Air is blown downward through the bed, and liquid products are collected below. The gases containing mists of oil and water are passed through packed towers and then cooled to remove entrained liquid. Some of the exhaust gas is recycled into the retort, and the remainder is vented to the stack.

Oil yields up to 62% have been obtained in seven runs made in the retort, starting with oil shale which assayed at 20-25 gal/ton. Shale blocks of 7 to 8 tons within the 180-ton charge were completely retorted in these runs. This result is very encouraging, and implies that even large blocks of oil shale in nuclear chimneys will yield oil. The oil obtained was reasonably fluid, and had a pour point of 55°F (13°C).

In the retorting process, shale must be heated to a temperature of 700 to 900°F (371 to 482°C) to decompose the kerogen

to oil. Other products formed are gas (~10%) and carbonaceous residue (up to 25%). These vary as process conditions are changed.

The yield of oil from oil shale retorting is usually expressed as a percentage of the oil content as determined by a Fischer assay.¹¹ The vaporized products released are condensed and collected, and the results are expressed as gallons of oil per ton of shale. Organic material is left behind which is not measured in the Fischer assay, but which is available for combustion in an in situ process.

NUCLEAR IN SITU CONCEPT

The concept of in situ oil shale retorting in a nuclear chimney (broken rock column) which forms the basis for this report is illustrated in Fig. 8. The broken rock column is formed by the collapse of rock into a cavity produced by a nuclear explosion. The explosion probably will be detonated after the formation is dewatered. Holes will then be drilled to provide an air inlet, an exhaust gas outlet and an outlet for oil. The following equipment will be installed: A low-pressure compressor (< 50 psi) at the surface to supply air; a separator-condenser to separate oil, water and other particulate matter, if any, from the exhaust gases; and an oil pump in the oil line to pump the oil from the chimney. The oil shale will be ignited at the top of the chimney and the combustion zone will move downward through the rubbleized rock. The hot gases from the combustion zone will transfer heat to the oil shale below, decomposing the oil shale and releasing the oil. The burn will proceed at

IN-SITU OIL RECOVERY FROM OIL SHALE

Fig. 8. Chimney of rubblized oil shale and holes required for in situ retorting process
Concept Painting Case 4.

a rate of 5 to 6 ft/day, thus requiring from three months to a year to retort one chimney, depending upon its height.

APPLICATION OF EXPERIMENTAL RESULTS TO THE IN SITU PROCESS

The range of process variables examined in the experimental retorts does not include all conditions expected in a nuclear chimney. For example, the porosity expected in nuclear chimneys of the size considered here ranges from 10 to 20% as compared to 30 to 40% in the

experimental retorts. The USBM has conducted experiments in both their 10-ton and 150-ton retorts under widely varying conditions. Because the experiments are largely empirical with no model or theory yet available to test against the results, it is difficult to predict what the optimum conditions are in the experimental retorts, and even more difficult to extrapolate to the optimum conditions for the much larger scale operation in situ. On the basis of examining the data available from the runs to date and after discussion with

experimenters at the USBM, we have estimated that a 60% yield from 20 gal/s. t. oil shale is achievable with an air flow of 10,000 scf/s. t. and a retort zone velocity of 0.23 ft/hr (0.07 m/hr). We believe this may reasonably be achieved, although it probably is not the maximum that will be achieved when operating conditions are maximized to fit the underground environment.

Conditions in situ will be different from those in the experimental retorts in the following respects: The bed porosity will be lower (0.10 to 0.20); the pressure will be higher due to the pressure head required to move the necessary amount of air and exhaust gas through drill holes; and the much larger mass of rock surrounded by unbroken rock will result in the loss of a smaller fraction of the heat from the retorting system. The base conditions for extrapolation to the conditions ex-

pected in a nuclear chimney are given in Table 3, along with a comparison with experiment.

We will assume that the rate of advance through the bed is limited by the rate at which heat can be conducted into shale fragments. The experimental rate then can be maintained in the chimney (in situ) even though the bed porosity is lower. We will assume that the same amount of air per ton of shale is required for combustion and heat transfer. The increased in situ pressure (13-21 psig) may result in lower yield, assuming that the driving force for migration of oil and vapor out of a fragment is a heat-induced pressure gradient.

The magnitude of the yield decrease due to pressure is unknown, but we will assume that it is compensated * by the increase resulting from better thermal efficiency and by extra oil obtained by

Table 3. Interpretation of USBM data used in extrapolating to chimney conditions.

	Composite USBM retort data used to extrapolate to chimney	Closest actual experiment USBM 150-ton retort	Predicted chimney conditions
Oil shale grade (Fischer assay)	20 gal/s. t.	20.8 gal/s. t.	20 gal/ton
Air requirement	10,000 scf/s. t. 312 m ³ /m. t.	11,400	10,000
Retort zone velocity	5.5 ft/day 0.23 ft/hr (0.07 m/hr)	5.4 ft/day 0.226 ft/hr	5.5
Bed porosity (vol fraction)	0.42	0.42	0.10 to 0.20
Pressure in retort	~3 psig	~3 psig	10-20 psig
Oil yield (vol fraction of Fischer assay)	0.60	0.624	0.60

* Run No. 6.

heating the walls of the chimney. The size of inlet and outlet holes for gas flow has been arbitrarily selected to keep the total pressure less than 50 psig. Pressures in the chimney are calculated to be between 13 and 21 psi. This pressure can be changed to optimize yield and cost when the quantitative effect of pressure on yield is known.

The costs of retorting oil shale in situ will vary with the size of the in situ retort and the depth because of variations in rock-breaking costs, drilling costs, and other factors. The six chimney sizes shown in Fig. 7 are used as a basis for estimating retorting conditions and costs. In addition, the depth of each must be known as that will have an im-

portant effect on drilling cost. The chimney height is assumed to be equal to oil shale thickness, and for each thickness the medium overburden thickness in Colorado was used. The total depth is the sum of oil shale and overburden thicknesses. Table 4 shows the assumed and calculated retorting conditions for the in situ process. The rate at which air must be supplied fixes the size of pipes connecting the chimney with the surface for any desired pressure drop. These calculations are of importance because a major part of the cost of this process is the cost of providing openings to the chimney for air and exhaust gases and the cost of pumping air through the system.

Table 4. Oil shale retorting and recovery data.

Oil shale thickness & chimney height	Oil shale in chimney (10 ⁶ m.t.)	Median overburden thickness	Bed porosity vol fraction	Air req'd per unit mass of oil shale	Velocity of zone advance	Air req'd per unit time 10 ³ m ³ /hr (10 ³ scf/min)	Retort time (days)	Rate shale retorted (m.t./day)	Rate oil recovered 60% recov. (barrels/day)	Oil produced per chimney 10 ³ barrels (per 32 chimneys)
163 m (500 ft)	0.97	152 m (500 ft)	0.198	10,000 scf/s.t. = 312 m ³ /m.t.	0.23 ft/hr = 0.07 m/hr	106 (63.5)	109	8923	2810	305 (3776)
305 m (1000 ft)	2.8	213 m (700 ft)	0.155			189 (111)	182	15455	4868	882 (28224)
427 m (1400 ft)	5.6	213 m (700 ft)	0.136			276 (62)	254	22060	6954	1764 (56448)
518 m (1700 ft)	8.4	244 m (800 ft)	0.122			340 (200)	308	27276	8590	2646 (84672)
579 m (1900 ft)	10.5	244 m (800 ft)	0.114			378 (222)	344	30505	9607	3307 (105824)
610 M (2000 ft)	12	213 m (700 ft)	0.109			403 (237)	362	33119	10431	3779 (120928)

Underground Plumbing

PRESSURE DROP IN CHIMNEY

Leva¹² has described methods for the calculation of pressure drop for fluid flow through packed beds. Using the

gas flow rates from Table 4, we have calculated the pressure drop in the chimneys (Fig. 7) to be no more than 1 psi for all chimney sizes. The pressure drop produced by the gas flow within

the chimney is therefore negligible compared to the pressure drop in the drill holes supplying air and carrying away exhaust gas. Uniform flow within the chimney should be possible with only one chimney opening each for entrance and exit of gases. The low pressure drop induced by gas flow allows the downward burn to be more or less self-stabilizing because of thermal convection.

PRESSURE DROP IN AIR SUPPLY AND EXHAUST GAS HOLES

It is desirable to minimize the pressure required for moving the required amount of air and the resulting exhaust gases. A low pressure is desirable in the chimney to maximize the recovery of oil from the shale during the retorting process.

Some arbitrary choices have been made on hole sizes and pressure drops which result in a set of parameters which we believe to be reasonable, although probably not the optimum combination. We have assumed that for all cases (Fig. 7), a 30-in. casing will be set to the expected top of the chimney and that the nuclear explosive will be emplaced in an uncased 26-in. hole drilled below the 30-in. casing. After stemming and detonating the explosive, the stemming material in the 30-in. casing will be drilled out, providing a 30-in. hole to be used as an air inlet. Table 5 shows the pressure drop in this air inlet hole ($T = 30^{\circ}\text{C}$) for each case, calculated using the pipe flow charts in Ref. 13.

Using the same method, we then calculated the size of the exhaust hole, assuming that the mass of gas would be increased by 30% in the combustion

process and the temperature of gas in the pipe would increase to 100°C . The size was also selected to yield a total pressure drop in the system less than 50 psig. The cost of supplying air to large chimneys can probably be minimized by increasing the size of the exhaust hole, thereby reducing the pressure even more, in spite of the increased cost of providing a larger exhaust hole. Table 5 shows sizes required for the exhaust holes. A number of smaller holes may be substituted for a single hole, but probably at a considerable increase in cost. As an example, in the largest chimney (Case 6) eight 20-in.-diam holes ($\Delta P = 32$ psi) would be required to substitute for the single 48-in.-diam hole ($\Delta P = 15$ psi).

CONNECTION OF HOLES TO CHIMNEY

The air inlet hole will be produced by drilling the stemming material out of the emplacement hole, thereby establishing communication with the chimney. The exhaust gas hole is more of a problem. Techniques for drilling large holes have been developed at the Nevada Test Site, but no technology exists at present for directional drilling of such large holes. We propose, therefore, to drill a large hole as close to the chimney wall as practical, avoiding most of the highly fractured rock produced by the nuclear explosion near the bottom of the chimney. We then propose to set casing. The connection would be made by drilling several hundred feet below the casing, emplacing a high-explosive charge (perhaps 50 tons or so), and detonating this to produce a fractured and permeable connection to the chimney.¹⁴ The hole would then be

Table 5. Air flow, hole sizes and pressure drops.

Example	Air flow		Air hole		Exhaust hole		Chimney		Total pressure drop (psi)
	Inlet	Exhaust	Inside diam of casing (in.)	ΔP of casing (psi)	Inside diam of casing (in.)	ΔP (psi)	P	ΔP	
	10^3 scf/min 10^3 m ³ /hr	130% of Inlet flow					(psi)	(psi)	
1	63.5 108	82.6 140	30	1	24	13	13	<1	14
2	111 189	144 246	30	4	30	20	20	<1	24
3	162 276	211 359	30	7	36	21	21	<1	28
4	200 340	260 442	30	14	48	13	13	~1	28
5	222 378	289 491	30	24	48	14	14	~1	39
6	237 403	308 524	30	21	48	15	15	~1	37

cleaned out to complete the connection. The plan is illustrated in Fig. 8.

The hole required for pumping oil out of the chimney is much smaller, and directional drilling techniques can be used

to drill into the bottom of the chimney. Water produced by the combustion process and otherwise released from the formation can be pumped out through the same hole as the oil.

Environmental Impact of In Situ Oil Shale Development

Any significant development of such a large resource as the oil shale in the Piceance Basin will affect the Basin. The effects of mining and retorting of oil shale in surface plants has been described by many people. An idea of the magnitude of the effects of this "conventional" method of oil shale development can be found in Ref. 15. Most of the effects result from the necessity of removing very large volumes of rock from the ground and disposing of this material after retorting, and the consequences of

bringing a sizable work force into the area.

We believe that in situ processes offer a significant overall reduction in the environmental effects regarded as harmful. Because the requirement to move massive volumes of rock is eliminated, the effect on the landscape is greatly reduced. In addition, a much smaller worker population is required.

However, other effects on the environment result from a nuclear in situ development of oil shale. Some of these are

temporary, some permanent. In this section we will attempt to describe the major effects, with emphasis on those peculiar to nuclear explosives.

HYDROLOGY

The major use of water in the Piceance Creek Basin is for irrigating hay meadows and feed crops. The streams are adequate for these purposes during the early part of the growing season, but inadequate during the late summer months. Because of lack of arable land, only a few wells have tapped the groundwater for irrigation. Springs and small wells supply the sparse population with water for domestic and stock use.

A summary of the groundwater characteristics¹⁶ in the Basin is given in Table 6. The semiarid region is underlain by a multiaquifer system and drained by a system of small streams, principally Piceance and Yellow Creeks. The subsurface movement of groundwater is from the south, east and west toward the north central part of the Basin. Much of the water is saline because of the leaching of soluble salts present in the Green River Formation. The area covered by the leached zone is shown in Fig. 9. This zone is high in permeability, and most of it contains water too saline to be of use for agricultural or most industrial processes. Where this saline water discharges into surface streams, it causes undesirable contamination. As a generalization, the transmissivity of the leached zone is highest in the center and decreases markedly toward the edge of the zone.

Although numerous holes drilled in the Basin have provided some information, much more is needed to evaluate the total long-range effects of a major oil shale development on the hydrology of the region. The development of any kind of industry that brings people into the area would mean added competition for the limited water resources. In addition, groundwater interferes either with mining of oil shale or with in situ retorting processes, and must be removed. Fresh groundwater is useful if pumped to the surface, but much of the groundwater in the Basin is so saline that removal and disposal is a problem. In addition, contamination of fresh groundwater with saline groundwater or with radioactivity from the nuclear explosions must be considered.

Some development probably can occur with minimal effects on groundwater, especially outside the saline and leached zones. Major development such as a Basin-wide oil shale industry will probably disrupt the groundwater system by changing normal flow rates and patterns. The environmental and economic cost of the disruption must be evaluated and balanced against the benefit of producing oil from the oil shale.

Appendix B contains an analysis of the economic cost of removing water from the area being retorted, along with several methods of disposal of saline water. The problem of radioactive contamination is considered further in the Radioactivity section.

GROUND MOTION

The detonation of a nuclear explosive underground produces a shock wave and movement of the ground which is similar

Table 6. Summary of geologic units and their water-bearing characteristics.

System	Series	Geologic unit	Thickness (ft)	Physical character	Water quality	Hydrologic character
Quaternary	Holocene and Pleistocene(?)	Alluvium	0-140	Sand, gravel, and clay partly fill major valleys as much as 140 feet; generally less than half a mile wide. Beds of clay may be as thick as 70 feet; generally thickest near the center of valleys. Sand and gravel contain stringers of clay near mouths of small tributaries to major streams.	Near the headwaters of the major streams, dissolved-solids concentrations range from 250 to 700 mg/l. Dominant ions in the water are generally calcium, magnesium, and bicarbonate. In most of the area, dissolved solids range from 700 to as much as 25,000 mg/l. Above 3,000 mg/l the dominant ions are sodium and bicarbonate.	Water is under artesian pressure where sand and gravel are overlain by beds of clay. Reported yields as much as 1,500 gpm. Well yields will decrease with time because valleys are narrow and the valley walls act as relatively impermeable boundaries. Transmissivity ranges from 20,000 to 150,000 gpd per ft. The storage coefficient averages 0.20.
Tertiary	Eocene	Green River Formation	Evolution Creek Member	Interfingering and gradational beds of sandstone, siltstone, and marlstone; contains pyroclastic rocks and a few conglomerate lenses. Forms surface rock over most of the area; thins appreciably westward.	Water ranges from 250 to 1,800 mg/l dissolved solids.	Beds of sandstone are predominantly fine grained and have low permeability. Water moves primarily through fractures. The part of the member higher than valley floors is mostly drained. Reported to yield as much as 100 gpm where tested in the north-central part of the basin. Member has not been thoroughly tested, and larger yields may be possible.
			Parachute Creek Member	Kerogenaceous dolomitic marlstone (oil shale) and shale; contains thin pyroclastic beds; fractured to depths of at least 1,800 feet. Abundant saline minerals in deeper part of the basin. The member can be divided into three zones—high resistivity, low resistivity or leached, and Mahogany (oldest to youngest), which can be correlated throughout basin by use of geophysical logs.	Water ranges in dissolved-solids content from 250 to about 63,000 mg/l. Below 500 mg/l calcium is the dominant cation; above 500 mg/l, sodium is generally dominant. Bicarbonate is generally the dominant anion regardless of concentration. Fluoride ranges from 0.0 to 54 mg/l.	High resistivity zone and Mahogany zone are relatively impermeable. The leached zone (middle unit) contains water in solution openings and is under sufficient artesian pressure to cause flowing wells. Transmissivity ranges from less than 3,000 gpd per ft in the margins of the basin to 20,000 gpd per ft in the center of the basin. Estimated yields as much as 1,000 gpm. Total water in storage in leached zone 2.5 million acre-feet, or more.
			Garden Gulch Member	Papery and flaky marlstone and shale; contains some beds of oil shale and, locally, thin beds of sandstone.	One water analysis indicates dissolved-solids concentration of 12,000 mg/l.	Relatively impermeable and probably contains few fractures. Prevents downward movement of water. In the Parachute and Roan Creeks drainages, springs are found along contact with overlying rocks. Not known to yield water to wells.
			Douglas Creek Member	Sandstone, shale, and limestone; contains oolites and ostracods.	The few analyses available indicate that dissolved-solids content ranges from 3,000 to 12,000 mg/l. Dominant ions are sodium and bicarbonate, or sodium and chloride.	Relatively low permeability and probably little fractured. Maximum yield is unknown, but probably less than 50 gpm.
			Anvil Points Member	Shale, sandstone, and marlstone grade within a short distance westward into the Douglas Creek, Garden Gulch, and lower part of the Parachute Creek Member. Beds of sandstone are fine grained.	The principal ions in the water are generally magnesium and sulfate. The dissolved-solids content ranges from about 1,200 to 1,800 mg/l.	Sandstone beds have low permeability. A few wells tapping sandstone beds yield less than 10 gpm. Springs issuing from fractures yield as much as 100 gpm.
		Wasatch Formation	300-5,000	Clay, shale, lenticular sandstone; locally, beds of conglomerate and limestone. Beds of clay and shale are the main constituents of the formation. Contains gypsum.	Gypsum contributes sulfate to both surface-water and ground-water supplies.	Beds of clay and shale are relatively impermeable. Beds of sandstone are poorly permeable. Not known to yield water to wells.

Fig. 9. Groundwater map of Piceance Creek Basin.

in many respects to a small earthquake. The frequency of motion is generally higher and the motion does not last as long as an earthquake. A detailed estimate of the ground motion has been made for the Rio Blanco experiment,¹⁷ and preliminary results confirm its accuracy. In the Rio Blanco experiment, three 30-kt nuclear

explosives were detonated in the Piceance Basin for the purpose of stimulating the production of natural gas from gas-bearing formations of low permeability. Estimates of acceleration versus distance for Rio Blanco are shown in Fig. 10. A scaling rule¹⁸ may be used to estimate the acceleration expected for different

Fig. 10. Predicted peak resultant vector acceleration versus distance, Rio Blanco Event.

depths of burst and for different explosive yields relative to Rio Blanco:

$$a = \left(\frac{W}{W_{RB}} \right)^{0.33} \left(\frac{DOB}{DOB_{RB}} \right)^{0.58} a_{RB}$$

where a = acceleration, W = explosive yield, DOB = depth of burst and the subscript RB refers to the estimates for Rio Blanco.

Most of the oil shale can probably be developed using explosive yields no greater than 140 kt and depths of burst less than 2700 ft. Using these values for yield and depth of burst and comparing them to the numbers for Rio Blanco ($W = 123$ kt, $DOB = 6370$ ft), the acceleration expected for the shallower but larger yield explosive may be obtained. The acceleration expected is about 64% of that estimated for Rio Blanco for any given distance. For a 140-kt explosion in oil shale, an acceleration of 0.3 g is expected at a distance of approximately 7-1/2 miles, and an acceleration of 0.1 g is expected at 11 miles. Thus, using current practice, precautionary measures would be required within 11 miles of the detonations, and temporary evacuation would be requested of persons within 7-1/2 miles. These measures would be required only on the detonation days. Some minor damage would be expected to structures within 20 miles. A map of the Basin showing the area of thick oil shale and the explosive yields required is shown in Fig. 11. The

distances from the nearest major towns are indicated for reference. The effect of limiting the maximum yield to 140 instead of 160 kt would result in the loss of only 5 billion barrels of potential oil in place (see Fig. 5). About \$50,000 damage was estimated for the Rio Blanco experiment before the shot (May 17, 1973). At this time, it appears that actual damage will be about half that estimated. Damage costs for detonations in oil shale would be much less because the ground motion expected is smaller, and because successive detonations in the same area will not result in much additional damage. The inconvenience to people caused by nearby detonations is something that cannot be analyzed on an economic basis alone. Many people will accept the inconvenience, especially if they have a stake in the benefits of such an operation; others may not. Because the oil shale will become so important to the nation, it is hard to imagine that a solution to this problem will not be found.

RADIOACTIVITY

The detonation of a nuclear explosive produces radioactive materials. The kind and quantity of these materials is a function of the kind of explosive (fission or fusion), and to some extent the rock material in which the explosion occurs.

Before a safety analysis can be made, all possible ways in which radioactivity might be transported to man's environment must be examined. It is also important to know the kind, amount, and time of introduction of this radioactivity. After such factors are known, the possible exposure can be compared to

*The three 30-kt nuclear explosives detonated simultaneously in one drill hole were estimated to produce ground motion equivalent to a single 123-kt explosive.

Fig. 11. Location of oil shale suitable for nuclear *in situ* retorting, and explosive yields required.

exposure from other sources such as natural background.

Possible ways in which radioactivity could conceivably be released are:

1. Breakthrough of radioactive debris and gases to the atmosphere from the explosion-produced cavity.
2. Release of radioactive gas from the chimney during the retorting of the oil shale.
3. Radioactive material could be contained in the oil or water pumped from the chimney.

4. Radioactivity from the chimney could be dissolved by groundwater and transported to the surface or to an aquifer used by man for a water supply.

Experience gained in underground nuclear testing indicates that the chance of prompt venting of the cavity is very low for most rock types, providing the detonations are deep enough and drill holes are properly sealed. The oil shale must be carefully evaluated in this regard because of the relative thinness of

the overburden and the lack of experience in rock of the same or similar composition.

The oil shale being considered contains carbonate materials (Table 1) which if heated to high temperature will decompose and/or react with silicate rock, producing carbon dioxide gas.¹⁹ If enough of this CO₂ gas is produced, high pressures could result, thus providing a driving force for breaking open paths to the surface and allowing radioactive gases and debris to escape.

The increased cavity pressure which results from the carbonate and kerogen of the oil shale may or may not be a problem for the size of chimneys contemplated for this application. Experimental and theoretical work is required to better define this question. If detonation in the oil shale containing carbonates should prove to be a problem, detonation of explosives in non-carbonate rocks underneath or interlayered within the oil shale formation would avoid it.

During the retorting process radioactive gases in the chimney, principally tritium (³H), krypton (⁸⁵Kr), and argon (³⁷Ar), will be released into the atmosphere at the site. Concentration levels and potential exposures should be comparable to those expected in the Rio Blanco experiment, provided that a low tritium explosive is used.¹⁵ As an example, the maximum exposures calculated for populations near Piceance Creek and Meeker would be much less than 1% of natural background.

Radioactive material other than tritium contained in the oil as particulate matter or contained in the water is not of concern because it can be easily separated from the oil and reintroduced underground.

The amount of tritium produced in the explosion would be distributed among the hydrogen-bearing compounds in the chimney, including oil and water. Schwartz *et al.*¹⁹ have estimated that the oil might contain about 5 μ Ci of tritium per gallon of oil (for a 100-kt explosive producing 2000 Ci of tritium). The effectiveness of flushing techniques prior to oil retorting is not known, and might reduce this level. The exposure of a population using gasoline from this source was estimated to be less than 0.1 mrem/yr, or less than 0.1% of background. In arriving at this estimate, it was assumed that all gasoline used in the Los Angeles basin is from this single source. Thus, a large-scale commercial use of oil produced by this process appears feasible from a safety standpoint.

Most of the radioactivity produced in the explosion is contained in the molten rock, and is trapped as the molten rock freezes soon after the detonation. Some of the more volatile radioactivity is adsorbed on the rubble in the chimney. In assessing any possible hazard from groundwater movement, we must consider (1) the rate of solution of radioactivity in groundwater, (2) the rate and direction of movement of groundwater, and (3) the adsorption and precipitation of radioactivity as the groundwater moves through the rock. This kind of assessment must be done for the Piceance Basin before any project of this kind can proceed on a large scale. On the basis of previous experience, laboratory experiments and theoretical considerations, we see no reason why transport of radioactivity by groundwater will prove to be an unacceptable hazard in this area.

A commercial nuclear in situ development in the Piceance Basin would require drilling activity and frequent explosions during the time of oil production. Relatively small surface facilities for compressing air, storing oil, and perhaps treating the oil before introduction into a pipeline would be required. All these activities are transient in that they would continue during the time of production, area by area. Both short- and long-term attention must be given to the distribution of radioactivity underground.

In contrast to the environmental effects of nuclear in situ retorting, mining and surface retorting of the oil shale would require massive and permanent disruption of the surface either because of the mining operation itself or the necessity to dispose of large volumes of waste rock produced in the process. As an example, consider the annual production of 121 million barrels (compare to Case 6) of oil by a

process of mining oil shale containing 35 gal/s.t. of oil and assume 100% recovery in the retorting process. This would require mining and processing of 145 million s.t./yr of oil shale or almost 400,000 s.t./day. After mining, crushing and processing (assuming 30% bulking porosity) this rock would cover 1 mi² to a depth of about 94 ft, and this much rock would have to be disposed of each year. Because the rock occupies more space after mining (because of bulking caused by breaking into pieces) it will not fit in the mined openings either underground or in open pits, and the excess for each year would still cover an area of 1 mi² to a depth of 22 ft.

The conclusion is that the total environmental disruption resulting from a nuclear in situ process is potentially very much smaller than that for any process requiring mining of oil shale.

Cost Projections

Accurate estimates of the cost of oil produced by in situ retorting of oil shale in nuclear chimneys will not be possible until the technology is developed and demonstrated. Nevertheless, it is desirable to identify the major capital and operational cost items in the process as presently conceived to provide guidance for research and development decisions that will be made. To do this, many assumptions must be made to determine such things as the scale of operations, the rate of development and production, the sales price of oil and tax treatment of such an operation.

We shall assume that 32 chimneys will be fired annually, with 8 detonations on 1 day every 3 months. This will minimize the inconvenience to nearby residents. It is estimated that development will take 1 year before production begins, with the first 8 shots occurring at 9 months.

Estimates were made for six chimney sizes designed to match six different oil shale thicknesses (see Fig. 7). The annual production will vary with the size of the chimneys and, as will be evident, the economy of large scale has an important influence on the costs. The approach has

been to assemble costs associated with each chimney and then to multiply these by the number of chimneys and add on other costs which can be identified as applicable to the whole operation. This approach does not take advantage of such cost savings as the use of one exhaust hole for more than one chimney.

The major costs associated with single chimneys of various sizes are summarized in Table 7. We have estimated all hole costs assuming that they would be drilled by contract drillers. We used the AEC price estimates given for planning purposes for the cost of the nuclear explosives.²⁰ The cost of pumping air was estimated from data given by Peters and Timmerhaus,²¹ assuming 80% efficiency and 1¢ per kWh for electricity. Compressor costs were estimated using data from Ref. 21 with the price escalated 4% per year to 1973. Oil pumping costs were estimated from Ref. 22 and include pumping a comparable amount of water.

Costs applicable to the whole project include access roads, offices, etc.; safety and environmental studies; and capital equipment and facilities which are

used for more than one chimney either because they are portable and can be re-used or are applicable to the project, for example, storage tanks.

Costs expended before production begins are divided between capital and development costs. The development costs are paid from capital and then written off during the first year of production as deferred development costs. The non-capital development costs are those that are treated as operating expenses after production begins. All capital is arbitrarily depreciated for twenty years on a straight line basis.

Because there is no definition of how oil from oil shale will be treated in regard to taxes and royalties, it has been assumed in this estimate that land will be available for the payment of a 12-1/2% production royalty and that the usual depletion rules applied to the oil industry will apply to the oil produced.

Summaries of development, capital and operating costs are shown in Tables 8-10. All summaries apply to the 32 chimney/yr operation. The use of capital equipment such as compressors

Table 7. Summary of operating and capital costs for single chimneys of various sizes \$(000)'s.

Case	Oil shale thickness and chimney height	Median overburden thickness	Emplacement hole cost including stemming and emplacement	Operating Cost								Capital cost	
				Nuclear explosive		Air hole drillback incl. casing	Exhaust hole incl. casing	Oil production hole incl. 8-5/8-in. casing	Instrument hole	Air pumping cost	Oil pumping cost incl. pump maintenance	Air compressor cost (5 stages)	Oil pump cost
				(Yield range) median	Cost ²⁰								
1	183m 600'	152m 500'	171.7	(7-17) 10 kt	375	17.3	247.3	61.7	5.5	153	3.1	278	10
2	305m 1000'	213m 700'	231.7	(22-43) 30 kt	420	19.8	295.1	86.1	8.5	446	15.1	405	14
3	427m 1400'	123m 700'	267	(48-81) 81 kt	450	19.8	419	102.3	10.5	912	37.1	544	18
4	518m 1700'	244m 800'	318.3	(85-120) 100 kt	465	22.4	612.2	122.6	13	1367	68.8	658	25
5	579m 1900'	244m 800'	323.5	(110-150) 120 kt	475	21.1	629.8	126.7	13.5	1486	89.2	709	30
6	610m 2000'	213m 700'	319.9	(120-160) 130 kt	480	19.8	629.8	126.7	13.5	1906	102.0	755	35

Table 8. Development costs, in thousands of dollars.

<u>Indirect</u> (not chargeable to chimney)						
Access roads, offices, etc.	1,200					
Safety and environmental studies	800					
	2,000					
	Case					
<u>Direct</u>	1	2	3	4	5	6
8 Emplacement holes with nuclear explosives emplaced	4,374	5,214	5,736	6,266	6,388	6,399
8 Drillback for air inlet hole	138	158	158	179	169	158
8 Exhaust holes	1,978	2,361	3,352	4,898	5,038	5,038
8 Oil production wells	494	689	818	981	1,014	1,014
8 Instrument holes	44	68	84	104	108	108
Total Development Costs	9,028	10,490	12,148	14,428	14,717	14,717
Including 30% for management and contingencies	11,736	13,637	15,792	18,756	19,132	19,132

Table 9. Capital costs, in thousands of dollars.

	Case					
	1	2	3	4	5	6
Air compressors	2,502	6,480	12,512	17,766	21,979	24,288
Separator- condensers	416	728	1,040	1,280	1,431	1,552
Oil pumps	90	224	414	675	930	1,120
Installation costs on above (35%)	1,053	2,601	4,888	6,902	8,519	9,436
Storage tanks (3-day production)	521	1,849	3,707	5,548	6,935	7,916
Total materials + installation	4,582	11,882	22,561	32,171	39,794	44,312
Contingencies 30%	1,375	3,565	6,768	9,651	11,938	13,294
Total depreciable capital	5,957	15,447	29,329	41,822	51,732	57,606
Working capital (25% of operating costs)	10,760	15,831	23,064	31,089	35,098	37,415
Total capital	16,717	31,278	52,393	72,911	86,830	95,022
Depreciation = $\frac{\text{Deprec Cap}}{20}$	298	772	1,466	2,091	2,587	2,880

Table 10. Operating costs (annual), in thousands of dollars.

	Case					
	1	2	3	4	5	6
<u>Breakage</u>						
32 Emplacement holes, nuclear explosive, emplacement and stemming	17,494	20,854	22,944	25,066	25,552	25,597
<u>Underground Plumbing</u>						
32 Drillback for air inlet	554	634	634	717	675	634
32 Exhaust holes	7,914	9,443	13,408	19,590	20,154	20,154
32 Oil production holes	1,974	2,755	3,274	3,923	4,054	4,054
32 Instrument holes	176	272	336	416	432	432
<u>Retorting</u>						
Air compressor operating cost	4,896	14,272	29,184	43,744	54,272	60,992
Oil pump operating cost	99	482	1,187	2,201	2,855	3,262
	33,107	48,712	70,967	95,657	107,994	115,125
Add 30%, contingencies and management	43,039	63,326	92,257	124,354	140,392	149,662

on more than 1 chimney is taken into account where the retorting of a chimney is shorter than 1 year.

An example of an annual income statement for Case 4 is shown in Table 11. All cases (1-6) were treated similarly, and the results are summarized in Table 12. Figure 12 shows the operating costs per barrel and per metric ton of oil shale retorted plotted versus oil shale thickness. Figure 13 shows the price of oil at the wellhead versus oil shale thickness for various rates of return on investment (discounted cash flow internal rate of return).

A number of conclusions can be drawn from the data in Table 11 and Figs. 12 and 13. Very little capital is required

for in situ retorting of oil shale using this method. The capital costs vary from \$0.79 to \$1.71 per barrel of annual production capacity, or \$288 to \$624 per barrel of daily production capacity. Capital investments in conventional new fields in the U.S. are about \$5500 per barrel of daily production, and in the Middle East about \$275 per barrel.²³ To the extent that capital requirements are a limit on the expansion of energy availability, the in situ process is very advantageous. Because the capital requirements are so low, the rate of return is very sensitive to the price of oil, i.e., a small increase in price results in a large increase in the rate of return (see

Table 11. Annual income statement.

Case 4: 1700 feet of oil shale - 32 Chimneys per Year (100 kt) Annual Production 84,672,000 Barrels			\$(000)'s	
			Yr. 1	Yr. 2-20
Gross Sales @ \$2.10/barrel			186,278	186,278
12 1/2% Royalty			23,285	23,285
Gross Income			162,993	162,993
Oper. Costs			124,354	124,354
Deferred Development			18,756	-
Colorado Production Tax			8,308	8,308
Depreciation			2,091	2,091
Net income before depletion			9,484	28,240
Depletion 22% of Gross Inc. } smaller of			[35,858]	[35,858]
50% of Net			4,742	14,120
Net income before Income taxes			4,742	14,120
Colo. Inc. tax 5%			237	706
Net income before Fed. Inc. Tax			4,505	13,414
Fed. Inc. Tax 48%			2,162	6,439
Net income			2,343	6,975
Depreciation			2,091	2,091
Depletion			4,742	14,120
Deferred Development			18,756	-
Cash Flow			27,932	23,186
Capital Investment	41,822			
Working Capital	31,089			
Total Capital	72,911			

Yrs to return capital 2.9 yr
Discounted cash flow rate of return 25.7%

Table 12. Summary of economic estimates.

Oil Shale Thickness (ft)	600	1000	1400	1700	1900	2000
Case	1	2	3	4	5	6
Annual Production (million barrels)	9.776	28.244	56.448	84.672	105.824	120.928
Capital Investment (million dollars)	16.717	31.278	52.393	72.911	86.830	95.054
Capital Investment (\$/B of annual capacity)	1.71	1.11	0.93	0.86	0.82	0.79
Operating Cost/B (including contingencies)	4.40	2.24	1.63	1.47	1.33	1.24
Land Cost/B (12-1/2% royalty)	0.75	0.38	0.28	0.26	0.23	0.22
Price/B to yield 20% ROR	5.97	3.07	2.26	2.04	1.85	1.73

Fig. 12. Operating costs versus oil shale thickness.

Fig. 13). The major costs are operating costs. Retorting costs are more or less constant per barrel because the major item is the cost of pumping air. The unit cost of breaking or rubblizing the shale with nuclear explosives and the unit cost of underground plumbing (drilling and casing costs) decrease rapidly with increasing shale thickness.

The obvious conclusions of these estimates is that oil can probably be produced very profitably at today's oil prices. The breakeven point versus thickness is only approximately defined with the information available, but most of the resource is available in the thick oil shales (see Fig. 2), and the shales thicker than 1200 ft contain most of the resource (539 billion barrels). Another 102 billion barrels is available in the thickness range 800 to 1200 ft. These estimates assume the successful development of technology as projected in this report, including breakage of the estimated amount of rock per explosive and successful retorting of the oil shale at the yield projected (60%). At the same time some conservative assumptions have been used, and improvements in the process may lead to significant reductions

Fig. 13. Price of oil at wellhead versus oil shale thickness.

in cost over those projected. For example, clustering of chimneys may permit the use of a single exhaust hole for more than one chimney, and any improvement in yield above 60% because of the smaller heat loss and the extended retorting zone expected in situ will reduce costs significantly.

Properties of Oil Produced from Oil Shale and Possible Pretreatment Required

Shale oil from retorting is similar to petroleum, and can be handled by conventional modern refineries with only small variations in the process.³ The nitrogen content of the oil shale is above the range of most conventional crude

oils, however, and additional facilities may be required at the refinery if a high fraction of crude shale oil is to be processed. If catalytic hydrogenation is used to remove the nitrogen as ammonia, sulfur is also removed as H_2S and then

converted to sulfur. This process also reduces the viscosity of the shale oil. The viscosity is of particular interest because shale oil may be difficult to move through pipelines because of its high viscosity. The viscosity and other properties of shale oil vary with the retorting conditions.²⁴ Shale oil produced by an in situ process may be less viscous than that obtained from surface retorts but whether the viscosity will be low enough for transport by pipeline without pretreatment or with a simple pretreatment such as an additive to reduce the viscosity remains to be determined.

If pretreatment for pipeline transport is necessary it may be desirable to perform the catalytic hydrogenation process in the field before transport to a refinery. The costs of refining and marketing refinery products favor locating the refinery near the market, and large

scale refining in Western Colorado would increase the demand for the already limited water supply. A suitable compromise might be to pretreat the shale oil in Colorado before transport in pipelines to refineries. In the economic estimates we have assumed that shale oil would be sold at the wellhead at the prices indicated. If pretreatment should prove necessary or desirable, the cost of pretreatment must be added to these wellhead prices. The total should still be below the present price of petroleum because the product would be upgraded enough to command a premium price. The cost of catalytic hydrogenation is estimated in Ref. 3. Capital costs were estimated at \$5.28 per barrel of annual capacity for a 36,500,000 barrel/yr capacity, and operating costs were estimated at \$0.44/B for the first 15 yr and \$0.51/B thereafter because of increased maintenance.

Development of Nuclear In Situ Retorting Required for Commercial Application

In this paper we have presented a concept that we believe is a realistic extrapolation from present technology. Although little fundamentally new knowledge may be required, a considerable amount of engineering research and development is necessary to bring the concept to commercial application. In this section we will attempt to outline the problems that need to be solved and some of the questions that need to be answered. These questions fall into three main areas, although they are closely related in many respects:

1. Retorting process
2. Effects of nuclear explosions on oil shale
3. Ground water

RETORTING PROCESS

The USBM work needs to be extended. An adequate calculational model needs to be developed and tested which will describe the retorting conditions in a large in situ retort. This model must be based on data from laboratory and pilot plants

on the surface and may require the non-nuclear construction of a small retort in the field (in situ). The effects of size scale up on heat loss, geometry of the combustion zone and retort zone, bed porosity and other variables affecting the process must be better understood in order to control the in situ process and achieve maximum oil yield.

EFFECTS OF NUCLEAR EXPLOSIONS ON OIL SHALE

Although much experience has been gained with underground nuclear explosions, the specialized application we are considering will require considerably more. Specifically, we must gain experience with oil shale to establish the height of chimneys for various explosive yields at the depth of interest (<3000) so we can construct the in situ retort to match the height of the oil shale. The evolution of gases from the oil shale before and after cavity growth must be understood in detail. Unlike rocks composed almost entirely of silicates, oil shale contains kerogen as well as carbonates. Both of these materials will produce gas when subjected to heat, and gas evolution due to these reactions must be understood for optimum control of the retort process as well as for safe detonation of nuclear explosives. This work will require laboratory studies and analysis and field experiments in Colorado, possibly preceded by nuclear explosive experiments at the Nevada Test Site in rocks similar in some important respects to the oil shale in Colorado, i. e., similar in carbonate composition and permeability.

Another area requiring development is the effect of explosions in close

proximity to previously constructed chimneys. This report assumes for purposes of economic estimates that chimneys are located far enough apart so that they do not affect one another. Eventually we will want to place chimneys close enough together so that they do interact to break as much oil shale as possible in the area being developed and thereby achieve maximum utilization of the resource. This will probably result in cost reduction as well if more rock is broken per explosion and/or if holes can be used for more than one chimney.

For example, if chimneys are placed in an array such that one-half of the shale in place is broken and this is subsequently retorted at 60% oil recovery, the recoverable reserves are 30% of those in place. This compares well with recovery from conventional oil fields, and for the oil shale thicker than 800 ft and containing more than 20 gal/ton, this would mean recoverable reserves of 192 billion barrels ($641 \times 0.5 \times 0.6 = 192$).

GROUNDWATER

A better understanding of the groundwater in the Piceance Basin is needed for several reasons. Groundwater is of interest because the chimney region must be pumped dry and kept relatively dry during in situ retorting. This requires that the amount of water that must be pumped, its quality, and the disposal method all must be understood so that costs and environmental effects can be predicted. This includes effects on local water supplies, disposal of saline water possibly by reinjection, and water required for domestic and industry use.

To determine the rates of movement of radioactive species, we must know the groundwater movement, and also know what radionuclides are present in the chimney and their decay and interaction with rock. In general, this does not appear to be a likely problem, but detailed studies are required to assure that it is not.

HISTORY OF NUCLEAR DEVELOPMENT OF OIL SHALE

On several occasions the possibility of developing technology for nuclear in situ retorting has been examined. An extensive study was conducted by a joint government-industry group in the mid 1960's. The feasibility of using nuclear explosions to develop oil shale was examined, and an experiment called Bronco was designed.²⁵ Industry was represented by CER Geonuclear Corporation acting for about a score of oil companies, and the government was represented by the AEC and the USBM. Lengthy negotiations on a contract to perform the experiment were conducted through 1968, but were never successfully concluded. The major obstacle was the inability to resolve the management roles of industry and government. In addition, serious difficulties arose on the disposition of already existing patent rights.

In 1970 and 1971, CER Geonuclear and Western Oil Shale Corporation made another attempt to assemble a group of companies to support a joint industry-government project. A symposium²⁶ was held in Laramie, Wyoming in February of 1971 to review the technology and describe the project, called Project Utah. It was proposed to conduct a nuclear

experiment on private land in Utah to examine only the nuclear breakage part of the technology with the option to proceed with retorting only after the nuclear breakage was successful. Too little interest existed in the oil industry to proceed with the proposed project.

GOVERNMENT-INDUSTRY IMPASSE

The impasse that exists between industry and the Federal government in regard to the development of oil shale by conventional means seems to apply to nuclear development as well. The issues are complex, and many opinions and viewpoints exist as to what the problems are and how they may be resolved.

The Federal government owns 80% of the oil shale area in the Piceance Creek Basin. In the center of the Basin, the area suitable for nuclear in situ retorting, the percentage is higher. The government is concerned that the public be protected against any "giveaway" of public lands to any minority (the oil industry), and are understandably reluctant to release any significant amount of this land.

The oil industry is reluctant to proceed with a costly development of oil shale technology which they view as being only marginally profitable in the near future, especially so because the first one to develop the technology will not necessarily have any competitive advantage over other companies. This is so because the land availability and tax rules are subject to government control in a way as yet undefined.

The nuclear in situ method appears even more difficult for industry to

develop because a substantial part of the development effort is in the area of nuclear explosive effects and safety, and this is necessarily a government monopoly. Thus no significant development of oil shale seems likely until a national policy decision is made. This could range anywhere from a government TVA-type project to develop the technology and sell oil to oil companies, to a clearly defined policy for making the land available to private industry for development.

Under present economic conditions it may be only marginally profitable to produce oil by the conventional mining and retorting methods, and the amount of oil which may be produced is relatively small (20 billion barrels)³ compared to the total resource, even though it is large compared to other domestic oil reserves.

The nuclear in situ development may be a difficult political problem. If, as concluded here, this method can in fact produce oil at prices between \$2 and \$3 a barrel, with reserves in place as large as 640 billion barrels the oil shale can not only be a major factor in the total energy supply, but it has the potential of completely disrupting the status quo of the oil industry. A national policy decision of major long-term impact is required to determine whether and how this resource will be developed.

CONCLUSIONS

We have examined the possibility of producing oil from oil shale by retorting it in situ after breaking it with underground nuclear explosives. We have developed a conceptual plan, defined the resource applicable to this method, and projected the cost. We believe that this method can be developed with a high probability of success. The reserves of oil in place suitable for this method by reason of thickness and grade occur in the Piceance Creek Basin of Colorado and total approximately 640 billion barrels. The cost projections indicate that a price of \$1.73 to \$3.07 per barrel would be required at the wellhead for a 20% return on investment. To this must be added the cost of dewatering, which is less certain (see Appendix B). If \$0.25 per barrel is allowed for dewatering, the price for a 20% return would range from about \$2.00 to \$3.30 per barrel.

The necessity for government involvement arising from Federal ownership of the resource and the necessity for a significant government contribution to the development of the nuclear in situ method appears to require either government development of the resource or an official policy defining how industry and government may jointly develop this resource.

The potential contribution to the energy resources of the nation is so large that this method of oil recovery from oil shale must be considered.

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Appendix A

Oil Shale Resources of the Green River Formation Suitable for Nuclear In Situ Processing

The Green River Formation has been assessed for the most part in terms of its suitability for conventional processing. This requires mining the oil shale, retorting the oil shale in retorts constructed for the purpose, and finally disposal of the spent shale. The costs of this process are such that it has been necessary to focus on high-grade layers of oil shale covered by a minimum amount of overburden.

In situ processes offer potential advantages compared to conventional ones, including lower cost, larger resource suitable for development, and smaller adverse effects on the environment. In this Appendix we will assess the resource in the thickness and grade range of interest for in situ processes, and especially for nuclear in situ processes. Basic information on thickness, grade and depth is available in various published reports of the U.S. Geological Survey and the U.S. Bureau of Mines,²⁷⁻³⁹ but it is not available in a form which allows easy assessment of the resource for this purpose. Borg⁴⁰ has used the data from the above-referenced reports to prepare and update isopach and depth-of-overburden maps for 15 gal/ton and 20 gal/ton oil shale in the Piceance Creek Basin of Colorado. Resource estimates have been made from these maps and from USGS and USBM published maps in Colorado and Utah. We expect that a more exhaustive and de-

tailed compilation will be available at some future time from USGS or USBM publications, but we do not expect that any changes will be large enough to affect the conclusions of this report. For this survey we have considered only oil shale thicker than 400 ft and richer than 15 gal/ton. The justification for these limits is based on processing technology and cost, breakage costs, and the relatively small amount of resource available in thicknesses less than 400 ft and the small error resulting from its omission.

COLORADO

Figures A-1 and A-2 are isopach maps showing respectively the thickness of oil shale averaging more than 15 gal/s.t. (62.6 l/m.t.) and more than 20 gal/s.t. (83.5 l/m.t.). Figure A-3 shows the thickness of overburden for the 20 gal/s.t. oil shale. Figure A-4 is an isopach of 25 gal/s.t. (104.3 l/m.t.) taken without change from a USBM report.³³ The areas of various thicknesses were measured from these maps using a planimeter. From the values of thickness, area and grade, an estimate of the amount of oil in place can be made. These data and the estimates are shown in Table A-1. In oil shale thicker than 400 ft (122 m) and averaging 15 gal/s.t. (62.2 l/m.t.) oil, more than 789 billion barrels (126×10^9 m³) of oil are in place. If the grade limit

Fig. A-1. Isopach map of oil shale containing 15 gal/ton - Colorado.

is increased from 15 gal/s.t. (62.6 l/m.t.) to 20 gal/s.t. (83.5 l/m.t.) more than 718 billion barrels ($114 \times 10^9 \text{ m}^3$) of oil still are in place. A further increase to 25 gal/s.t. (104.3 l/m.t.) with thickness more than 500 ft (no comparable data for 400 ft) reduces the amount of oil in place to 350 billion barrels ($63 \times 10^9 \text{ m}^3$).

A less accurate estimate for the Colorado oil shale (Piceance Basin) less than 400 ft thick and containing more than 15 gal/s.t. (62. l/m.t.) indicates that there is a relatively small amount of oil

in place in this thin oil shale. The total area of the Green River Formation in the Piceance Basin is about 2600 mi^2 (6734 km^2). Subtracting the area of oil shale more than 400 ft (122 m) thick from this leaves 1700 mi^2 (4403 km^2). If the average thickness is 200 ft (61 m), the oil in place is 243 billion barrels ($38.7 \times 10^9 \text{ m}^3$). This estimate is too large because grade as well as thickness decreases near the edges of the basin. Nevertheless, it illustrates that most of the resource in the Piceance Creek Basin

Fig. A-2. Isopach map of oil shale containing 20 gal/ton - Colorado.

of Colorado is contained in thick oil shales. This is shown graphically in Fig. A-2 for oil shale containing more than 20 gal/s. t. (83.5 l/m. t.).

UTAH

Figure A-5 is an isopach map of oil shale containing more than 15 gal/s. t. (62.6 l/m. t.) in the Uinta Basin of Utah. Estimates of oil in place were made using the same methods described previously. The estimates are shown in Table A-2.

The oil in place in Utah in oil shale of thickness more than 400 ft and containing more than 15 gal/s. t. (62.6 l/m. t.) is approximately 71.6 billion barrels ($11.5 \times 10^9 \text{ m}^3$). None is as thick as 800 ft (244 m), and the overburden is thicker than in Colorado. Only a small part of the oil shale more than 400 ft thick is buried by less than 1000 ft of overburden.

Because of depth of burial, low grade (15 gal/s. t. or 62.6 l/m. t.) and thinness, the oil shale in Utah will be much more difficult to develop than that in Colorado.

Fig. A-3. Overburden thickness for 20 gal/ton oil shale, Colorado.

WYOMING

The oil shales in Wyoming are not as well explored as they are in Colorado and Utah, and data are not sufficient to prepare the kind of isopach and overburden maps that are available for the oil shale in the other two states. There are no known oil shales containing more than 15 gal/s.t. (62.6 m/m.t.) and with continuous thicknesses in excess of 400 ft (122 m).

A summary of three sites may be illustrative of the most that may be expected⁴¹ in Wyoming.

Site 1 – North Central Green River Basin

A drill hole intersects 230 ft (70.1 m) of 15 gal/s.t. (62.6 l/m.t.) of oil shale covered by 450 ft (137 m) of overburden.

Site 2 – South Central Green River Basin

No data from drill holes, but it is inferred on the basis of geology that there

Fig. A-4. Isopach map of oil shale containing 25 gal/ton - Colorado. (Taken from Ref. 33.)

Table A-1. Estimate of oil shale and oil in place - Colorado.

Oil shale thickness (ft)	Oil shale $\rho = 2.3 \text{ g/cm}^3$			Oil in place		Oil shale thickness (meters)
	(mi ²)	(km ²)	(km ³)	(barrels)	(m ³)	
<u>Containing more than 15 gal/s.t. (62.6 l/m.t.)</u>						
400-800	319+	826+	151+	136×10^9	21.7×10^9	122 - 244
800-1200	78	202	32	56	8.9	244 - 366
1200-1600	131	340	145	131	20.8	366 - 488
1600-1800	65	168	87	79	12.5	488 - 549
1800-2000	218	565	327	295	47.0	549 - 610
>2000	65	168	> 102	> 92	> 14.6	> 610
Total				$> 789 \times 10^9$	$> 126 \times 10^9$	
<u>Containing more than 20 gal/s.t. (83.5 l/m.t.)</u>						
400-800	135	349	64	77×10^9	12.3×10^9	122 - 244
800-1200	103	280	85	102	16.3	244 - 366
1200-1600	180	466	199	240	38.1	366 - 488
1600-1800	52	135	70	84	13.4	488 - 549
1800-2000	77	199	115	139	22.0	549 - 610
>2000	40	104	> 63	> 76	> 12.1	> 610
Total				$> 718 \times 10^9$	$> 114 \times 10^9$	
<u>Containing more than 25 gal/s.t. (104.3 l/m.t.)</u>						
100-250	461	1194	64	96×10^9	15.3×10^9	30.5 - 76
250-500	94	244	28	42	6.7	76 - 152
500-1000	95	247	56	85	13.6	152 - 305
1000-1500	104	269	103	155	24.6	305 - 457
>1500	64	165	> 75	> 114	> 18.1	> 457
Total				$> 492 \times 10^9$	$> 78 \times 10^9$	

might be 250 ft (76.2 m) of 15-20 gal/s.t. (62.6-83.5 l/m.t.) oil shale under an overburden of 500-1000 ft (152.4-304.8 m).

Site 3 - Washakie Basin

A total of 400 ft (122 m) of 15 gal/s.t. (62.6 m/m.t.) oil shale under an overburden of 2000-2500 ft (610-762 m). One bed is 250-300 ft (76.2-91.4 m) thick,

separated from another by a barren zone 60-80 ft (18.3-24.4 m) thick.

A summary of these resource estimates is shown in Table 2 in this report and compared with estimates published by the USBM. Comparisons are difficult because of differences in grade limits and thickness ranges, as well as different assumptions made where data are lacking.

Fig. A-5. Isopach map of oil shale containing 15 gal/ton - Utah. (Taken from Ref. 39.)

Table A-2. Estimate of oil shale and oil in place - Utah.

Oil shale thickness (ft)	Oil shale $\rho = 2.3 \text{ g/cm}^3$			Oil in place		Oil shale thickness (meters)
	(mi ²)	(km ²)	(km ³)	(barrels)	(m ³)	
400-500	62	160.6	22.0	33.3×10^9	5.3×10^9	122 - 152
500-600	32	82.9	13.9	21.0×10^9	3.3	152 - 183
600-700	19	49.2	9.7	14.7×10^9	2.5	183 - 213
>700	3	7.8	1.7	2.6×10^9	0.6	>213
Total				71.6×10^9	11.5×10^9	

It is clear that almost all the oil shale thick enough and rich enough to meet our criteria for in situ processing [>400 ft (122 m) thick and >20 gal/s. t. (83.5 l/m.t.)]

is in the Piceance Creek Basin in Colorado. Furthermore, a large part of the resource, at least 720 billion barrels ($115 \times 10^9 \text{ m}^3$) of oil in place is available that meets the

criteria. The size of this resource is decreased by only 80 billion barrels by doubling the thickness requirement to 800 ft (244 m). An increase in grade required to 25 gal/s. t. (104.3 l/m. t.) cuts the resource approximately in half, while a decrease to 15 gal/s. t. (62.6 l/m. t.) in grade required only increases the resource by 70 billion barrels.

More significant perhaps is a comparison of this amount of oil in place, 720 billion barrels, with the 160 billion barrels of oil in place of the range 30-35 gal/s. t. (125.2-146.0 l/m. t.); more than 25 ft (7.6 m) in thickness; and less than 1000 ft (305 m) below the sur-

face. Of this latter reserve, only 34 billion barrels is being considered for conventional mining and surface retorting.³ The requirements for consideration are that it be shallow enough for economical mining, contain more than 35 gal/s. t. (146.0 l/m. t.) and be at least 30 ft thick. The oil in place suitable for mining is only much smaller than the resource suitable for in situ processing, but mining of the high-grade portion may seriously disrupt the remainder of the resource. Underground mine workings in the deposit may prevent the economical control of fluid flow necessary for in situ processing.

Appendix B

Dewatering Plan and Cost Estimate

The general plan is to dewater the water-bearing portion of the Green River Formation in the areas in which chimneys are constructed and keep them dewatered as long as the in situ retorting process continues. Because the quality of the groundwater in the Green River Formation is generally too poor to be placed in surface streams and rivers, it is proposed that the water be pumped through pipelines and reinjected into the same formation some distance away.

The effect on the groundwater levels and the general method is illustrated in Fig. B-1.⁴² A circle of pumping wells will be placed around the area to be dewatered and the water will be moved in a pipeline to wells located further away where the water will be reinjected into the same formation. The flow or pumping

rate required is approximated by Eq. (B-1)⁴² if the water level h_w at r_w is much less than h_0 :

$$Q_0 = T_0 h_0 2\pi \frac{H}{h_0} \frac{1 - (h_0/2H)}{\ln(r_i/r_w)} \quad (B-1)$$

where T_0 is the transmissivity of the aquifer and the other terms are defined in Fig. B-1.

The nature of the change in pumping rate versus time is illustrated in Fig. B-2.⁴² This shows that the pumping rate decreases with time according to some power function, and approaches a constant rate dependent upon the reinjection distance. The longer the reinjection radius compared to the dewatered radius the smaller the required steady-state

Fig. B-1. Section illustrating dewatered area of oil shale.

pumping rate, other things being equal. Actual times and pumping rates vary with the other variables in Eq. (B-1). Pumping rates vary during an initial period before steady-state rates are

reached. To estimate hole and pump sizes and pumping rates, we determined the total quantity pumped during this initial period by integrating under the curve (Fig. B-2). We then assumed this amount was pumped

Fig. B-2. Dimensionless pumping rate for confined-unconfined flow with the parameter $h_w/h_0 = 0.01$, $H/h_0 = 2$, $S_c/S = 10^{-3}$.

during this initial period at a constant rate which is higher than the steady-state rate. Approximately 67% more water must be pumped during the initial period than during the steady-state period.

We have calculated pumping rates and estimated the cost for several different transmissivity T_0 and different total head differences H . A transmissivity of 5000 gpd/ft was picked as a reasonable value for the basin outside the leached zone, although it probably decreases considerably toward the edges of the basin. Heads, H , of 1000 and 2000 ft were used to determine the cost differences in pumping from different levels. Finally, a "worst" case kind of estimate was made assuming a transmissivity of 20,000 gpd/ft and a head of 2000 ft. This might apply to the leached zone in the central portion of the basin.

AREA DEWATERED

In the example of a commercial oil shale retorting operation, 32 chimneys per year are developed. Eight of these chimneys are detonated every quarter. The retorting time varies with chimney size, with the maximum being about 1 yr (109-362 days). We will assume the maximum time for the purpose of estimating dewatering times and costs. Assuming that the chimneys being retorted must not be disturbed by nearby nuclear detonations, we require four separate areas operating at any given time. On each of these, 1 yr of undisturbed time is allowed to finish the retorting before the next detonation. We assume that the initial pumping to obtain a steady-state rate is accomplished prior

to the start of retorting, and that the dewatering is then continued in each of the four areas for 4 yr.

During 20 yr of production, five sets of four systems each will be required to dewater the 20 areas required. Each area is assumed to be 1800 ft (549 m) in radius, and to have a capacity of 32 chimneys. This is probably conservative because the largest chimneys have 25-meter minimum separation and can hopefully be placed closer than that as the technology is developed. With this chimney spacing, only about 25% of the area is used. The injection radius is assumed to be ten times the dewatering radius of 1800 ft (549 m). The various pumping rates and times for the variables considered are shown in Table B-1, along with other data and estimates for three dewatering plans. These plans were developed for an aquifer thickness of 400 ft, transmissivities of 5000 and 20,000 gpd/ft, and heads of 1000 and 2000 ft. The hole sizes and number required are consistent with the pumping rates required, but are not optimized for minimum costs. For example, in plan C costs are probably much lower if larger and fewer holes are used.

METHOD OF COST ANALYSIS

Three examples of dewatering plans are included to cover the range of conditions expected in dewatering various parts of the Piceance Creek Basin. Because these estimates vary so widely, the dewatering costs have been separated from the other cost estimates for the in situ retorting of oil shale. To do this, we assume that money to meet all the costs of dewatering is borrowed at the time needed including

Table B-1. Dewatering plans for one area.

	Plan A	Plan B	Plan C
Aquifer thickness, h_0 (ft)	400	400	400
Transmissivity, T_0 (gpd/ft)	5,000	5,000	20,000
Head, H (ft)	1,000	2,000	2,000
Initial period			
Pumping rate (gpm)	12,660	28,485	113,930
Time (yr)	1.3	1.3	0.3
Steady state			
Pumping rate (gpm)	7,580	17,055	68,220
Time (yr)	4	4	4
Hole size (in.)	14	16	16
Dewatering hole No. reqd.	6	10	38
Injection hole No. reqd.	4	5	19
Hole cost ea. (\$)	26 K	82 K	82 K
Pump cost ea. (\$)	40 K	78 K	78 K
Pipeline size (in.)	22	32	60
Pipeline cost/mile (\$)	90 K	120 K	600 K
Pipeline length total	14 mi	14 mi	14 mi
Pumping station - cost for 4 ea. (\$)	286 K	480 K	1,944 K
Pumping costs - pump station			
Initial period (\$/yr)	89.6 K	202 K	806 K
Steady state (\$/yr)	53.6 K	120.7 K	483 K
Pumping costs - dewatering holes			
Initial period (\$/yr)	317 K	1,426 K	5,703 K
Steady state (\$/yr)	190 K	854 K	3,415 K

pre-production start-up costs, capital and operating costs. Using discounted cash flow methods, we can then calculate the annual payment required during the 20 yr of production to pay back the borrowed funds at some rate of return. This amount may then be compared to the annual production rate to obtain a cost per barrel for dewatering. Total capital and operating costs for one area of one system are shown in Table B-2. Two years are allowed for construction and initial dewatering, followed by four years

of steady-state pumping during production. The next area is prepared during steady-state operation of the first area. In 20 yr, one system will provide constant output in five areas at a rate of eight chimneys per year. Four systems would be operated on a staggered schedule (quarterly) to produce 32 chimneys per year. The dewatering costs for plans A, B, and C and retorting cases 1-6 are shown in Table B-3 for a 20% return on non-equity investment. If equity capital is used, an allowance must be made for taxes.

Because the size of the area to be dewatered was selected to fit the largest chimneys, costs will be too high for small chimneys. Ignoring this consideration, another conclusion may be drawn from Table B-3 and a general knowledge of basin hydrology. Near the edges of the

basin the water quality is good and aquifers are relatively thin and relatively low in transmissivity. Plan A will therefore be more than adequate for cases 1-3. The major water problem in terms of quantity of water to be pumped as well as salinity of the water occurs in the center of the

Table B-2. Capital and operating costs for dewatering one area (32 chimneys producing for 4 yr).

	Plan A	Plan B	Plan C
<u>Capital costs (thousands of dollars)</u>			
Holes	260	1,230	4,592
Pumps incl. installations	239	782	2,973
Pipeline	1,260	1,680	8,400
Pumping stations	286	480	1,944
20% contingency on holes and pumps	100	402	1,513
Total capital	2,145	4,574	19,422
<u>Operating costs (thousands of dollars)</u>			
Initial period			
Pumping stations	116/1.3 yr	263/1.3 yr	242/0.3 yr
Pumping wells	412/1.3 yr	1854/1.3 yr	1711/0.3 yr
Steady state			
Pumping stations	53.6/yr	120.7/yr	483/yr
Pumping wells	190/yr	854/yr	3415/yr
30% contingency mgmt. and overhead	73/yr	292/yr	1169/yr

Table B-3. Dewatering costs for different cases and dewatering plans.

Case	Annual production (10 ³ barrels)	Dewatering cost per barrel (\$)		
		Plan A	Plan B	Plan C
1	9,776	0.62	1.74	6.07
2	28,224	0.22	0.60	2.10
3	56,448	0.11	0.30	1.05
4	84,672	0.07	0.20	0.70
5	105,824	0.06	0.16	0.56
6	120,928	0.05	0.14	0.49

basin in the leached zone. The oil shale thickness is greatest also in this region, so Plan C will apply more nearly to cases 4-6. The conclusion is that the cost of dewatering will probably add no more than about 50¢ per barrel to the selling price of oil. It should be noted that the problem of dewatering and disposal of the water is present for any process of oil recovery from oil shale. Whether the oil shale is mined by underground or open pit methods or retorted in-place after rubblization by caving or nuclear explosives, the same water must be moved.

Other things will need to be considered in addition to the economic and technical feasibility of pumping the water away, as discussed so far. The effect on the quality and quantity of surface flow as well as the effect on the groundwater in alluvial aquifers must be considered. These are the water resources of most interest to the present economy of the basin.

The maximum pumping rate considered in this report is for the leached zone in the center of the basin where the transmissivity is assumed to be 20,000 gpd/ft. If in fact this is an accurate number, the amount of water to be pumped at steady state is $272,888 \text{ gpm} = 1206$

acre-ft/day = 440,000 acre ft/yr. If the storage capacity of the basin is 2.5 million acre-ft, then an amount of water equivalent to the total storage in the basin is moved every 5 to 6 yr. If production is increased beyond the projected levels in the center of the basin it will be desirable, if not necessary, to consider disposing of the water outside the basin. One possible solution is to pump the water (which is saline) to the Great Salt Lake where it might be welcome as a means of retarding the rate of shoreline retreat. Again, the effect on water resources in the Piceance Creek Basin must be better understood and considered in comparison with the necessity for developing oil production from oil shale.

To maintain a balanced perspective, however, it must be remembered that the high transmissivity used in the leached zone may not be representative, and also that a very large amount of oil shale exists outside the leached zone where dewatering is a much smaller problem. In the worst case, dewatering does not appear to be a technical or economic problem which will deter the development of oil shale.

Further information and political judgments are required to determine whether it will be an environmental limitation.

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