Oil Shale: A Solution to the Liquid Fuel Dilemma

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Oil Shale: A Solution to the Liquid Fuel Dilemma

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Foreword

The ACS Symposium Series was first published in 1974 to provide a mechanism for publishing symposia quickly in book form. The purpose of the series is to publish timely, comprehensive books developed from the ACS sponsored symposia based on current scientific research. Occasionally, books are developed from symposia sponsored by other organizations when the topic is of keen interest to the chemistry audience.

Before agreeing to publish a book, the proposed table of contents is reviewed for appropriate and comprehensive coverage and for interest to the audience. Some papers may be excluded to better focus the book; others may be added to provide comprehensiveness. When appropriate, overview or introductory chapters are added. Drafts of chapters are peer-reviewed prior to final acceptance or rejection, and manuscripts are prepared in camera-ready format.

As a rule, only original research papers and original review papers are included in the volumes. Verbatim reproductions of previous published papers are not accepted.

ACS Books Department

Preface

This book is the result of a symposium on oil shale presented at the Fall 2008 and National Meetings of the American Chemical Society. Thirteen papers were presented in two sessions at the Meeting. For a more comprehensive product, other people working on oil shale were invited to submit manuscripts for consideration for publication in the book. All manuscripts were peer reviewed.

The United States of America is endowed with abundant oil shale deposits from which about one trillion barrels of oil can be recovered. These huge domestic oil resources are currently untapped. Interest in developing the oil shale resources of the United States of America's has increased in the last few years as a result of high prices of conventional crude oil and concerns about reliable and secure energy supplies to meet our nation's growing demand. The technology to cleanly develop affordable fuels from oil shale requires advances in research, development and demonstration (RD&D).

In recent years, research and development activities on oil shale have significantly increased to accelerate oil shale technology while minimizing the environmental impact in an effort to enhance its commercial development. This symposium series book describes recent research and developments of various aspects (characteristics, production, processing, upgrading, utilization, environmental, economics, policy, and legal) of oil shale development.

The form of this book is organized in the following six parts:

- General overview of oil shale and oil shale technology
- Resource assessment and geology,
- Chemistry and process modeling,
- Industrial oil shale processes,
- Environmental issues affecting oil shale development, and
- Economics, legal, policy, and social issues related to oil shale development.

The authors of each chapter are sharing their timely research and their expert insights in this book. The diversity of their experiences is taking oil shale advancement forward.

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Chapter 1

An Overview of Oil Shale Resources

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There are vast quantities of oil shale around the world in deposits located in 27 countries. The quality, quantity, and origins of these shale deposits vary greatly. The United States has the largest known resource of oil shale in the world - an estimated 6 trillion barrels (*1*). Other significant deposits of oil shale can be found in Russia, Brazil, Estonia, and China. The world's oil shale resources are largely untapped and may represent considerable oil reserves with suitable economic conditions and advances in extraction technology.

Oil Shale Background Information

What Is Oil Shale?

Oil Shale is a sedimentary rock embedded with organic material called kerogen. It is essentially a geologically immature form of petroleum. The rock has not been under the necessary heat, pressure, and/or depth for the right length of time required to form crude oil. However, this immature form of petroleum can be converted to fuel feedstock (syncrude) through the process of heating and hydrogenation.

Formation and Deposition

Oil shale is formed from organic material which may have several different origins. It is often categorized according to the origin of the organic material into three major categories: terrestrial, lacustrine, and marine (*2*).

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- Terrestrial oil shale is formed from organic material, plant and animal matter that once lived on land, similar to the material that produces coal.
- Lacustrine oil shale descends from fresh or brackish water algae remains.
- Marine oil shale deposits are the result of salt water algae, acritarchs, and dinoflagellates.

The origin of the oil shale may impact its quality and/or the other minerals that are found within the deposit.

Distribution

Deposits of oil shale may be found at varying depths below the surface. Oil shale occurs in nearly 100 major deposits in 27 countries worldwide (*3*). It is generally found at shallow depths of less than 900 meters, whereas deeper, warmer geologic zones are required to form conventional oil. Some deposits are close to the surface in relatively thin beds of shale. Other deposits may be found deeper beneath the surface (greater than 300 meters) in very thick beds (300 meters or more in thickness).

Lithology

Oil shale is found in different host rock types, but most deposits are either carbonate or silica based. The type of rock that comprises the shale body affects the mining and heating approaches, moisture content, and air and carbon emissions released during processing. Silica and clay based oil shales tend to have higher moisture contents. Carbonate rock may crumble in mining, crushing, and handling creating small particles called fines. Fines require different retorting approaches than lump shale. Fines can also contaminate shale oil with particulates that are difficult to remove. Carbonate rock also decomposes when subjected to high temperatures causing the creation and release of carbon dioxide emissions.

Composition

The composition of oil shale may vary according to the depositional mechanism and setting. The composition of the original organic matter may impact the chemical composition of the embedded kerogen.

Quality Factors

The quality of oil shale is important in determining its suitability for production. Some of the important determinants of quality include:

- Richness/Grade (litres per ton l/t)),
- Organic material content (as a percentage of weight),
- Hydrogen content,

- Moisture content, and
- Concentrations of contaminants including:
    - Nitrogen and
    - Sulfur and metals.

Richness/Grade

The commercial desirability of any oil shale deposit is dependent on the richness of the shale. Commercially attractive grades of oil shale contain 100 l/t or more. There are some deposits of oil shale that contain 300 l/t (*4*). The richness may in fact result in greater yields than determined by Fischer Assay due to efficiencies in processing.

Oil shales vary considerably in terms of richness or grade, which is determined by the percentage of organic carbon in the ore. Yield is an expression of the volume of shale oil that can be extracted from the oil shale. Richness of oil shale may be assessed by methodologies including Fischer Assay which is the traditional method but may not provide the total potential volume of oil that can be produced from the shale. A newer method, known as Rock-Evaluation, may provide a better measure of true potential yield (*5*).

Recoverability

The volume of oil shale is often expressed as the oil shale in place. This is an estimate of the total volume of oil shale contained in the ore taking into account the quality of the resource. Some deposits also have estimates of the recoverable resource which takes into consideration additional factors to determine the volume of shale that may actually be extracted from the ore. There is variation in the degree that individual deposits around the world have been evaluated or characterized; thus, the volume of shale oil is not fully known.

Global Oil Shale Resources

It is estimated that there are at least 8 trillion barrels of oil shale resource around the world (*6*). Countries are ranked according to the respective volumes of oil shale resource in place. The United States' oil shale resources surpass all other countries with an estimated 6 trillion barrels of resource in place. Russia, the Democratic Republic of Congo, and Brazil are the next highest ranked countries with volumes ranging from 80 billion barrels to almost 250 billion barrels of resource. Figure 1 displays the world oil shale resources estimated in each country and also provides the country's rank (*7*).

Of the twenty-seven countries around the world with known deposits of oil shale, Table I presents the top ten with the most abundant resource (*8*, *9*). Following the chart, there are descriptions of eight of the top ten countries and some additional deposits around the world. Based on available data, the origin, characteristics, and other details about deposits will be discussed.

United States

The United States (U.S.) is endowed with the largest oil shale resource in the world. The resource is located in 3 concentrated areas as displayed in Figure 2. The largest and most concentrated deposit of oil shale in the world is located in the western U.S. in the states of Colorado, Wyoming, and Utah. This large deposit is known as the Green River Formation. A second, less concentrated and lower quality deposit is located in the eastern U.S., stretching across Kentucky, Ohio, Tennessee, and Indiana. There are also smaller deposits located in the states of Alaska and Texas.

Total U.S. resource is estimated to approach six trillion barrels of oil shale in place. Of this large resource, two trillion barrels are considered high quality resource; 1.2 trillion barrels may ultimately be recoverable; and at prices in the range of 50 to 130 U.S. dollars per barrel of crude, potential shale oil reserves are estimated at 600 to 800 billion barrels (*10*). Figure 3 below provides this categorization of the resource.

The U.S. resources have been extensively characterized in terms of their quality and grade. Thousands of cores have been drilled and analyzed and numerous assessments have been made by industry and the government. Most often, U.S. resources are considered as three distinct oil shale regions (the western, eastern, and Alaska) due to differences in the oil shale in each location. Table II displays the quality of the oil shale in each of the three regions (*11*).

Table III highlights the major characteristics of oil shale resources in the U.S. including the origin of the shale, the areal extent of the deposit, and the geologic period of its formation for the two most significant oil shale regions in the U.S. (*12*). Following the table is a detailed description of the U.S.'s western and eastern resources of oil shale.

Western Resources

The most abundant resource is located in the western U.S. in the states of Colorado, Utah, and Wyoming in a geologic setting known as the Green River Formation. These deposits occur across 40,200 square kilometers (16 million acres) of land. It is estimated that the deposits contain approximately 1.2 trillion barrels of oil equivalent. Of the 1.2 trillion barrels, the majority are located on federally owned land managed by the U.S. Department of the Interior. Access to these resources for commercial development has been restricted by the federal government pursuant to regulations.

More than a quarter million assays have been conducted on core and outcrop samples for the Green River oil shale. Results have shown that the richest zone, known as the Mahogany zone, is located in the Parachute Creek, Colorado member of the Green River Formation. This zone can be found throughout the formation

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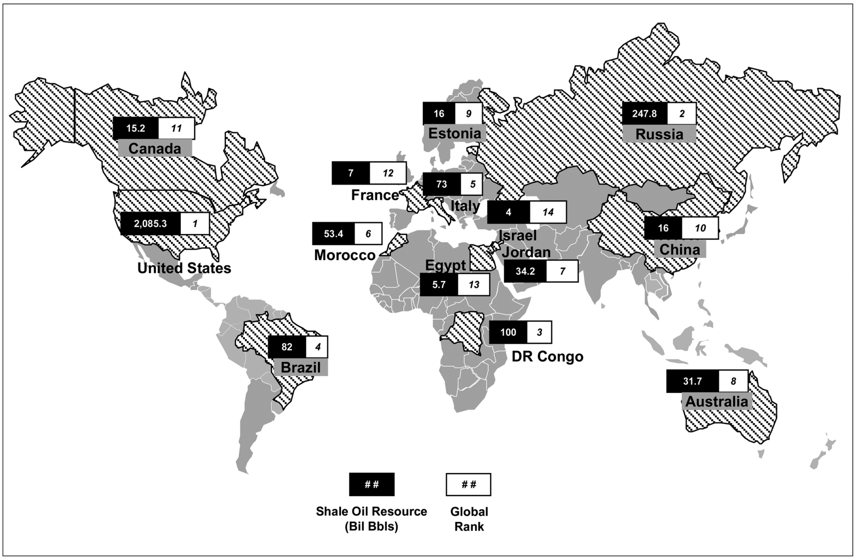

Figure 1. Map of World Resources

Table I. Top Ten Ranked Countries by Oil Shale Resource Volume

Rank	*Deposit Location*	*Resource in Place (Billions Bbls)*
1	United States	6,000
2	Russia	248
3	Democratic Republic of the Congo	100
4	Brazil	82
5	Italy	73
6	Morocco	53
7	Jordan	34
8	Australia	32
9	Estonia	16
10	China	10

and is easily identifiable. A layer of volcanic ash several centimeters thick, known as the Mahogany marker, lies on top of the Mahogany zone. Because of their relatively shallow nature and consistent bedding, the resource richness is well known, leading to a high degree of certainty relating to resource quality. By Fisher Assay, yields are estimated from 42 to 209 l/t and, for a few meters in the Mahogany zone, up to about 271 l/t.

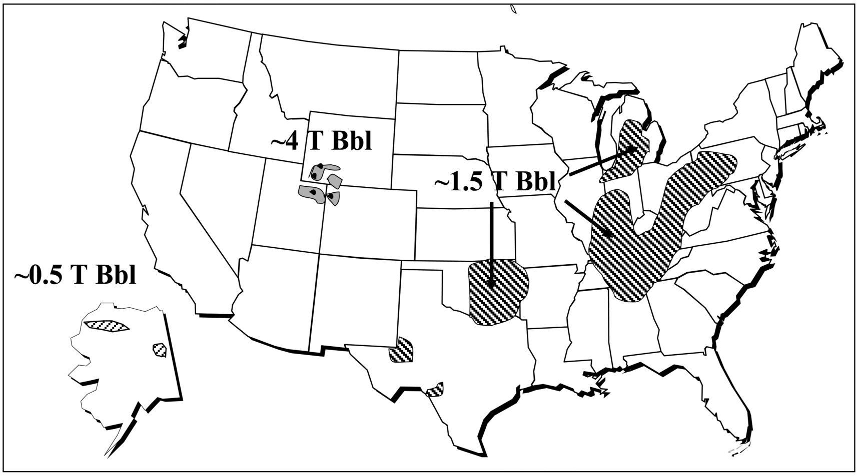

Figure 2. U.S. Oil Shale Resources

Eastern Resources

The U.S. has large oil shale deposits located in the eastern portion of the country that have also been well characterized. Much is known about the location, depth, and carbon content of the eastern resource. In comparison to the western U.S. oil shale resource, eastern shale is not as concentrated, but rather spread across a number of states. Eastern shale also has a different organic content than that of western oil shale. Conventional retorting of eastern shale yields less shale oil and a higher carbon residue.

Ninety-eight percent of these accessible deposits are in the states of Kentucky, Ohio, Tennessee, and Indiana. The Kentucky Knobs region has resources of 16 billion barrels, at a minimum grade of 100 l/t. Near-surface mineable resources are estimated at 423 billion barrels (*13*).

Russia

Russia has the second largest known resources of oil shale in the world. Russia contains at least 80 deposits of oil shale. Mined shale from the Kukersite deposit in the Leningrad district is burned as fuel in the Slansky electric power plant near St. Petersburg. In addition to the Leningrad deposit, the best deposits for exploitation are those in the Volga-Pechersk oil-shale province, including the Perelyub-Blagodatovsk, Kotsebinsk, and the Rubezhinsk deposits. These deposits contain beds of oil shale ranging from 0.8 to 2.6 meters in thickness but are also high in sulfur (4–6 percent, dry basis) (*14*).

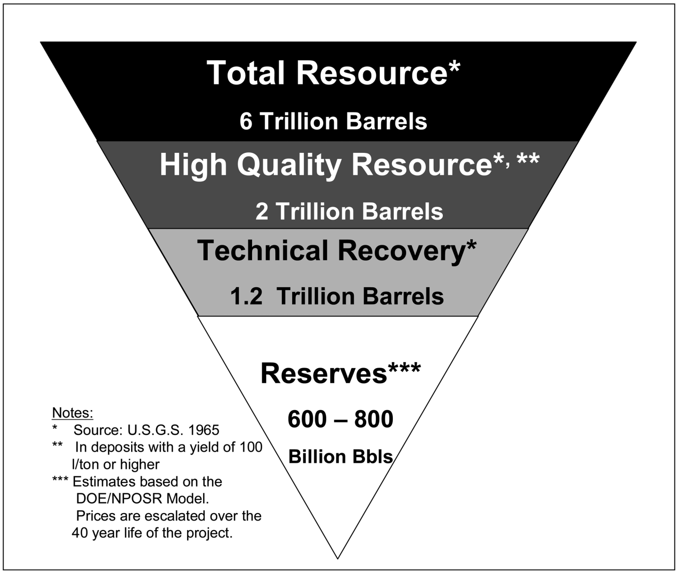

Figure 3. U.S. Oil Shale Resource Characterization

Table II. U.S. Oil Shale Quality by Region (Billions of Barrels)

	Quality		
Deposit Location	*20–40 (l/t)*	*40-100 (l/t)*	*100-400 (l/t)*
Western (Green River)	4,000	2,800	1,200
Eastern (& Central)	2,000	1,000	N/A
Alaska	Large	200	250
Total	6,000+	4,000	2,000+

Table III. U.S. Oil Shale Characteristics by Region

Deposit Location	*Origin*	*Area (km²)*	*Geologic Period*
Western	Lacustrine	65,000	Eocene
Eastern	Marine	725,000	Devonian/Mississippian

Brazil

Brazil is ranked fourth in terms of oil shale resources. The country contains at least nine deposits of oil shale (*15*) as displayed in Figure 4. Two of these deposits have been well characterized, the Paraíba Valley deposit and the Iratí Formation.

The Paraíba Valley deposit is located in the state of São Paulo, northeast of the city of São Paulo. The region is estimated to contain approximately 2 billion barrels of oil shale with as much as 840 million barrels that may be ultimately recoverable.

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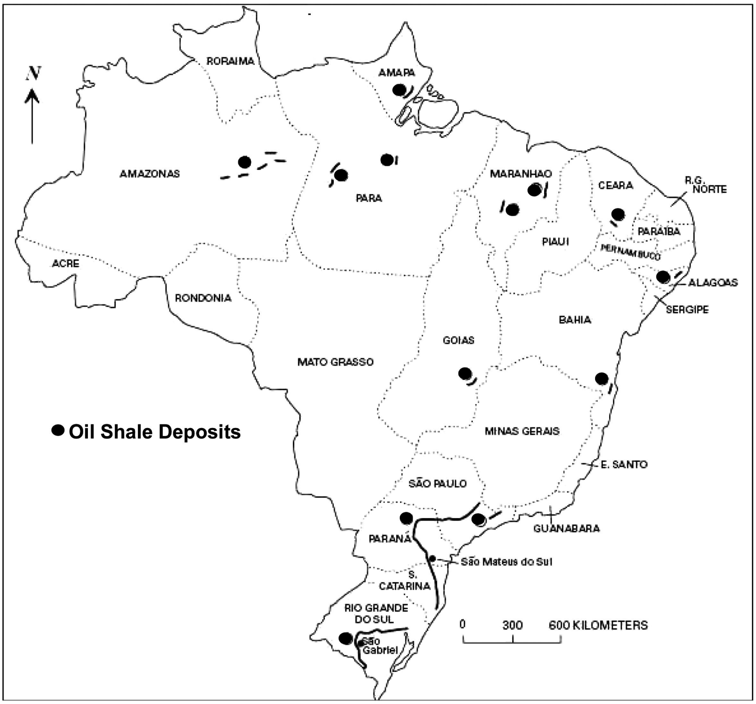

Figure 4. Map of Brazil's Oil Shale Resources (16)

The Iratí Formation is located in the southern part of Brazil cropping out in the northeastern part of the state of São Paulo, extending southward for 1,700 kilometers to the southern border of Rio Grande do Sul. The total area of the Iratí Formation is unknown because the western part of the deposit is covered by lava flows. Table IV highlights the major characteristics of oil shale resources for the Paraíba Valley and Iratí deposits (*17*).

The oil shale in the Iratí Formation is characterized in further detail. In the State of Rio Grande do Sul, it is known that the oil shale is in two beds separated by 12 meters of shale and limestone. The beds are thickest in the vicinity of São Gabriel, where the upper bed is 9 meters thick and thins to the south and east, and the lower bed is 4.5 meters thick and also thins to the south. In the State of Paraná, in the vicinity of São Mateus do Sul-Iratí, the upper and lower oil shale beds are 6.5 and 3.2 meters thick, respectively. In the State of São Paulo and part of Santa Catarina, there are as many as 80 beds of oil shale, each ranging from a few millimeters to several meters in thickness, which are distributed irregularly through a sequence of limestone and dolomite. Some resources are being actively mined and converted to oil and gas by Petrobras Brazil in commercial quantities (*18*).

Table IV. Brazil Oil Shale Characteristics by Deposit

Deposit Location	*Origin*	*Area (km²)*	*Geologic Period*
Paraíba Valley	Lacustrine	86	Tertiary
Iratí	Marine	unknown	Permian

Morocco

The Kingdom of Morocco is endowed with a large resource of oil shale and at least 10 distinct oil shale deposits (Figure 5).

The two deposits that have been explored most extensively are the Timahdit and the Tarfaya deposits. The Timahdit deposit is located about 250 kilometers southeast of Rabat. It underlies an area about 70 kilometers long and 4 to 10 kilometers wide. The thickness of the oil shale ranges from 80 to 170 meters. The moisture content ranges from 6 to 11 percent, and the sulfur content averages 2 percent. Total oil shale resources in the Timahdit deposit are estimated at 18 billion tons. Oil yields are expected to average 70 l/t.

The Tarfaya deposit is located in the southwestern most part of Morocco, near the border with Western Sahara. The oil shale averages 22 meters in thickness and its grade averages 62 l/t. The total oil shale resource is estimated at 86 billion tons. The moisture content of the Tarfaya oil shale averages 20 percent and the sulfur content averages about 2 percent. Table V provides the highlights of the characteristics of the Timahdit and Tarfaya deposits.

Jordan

The Hashemite Kingdom of Jordan ranks seventh in world oil shale resources. Within Jordan, 24 oil shale deposits have been identified. Of the 24 major oil shale deposits, five have been identified by the Natural Resources Authority (NRA) of Jordan as having near term development potential and were further characterized by geologic and engineering analyses. These deposits are all located in central Jordan south of the capital city, Amman. Oil shale deposits outside of central Jordan tend to be more deeply buried. Figure 6 displays all of the oil shale deposits in Jordan.

The five deposits that are well characterized in Jordan are: El-Lajjun, Sultani, Jurf Ed-Darawish, Attarat Um Ghudran, and Wadi Maghar. Characteristics of these deposits are displayed in Table VI and more detailed descriptions follow.

The El-Lajjun deposit is located about 110 kilometers south of Amman. The deposit is approximately 30 meters thick with an average oil yield of about 121 l/t. Overburden, material deposited above the oil shale, is about 30 meters. The deposit is estimated to contain a total of 1.6 billion barrels of oil shale with potentially 800 million barrels being ultimately recoverable.

The Sultani deposit is located 130 kilometers south of Amman and in close proximity to the El-Lajjun oil shale deposit. This deposit is estimated to contain

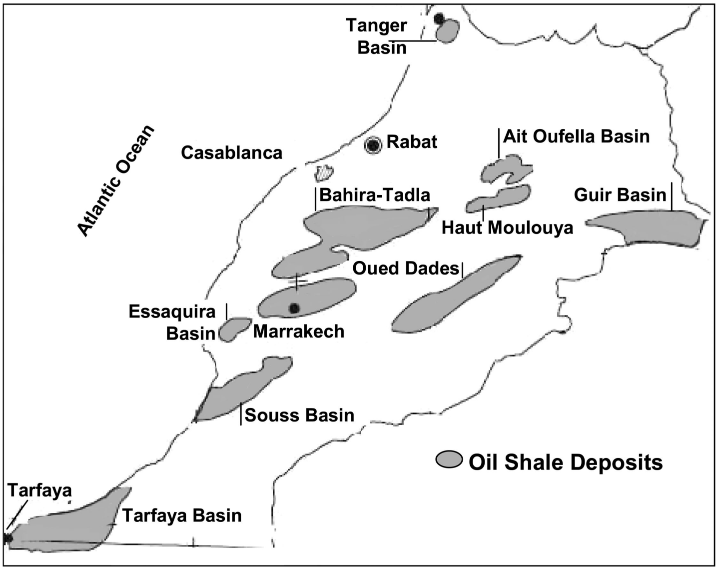

Figure 5. Map of Moroccan Resources

Table V. Moroccan Oil Shale Characteristics by Deposit

Deposit Location	*Origin*	*Area (km²)*	*Geologic Period*
Timahdit	Marine	196	Cretaceous
Tarfaya	Marine	2,000	Cretaceous

1.1 billion barrels of oil shale. At 88 l/t, the oil content is somewhat lower than the El-Lajjun deposit and the overburden is greater than 60 meters thick.

The Jurf Ed-Darawish deposit is located 115 kilometers south of Amman. This deposit is larger than the nearby Sultani deposit and its oil shale thickness is greater at 60 meters. Average overburden thickness is about 45 meters. Oil content is relatively low at 67 l/t. The Jurf Ed-Darawish deposit is estimated to contain total resources of 3 billion barrels.

Two additional large deposits in Jordan are Attarat Um Ghudran and Wadi Maghar. The oil shale resource in these deposits is relatively thick at about 43 meters, overburden has a similar thickness, and oil content is approximately 80 l/t. Total resources may reach 27 billion barrels; however, the deposits have not been fully analyzed.

A sixth deposit lies to the north and east of Amman. These resources are deeper and thicker than the central Jordanian deposits and are all targets for potential in-situ development.

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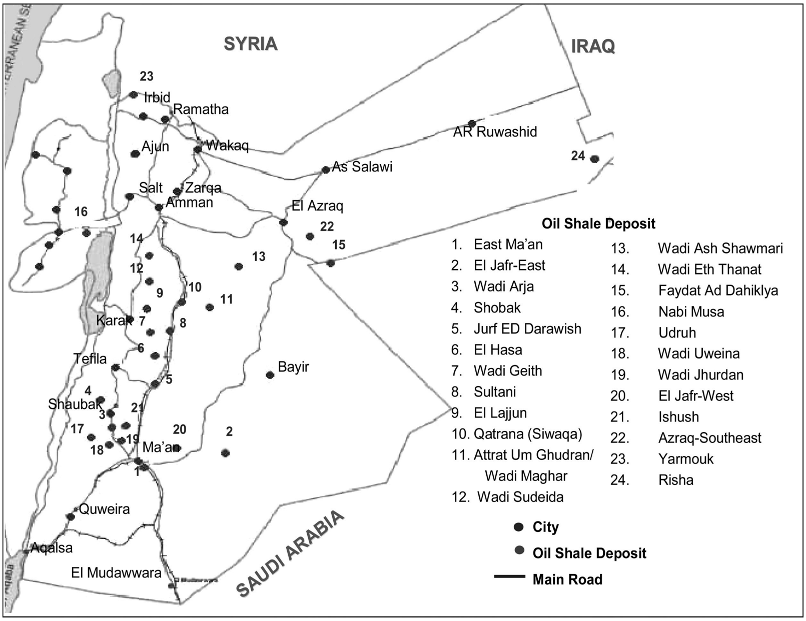

Figure 6. Jordanian Oil Shale Resources

Table VI. Jordanian Oil Shale Characteristics by Deposit

Deposit Location	*Origin*	*Area (km²)*	*Geologic Period*
El-Lajjun	Marine	13	Cretaceous
Sultani	Marine	14	Cretaceous
Jurf Ed-Darawish	Marine	56	Cretaceous
Attarat Um Ghudran/Wadi Maghar	Marine	480	Cretaceous

Australia

Australia ranks eighth among the largest oil shale resource holdings in the world. It is estimated that Australia contains approximately 58 billion tons of oil shale from which 24 billion barrels of shale oil may ultimately be recoverable (*19*). The oil shale is located in the eastern portion of the country in the states of Queensland, New South Wales, South Australia, Victoria, and Tasmania. Figure 7 provides a map of the country's deposits.

The deposits having the best potential for economic development are those located in Queensland and include the Rundle, Stuart, and Condor deposits. Queensland contains both toolebuc and torbanite deposits (*21*). Table VII displays characteristics of some of the major oil shale deposits in Australia.

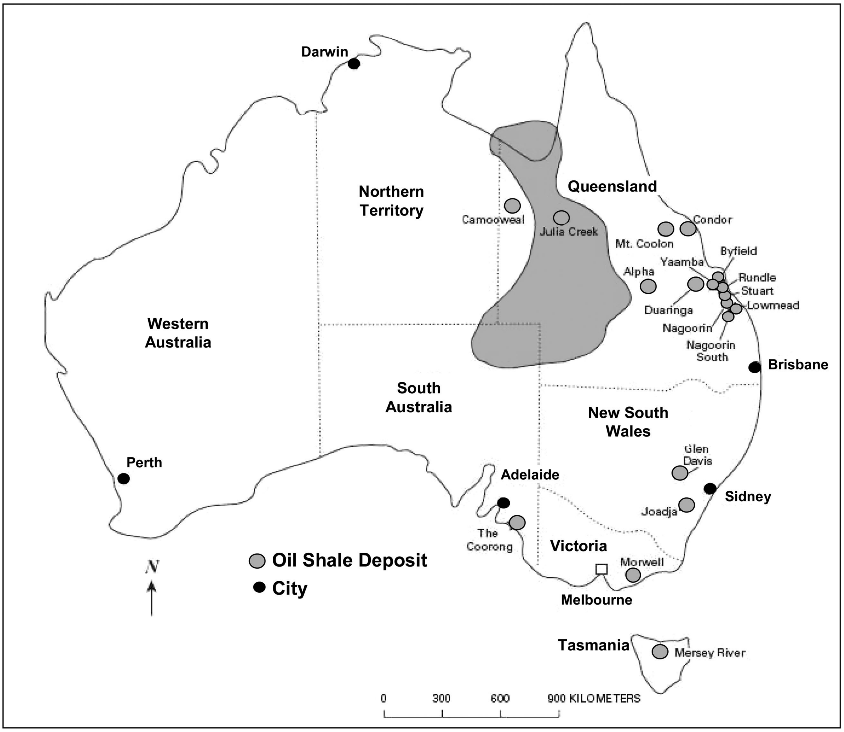

Figure 7. Australian Oil Shale Deposits (20)

New South Wales contains a large volume of oil shale resources. There are as many as 30 individual deposits in this region. The quality of the shale there ranges from 220 to 250 l/t, but may be as high as 480 to 600 l/t. There are two small deposits of torbanite (lacustrine) oil shale in Queensland, one of which may represent 19 million barrels of oil in place (*22*).

Australia also contains toolebuc (marine) deposits of oil shale. There are toolebuc deposits in parts of the Eromanga and Carpenteria basins located in Queensland and adjacent states. The oil shale zone ranges from 6.5 to 7.5 meters in thickness with an average yield of about 37 l/t, making it a low-grade resource. The Toolebuc Formation may contain as much as 1.7 trillion barrels of oil shale in-place. Much of this resource is close to the surface. Estimates for recoverable resource total 1.5 billion U.S. barrels; however, the oil shale is too low grade for development thus far (*23*).

Eastern Queensland has nine oil shale deposits that have been extensively characterized including: Byfield, Condor, Duaringa, Lowmead, Nagoorin, Nagoorin South, Rundle, Stuart, and Yaamba. These deposits were found to contain quartz and clay minerals with lesser amounts of siderite, carbonate minerals, and pyrite along with oil shale. The sizes of the deposits range from 1 to 17.4 billion tons of shale oil with grades of around 50 l/t. Three of the largest deposits are Condor with an estimated 17.4 billion tons, Nagoorin with 6.3 billion

Table VII. Australian Oil Shale Characteristics by Deposit

Deposit Location	*Origin*	*Area (km²)*	*Geologic Period*
New South Wales	Lacustrine	-	Permian
Queensland (torbanite)	Lacustrine	-	Permian
Queensland (toolebuc)	Marine	484,000	Cretaceous
Eastern Queensland	-	-	Tertiary

tons, and Rundle with 5.0 billion tons (*24*). The Stuart deposit is the largest and is estimated to contain 3 billion barrels of oil shale in-place. The Stuart deposit has been considered for commercial development in the past.

Estonia

Estonian oil shale deposits are known as Kukersite (marine). The deposits have been known since the 1700s. The deposits underlay northern Estonia and extend eastward into Russia toward St. Petersburg where it is known as the Leningrad deposit. In Estonia, a somewhat younger deposit, the Tapa deposit, overlies the Estonia Kukersite deposit. The locations of the Estonian oil shale resources, the ninth largest in the world, are displayed in Figure 8.

As many as 50 beds of Kukersite oil shale are in the Kõrgekallas and Viivikonna Formations. These beds form a 20 to 30 meter thick sequence in the middle of the Estonia field. Individual beds are commonly 10 to 40 centimeters thick and reach as much as 2.4 meters. The organic content of the richest resource reaches 40 – 45 weight percent (*25*). Rock-Evaluation analyses of the richest-grade oil shale in Estonia show oil yields as high as 320 to 500 l/t.

Matrix minerals in Estonian Kukersite are low-Mg calcite (>50 percent), dolomite (<10–15 percent), and siliciclastic minerals including quartz, feldspars, illite, chlorite, and pyrite (<10–15 percent). It is estimated that Estonian Kukersite oil shale resources are 5.94 billion tons (*26*). Table VIII shows additional characteristics of the Estonian Kukersite oil shale deposit.

Another older oil-shale deposit, the Dictyonema Shale, underlies most of northern Estonia. This deposit ranges from less than 0.5 to more than 5 meters in thickness.

China

China has a large volume of oil shale resources estimated to be as much as 16 million barrels in-place (*27*) and is ranked 10th in terms of oil shale resources. China has two principal deposits located at Fushun and Maoming.

The Fushun deposit is in northeastern China just south of the town of Fushun in the Liaoning Province in the Jijuntun Formation. The Formation ranges from 48 to 190 meters in thickness with the lower 15 meters consisting of low-grade

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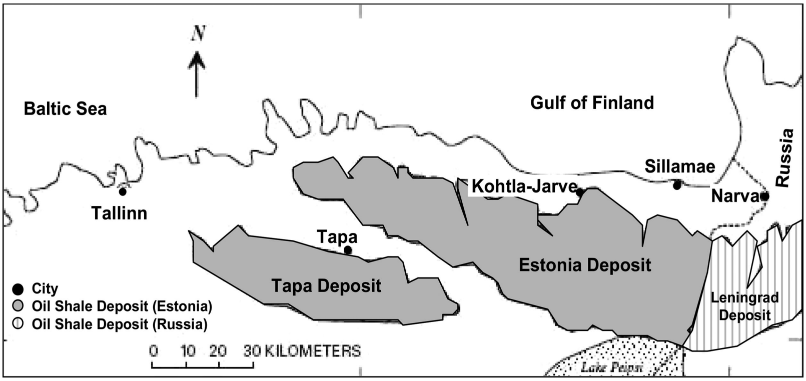

Figure 8. Map of Estonia Oil Shale Resources

Table VIII. Estonian Oil Shale Characteristics by Deposit

Deposit Location	*Origin*	*Area (km²)*	*Geologic Period*
Estonia	Marine	50,000	Ordovician

oil shale and the upper 100 meters being richer grade in beds of thin to medium thickness. The oil shale is estimated to be approximately 78–89 l/t of shale oil. The total resource of oil shale at Fushun is estimated at 3,600 million tons.

The Maoming oil shale deposit is 50 kilometers long, 10 kilometers wide, and 20 to 25 meters thick. In this deposit, the resource is estimated at 5 billion tons, of which 860 million are in the Jintang mine. The Fischer assay yield of the oil shale is 4 to 12 percent and averages 6.5 percent. Table IX provides more details about the characteristics of the deposits.

Other Significant Oil Shale Deposits

Canada

Canada has as many as 19 deposits of oil shale of both marine and lacustrine origin (*28*). The oil shales of the New Brunswick Albert Formation have the greatest potential for development. The Albert oil shale averages 100 l/t of shale oil. The Devonian Kettle Point Formation and the Ordovician Collingwood shale of southern Ontario yield relatively small amounts of shale oil (about 40 l/t). The Boyne and Favel deposits form large resources of low-grade oil shale in the Prairie Provinces of Manitoba, Saskatchewan, and Alberta. Outcrops of lacustrine oil shale on Grinnell Peninsula, Devon Island, in the Canadian Arctic Archipelago, are as much as 100 meters thick and samples yield up to 406 l/t.

Table IX. Chinese Oil Shale Characteristics by Deposit

Deposit Location	*Origin*	*Area (km^2)*	*Geologic Period*
Fushun	Lacustrine	-	Eocene
Maoming	Lacustrine	-	Tertiary

Israel

Israel has twenty deposits of oil shale with marine origin. The total estimated resource is 12 billion tons of oil shale. Israeli oil shale deposits range in thickness from 5 to 200 meters. The deposits have approximately 60 to 70 l/t and the shale has a high moisture content (~20 percent), high carbonate content (45 to 70 percent calcite) and high sulfur content (5 to 7 weight percent) (*29*).

Syria

Syrian oil shale resources are located in the Wadi Yarmouk Basin at the southern border of Syria and presumably part of the Yarmouk deposit located in northern Jordan (*30*). The deposit's origin is marine and contains minerals such as small amounts of quartz (1 to 9 percent), clay minerals (1 to 9 percent), and apatite (2 to 19 percent). The sulfur content of this deposit is 0.7 to 2.9 percent. Oil yields by Fischer Assay are 7 to 12 percent.

Sweden

Sweden contains an oil shale deposit known as Alum shale of marine origin. The Alum Shale is about 20 – 60 meters thick. It has been known for more than 350 years. The Alum Shale has a very high content of metals including uranium, vanadium, nickel, and molybdenum. The organic content of Alum Shale ranges from a few percent to more than 20 percent, being highest in the upper part of the shale sequence (*31*).

Thailand

Thailand contains lacustrine oil shale deposits near Mae Sot, Tak Province, and at Li, Lampoon Province. The Thai Department of Mineral Resources has explored the Mae Sot deposit with the drilling of many core holes. The Mae Sot deposit underlies about 53 square kilometers in the Mae Sot Basin in northwestern Thailand near the Myanmar (Burma) border. It contains an estimated 18.7 billion tons of oil shale, which is estimated to have a yield of 6.4 billion barrels of shale oil. The oil shale has a moisture content ranging from 1 to 13 percent and the sulfur content is about 1 percent. The deposit at Li has estimated resources of 15 million tons of oil shale with a potential yield of 50–171 l/t (*32*).

Turkey

Turkey contains lacustrine oil shale deposits which are widely distributed in middle and western Anatolia in western Turkey. The host rocks are marlstone and claystone in which the organic matter is finely dispersed. On the basis of available data, total resources of in-place shale oil for eight Turkish deposits are estimated at 284 million tons (about 2 billion barrels).

Summary of World Oil Shale Resources

World oil shale resources are characterized to varying degrees. The largest resource, the United States deposits, contain approximately 75 percent of the world's oil shale resources and a great deal is known about the quality and extent of these resources. However, there are many deposits around the world in which little is known about the quality and extent of the resource.

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Chapter 2

New Challenges and Directions in Oil Shale Development Technologies

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Economic, energy supply, and environmental challenges require new technologies to support diversification of global liquid fuels resources and markets. Higher oil prices make global oil shale resources more attractive. Mining and upgrading technologies for oil shale are proven at commercial scale. Retorting technologies to convert kerogen from shale ore into hydrocarbon liquids and gases continue to evolve to improve efficiency and reliability and address environmental, technical and regulatory challenges that constrain commercial development. Research and development activities in private industry, academia, and government-sponsored laboratories and research facilities continue to move oil shale technologies toward demonstration and commercialization. This chapter describes the major technical approaches for oil shale mining and processing and conversion of kerogen to refinery-quality feedstocks, current retorting technologies, and technology innovations that address technical challenges to commercial oil shale development.

Introduction

Oil shale is a sedimentary rock (carbonate or silica-based) that contains organic kerogen – a solid, immature form of petroleum. The solid does not melt and is insoluble. Conversion of the solid kerogen to hydrocarbon liquids and gases requires heating the raw ore to pyrolysis temperatures. Pyrolisys produces hydrocarbon gases and vapors that when condensed would become liquid shale oil (*1*).

Natural conversion of kerogen to crude oil occurs subsurface in the oil temperature "window" of up to ~200°C over a period of millions of years. However, this reaction can be accelerated in surface and in-situ processes by increasing the temperature. Surface reactors can convert kerogen to hydrocarbon liquids in about one hour at temperatures of ~500°C. However, heating at ~500°C leads to significant hydrocarbon degradation and requires the end-product to be upgraded by hyrdoretorting before refining into fuels. In-situ processes heat the kerogen at a lower temperature (350°C) for a period of months, resulting in high quality products that require less upgrading.

Raw kerogen liquids may be lower in hydrogen content and higher in nitrogen and sulfur than conventional crude oil, thus requiring hydrotreating and upgrading to meet refinery feedstock standards. These upgraded feedstocks can then be used to produce high quality, ultra low sulfur diesel, jet, and naphtha based fuels as well as other high-value specialty chemicals.

Although a variety of approaches are available for accessing oil shale, converting the kerogen to hydrocarbon liquids and gases, and upgrading kerogen oil, ore access and conversion technologies fall under two general approaches (Figure 1):

- Surface retorting of mined (surface or underground) shale or
- In-situ (underground) retorting of kerogen still embedded in its natural depositional setting

Numerous technologies and variations have been conceived, developed, and tested under each approach. All have demonstrated the fundamental technical feasibility of applying heat to achieve pyrolysis and produce liquids and gases, with various levels of technical and economic success.

While mining and upgrading technologies are considered commercially proven, uncertainty remains about the commercial viability of retorting technologies that convert the kerogen-content of oil shale into valuable refinery feedstocks. Despite more than 65 years of public and private research, development and demonstration effort, and the continuous operation of small-scale oil shale plants in several countries, uncertainties remain about the commercial-scale viability of both surface and in-situ retorting technologies.

Technology Selection Criteria

Technology choice is primarily determined by the characteristics of the target resource, principally lithology and ore composition, depositional setting, and kerogen-richness, and heavily influenced by the environmental setting.

- Near-surface resources with economically viable stripping ratios (overburden to net pay ratio of ~1:1) tend to be candidates for surface mining (strip or open pit) and surface retorting.
- Deeper oil shale resources, and those accessible through outcrops, are candidates for underground mining with surface retorting.

- Some surface retorting technologies are better suited to processing lump shale (<15 millimeters diameter), while others are better suited to retorting smaller "fines" or particulates.
- Where shale deposits are deep, and the beds are very thick, in-situ heating techniques may be more effective from both technical and economic perspectives.
- Recent evidence suggests that new in-situ and surface-retorting approaches that heat shale at lower temperatures for longer periods may yield higher quality products that require little or no upgrading.
- Upgrading technology selection is largely dependent on the quality of the raw kerogen oil produced as determined by API gravity, sulfur, and nitrogen content.

Oil Shale Technology Maturation

Major oil shale technology development can require thousands of person-hours of effort and billions of dollars of investment over a period of decades to evolve from concept to successful demonstration at a commercially-representative scale. Development typically occurs in three major phases:

- **Laboratory:** Basic research, applied research, and bench-scale plants
- **Field Testing:** Field pilot plants and semi-works scale up
- **Commercial:** Scale-up from semi-works to commercially-representative scale demonstration plants, leading to full commercial-scale operating plants

As discussed more fully in the sections that follow, both the mining and upgrading technologies for oil shale are well developed and demonstrated at commercial scale. Conversion technologies are not as far along in the technology maturation process.

Technical confidence increases at each progressive phase, as does the level of project risk and the required capital investment. Failure at any point in the process can require stepping back, revising the approach or the design, or starting over again. Figure 2 depicts the path of energy technology evolution and commercialization.

By the early 1990s, more than 20 modern technologies for oil shale processing had been conceived and tested. Some encountered design or technology problems associated with scale-up. However, many others had advanced well beyond proof of concept in the lab to engineering, design, and field-testing at pilot or semi-works scale and produced significant volumes of shale oil.

Although most U.S. oil shale development efforts were terminated in the mid-1980s due to rising estimates of project costs and low global oil price and demand outlooks, several conversion technologies have been successfully demonstrated at commercially-representative scale or put into commercial operation. At least four surface technologies are currently in use, producing small commercial volumes of shale oil:

- Fushun (China)
- Petrosix (Brazil), and

- Kiviter and Galoter (Estonia)

The body of scientific and technical knowledge and understanding established by past efforts provides the foundation for new global research and technology development efforts that seek to advance oil shale mining, retort, and processing technology. New approaches and technologies are emerging and new challenges being addressed.

New Challenges

Today's oil shale technology and products must compete with conventional petroleum, as well as with emerging alternative liquid fuels, on the basis of cost, quality, and environmental impact.

In order to be commercially viable, current oil shale technology development efforts seek to economically address a new set of challenges posed by changing market conditions and stricter societal requirements and expectations. These new requirements pose technical challenges that impact the full scope of oil shale development activity, including resource access and recovery, conversion of kerogen to liquids and gases, disposition of production wastes, and collection and upgrading of produced hydrocarbons to refinery quality.

The global research community – including private companies, government supported laboratories, public and private universities, and other organizations – is actively pursuing development of new oil shale conversion technologies to meet both new and expected future economic, technical, environmental, and market imperatives. Major focal points of current oil shale RD&D include the following topic areas:

- Improving understanding of shale characteristics and depositional factors that may affect in-situ technology design and performance
- Improving recovery efficiency
- Improving process energy efficiency / net energy balances
- Reducing external energy requirements
- Reducing surface impacts affecting land use and habitats
- Reducing net water requirements
- Reducing generation or emissions of criteria air pollutants
- Achieving lifecycle carbon emissions equal to or less than conventional petroleum
- Protecting groundwater quality from in-situ processes
- Protecting ground water from surface operations
- Integrating oil shale development with other energy and economic development activity

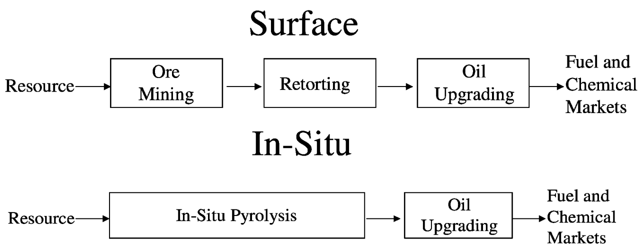

Figure 1. Conversion of Oil Shale to Products (2)

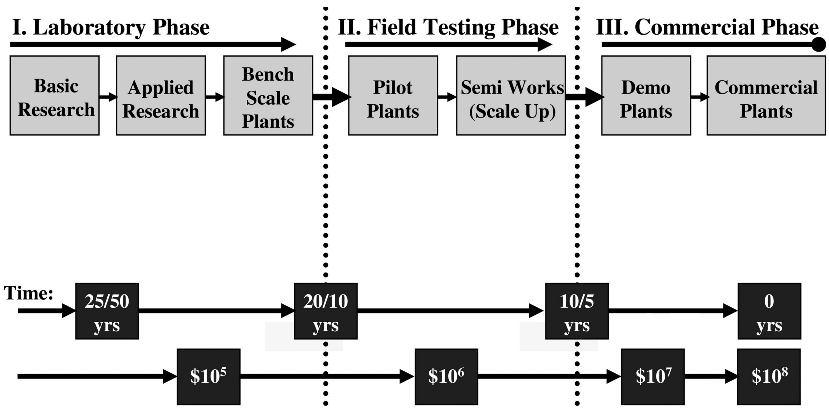

Figure 2. Evolution of Major Oil Shale Technologies (3)

Oil Shale Technologies and Trends

Oil Shale Mining Techniques

Despite the cyclical nature of U.S. and global efforts to develop oil shale resources and viable retort technologies, the technologies for surface and underground mining of coal and other mineral resources have advanced steadily.

State-of-the-art technologies have improved mine planning and design, excavation, materials handling, ore crushing and sizing, waste disposal, reclamation, restoration, and mine-safety technologies and practices. They are well demonstrated and commercially proven. Their application to oil shale will not differ fundamentally in design or practices from demonstrated commercial-scale applications for coal or other minerals. Continued advances in mining technologies can be expected to be largely transferable to surface and underground oil shale mining applications.

The major mining challenge for large-scale surface retorting operations will be the size of the surface or underground mines required to supply the large daily volumes of ore required to support continuous production at commercial scale. Surface plants producing 50,000 barrels per day could require mine outputs on the

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order of 25 million tons/year. However, some U.S. mines, such as the Bingham Canyon Copper mine in Utah, produce 450,000 tons of material per day.

Surface Mining

Where the resource deposit is relatively shallow (<150 feet of overburden) or in deeper deposits with acceptable stripping ratios (overburden to net pay thickness ratio (< ~1:1), surface mining may be applicable. Surface mining approaches include both open-pit and strip mining.

Surface mining techniques offer the combined benefits of lower costs and higher productivity than other mining techniques over the life of the project. Productivity advantages include not only the rate of production but also recovery efficiency, maximizing the economic recovery of kerogen-bearing shale from the deposit. In strip mining, the excavated and mined area may be used to store overburden or spent shale, facilitating timely mine reclamation and surface restoration. Open-pit mines have generally been deemed inappropriate for spent shale disposal (Figure 3) (*4*).

However, despite the economical and technical advantages of various surface mining approaches, they have been generally dismissed for oil shale activities in sensitive areas due to associated environmental impacts that may include:

- Surface area disturbance and associated habitats at mine and storage sites;
- Overburden and spent shale management requirements and costs (transport, handling, storage, and disposal);
- Risks to surface and groundwater quality associated with potential run-off, leachates, and altered drainage patterns;
- Air quality impacts from fugitive dust and equipment emissions, and
- Habitat disturbance due to noise from mining and transport equipment, crushing, and blasting operations (*4*).

Underground Mining

Underground mining is applicable for use in deeper resources or deep resources accessible by outcrop. Room and pillar mining is the favored approach for oil shale, rather than long-wall. This method, successfully demonstrated economically and technically in coal mining operations, excavates chambers, leaving pillars to provide vertical support. This approach is viable in seams up to 100 feet thick (*6*). Once excavated, the chambers may provide future storage for most -- but not all -- of the spent shale, due to volumetric expansion properties of crushed and heated shale.

A disadvantage of room and pillar approaches is lower resource recovery. Only approximately 60% of the target resources can be recovered due to the required size of the pillars (*7*). Rock strength, fracturing, and other shale properties may also limit the applicability of underground mining in some depositional settings (*8*). Another limiting factor in selection of underground mining is the

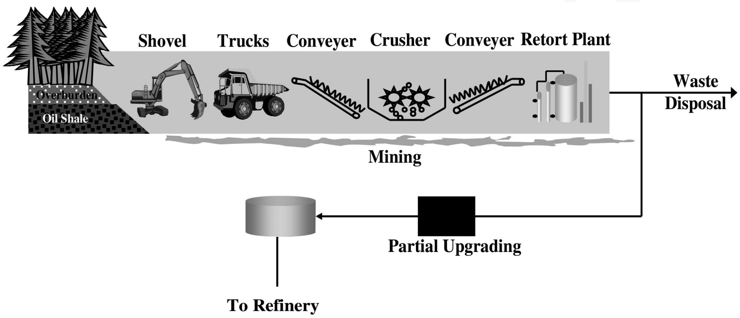

Figure 3. Surface Mining Example (5)

extensive up-front capital costs for mine facilities, pumping stations, ventilation, mine-accesses, and other underground mine safety systems and requirements.

Mining for Modified in-Situ Approaches

Where resource characteristics and depositional settings allow, the costs and challenges of ore mining and subsequent spent-shale disposal may be averted in favor of in-situ processes that heat kerogen-bearing ore in-place with limited or no excavation. Modified In-Situ (MIS) approaches require mining of a portion of the resource -- on the order of 10 percent -- to facilitate air-flow and create void space for in-situ combustion. Conventional underground mining techniques, including deep shafts, can be used to access the shale formation, rubbelize the shale, and transport it to the surface. The mined shale is then processed in surface retorts. However, new state-of-the-art in-situ processes, discussed later in this chapter, require no mining.

Oil Shale Retorting and Pyrolysis Technologies

Raw kerogen must be heated to pyrolysis temperatures to separate the organic content from the mineral content of the ore and to convert it from a solid to liquids and gases. The heating process is referred to as "retorting." Where mined ore is to be processed on the surface, the physical ore heating facility is generally referred to as a "retort." The thermal and chemical reaction by which the kerogen is converted from a solid to gases and liquids is referred to as "pyrolysis."

Surface retorting processes are essentially materials handling and manufacturing operations. They require large volumes of materials to be mined and crushed and large vessels to contain and heat the mined shale to retort temperatures. The vessels must be sized to efficiently handle and heat large volumes of shale in a short period of time. In carbonate shale, such as those common to the western United States, higher temperatures employed to heat shale faster and reduce shale "residence time" in the retort, can cause the non-kerogen shale material to breakdown, increasing carbon dioxide production. Equilibrium between temperature and residence time must be achieved.

The most efficient surface retorts process the shale in an oxygen-free environment to maximize production of high quality shale oils. Produced shale oil and gases must then be cleaned of impurities such as sulfur and nitrogen and upgraded to refinery standards. Emissions of criteria pollutants from mining, retorting, and upgrading operations must be managed to within public standards. Significant volumes of spent shale must be cooled, managed, and disposed of and mined areas must be reclaimed and restored. While retorting processes themselves may use little water, significant volumes may be required for mining, dust control, reclamation, and product upgrading. Surface and groundwater quality may be impacted by runoff from stored shale, overburden material, or spent shales, requiring diligent management.

Conversely, while in-situ processes may avert many of the costs, challenges, and potential environmental impacts associated with surface processes, they give rise to other significant challenges. They require drilling holes or shafts to access the resource and apply heat. They require efficient downhole heating technologies that can withstand harsh subsurface conditions. They also require effective methods to fracture the shale to allow consistent and effective heating of the entrained kerogen as well as to enable the produced fluids to travel from the shale body to producing wells.

Importantly, in-situ technologies require effective and reliable approaches to protect the heating area from groundwater intrusion and to protect surrounding groundwater from potential contamination by produced hydrocarbons or other toxins that may be present in the heating area after the shale oil and gases have been produced. Significant energy inputs from external sources may be required for some in-situ heating processes. Depending on the source of these energy inputs, they may contribute to significantly increasing the life-cycle carbon emissions of the overall in-situ process.

The general approaches, challenges, and current and emerging technologies and innovations associated with surface and it-situ oil shale processes are discussed below. Surface retorting processes including indirect, direct, and other heating variations will be discussed first. A discussion of in-situ processes challenges and innovations, will follow.

Surface Retorting Approaches and Technology

Generally, surface processing consists of three major steps: (1) oil shale mining and ore preparation, (2) pyrolysis of oil shale to produce kerogen oil, and (3) upgrading kerogen oil to produce refinery feedstock and high-value chemicals. This sequence is illustrated in Figure 4.

Conceptually, surface oil shale retorting seems to be a very simple process. Mined shale ore is cleaned of impurities, crushed and sized to retort specifications, dried to remove excess moisture, and heated in a surface vessel to retort temperatures, producing oil and gases that are captured as liquids gases and vapors for further processing. The residual mineral material is collected, cooled,

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Figure 4. Conversion of Oil Shale to Products (Surface Process) (2)

and disposed. But in reality, what may appear very simple in concept becomes very complex in design and execution.

Most surface processing technologies seek to heat oil shale ore to retort temperatures as quickly as possible. This can be achieved by reducing the size of the mined ore by crushing and sizing techniques – increasing preparation costs – or by increasing the temperature in the retort vessel – increasing energy cost. The principal objectives of the retort process are:

- High product yields (production volume, recovery efficiency, and product quality)
- High thermal efficiency
- Short "residence" time in the retort – less than one hour
- High process / operational reliability
- Low environmental impact

Retort technology viability is determined by a combination of factors, including thermal efficiency, resource recovery efficiency, production rate, product quality and purity, and mechanical reliability or "up-time." Increasingly, environmental factors are also a major determinant of efficacy, including water use and conservation, energy sources and heating methods, emissions of criteria air pollutants, spent shale composition and disposal, and carbon emissions. While addressing these challenges, retort technology development and demonstration requires lab- and pilot-scale processes to be economically and technically scalable to commercial size operations to be viable.

Table I provides a classification and overview of the surface retorting process that will be discussed in the following section.

Indirect Heating Methods

Early approaches for oil shale retorting involved indirect heating of the resource by transferring heat through the wall of a retort vessel to the ore. The low heat-conductivity coefficient of indirect heating limits the heat absorption rate of lump oil shale to several degrees per minute, requiring several hours to achieve retort temperature. This characteristic limits the size of the shale ore that can be efficiently heated, limits the capacity of the heating vessel, and limits the production rate and volume of the retort. Past technologies that applied indirect processes produced shale oil, but were characterized by poor scalability, high heating costs, and low thermal efficiency, making them inappropriate for commercial scale use.

Table I. Classification and Status of Some Surface Oil Shale Retorting Technologies (*3*, *9*)

	Surface Retorting Processes	
Heating Method	*Process*	*Last Status*
Indirect Heating	CRE C-SOS	Pilot Planned[b]
	EcoShale Incapsule	Field Pilot[b]
Direct Heating		
Gas Heat Carrier	Bureau of Mines GCR (USA)	Demonstration
	Paraho I & II (USA)	Pilot/Semi-Works
	Petrosix (Brazil)	Commercial[a]
	Union B (USA)	Demonstration
	Kiviter (Estonia)	Commercial[a]
	Fushun (China)	Commercial[a]
	Chattanooga PFBC (USA)	Pilot[b]
	Rotary Kiln w/ Sweep Gas (USA)	Lab[b]
Solid Heat Carrier	TOSCO II - Ceramic Ball (USA)	Semi-Works
	Lurgi-Ruhrgas (Multiple)	Pilot
	Galoter (Estonia)	Commercial[a]
	ATP (Canada, Australia)	Semi-Works[b]

[a] Currently in operation. [b] Currently in development.

At least two technologies are currently in development, however, that seek to overcome indirect heating limitations with new innovations.

CRE Energy, Inc.

The CRE Clean Shale Oil Surface Process (C-SOS), under development in Utah, uses an indirect-fired rotary kiln to heat crushed and sized oil ore up to 3/8 inch in diameter. The kiln may be fired by hydrogen – produced from an integrated coal gasification plant – to eliminate carbon dioxide emissions (Figure 5). By holding the retort temperature low (< 500°C) shale oil quality is maximized and degradation of the mineral component of the carbonate shale is minimize, avoiding generation of additional carbon dioxide emissions from the rotary kiln. A lab scale pilot is currently planned (*3*).

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EcoShale

The EcoShale In-Capsule™ Process, under development by Red Leaf Resources in Utah, integrates surface mining with a lower-temperature, slow "roasting" method that occurs in an impoundment that is constructed in the void space created by the shale mining excavation (Figure 6). A system of piping is erected in the impoundment which is then filled with the mined lump shale, sealed, and heated indirectly with hot gases circulated through the piping. Slow heating at lower temperatures is expected to facilitate uniform heating, and yield very high grade kerogen oils and hydrocarbon gases. The produced hydrocarbon gases can be circulated back to the heaters, and used for site power generation, making the process largely energy self sufficient. Residual heat in the spent shale is used to preheat shale in subsequent capsules, resulting in higher net thermal efficiency. The impoundment avoids the expense and limitations of constructing a steel retort vessel.

It protects the heating zone from groundwater intrusion and provides a permanent impoundment for the spent shale once retorting operations are complete, thus protecting the subsurface. Overburden can be restored quickly, allowing for quick reclamation and restoration of surface conditions. The first field-scale pilot test was conducted in 2009 (*10*).

Direct Heating Method

Many contemporary surface retorting approaches now favor direct heating, using either hot gas as the heat carrier for larger sized "lump" ores (>10 millimeters size) or solid heat carriers for smaller fines or particulates (0 - 25 millimeters in size). With the exception of limited volumes of external fuel that are required for initial start-up heating, many of these processes obtain most or all of the energy required for heating shale from combustion or circulation of hydrocarbon gases that are produced in the retorting processes, combustion of residual carbon coke remaining on the residual "spent" shale, and / or the capture and use of residual heat in the spent shale to pre-heat fresh shale entering the retort.

Extensive research and testing has been conducted with a variety of gas and solid heat carrier technologies for surface retorts since the 1940s. Gas heat carrier retorts are typically vertical retorts, fed from the top, with two chambers. An upper retort chamber heats the shale to pyrolysis temperatures. Shale oil vapors and hydrocarbon gases are recovered. Some of the cooled gases are combusted to provide heated gases for the retort chamber. Some of the cooled gases are also circulated to the lower chamber to help cool the coked shale. The lower chamber cools the coked shale, transferring heat from to coked shale to the circulating gases which is then used to heat fresh shale.

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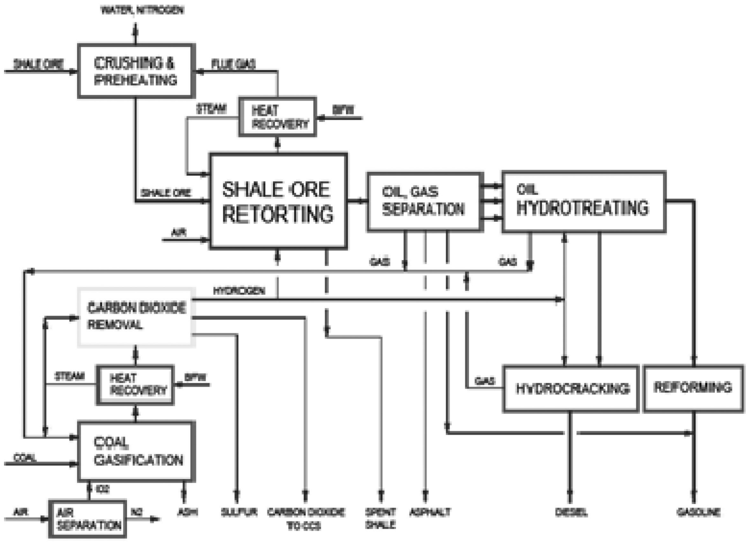

Figure 5. CRE C-SOS Process (3)

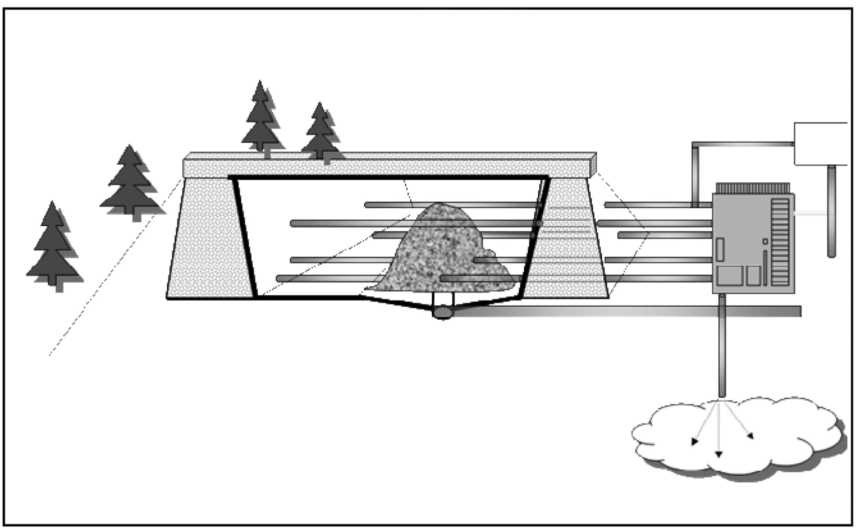

Figure 6. EcoShale's In-Capsule Process (10)

Bureau of Mines Retort

Several variations of the Gas Combustion Retort (GCR) developed for the U.S. Bureau of Mines by Cameron Engineers are currently in use for testing or shale oil production (Figure 7).

Between 1949 and 1955, three above ground gas combustion retorts were developed and operated by the U.S. Bureau of Mines, proving the technology.

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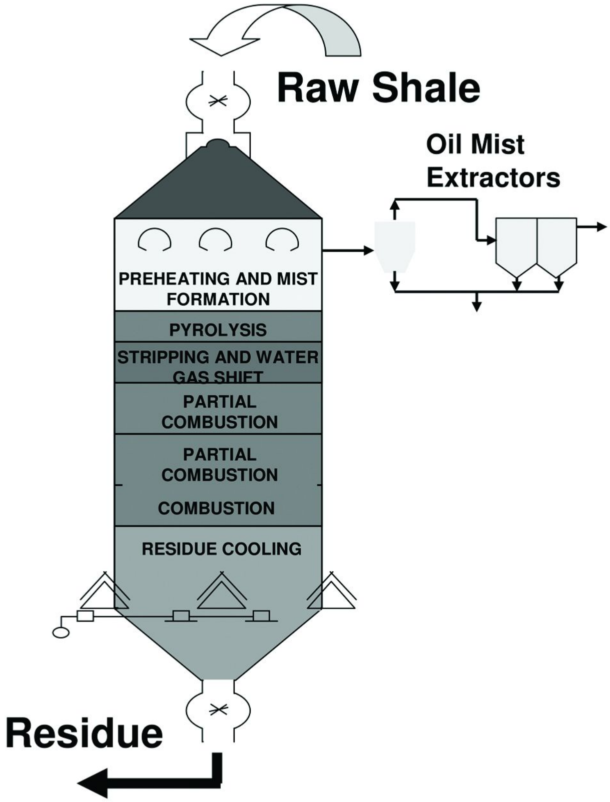

Figure 7. Gas Combustion Retort (2)

The original version of this two chamber vertical retort ignited the residual carbon coke on spent shale in the lower chamber to provide retort heat for fresh shale in the upper chamber.

Paraho Development Corporation

Subsequently, beginning in 1972, Paraho Development Corporation, a consortium of 17 private companies, produced approximately 110,000 barrels of shale oil using a modification of the Bureau of Mines GCR technology that was developed by Development Engineering Inc. The enhancements embodied in the Paraho technology allow the retort to be configured in either the original direct combustion mode or by circulating heated gases back to the retort to heat fresh shale (*11*).

Most of the fuel produced by Paraho was delivered to the U.S. Navy for fuels development and testing. The semi-works scale plant used for this effort was later decommissioned, but the pilot-scale test plant facility in Rifle, Colorado, has recently been refurbished for testing and design purposes by the successors of

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Paraho, now known as Shale Tech International. A next generation of the Paraho technology is under development by ShaleTech (Figure 8).

Petrosix

Another variation of the GCR technology, the Petrosix retort, has been in continuous commercial use in Brazil by Petrobras since approximately 1981. An initial 5.5 M diameter plant with a daily throughput capacity of 1,600 tonnes of shale ore was built in 1981. A larger 11m diameter GCR with 6,200 tonnes per day capacity was built in 199. Combined, the two Petrosix reactors currently process approximately 7,800 tonnes of shale per day to generate a slate of products that includes: 3,870 barrels of shale oil, 120 tonnes of fuel gas, 45 tonnes of liquefied petroleum gas and 75 tonnes of sulfur (*12*).

The failure to make use of the fixed carbon on the coked shale reduces the thermal efficiency of the Petrosix version of the GCR technology. It also affects the residual carbon content of the spent shale which must be disposed of, potentially affecting its environmental acceptability. However, the oil yield averages 85 to 90 percent of Fisher assay and the produced hydrocarbon gases have high calorific values. The technology has also demonstrated high operational efficiency, achieving up-time in excess of 94 percent over several years in operation.

The Petrosix GCR technology is currently being evaluated for use by the Oil Shale Exploration Company (OSEC) as part of a research and development (R&D) project on a BLM RD&D lease awarded to OSEC by the U.S. Department of the Interior, Bureau of Land Management in 2007. The Petrosix is also being considered for application in other oil shale deposits around the world.

Union B

The Union B Retort was developed by Union Oil Company of California and operated at various demonstration scales for over 6 years at the Long Ridge Project on Parachute, CO, before being shut down for economic and technical reasons in 1991. Designed to produce 9,000 Bbls/day, the maximum production never exceeded about 50 percent of that intended level. The Union B process employs a rock pump to move crushed shale upwards against a counter-flow of hot recycle gases (510 -538°C) that heats the shale and pyrolyzes the kerogen into vapors and gases. Heat for the gases is supplied by combustion of the residual carbon coked on the spent shale, making the process essentially energy self-sufficient. The process requires no cooling water – gases, solids, and produced liquids are cooled by the fresh shale entering the lower section of the retort. Importantly, "the reducing atmosphere maintained in the retort results in the removal of sulfur and nitrogen compounds through the formation of H_2S and NH_3 gas" which are captured and treated. This reduces the presence of these compounds in the produced shale oil, resulting in a higher quality shale oil that requires less upgrading. The produced

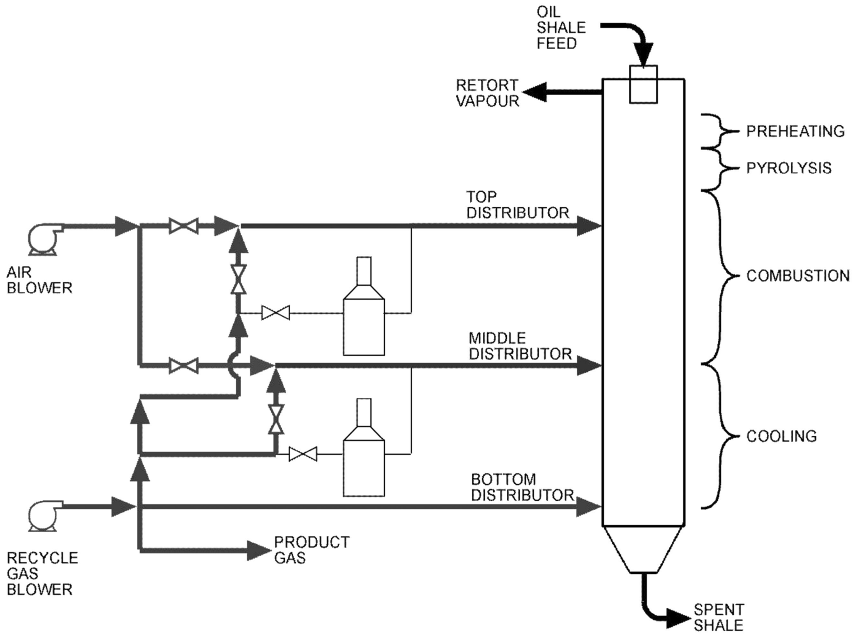

Figure 8. Paraho Process (3)

kerogen oil from Unocal's operations was usable as a low-sulfur fuel or as a very high quality feedstock for refining (*13*).

Other Variations

Other variations of the direct gas-heat carrier technology for lump shale include the small scale (3 meter diameter, 100-200 tons per day (tpd) throughput) Fushun lump shale retort that has been in use in China for more than 70 years, and the larger (1,000 tpd) Kiviter lump shale retorts employed by the Viru Keemia Group in Estonia.

The Fushun retort takes advantage of the fixed carbon residue on the coked shale by gasifying it, and using the resulting hot gas to heat fresh shale entering the top of the retort (Figure 9). This improves the thermal efficiency of the retort. However, the admission of air to the retort post-combustion introduces nitrogen, reducing the quality of the produced hydrocarbon gases, and the introduction of oxygen in the retort chamber causes some of the produced kerogen oil to be combusted, thus significantly reducing the shale oil yield to about 65 percent of Fisher assay. Due to the small scale of the technology, multiple retorts are typically arrayed with as many as 20 Fushun retorts sharing a single gas collection and condensation system. More than 120 of these retorts were in operation as of 2005 (*14*).

The Kiviter technology uses multiple internal pyrolysis chambers in the upper part of the retort, through which air and hot gases are circulated to achieve a thin-

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layer pyrolysis (Figure 10). As with the Petrosix GCR, there is no use of the fixed carbon on the remaining coked shale, thus reducing thermal efficiency to about 70 percent. Nitrogen content in the produced hydrocarbon gases reduces their calorific value, and the presence of oxygen in the retort reduces yield to about 75 to 80 percent of Fisher Assay. Nonetheless, two Kiviter retorts are effectively operated to produce shale oil and products at Yarve in Estonia (*15*).

Recent Innovations

More recent direct gas heat carrier approaches include a fluidized-bed heating process, injection of syn-gas from a coal gasifier, and a hydrogen-donor solvent technology, as follows:

Fluidized Bed Reactor with Fired Hydrogen Heater

Fluidized bed combustion technology was developed in the 1970s to combust coal for steam and power generation in the presence of carbonate materials that would capture sulfur and reduce emissions of Sulfur Dioxide (SO_2). This technology has recently been adapted and applied for use in oil shale retorting.

The Chattanooga Process, currently under development, introduces fresh crushed shale in to a non-combustion pressurized fluidized bed reactor. Heated hydrogen is injected from the bottom of the reactor, raising the temperature of the suspended shale particles to a processing temperature of ~500°C, and converting the kerogen to hydrocarbon vapors and gases, via thermal cracking and hydrogenation (Figure 11). In this unique approach, heated hydrogen is used as the heat conveyor, the fluidizing gas for the reactor bed, and as a reactant. Reactor overhead gases are cleaned of particulate solids in a hot gas filter and cooled. Hydrocarbon products are condensed and separated from the gas stream. Liquids can be lightly hydro treated to produce very low sulfur high grade synthetic oil.

In the Chattanooga Process, hydrogen is heated in an adjacent fired heater fueled by process off-gases and either supplemental gas or product oil, depending upon economic conditions, minimizing or eliminating external natural gas requirements. Use of hydrogen in the initial process phases enhances product quality and reduces the need for extreme hydrotreating.

Recovery of waste heat, power co-generation, and use of produced light hydrocarbon gases as hydrogen plant feedstock make the process virtually self sufficient by obtaining its energy requirements from the primary plant feedstock.

Dry processing of resource material eliminates water pollution and greatly reduces water usage. Greenhouse gas emissions are substantially reduced. The majority of the CO_2 is produced in the hydrogen reformer and can be captured through amine separation and sequestered. Decomposition of Western carbonate shale and formation of CO_2 are minimized due to the operating temperature range. Spent shale or sand is immediately available for land reclamation. This process has the ability to remove 99.8% of all sulfur.

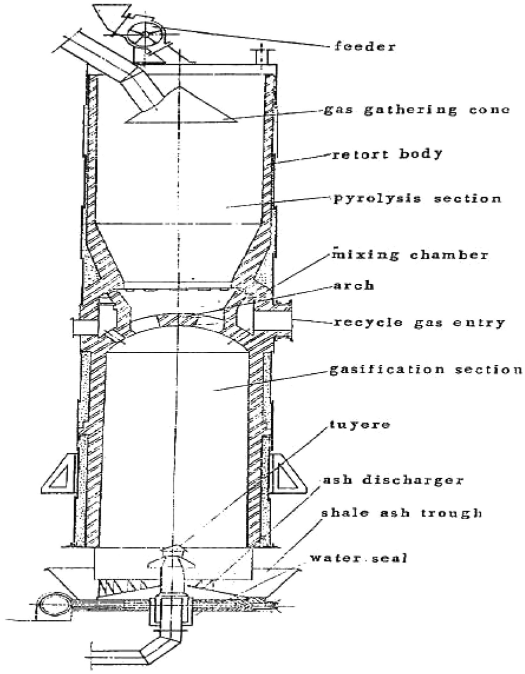

Figure 9. Fushun Retort (15)

According to the developers, high extraction yields are achieved due to the addition of hydrogen in the initial phase of processing. Pilot plant tests yielded 51.5 gals/ton from Colorado carbonate shale (with a Fischer Assay of 28.4 gal/ton). Two separate pilot plant tests on Kentucky shale also produced yields nearly double the Fischer Assay predictions. Based on pilot plant test results and with some hydrotreating, the product from oil shale would be in the range of 36°API Chattanooga Corp is preparing to design, construct and operate a demonstration facility as the next step in the commercialization process (*17*).

Rotary Kiln with Sweep Gas Injection from Integrated Gasifier

At least three U.S. companies, Syntec, EnShale, and Western Energy Partners, are working to develop and test an approach that injects heated synthetic gas created by a coal gasifier into a rotating kiln to directly heat and process crushed shale. The synthetic gas provides a hot, hydrogen-rich, sweep gas that interacts with the kerogen to produce energy rich hydrocarbon vapors and gases. The vapors are condensed to produce high-quality kerogen oil. The gases are stripped to remove sulfur. Residual heat from the gasifier is used to preheat the shale, improving thermal efficiency of the integrated process. Water reclamation from the gasifier also provides water required for hydrotreating and upgrading. This process has been studied and tested and proven at bench scale at the University of

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Utah. One of the developers has announced plans for a 50 Bbl/d field pilot plant (*18*).

Rendall Hydrogen-Donor Solvent Process

A hydrogen-donor solvent approach is being developed for oil shale in Australia (Figure 12). The Rendall Process feeds crushed run-of-the-mine shale to a conditioning unit to be slurried with a recycled stream from the distillation section of the plant that includes a middle-distillate fraction. That fraction, upon hydrogenation, becomes a hydrogen-donor solvent. The hydrogen-shale slurry is heated to retort temperatures (~450°C) and then fed to a kerogen conversion / hydrogenation reactor. The release of additional hydrogen from the hydrogen-donor solvent interacts with kerogen from the shale to result in a lighter fraction oil product. The hydrogen also reduces the organic sulfur content to hydrogen sulfide (which is later converted to elemental sulfur) and scavenges oxygen and nitrogen from the kerogen, improving product quality.

The process is estimated to yield approximately 95 percent light oil and 5 percent high-value hydrocarbon gases. Emissions are estimated to be equal to approximately 5 percent of the organic carbon in the shale feedstock. Solid wastes, principally spent shale, are free of hydrocarbons and insoluble. The process has been lab tested at bench scale. Blue Ensign, an Australia firm, is planning a 1 tonne/hour pilot plant in Townesville, Australia using Australian, silica-based, Julia Creek shale. The process has also been tested using Colorado carbonate-based Green River oil shale (*19*).

Solid Heat Carrier Technologies

Several technologies have been devised and evaluated for processing more finely crushed shale ore and making use of the fines produced in mining and ore sizing operations that are not suitable for "lump" shale processes.

In the 1970s, TOSCO conducted extensive development and testing of the TOSCO II retort technology which employed heated ceramic balls to capture and transfer residual heat from the retorted shale to help dry and pre-heat fresh shale entering the retort. This technology was to have been demonstrated at commercially-representative scale in Exxon's planned 47,000 Bbl/d Colony Project which was terminated during construction in 1982 due to rising costs and a low price outlook for crude oil.

The Lurgi approach uses a mixture of heated sand and hot shale for solid-to-solid heat transfer.

More recent approaches include a horizontal rotating kiln that recirculates hot shale ash (ATP), and more complex rotary drum with cyclone separation and hot solids recycle for shale heating and drying (Galoter). The Galoter process is being employed in commercial operations in Estonia.

Lurgi

The Lurgi-Ruhrgas process was developed in Germany for the devolatization of coal fines. The application of the Lurgi-Ruhrgas process to oil shale was intended to integrate kerogen retorting with hydrocarbon refining in a single plant. The heating approach mixes fresh crushed shale (<0.25 inch diameter) with a mixture of six times as much heated spent shale and sand (heat carriers) to raise the average temperature above retort temperature, causing the fresh shale to release kerogen vapors and hydrocarbon gases. Sand and processed shale are returned to the bottom of the process, reheated with combustion gases, and recycled back through a lift pipe to process more fresh shale. Small particle sizes require a variety of mechanisms including sedimentation, centrifuging, cyclones, and electrostatic precipitators to remove fines from produced kerogen oil liquids (Figure 13) (*20*).

Galoter

The newer Galoter retort design, Figure 14, is a horizontal fluidized bed retort with a throughput capacity of about 3,000 ton per day (roughly half the capacity of the Petrosix 11 meter retort and three times the capacity of the Kiviter). Using shale ash as a solid heat carrier, the process is more thermally efficient, reducing energy inputs, and achieves a higher yield on the order of 85 to 90 percent of Fisher Assay. The design also delivers a higher quality of produced gases. Although the process is far more complex than the Kiviter, plant availability has steadily improved, recently achieving a very high level of operating "up-time."

Alberta Taciuk Process (ATP) – Horizontal Rotating Kiln

The Alberta Taciuk Process is a horizontal rotating kiln design with very high thermal efficiency and high production efficiency, achieving shale oil production of 90 percent of Fisher assay or greater (Figure 15). The ATP Process was developed in 1976 for treating Alberta oil sands and later refined for use in oil shale and contaminated waste treatment options. The process was subsequently scaled up and demonstrated at commercially-representative scale in the Stewart deposit in Queensland Australia.

The ATP process combines gas recirculation and direct and indirect heat transfer from circulated hot solids in a rotating kiln. As with other surface retorts, the process is largely energy self-sufficient. Some of the hot processed shale is re-circulated in the retort with fresh shale to provide pyrolysis heat by direct, solid-to-solid heat transfer. The ATP Process has successfully produced over 1.5 million barrels of shale oil from a 4500 Bbl/d reactor at the Stuart Shale Oil Project in Queensland, Australia. Until recently, however, ATP had not been tested or demonstrated using carbonate-based U.S. oil shale. OSEC recently shipped over 300 tons of shale from the White River Mine site for testing in the

ATP in Alberta. The technology was judged a technical success, but the project was suspended in 2004.

Oil Shale Exploration Company is the recipient of a federal Oil Shale RD&D lease at the White River site in Utah. The ATP process is also being considered for use in several other projects including oil shale development efforts in China and in the Kingdom of Jordan.

In-Situ Technologies

In-situ oil shale processes introduce heat to the kerogen bearing ore while it is still embedded in its natural geological formation.

There are both advantages and disadvantages related to operations, requirements, products and quality, and environmental impacts associated with applying in-situ technologies versus surface retorting approaches.

- Materials handling is greatly reduced as only to organic content of the shale, not the entire ore body, is contacted and produced to the surface. There is no overburden to be mined, little or no subsurface mining, and no spent shale to be disposed.
- In deep and thick deposits, where in-situ approaches are most applicable, more of the resource can be contacted and heated, although less of the products will be recovered.
- Water requirements for mining, reclamation, dust control, and spent shale disposal are largely eliminated.
- Net energy efficiencies for the integrated process – from resource access and recovery, through retorting and upgrading – to waste disposal can be improved relative to some surface-based mining and retorting processes.
- Emissions of criteria air pollutants can be significantly reduced.
- Depending on the source of heating energy, lifecycle carbon emissions could also be reduced.
- Surface impacts on wildlife habitats, including those from noise, would be reduced, due to the lack of mining activity, or requirements for storage of overburden, shale, and spent shale.
- Potential surface and groundwater impacts of leachates from overburden, shale, and spent shale would be avoided.

In-situ processes also pose some significant disadvantages relative to surface approaches:

- Early approaches experienced difficulty controlling both the temperature and the directional mobility of heat in the shale formation. Excess heat can reduce shale oil quality, recovery efficiency, and yield and increase subsurface environmental impacts and emissions.
- Subsurface processes face challenges associated with heating efficiency. Shale is a slow heat absorber and not a good heat conductor. Fracturing by natural or induced methods is typically needed to achieve even and effective heat distribution through the formation and increase the surface area for heating.

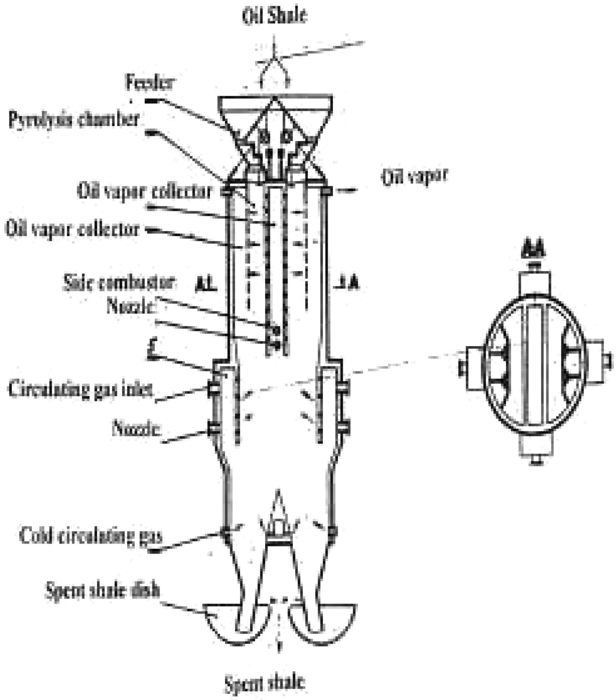

Figure 10. Kiviter Vertical Retort (16)

- Typically, in-situ processes require far greater heating time than surface approaches, resulting in longer lead-times and energy-investment periods before production of hydrocarbons begins.
- Product recovery is also constrained by inconsistent (heterogeneous) permeability and porosity in the shale formation, presenting challenges for recovering the produced hydrocarbon gases, vapors, and liquids.
- Subsurface heating – whether through direct combustion or in-situ heating - may leave residual carbon in the form of char on the remaining mineral body of the formation.
- In-situ combustion approaches use some of the shale itself as fuel for heating the rest of the formation. Many in-situ heating methods, however, require an external heat source, impacting energy efficiencies.
- As with conventional oil production, production efficiency can be relatively low. Effective means are required to "sweep" the produced hydrocarbons through the formation to the production well.
- Intrusion of groundwater into the heating area can result in inefficient heating and creation of unwanted steam, requiring effective methods for isolating the production area.
- Residual unswept hydrocarbons and char can both present contamination risks for groundwater, also requiring effective methods for isolating the heating area. Fracturing may also affect subsurface ground water patterns.

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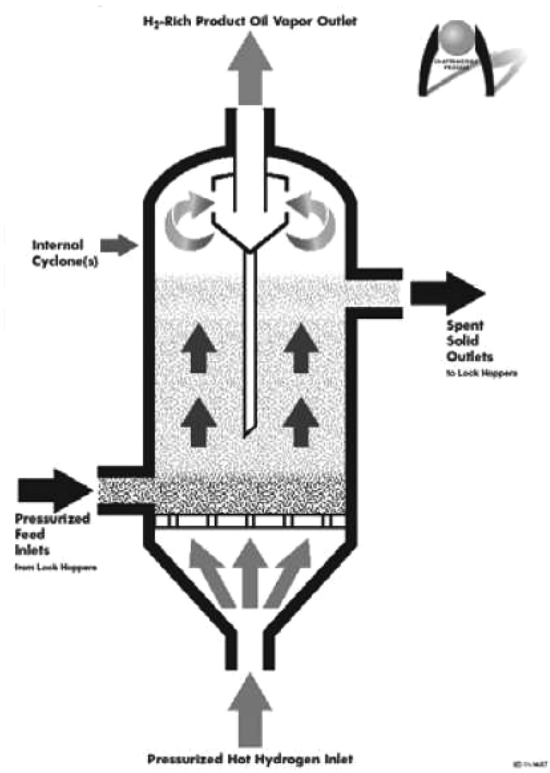

Figure 11. Chattanooga Process (17)

- Carbon dioxide may be produced by subsurface heating and degradation of the carbonate minerals that comprise most U.S. western oil shale. Carbon dioxide may also be generated in significant quantities by some energy sources used for subsurface heating.
- All of these potential disadvantages are targets for ongoing research, development, and demonstration efforts in government, industry, and the research community.

In-Situ Combustion Approaches

There are two general in-situ approaches:

- True in-situ (TIS) in which there is minimal or no disturbance of the ore bed, (Figure 16) and
- Modified in-situ (MIS), in which the ore bed is rubblized either through direct blasting or after partial mining to create void space (Figure 17).

Most early processes involved combusting some of the subsurface resource to generate heat needed to convert kerogen from the remaining resource to hydrocarbon liquids and gases, which could then be produced to the surface through conventional oil wells.

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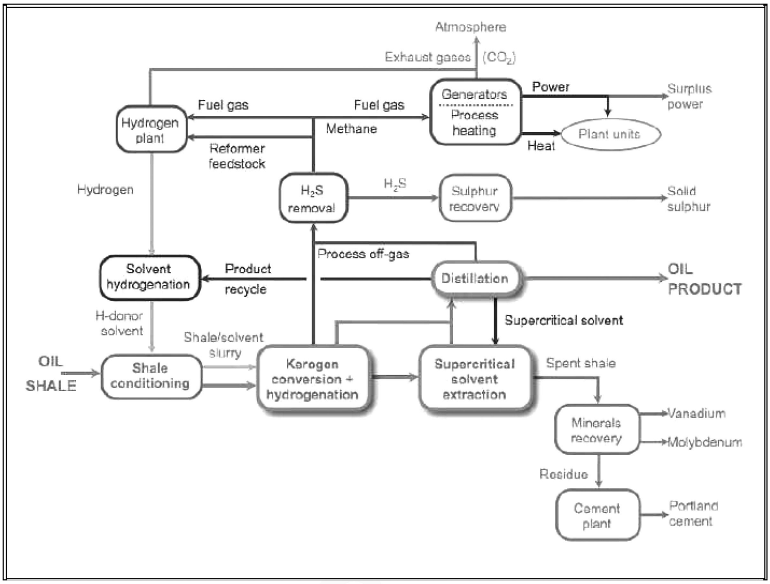

Figure 12. Rendall Hydrogen-Donor Solvent Process (19)

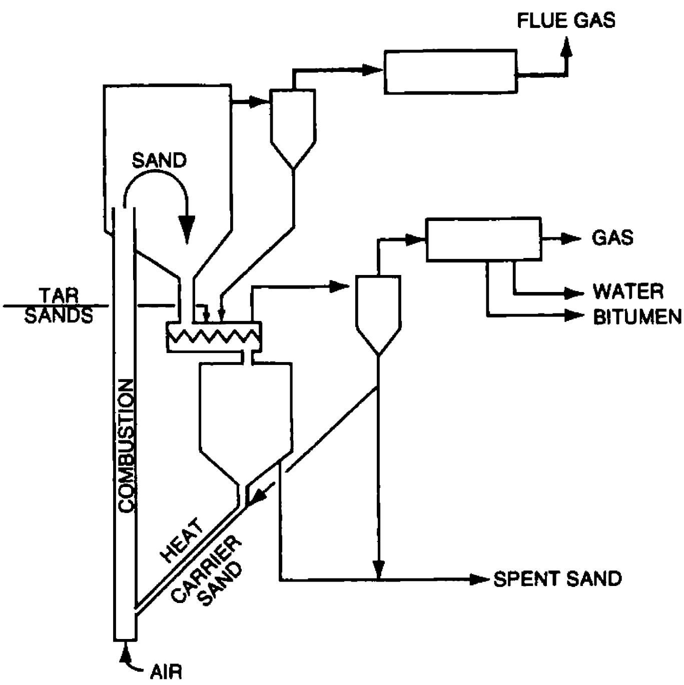

Figure 13. Lurgi Process (1)

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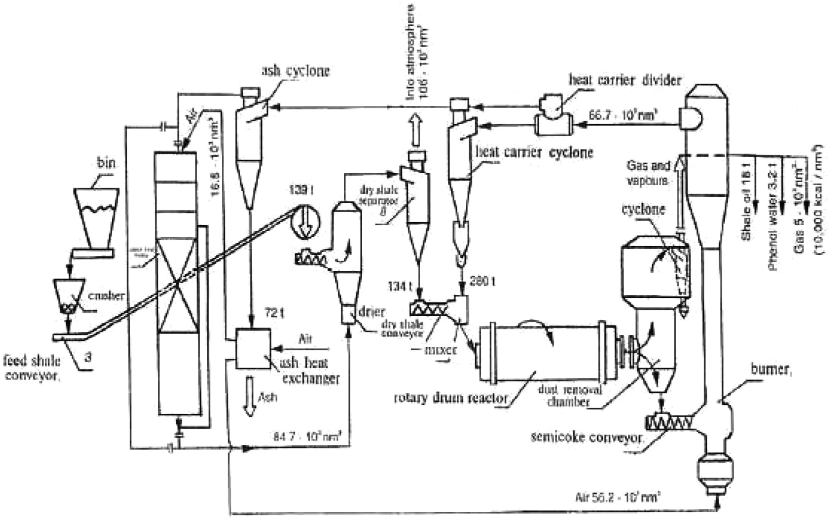

Figure 14. Galoter Process (21)

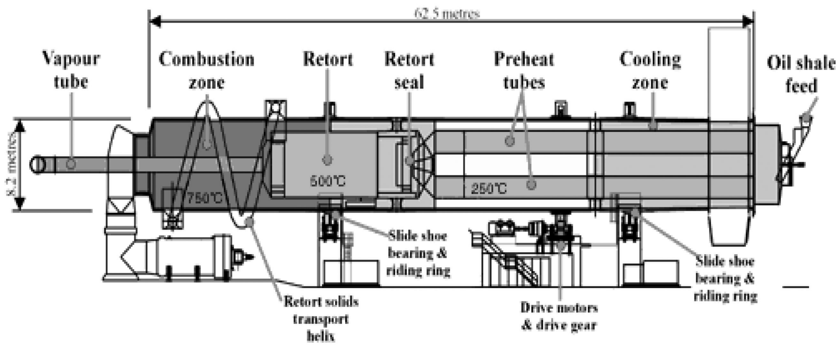

Figure 15. ATP Horizontal Rotator Kiln (2)

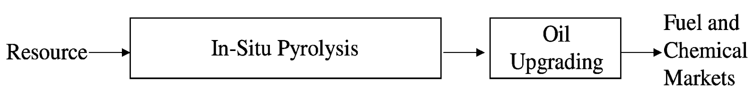

Figure 16. Conversion of Oil Shale to Products (True In-Situ Process) (2)

Both of these in-situ combustion approaches faced major challenges, however, primarily related to sustaining and controlling the subsurface combustion, directing and communicating heat through the target shale formation, generation of subsurface pollutants, and degradation of the subsurface environment, including groundwater quality. The MIS approaches achieved significant advances in terms of air, temperature, and combustion control, but emissions and subsurface environmental impacts continue to be challenges for MIS approaches.

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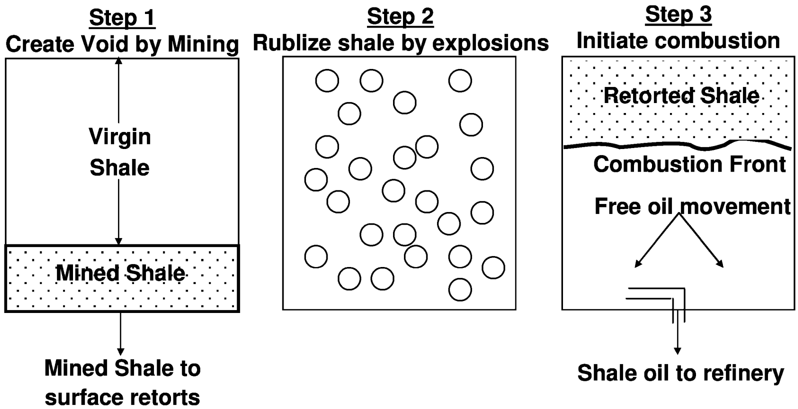

Figure 17. Conversion of Oil Shale to Products (Modified In-Situ Process) (22)

Table II provides an overview of the In-Situ Process that will be discussed in the following section.

Early In-Situ Approaches and Variations

Lessons learned from early attempts with true in-situ combustion led to a number of variations intended to address technical challenges associated with heat control, fracturing, and sweep efficiency. According to (Lee, 1991), Sinclair Oil and Gas attempted to use high pressure air to sweep produced hydrocarbons to the production wells. Equity Oil and Gas attempted to inject heated natural gas to serve as a heat carrier – in lieu of direct combustion – and to improve sweep efficiency. Dow Chemical, in experiments in eastern shale resources, applied blasting techniques to fracture shale formations. Dow also experimented with electric resistance heaters -- an approach later adapted by Shell. Geokinetics, Inc. laid the fundamental groundwork for modified in-situ processes with the use of mined, horizontal retort voids for use in thin deposits (*23*).

The Occidental Modified In-Situ Retort, completed in 1984, involved sinking a mine shaft and blasting and rubblizing a portion of the shale body to allow void space for heating and retorting. The process integrated surface retorting operations for the mined shale. While technically a success in terms of process performance and product recovery and quality, the project also raised numerous potential environmental impacts associated with in-situ combustion approaches (*24*).

Table II. Classification and Status of Some In-Situ Oil Shale Retorting Technologies (*3*, *9*)

	In-Situ Process	
Heating Method	*Process*	*Last Status*
True In-Situ	Sinclair High Pressure Air	Pilot
Combustion	Laramie Energy Tech. Center	Pilot
Modified In-Situ	Geokenetics Horizontal	Pilot
Combustion	Occidental Surface Combination	Demonstration
In-Situ Heating		
Down Hole Heater	DOW Resistance Heating	Pilot
	Shell Electric Resistance Heating	Demonstration[a]
	IEP Geothermic Fuel Cell	Lab[a]
Radio Frequency	Radio-Frequency w/ Critical Fluids	Lab[a]
	P-W Borehole Microwave	Pilot Planned[a]
Direct Current	Electro-Frac™	Pilot Plan[a]
Heat Gas Injection	Equity Hot CO_2 Injection	Pilot
	Earth Search Sciences/Petro-Probe	Pilot[a]
	AMSO Deep Illite	Lab[a]
	MWE In-Situ Vapor Extraction	Pilot[a]
	Chevron CRUSH	Lab[a]
Groundwater	Shell Freezewall Technology	Pilot (in progress)[a]
Protection	EcoShale Incapsule	Field Pilot[a]

[a] Currently in development.

New Approaches to In-Situ – Thermally Conductive Conversion

Much has changed, however, in the area of in-situ retorting. The most significant change is a major shift away from the concept of in-situ combustion, in favor of direct heating without combustion. Most current in-situ activity focuses on this new thermally-conductive conversion approach. Several new in-situ technologies are in varying stages of development and assessment. The recent advances in in-situ oil shale technology are both numerous and ground breaking. These new variations on the traditional approaches described above may offer:

- Improvements in thermal efficiencies
- Reductions in energy use
- Reductions in net water use
- More efficient capture of regulated emissions
- Effective carbon management
- Higher production yields, and/or

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- Increased product quality as measured by API gravity and other standard measures.

New in-situ approaches can be classified into three groups:

- Downhole heaters
- Direct current heating
- Hot gas injection

One group employs downhole heaters – rather than mining or in-situ combustion – to heat the shale body to achieve pyrolysis and produce hydrocarbons. Another approach fractures and applies a direct current to heat the formation. The third approach, a variation on early concepts, injects heated gas to heat the shale and recover produced hydrocarbon gases and vapors. Each of these approaches is explored below.

Down Hole Heaters

Shell In-Situ Conversion Process (ICP)

For more than a quarter of a century, Shell's Mahogany Research Project has conducted research on Shell's innovative In-Situ Conversion Process (ICP) to recover oil and gas from oil shale in Colorado. ICP involves placing either electric or gas heaters in vertically drilled wells and gradually heating the oil shale interval over a period of several years until kerogen is converted to hydrocarbon gases and kerogen oil which is then produced through conventional recovery means. Electric heaters, inserted in heater wells, gradually heat shale beneath surface at a target depth zone 1,000 to 2,000 feet subsurface. The rock formation is heated slowly over a period of years to ~350°C (650 to 750°F), changing the kerogen in oil shale into oil and gas (Figure 18).

ICP, when applied to oil shale, produces a range of gases including propane, hydrogen, methane, and ethane, as well as high quality liquid products – jet fuel, kerosene, and naphtha – after the initial liquid product is hydro-treated.

ICP appears to improve heat distribution in the target deposit, overcoming heat-front control problems traditionally associated with prior in-situ combustion processes. Due to the slow heating and pyrolysis process, the product quality is much better and subsequent product treating is less complex as compared to oil produced by surface retorting or conventional in-situ approaches.

The gradual heating process is also expected to induce fracturing in the shale – assisting in uniform heating and providing pathways for produced gases and vapors to migrate to producing wells.

ICP produces approximately 1/3 gas and 2/3 light oil. Shell estimates that potential yields in the thickest and richest deposits could range from 100,000 to 1 million barrels of oil equivalent per acre. The process yields high quality feedstocks (>30 API gravity) that require only minimal upgrading to produce jet, diesel, and motor gasoline fuels. A recent field test on private Shell lands in Colorado demonstrated the efficacy of the ICP technology for producing significant volumes of high quality product.

Commercial scale application of the ICP technology using electric heaters will require extensive electric power generation facilities. Shell engineers have estimated that the process will generate three times the energy it uses. Hydrocarbon gases produced by the ICP may be used to generate electricity to reduce power requirements. Shell is also exploring the use of gas-fired heaters and other approaches to reduce electric power demand and improve thermal efficiency.

The slow, lower temperature heating process is expected to generate significantly lower carbon emissions than traditional surface retorting processes, because the lower heating temperatures preserve the integrity of the carbonate host rock. Ultimately, however, the carbon profile of an ICP project will depend largely on the energy source used for power or heat generation – coal, nuclear, gas, hydro, solar, or wind.

Shell has engineered and begun testing a freezewall technology to protect the heating zone from groundwater intrusion and to protect the groundwater from potential contamination (Figure 19). Once the hydrocarbons within a heating area have been produced and the subsurface area has been cleaned by repeated steam flushing, the freezewall is terminated allowing resumption of unimpeded groundwater flow.

The ICP requires no process water but would require water resources for post-production cleaning and site reclamation and restoration, as well as for product upgrading and site operations. Net water requirements are estimated to be less than 3 barrels per barrel of oil equivalent produced.

Field tests in Colorado on privately held lands expected to be expanded with several technology variations on three oil shale RD&D leases that were awarded to Shell by the U.S. Bureau of Land Management in 2006. Shell has also been awarded a concession from the Kingdom of Jordan to evaluate and apply the technology in deep oil shale deposits within the Kingdom.

IEP's Geothermic Fuel Cell

Another novel downhole heater approach is the application of geothermic fuel cells to produce heat and energy. Originated in Sweden during World War II, the use of geothermics has since expanded to applications to remove toxic wastes and to produce fuels from heavy oil, tar sands, and other resources.

Independent Energy Partners (IEP) has developed a heating technology applying a "geothermic fuel cell" to convert kerogen to shale oil, in-situ, while using minimal external energy sources (Figure 20). In the IEP concept, a high-temperature fuel cell stack is placed in the formation to heat the kerogen-bearing formation and release hydrocarbon liquids and gases into collection wells.

A portion of the gases are processed and returned to the fuel cell stack, with the rest available for sale. After an initial warm up period (during which the cells are fueled with externally sourced gas) the process becomes self-fueling from gases liberated by its own waste heat. The system, in steady-state operation, produces oil, electricity and natural gases. The GFC process developer estimates

In Oil Shale: A Solution to the Liquid Fuel Dilemma; Ogunsola, O., et al.;
ACS Symposium Series; American Chemical Society: Washington, DC, 2010.

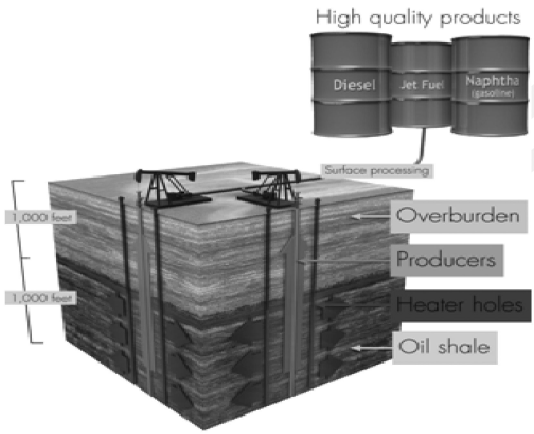

Figure 18. Shell's ICP Process (3)

Figure 19. Shell's Freezewall (3)

a potential net energy ratio of approximately 18 units of energy produced per unit used, when primary recovery is combined with residual char gasification and resulting syntheses gas.

According to IEP, Geothermic fuel cells heat formations by solid-to-solid conduction more efficiently than non-conductive applications. GFCs produce heat at a uniform rate along their length and therefore heat the formation uniformly

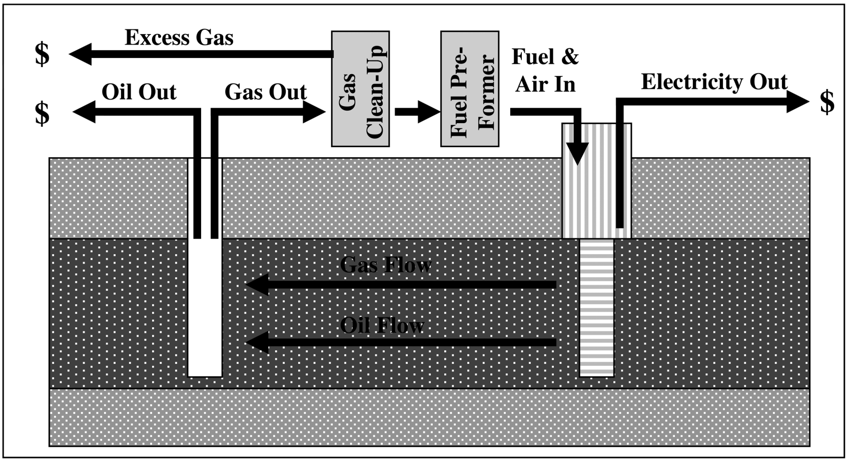

Figure 20. IEP's Geothermic Fuels Cells Process (3)

from top to bottom, leading to greater yields, improved recovery efficiency, and simplified production cycles.

Raising the formation temperature increases fluid pressure in the heated zone by 100 to 200 pounds per square inch (psi) over native pressure, which can be enough to fracture oil shale. Alternatively, the formation can be pre-fractured to enhance the hydrocarbon flow and communication between heating and producing wells.

Unlike other conductive approaches, geothermic fuel cells do not consume vast amounts of external energy — rather, they become self-fueling. IEP estimates the geothermic fuel cells would yield approximately 174 kilowatt hours (Kwh) of electric power per barrel recovered.

GFCs are also expected to produce only minimal air emissions. With no combustion involved – fuel cells produce electricity through an electrochemical reaction – there is negligible production of NO_x, SO_2, particulate or toxic emissions.

GFCs are essentially self-sufficient in process water use. They produce steam as an exhaust which is re-circulated through fuel pre-reformers, thus obviating most if not all needs for outside process water.

GFCs produce minimal surface impact compared to mining and retorting operations that dispose of high quantities of waste "tailings" and dust. Since GFCs utilize a true "in-situ" approach, in which the ore body is left in place relatively undisturbed, waste disposal problems are eliminated.

IEP has entered into research and development relationships with the U.S. DOE Pacific Northwest National Lab and French oil company Total to advance the development of the GFC technology.

Radio-Frequency Heating

Working much like a microwave oven, radio frequency energy can also be used to generate heat for retorting. Extensive research has been conducted since the 1970s to design and test the application of radio frequency (RF) energy to improve oil shale retorting. There are several variations of RF energy applications for oil shale in development.

Schlumberger and Raytheon-CF Radio-Frequency with Critical Fluids

Raytheon and CF Technology have developed a patent-pending extraction methodology that uses radio frequencies to heat the shale to pyrolysis temperatures and supercritical carbon-dioxide to "sweep" the produced liquids and gases to production wells. With this technology, wells are drilled into the shale strata using standard oil industry equipment. Tuneable RF antennae, or transmitters, are lowered into the formation and then transmit RF energy to heat the buried shale.

Once heating and pyrolysis have occurred, super critical carbon dioxide is pumped into the shale formations to extract the produced oil from the rock and carry the oil to an extraction well. At the surface, the carbon dioxide fluid is separated and pumped back into injection wells, while the oil and gas are refined into fuels and other products.

This extraction technology can begin to produce oil and gas within only a few months, compared to years of heating required by other in-situ heating processes. The process is also "tunable" allowing heat to be directed consistently to the desired target and facilitating production of various products.

However, as with the Shell ICP, the RF/CF technology consumes significant electrical energy to generate the RF energy. According to Raytheon, for oil shale, this technology may recover four to five barrels of oil equivalent (BOE) for every barrel of energy consumed.

Ultimately, a self-sequestration approach, in which CO_2 is reinjected into the depleted kerogen-bearing formation, is expected to yield a neutral carbon foot print for process operations.

In 2007, Raytheon and CF Technologies sold the integrated technology to Schlumberger, one of the world's largest oil field service companies, to commercialize the technology and facilitate its application in heavy oil and oil shale projects (*3*).

Another oil shale technology company, Phoenix-Wyoming, also seeks to apply borehole microwave heating technology. According to Phoenix-Wyoming, field tests have indicated that microwave technology can heat shale up to 50 times faster than in-situ heating using electric conduction methods. The effects of this faster heating approach on formation temperature, carbon profile, recovery efficiency, and product quality are not known.

Direct Current In-Situ Heating

Another novel approach to in-situ heating involves applying an electrical current through the oil shale formation to conduct heat to the shale.

ExxonMobil's' Electrofrac™ Process for in-situ oil shale conversion is designed to heat oil shale in-situ by hydraulically fracturing the oil shale and filling the fractures with an electrically conductive material, thus forming a heating element (Figure 21). Electricity is conducted from one end of the fracture to the other, making the fracture a resistive heating element. Heat flows from the fracture into the oil shale formation, gradually converting the oil shale's solid organic matter into oil and gas. Using fractures created from horizontal wells is expected to allow Exxon to achieve a conductive zone that will heat the resources to pyrolysis temperature, forming liquids and gases that can be produced by conventional recovery technologies.

ExxonMobil screening of over thirty candidate technologies concluded that linear heat conduction from planar heat sources is likely to be the most effective method for "reaching into" organic-rich rock to convert it to oil and gas. According to ExxonMobil, planar heaters such as these should require fewer few wells than wellbore heaters and offer a reduced surface footprint.

This process has the potential to provide cost-effective recovery in deep, thick formations with less surface disturbance than other proposed methods. Results from laboratory experiments and numerical modeling have been encouraging, and field tests have been initiated to test Electrofrac process elements on a larger scale. Many years of research and development may be required to demonstrate the technical, environmental, and economic feasibility of this breakthrough technology.

As with the Shell technology, the Exxon in-situ approach may also require strategies to prevent groundwater intrusion and protect groundwater from contamination by produced hydrocarbons and other compounds. Both the Shell ICP and Exxon Mobil Exectrofrac™ technologies require the generation of significant quantities of electric power to provide process heat.

In-Situ Hot Gas Injection

Hot gas injection approaches, originally considered by Sinclair and others, have also attracted the attention of technology developers for potential application in oil shale development.

Chevron CRUSH

The Chevron CRUSH process builds on in-situ concepts developed by Sinclair, Equity, Geokinetics and others to used natural and induced fractures between wells to improve heat distribution and fluid-flow through oil shale formations and to circulate heated gases to convert embedded kerogen into hydrocarbon vapors and gases. Where early approaches used natural gas

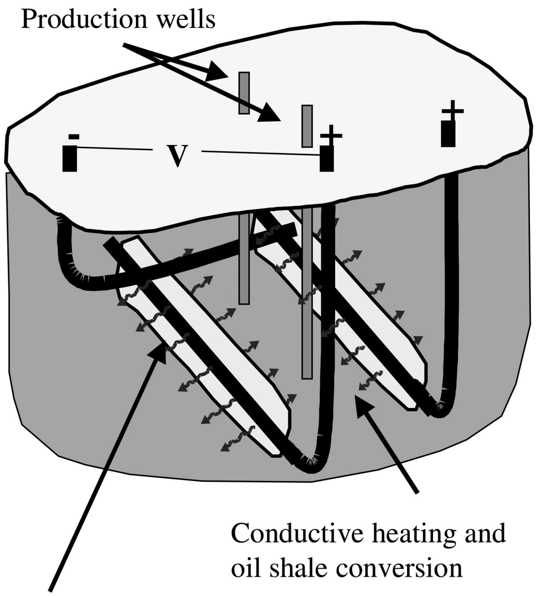

Figure 21. Electrofrac™ Process (3)

(methane), the Chevron process uses heated carbon dioxide as the gas heat carrier. The Chevron approach seeks to achieve uniform permeability through the targeted production zone by drilling wells and applying a series of complex fractures by injecting CO_2 to create a rubblized production zone (Figure 22) (*25*).

The fracturing technology would allow large horizontal zones "approximately 1 to 5 acres wide and 50 feet high within the center of the 200 foot thick oil shale deposit." to be rubblized. Thus, a large vertical area of remaining shale, above and below the rubbleized "pocket" would remain as a natural, unfractured, and impermeable barrier protecting groundwater aquifers above and below the oil shale formation. This approach is intended to protect the heating zone from groundwater intrusion and protect groundwater from contamination by produce hydrocarbons and other heavy metals potentially released by in-situ heating.

The retorting process combines both in-situ heating and in-situ combustion. Initially, heated CO_2 is injected and cycled through the rubblized zone to decompose the kerogen into producible hydrocarbons. The remaining organic matter in the previously heated and depleted zones would then be combusted to generate hot gases required to heat the circulated CO_2 for use in successive oil shale intervals or "pockets", improving overall thermal efficiency of the process. The CO_2 will serve as a critical fluid to mobilize and sweep the produced hydrocarbon fluids to production wells.

Chevron Shale Oil Company, a part of Chevron U.S.A. Inc, has secured an RD&D lease tract in Rio Blanco County, Colorado where the company will conduct oil shale research, development, and demonstration. Chevron plans to test the technology in several laboratory, bench, and small field tests. Chevron proposed a pilot test to BLM consisting of a minimum of 2-5 spot patterns (4 injectors and 1 producer per pattern) (*25*).

PetroProbe / Earth Search Sciences

Earth Search Sciences, Inc., has licensed a new processing system that it believes to have great potential for recovering oil from oil shale deposits. The in-situ process can gasify and recover products from oil shale deposits as deep as 3,000-plus feet.

In the PetroProbe process, air is superheated in a burner on the surface, its oxygen content carefully controlled. As superheated air travels down a borehole, it interacts with the oil shale and brings hydrocarbons to the surface in the form of hot gases. The gases are then condensed to yield light hydrocarbon liquids and gases (Figure 23). The process achieves a controlled and relatively quick production of product.

No mining is involved in the technology. The process begins by drilling into the body of oil shale and locating a processing inlet conduit within the hole. An effluent conduit is anchored around the opening of the hole at the ground surface. Pressurized air is introduced to an above-ground combustor, superheated and directed underground into the oil shale through the inlet conduit to heat the rock and convert the kerogen to a gaseous state.

Radiant heat in the inlet conduit produces a non-burning thermal energy front of predictable radius in the oil shale surrounding the hole. High temperatures and correct pressures cause the porous marlstone to gasify and allow its gaseous hydrocarbon products to be withdrawn as an effluent gas. Four products result: Hydrogen; 45°API gravity condensate; 1,000 btu methane gas, and water.

This is a self-sustaining system: effluent gas is transferred to a condenser where it is allowed to expand and cool; the gaseous fraction is separated from the liquid fraction and scrubbed to provide an upgraded synthesis gas; a portion of this gas is recycled and combined with other recycled feed stocks to create continuous fueling within the combustor – resulting in a significant product cost savings.

The process is environmentally sensitive. Produced CO_2 is compressed, and then pumped back into the oil shale body where it remains. Earth Search Sciences' patented remote sensing technology is used to establish a baseline before the project starts. Thereafter, continual monitoring during testing and production provides early-warning of problems, allowing them to be fixed quickly.

An important feature of the PetroProbe technology is its minimal surface footprint. Each complete plant will cover approximately one acre of land and produce for 10 to 20 years before depletion occurs. The surface plant's portable design allows it to be dismantled and moved to the next site. Subsurface, the formation retains 94 to 99% of its original structural integrity once the kerogen has been gasified.

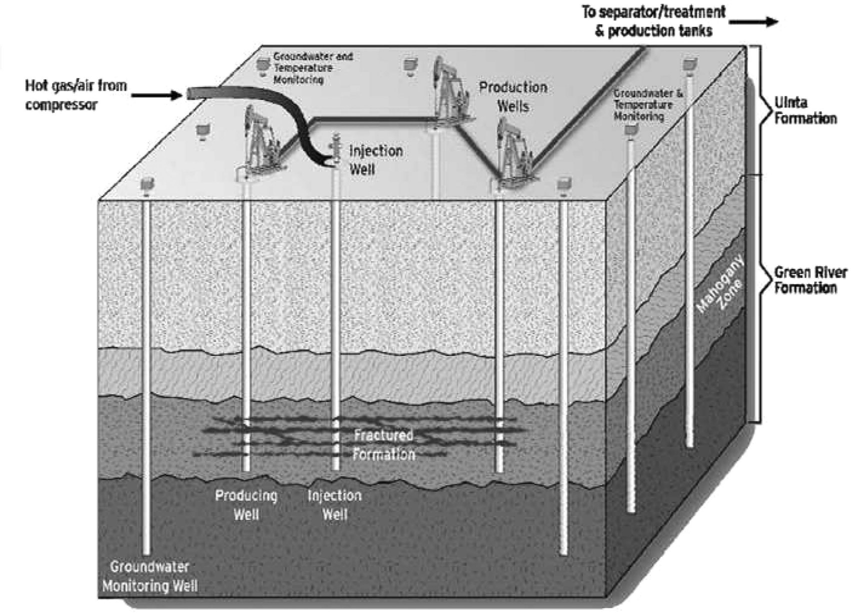

Figure 22. Chevron CRUSH (26)

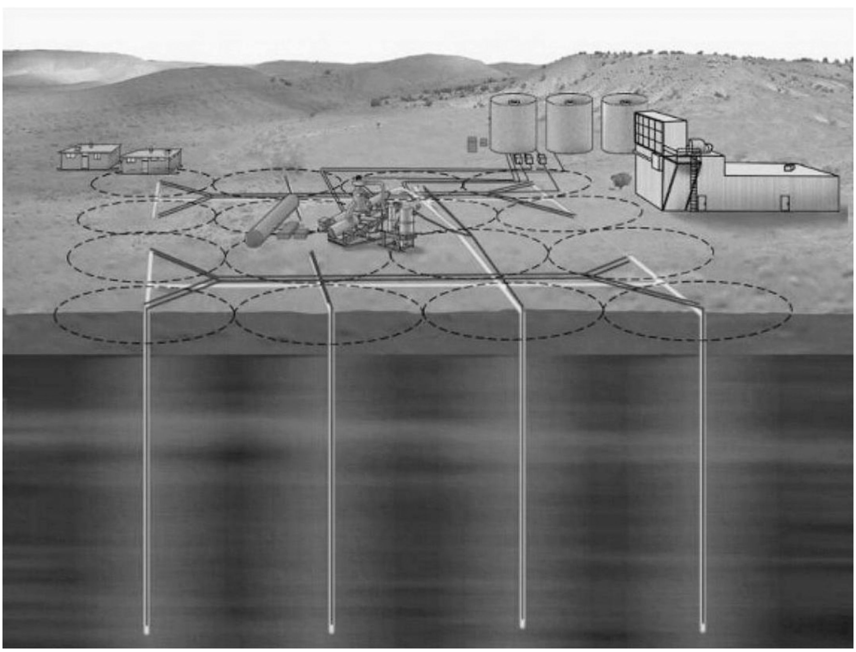

Figure 23. PetroProbe Process (26)

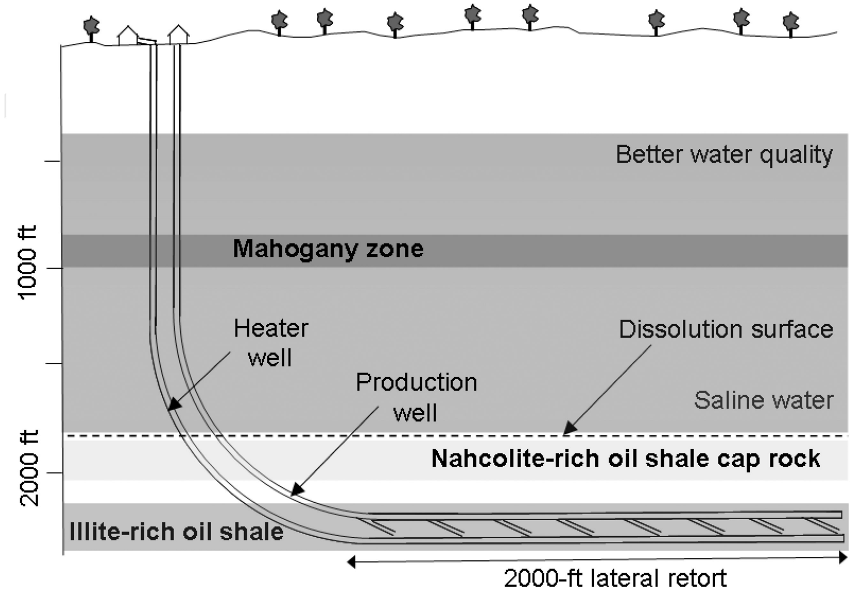

Figure 24. AMSO-EGL (26)

AMSO –EGL Technology

American Shale Oil, LLC (AMSO), formerly E.G.L. Oil Shale, LLC, is developing innovative, environmentally sustainable, in-situ shale oil extraction processes. AMSO is developing a new process for in-situ retorting of oil shale.

The AMSO-EGL Oil Shale process (patent pending) involves the use of proven oil field drilling and completion practices coupled with AMSO's unique in-situ retorting technology. The approach incorporates closed loop heating and lateral in-situ retorting to maximize energy efficiency while minimizing environmental impacts. Heat is introduced to the retort using a series of pipes placed near the base of the oil shale bed to be retorted (Figure 24). In many ways, this approach appears to emulate the successful Steam Assisted Gravity Draining (SAG-D) approach currently in use for heavy oil and oil sands development.

AMSO's proprietary process utilizes thermal spalling, convection and refluxing mechanisms to enhance heat distribution through the retort. The lateral retort approach efficiently distributes heat and minimizes surface disturbance by reducing the number of wells per area retorted.

After initial start-up, combustion of the gaseous hydrocarbons and hydrogen, co-produced with the shale oil, is expected to provide sufficient heat to liberate shale oil and gas from the deposit. In this way, shale oil is retorted without consumption of the produced shale oil or the use of external energy such as electricity and natural gas.

By targeting the illite-rich oil shale more than 2,000 feet below the surface, the technology and its application avoid the risk of contacting or degrading groundwater quality. This interval is hundreds of feet below the source of

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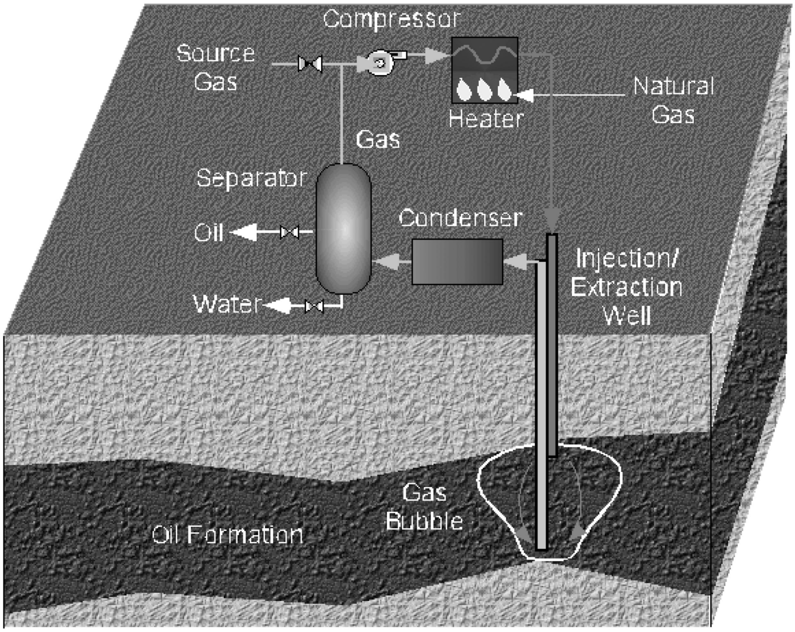

Figure 25. In-situ Vapor Extraction (IVE) Schematic (26)

useful ground water. Multiple geologic barriers, including 100 to 300 feet of nahcolite-rich oil shale, will protect usable ground water from retort impacts.

AMSO has just completed drilling operations and characterization of the site's geology and hydrology. A pilot retort experiment is scheduled to begin in 2010. The results of the pilot retort and additional field tests will demonstrate commercial viability.

In-Situ Vapor Extraction

Mountain West Energy (MWE) is developing in-situ vapor extraction (IVE) technology, a low-cost, scalable, fast, low-impact oil recovery process to produce oil from oil shale, oil sands, heavy oil reservoirs, and depleted conventional wells (Figure 25). In addition, IVE produces high-quality oil. MWE has demonstrated IVE in the laboratory, completed Phase 1 computer modeling, and started testing its technology in the field at the DOE's Rocky Mountain Oilfield Testing Center (RMOTC). MWE's technology is unique and innovative in that it vaporizes the oil and sweeps it to the surface as a gas, instead of a liquid.

MWE's IVE process uses a high temperature carrier gas injected into the target hydrocarbon formation to heat the oil by convection to the vaporization temperature. The carrier gas sweeps the oil vapors to the surface, where the oil is condensed and separated. The carrier gas is then re- circulated.

IVE recovers oil as a vapor, reducing the problems associated with flowing viscous, liquid oil through the formation. One implementation of IVE uses a

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single, vertical or horizontal well, which reduces costs, improves profitability, and minimizes environmental impact.

IVE is capable of cost effectively recovering oil at any depth from 300 feet to 6,000 feet, which makes unconventional oil extraction technically and economically feasible for a large quantity of unconventional oil.

MWE's IVE technology has been successfully demonstrated on oil shale and conventional oil in a bench-scale system at the company's laboratory. IVE was able to recover 62% of the original-oil-in-place. Even higher recovery rates are expected by improving the sweep efficiency of the carrier gas with MWE's flow control technologies. In addition, MWE has completed Phase 1 computer modeling of IVE in conjunction with Dr. Milind Deo of the Petroleum Research Center at the University of Utah.

This technology has recently been selected by San Leon Energy for pilot testing and demonstration in Morocco's oil shale resources.

Conclusions

Oil shale technologies continue to improve and mature. Building on the lessons of past development efforts, oil shale technology developers are defining, testing, and demonstrating new approaches that overcome the technical issues of the past – such as energy use, thermal efficiency, oil yield, gas richness, water use, spent shale management, emissions controls, and ground water protection.

These new technologies are also responding to the new challenges presented by global climate change. More thermally efficient technologies require less energy inputs, produce higher yields, improve the quality of produced shale oil and gases, reduce and manage carbon emissions, and protect the environment. These and other innovations promise to improve operability and reliability, while maintaining capital and operating costs that will be competitive with conventional oil and gas.

Industry is making major investments in technology research development and demonstration to advance these technologies and innovations from bench and pilot scale to demonstration of economic and technical and economic feasibility at commercially representative scale

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Chapter 3

Lake Level Controlled Sedimentological Heterogenity of Oil Shale, Upper Green River Formation, Eastern Uinta Basin, Utah

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The Green River Formation comprises the world's largest deposit of oil-shale and has enormous potential to meet global energy requirements, yet a detailed sedimentological characterization of these lacustrine oil-shale deposits in the subsurface is lacking. This study analyzed ~300 m of cores correlated to gamma and density logs in well P4 in the lower to middle Eocene (49.5–48.0 Ma), upper Green River Formation of the eastern Uinta Basin, Uintah County, Utah. In well P4, three distinct facies associations are identified that represent three phases of deposition linked to hydrologic evolution of the Lake Uinta.

The three phases of depositions are 1) an overfilled, periodically holomictic lake system, with deposition of primarily clastic mudstones, followed by 2) a balanced-filled, uniformly meromictic lake system, with deposition of primarily calcareous and dolomitic mudstones, followed by 3) an underfilled, evaporative lake system with nahcolite precipitation. The richest oil-shale zones were deposited during the second depositional phase. Although the studied interval is

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