Coaxing Oil from Shale

Oil shale is plentiful, but producing its petroleum can be complicated. Since the 1800s, these rocks have been mined and fed into surface facilities where liquid hydrocarbons were extracted. Now, operators are developing methods to heat the rock in situ and pipe the liberated oil to the surface. They are also adapting oilfield technology to evaluate these deposits and estimate their fluid yields.

Oil shale is the term given to very fine-grained sedimentary rock containing relatively large amounts of immature organic material, or kerogen. It is essentially potential source rock that would have generated hydrocarbons if it had been subjected to geologic burial at the requisite temperatures and pressures for a sufficient time. In nature, it can take millions of years at burial temperatures between 100°C and 150°C [210°F and 300°F] for most source rocks to generate oil. But the process can be accelerated by heating the kerogen-rich rock more quickly and to higher temperatures, generating liquid hydrocarbons in much shorter time: from a matter of minutes to a few years.

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Forcing petroleum products from immature formations is one of the more difficult ways to extract energy from the Earth, but that has not kept people from trying. From prehistoric times to the present, oil shale, like coal, has been burned as fuel. Methods for coaxing oil from the rock to produce liquid fuels have existed for hundreds of years. The earliest such ventures mined oil shale and heated it in processing facilities on the surface to obtain liquid shale oil and other petroleum products. More recently, methods have been tested to heat the rock in situ and extract the resulting oil in a more conventional way: through boreholes. These approaches are being developed, but the world’s oil shale resources remain largely untapped.

Current estimates of the volumes recoverable from oil shale deposits are in the trillions of barrels, but recovery methods are complicated and expensive. However, with today’s sustained high prices and predictions of future oil shortages in the coming decades, producing oil from shale may soon become economically viable. Therefore, several companies and countries are working to find practical ways to exploit these unconventional resources.

This article explains how oil shales form, how they have been exploited in various parts of the world and which techniques are currently being developed for tapping the energy they contain. Examples from the western US illustrate innovative applications of oilfield technology for evaluating oil shale deposits and assessing their richness.

**Oil Shale Formation**

Oil shales form in a variety of depositional environments, including freshwater and saline lakes and swamps, near-shore marine basins and subtidal shelves. They may occur as minor sedimentary layers or as giant accumulations hundreds of meters thick, covering thousands of square kilometers (above right).

As with other sedimentary rocks, compositions of shales containing organic material range from mostly silicates to mostly carbonates, with varying amounts of clay minerals (right). Mineral composition has little effect on oil yield, but it can impact the heating process. Clay minerals contain water, which may affect the amount of heat required to convert the organic material to petroleum. Carbonate shales, upon heating, generate additional CO2 that must be considered in any oil shale development program. Many deposits also contain valuable minerals and metals such as alum, nahcolite, sulfur, vanadium, zinc, copper and uranium, which may themselves be targets of mining operations.

![Outcropping oil shales. The oil shale of the Green River Formation in the Piceance Creek basin in Colorado covers about 3,100 km² (1,200 mi²). The inset (top) shows a hand specimen from that region, with dark layers of rich oil shale interbedded with pale layers of lean shale. The white scale bar is 7.2 cm (2.8 in.) long. (Outcrop photograph courtesy of Martin Kennedy, University of Adelaide. Inset photograph courtesy of John R. Dyni, US Geological Survey, Denver.)](image)

![Shale mineralogy. Worldwide average shale composition regardless of organic content (black diamond) is high in clay minerals and contains some quartz and feldspar with little or no calcite or dolomite. Organic-rich shales (other diamonds and dots) tend to have a wider variety of compositions. Oil shales from the Green River Formation are highlighted in dotted blue ovals. Those from the Parachute Creek Member (green squares) have low clay-mineral content, while oil shales from the Garden Gulch Member (red dots) are richer in clay minerals. Gray lines subdivide the triangle into compositional regions. (Adapted from Grau et al, reference 32.)](image)
Interspersed between the grains of these rocks is kerogen—insoluble, partially degraded organic material that has not yet matured enough to generate hydrocarbons. The kerogen in oil shale has its origins predominantly in the remains of lacustrine and marine algae, and contains minor amounts of spores, pollen, fragments of herbaceous and woody plants and remnants of other lacustrine, marine and land flora and fauna. The type of kerogen has a bearing on what kind of hydrocarbon it will produce as it matures thermally. The kerogens in oil shale fall into the Type I and Type II classifications used by geochemists (left).

The thermally immature kerogens in oil shales have undergone low-temperature diagenesis but no further modifications. Some other organic-rich shales may have reached thermal maturity but not yet expelled all of their liquid petroleum products. To distinguish them from oil shales, for the purposes of this article, mature, organic-rich shales that have not expelled all of their oil are called oil-bearing shales. Examples of these are the Bakken, Monterey and Eagle Ford shales, which currently produce oil in the US. Other organic-rich shales are more thermally mature or of different kerogen type and contain gas instead of oil, such as the Barnett, Fayetteville and Marcellus shales, also in the US.

Many shales attain source-rock status, achieving full maturity and expelling their oil and natural gas, which then migrate, and under the proper conditions, accumulate and become trapped until discovered and produced. Some such shales can manifest in several ways. For example, the Kimmeridge Clay Formation is the main source rock for the oil fields of the North Sea, but where it outcrops in England it is an oil shale. Similarly, the Green River shale, which is presumed to be the source rock for the oil produced from the Red Wash field in Utah, USA, outcrops in the same region. It also contains the world’s largest reserves of shale oil.

Oil Shales in Time and Space

The earliest use of oil shale was as fuel for heat, but there is also evidence of weaponry applications, such as flaming, oil shale–tipped arrows shot by warriors in 15th-century Asia. The first known use of liquid petroleum derived from shale dates to the mid-1300s, when medical practitioners in what is now Austria touted its healing properties. By the late 1600s, several municipalities in Europe were distilling oil from shale for heating fuel and street lighting. In the 1830s, mining and distillation activities began in France, and reached commercial levels there and in Canada, Scotland and the US by the mid-1800s. The country with the longest history of commercial shale oil production is Scotland, where mines operated for more than 100 years, finally closing in 1962.

Fuel shortages during the two World Wars encouraged other countries to exploit their oil shale resources. Tapping a kerogen-rich carbonate sequence, Estonia began mining oil shale from a deposit about 20 to 30 m [65 to 100 ft] thick that covers hundreds of square kilometers in the northern part of the country. The operation continues today.

The shale, which occurs as 50 or so beds of organic-rich shallow marine sediments alternating with biomicritic limestone, is produced from open-pit mines at depths to 20 m. Where the shale is buried deeper than that, down to 70 m [230 ft], it is accessed by underground mines. Roughly three-quarters of the mined rock supplies fuel for electric power plants, providing 90% of the country’s electricity. The remainder is used for heating and as feedstock for petrochemicals. In the past 90 years, 1 × 10^9 metric tons [1 × 10^9 Mg, or 1.1 billion tonUS] of oil shale has been mined from the primary Estonia deposit (left).

China has a significant history of oil shale mining as well, with shale oil production beginning in the 1920s. In the Fushun area, extensive shale layers 15 to 58 m [49 to 190 ft] thick are mined along with coal, both from Eocene lacustrine deposits. The total resource of oil shale at Fushun is estimated at 3.3 × 10^9 Mg [3.6 billion tonUS]. As of 1995, Fushun’s petroleum production capacity from shale was 66,000 m^3/yr [415,000 bbl/yr].

Brazil began developing an oil shale mining and processing industry in the 1960s. The national oil company, Petroleos Brasileiro SA (Petrobras),

![Image of kerogen maturation](left)

More than a century of commercial oil shale mining. Tonnage of mined shale rose dramatically in the 1970s when oil prices were also rising, it peaked in 1980, but declined as oil prices made shale oil noncompetitive. Several countries continue to mine oil shale as a source of heat, electricity, liquid fuel and chemical feedstock. Since 1989, mined shale tonnage has started to increase again. (Data from 1880 to 1998 from Dyni, reference 1.)

![Image of oxygen/carbon ratio](left)
established the Shale Industrialization Business Unit (SIX) to exploit the country's several large oil shale deposits. The Itatí Formation, which outcrops extensively in southern Brazil, contains reserves of more than $1.1 \times 10^8$ m$^3$ of oil and $2.5 \times 10^{10}$ m$^3$ of gas. Surface facilities at São Mateus do Sul, in the state of Paraná, are capable of processing $7,100$ Mg of shale per day to produce fuel oil, naphtha, liquefied petroleum gas (LPG), shale gas, sulfur and asphalt additives.

To date, almost all the oil extracted from the world's oil shale has been from rock that was mined and then processed at surface facilities. Mining is typically performed either through surface mining or through underground mining using the room-and-pillar method associated with coal mining. After mining, oil shale is transported to a facility—a retort—where a heating process converts kerogen to oil and gas and separates the hydrocarbon fractions from the mineral fraction. This mineral waste, which contains substantial amounts of residual kerogen, is called spent shale. After retorting, the oil must be upgraded by further processing before being sent to a refinery.

Mining operations require handling massive volumes of rock, disposing of spent shale and upgrading the heavy oil. The environmental impact can be significant, causing disruption of the surface and requiring substantial volumes of water. Water is needed for controlling dust, cooling spent shale and upgrading raw shale oil. Estimates of water requirements range from $2$ to $5$ barrels of water per barrel of oil produced. The world's oil shale deposits are widely distributed; hundreds of deposits occur in more than $30$ countries (above). Many formations are at depths beyond mining capabilities or in environmentally fragile settings. In these areas, heating the rocks in place may offer the best method to hasten kerogen maturation. If ways can be found to do this safely, efficiently and cost effectively, the potential prize is immense. By conservative estimate—because oil shales have not been the target of modern exploration efforts—resources of the world's oil shale total about $5.1 \times 10^{11}$ m$^3$ (3.2 trillion bbl). It is estimated that more than $60\%$ of this amount—roughly $3 \times 10^{11}$ m$^3$ (2 trillion bbl)—is located in the US.

### Converting Oil Shale to Shale Oil

Translating volume of rock to volume of recoverable oil requires information on oil shale properties, such as organic content and grade, which can vary widely within a deposit. Traditionally, for the purposes of surface retorting, oil shale grade is determined by the modified Fischer assay method, which measures the oil yield of a shale sample in a laboratory retort. A $100\text{ g}$ sample is crushed and sieved through a 2.38-mm mesh screen, heated in an aluminum retort to $930\text{°F}$ at a rate of $12\text{°C/min}$ (22°F/min) and then held at that temperature for 40 min. The resulting distilled vapors of oil, gas and water are condensed and then separated by centrifuge. The quantities delivered are weight percentages of oil, water and shale residue and the specific gravity of the oil. The difference between the weight of the products and that of the starting material is

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13. Screen mesh of –8 means the particles can pass through a wire screen with 8 openings per linear inch.
recorded as “gas plus loss.” The oil yield is reported in liters per metric ton (L/Mg) or gallons per short ton (galUS/tonUS) of raw shale. Commercially attractive oil shale deposits yield at least 100 L/Mg [72 galUS/tonUS], and some reach 300 L/Mg [24 galUS/tonUS].

The Fischer assay method does not measure the total energy content of an oil shale because the gases, which include methane, ethane, propane, butane, hydrogen, H2S and CO2, can have significant energy content, but are not individually specified. Also, some retort methods, especially those that heat at different rates or for different times, or that crush the rock more finely, may produce more oil than that produced by the Fischer assay method. Therefore, the method only approximates the energy potential of an oil shale deposit.

Another method for characterizing organic richness of oil shale is a pyrolysis test developed by the Institut Français du Pétrole, in Reuil-Malmaison, France, for analyzing source rock. The Rock-Eval test heats a 50- to 100-µg [0.00011- to 0.00022-lbm] sample through several temperature stages to determine the amounts of hydrocarbon and CO2 generated. The results can be interpreted for kerogen type and potential for oil and gas generation. The method is faster than the Fischer assay and requires less sample material.

The reactions that convert kerogen to oil and gas are understood generally, but not in precise molecular detail. The amount and composition of generated hydrocarbons depend on the heating conditions: the rate of temperature increase, the duration of exposure to heat and the composition of gases present as the kerogen breaks down.

Generally, surface-based retorts heat the shale rapidly. The time scale for retorting is directly related to the particle size of the shale, which is why the rock is crushed before being heated in surface retorts. Pyrolysis of particles on the millimeter scale can be accomplished in minutes at 500°C; pyrolysis of particles tens of centimeters in size takes hours.

In situ processes heat the shale more slowly. It takes a few years to heat a block tens of meters wide. However, slow heating has advantages. Retorting occurs at a lower temperature so less heat is needed. Also, the quality of the oil increases substantially (above left). Coking and cracking reactions in the subsurface tend to leave the heavy, undesirable components in the ground. As a result, compared with surface processing, in situ heating can produce lighter liquid hydrocarbons with fewer contaminants.

During in situ conversion, the subsurface acts as a large reactor vessel in which pressure and heating rate may be designed to maximize product quality and quantity while minimizing production cost. In addition to generating a superior product relative to surface processing, in situ methods have a reduced environmental impact in terms of surface disturbance, water requirements and waste management.

Several companies have developed methods for heating oil shale in situ to generate shale oil. They are testing these techniques in the rich subsurface deposits of the western US.

The Epitome of Oil Shales
The Green River Formation at the intersection of the states of Colorado, Utah and Wyoming, USA, contains the most bountiful oil shale beds in the world. Estimates of the recoverable shale oil in this area range from 1.2 to 1.8 trillion bbl [1.9 to 2.9 × 1013 m3]. Nearly 75% of the resources lie under land managed by the US Department of the Interior.

The fine-grained sediments of this formation were deposited over the course of 10 million years in Early and Middle Eocene time, in several large lakes covering up to 25,000 mi2 [65,000 km2]. The warm alkaline waters provided conditions for abundant growth of blue-green algae, which are believed to be the main component of the organic matter in the oil shale. The formation is now about 1,600 ft [500 m] thick and in places has shale layers that contain more than 60 galUS/tonUS [250 L/Mg] of oil (next page). A particularly rich and widespread layer, called the Mahogany zone, reaches a thickness of 50 ft [15 m]. It contains an estimated 173 billion bbl [2.8 × 1010 m3] of shale oil. The Green River area has been well studied, with more than 750,000 assay tests performed on samples from outcrops, mines, boreholes and core holes.

Settlers and miners began retorting oil from the shale in the 1800s. The region experienced mining and exploration booms from 1915 to 1920 and again from 1974 to 1982, each period followed by busts. In 1980, Unocal built a major plant for mining, retorting and upgrading oil shale in the Piceance Creek basin in Colorado; it operated until 1991. During that time, the company produced 4.4 million bbl [700,000 m3] of shale oil.

Recently, oil price volatility and growing energy needs have combined to again focus interest on the region. In 2003, the US Bureau of Land Management initiated an oil shale development program and solicited applications for research, development and demonstration (RD&D) leases.

Several companies applied for and received lease awards to develop in situ heating techniques on public lands, and some are testing methods...
on privately held land. Examples from three companies—Shell, ExxonMobil and American Shale Oil LLC (AMSO)—show the range of concepts being applied to the challenges of in situ retorting in the Green River oil shale.

Shell has done extensive laboratory and field work in efforts to demonstrate commercial viability of in situ retorting using downhole electric heaters. The process follows a method developed in Sweden during World War II—a technique used until 1960, when cheaper supplies of imported oil became available.

Shell participated in early mining and surface retort attempts in the Green River area, but chose to withdraw from those in the mid-1990s to focus on an in situ method. Years of laboratory testing, thermal simulations and field pilots contributed to the development of Shell’s in situ conversion process (ICP). Through seven field pilot tests, Shell has investigated a variety of heating methods—including injected steam and downhole heaters—and well configurations with patterns of wells of varying depths for heating, producing and dewaxing (previous page, top right).

16. Pyrolysis is the controlled heating of organic matter in the absence of oxygen to yield organic compounds such as hydrocarbons.
The ICP method uses closely spaced downhole electric heaters to gradually and evenly heat the formation to the conversion temperature of about 650°F [340°C]. Depending on heater spacing and the rate of heating, the time projected to reach conversion temperature in a commercial project ranges from three to six years. Tests have demonstrated liquid-recovery efficiencies greater than 60% of Fischer assay value, with the low-value kerogen components left in the ground. The resulting oil is of 25 to 40 degree API gravity. The gas contains methane [CH₄], H₂S, CO₂ and H₂. Taking into account the oil equivalence of the gas generated, the recovery efficiency approaches 90% to 100% of Fischer assay value.

From results of the pilot testing, a commercial-scale project is expected to have an energy gain close to 3, meaning the energy value of the products is three times the energy input to obtain them.

Commercialization of the ICP process requires a method that prevents water influx to the heated volume and contains the fluid products, thereby maximizing recovery and protecting local aquifers. The Shell ICP process makes use of a freeze wall, created by circulating coolants, to isolate the heated formation from groundwater. Use of a freeze wall is a relatively common practice in some underground mining operations. The formation is heated, the oil is produced and the residual shale is cleaned of contaminants by flushing with clean water. The recovered oil in one test had 40 degree API gravity, similar to modeling results for oil produced at heating rates of 1°C/h [0.5°F/h] and 27 MPa.

Pilot testing of the freeze wall began in 2002 with 18 freeze wells arranged in a circle 50 ft across. One producer, two heating wells and eight monitor wells were located within the freeze circle (left). After five months of cooling, the freeze wall was complete. This pilot showed that a freeze wall could be established and could isolate fluids inside the circle from those outside.

Shell tested the freeze wall concept on a larger scale starting in 2005, with an ambitious project involving 157 freeze wells at 8-ft [2.4-m] intervals to create a containment volume 224 ft [68 m] across (next page, top). The operator began chilling in 2007 by circulating an ammonia-water solution—initially at shallow depth and gradually deepening. As of July 2009, the freeze wall was continuing to form in the deeper zones, down to 1,700 ft [520 m]. The test is designed to evaluate the integrity of the freeze wall, and will not involve heating, or production of hydrocarbons.

ExxonMobil is also pursuing research and development of a process for in situ oil shale conversion. The company’s Electrofrac process hydraulically fractures the oil shale and fills the fractures with an electrically conductive material, creating a resistive heating element. Heat is thermally conducted into the oil shale, converting the kerogen into oil and gas, which are then produced by conventional methods. Calcined petroleum coke, a granular form of relatively pure carbon, is being tested as the Electrofrac conductor. By pumping this material into vertical hydraulic fractures, ExxonMobil hopes to create a series of parallel planar electric heaters (next page, bottom). As in the Shell ICP method, the resistive heat reaches the shale by thermal diffusion. A potential advantage of the Electrofrac process is that, compared with line sources, the greater surface area of planar fracture heaters will permit fewer heaters to be used to deliver heat to the subsurface volume. The use of planar heaters should also reduce surface disturbance when compared with line sources or wellbore heaters.

Large-scale freeze wall test. In a step toward supporting commercial viability of the ICP, Shell is testing a large-scale freeze wall for isolation and containment. In addition to the freeze wells shown in the plan view (left) there are 27 observation holes for geomechanical, pressure, fluid level and temperature measurements; 30 special-use holes for venting, squeezing, water reinjection, water production and hydraulic fracturing; and 40 groundwater monitoring holes. An artist’s rendering (right) depicts the freeze wall in 3D.

The ExxonMobil Electrofrac process. Horizontal wells penetrate the oil shale. The horizontal sections are hydraulically fractured (left) and filled with electrically conductive proppant made of calcined coke (bottom right). A 20/40 mesh proppant (top right) is displayed for scale. Field testing has shown it is possible to create an electrically conductive fracture and heat it for several months. The plus and minus signs indicate electric charge applied to heat the fractures. (Illustration and photographs courtesy of ExxonMobil.)
Prior to embarking on field research, ExxonMobil conducted modeling and laboratory studies addressing several important technical issues for the Electrofrac process. These included establishing the following:

- That the conductant in the fracture can maintain its electrical continuity while the surrounding rock is heated to conversion temperatures.
- That oil and gas generated by the process are expelled from oil shale, not only at surface conditions, but also under in situ stress conditions.
- That a completion strategy can be designed to create fractures that deliver heat effectively.

Based on these results, ExxonMobil advanced to field research to test the Electrofrac method in situ. The test site is at the company-owned Colony oil shale mine in northwest Colorado. The Colony mine provides a large, highly accessible volume of rock for testing. ExxonMobil has created two Electrofrac fractures at Colony by drilling horizontally into the oil shale and pumping a slurry of calcined petroleum coke, water and portland cement at pressures sufficient to break the rock. The larger of the two Electrofrac fractures has been heavily instrumented to measure temperature, voltage, electrical current and rock movement. As a preliminary test of the Electrofrac process, the fracture was heated to relatively low temperatures. This low-temperature experiment was not intended to generate oil or gas. To date, the results of this field program have been encouraging. They demonstrate that it is possible to create an electrically conductive hydraulic fracture, to make power connections to the fracture and to operate it, at least at low temperature, for several months.

AMSO, 50% owned by Total, proposes to use the CCR conduction, convection and reflux process to recover shale oil. By focusing the heating effort on shales beneath an impermeable shale caprock, this method isolates production zones from protected sources of groundwater.

The company plans to drill two horizontal wells—a heater below a producer—in the bottom of the illite shale at the base of the Green River Formation (above left). Heat is delivered by a downhole burner that eventually runs on produced gas. As the kerogen decomposes, the lighter products—hot vapors—rise and reflux. Heat is distributed through the formation by the refluxing oil; thermomechanical fracturing, or spalling, creates permeability for the convective heat transfer.

The concept for commercial-scale production uses an array of horizontal wells about 2,000 ft [600 m] long at 100-ft [30-m] intervals (left). The formation is heated slowly, yielding oil with lower concentrations of heteroatoms and metals than that generated by surface processing methods. Meanwhile, the aromatic portions of kerogen tend to stay in the rock matrix as coke. More than enough gas is coproduced to provide the energy required to operate a self-sustaining commercial retorting process, and it is likely that most of the propane and butane produced can be exported to market.

Computational studies show that heat delivery by convection and conduction is much more effective than by conduction alone. The CCR process is estimated to give a total energy gain between 4 and 5, counting all the surface facility requirements, including an oxygen plant for producing pure CO₂ from the downhole burner. The method is projected to use less than one barrel of water per barrel of oil produced. No water is needed to clean spent retorts because they remain isolated from usable groundwater.
AMSO’s initial RD&D pilot test is currently under construction and will begin in mid-2011. Heating will take up to 200 days. The operation will retort a formation volume equivalent to 4,000 tonUS [3,600 Mg] of oil shale and produce up to 2,000 bbl [320 m3] of shale oil. Development of a commercial operation will proceed in steps up to 100,000 bbl/d [16,000 m3/d], with plans to sustain that production for 25 years. That translates into about 1 billion bbl [1.6 × 108 m3] of oil to be produced from an 8-mi2 [20.8-km2] lease.

Evaluating Oil Shales
Companies are looking at ways to assess oil shale richness and other formation properties without having to take core samples and perform Fischer assay analysis. Methods that show promise include integration of several conventional logging measurements, such as formation density, magnetic resonance, electrical resistivity and nuclear spectroscopy.

One way of quantifying kerogen content is by combining density porosity and magnetic resonance responses. In a formation with porosity that is filled with both kerogen and water, the density porosity measurement does not distinguish between kerogen- and water-filled porosity. However, the magnetic resonance measurement sees the kerogen as a solid, similar to the grains of the rock, and so senses a lower porosity. The difference between the magnetic resonance and density readings gives kerogen volume. The volume of kerogen can be related empirically to Fischer assay values for oil shales in the region.

The method was tested in an AMSO oil shale well in the Green River basin. Kerogen content was calculated from density porosity and magnetic resonance logs (right). Using a correlation between kerogen content and Fischer assay


29. Heteroatoms are atoms of elements other than hydrogen and carbon—the components of pure hydrocarbons. They commonly consist of nitrogen, oxygen, sulfur, iron and other metals.


Kerogen content from porosity measurements in Green River oil shales. Neither gamma ray (Track 1, dashed green) nor resistivity measurements (Track 2) show much correlation with kerogen content, but porosity measurements are more useful. The difference between density porosity (Track 3, red) and nuclear magnetic resonance (NMR) porosity (green) represents kerogen-filled porosity (gray). The kerogen volumes can also be depicted as a log (Track 4) of total organic matter (TOM, red), which compares favorably with laboratory Fischer assay results on core samples (black dots). Mineralogical analysis incorporating ECS elemental capture spectroscopy measurements (Track 5) indicates the high levels of calcite and dolomite in these shales, as well as the presence of rare minerals such as dawsonite (light gray) and nahcolite (solid pink) in some intervals.
results on Green River shales, researchers computed an estimated Fischer assay log based on the wireline logging measurements (above). The estimated Fischer assay values show excellent agreement with those from laboratory measurements on cores from the same interval.

Another approach distinguishes mineral from organic content using spectroscopy data. The ECS elemental capture spectroscopy sonde measures concentrations of silicon \([\text{Si}]\), aluminum \([\text{Al}]\), calcium \([\text{Ca}]\), iron \([\text{Fe}]\), sulfur \([\text{S}]\), potassium \([\text{K}]\), sodium \([\text{Na}]\), magnesium \([\text{Mg}]\), titanium \([\text{Ti}]\) and gadolinium \([\text{Gd}]\).\(^{31}\) Grain mineralogy is computed from these element concentrations.

The total carbon concentration comes from the RST reservoir saturation tool. Of this concentration, some carbon is inorganic and some organic. The inorganic carbon combines with calcium and other elements to form calcite and dolomite, along with lesser-known minerals, such as nahcolite \([\text{NaH(CO}_3]\)) and dawsonite \([\text{NaAl(CO}_3(\text{OH})_2]\)), which are common in Green River shales. The ECS concentrations of Ca, Mg and Na are used to compute the inorganic carbon. The remainder, called total organic carbon (TOC), makes up the kerogen.

Using this spectroscopy method, researchers computed a TOC log for an AMSO well in the Green River basin, showing a good match between log-based results and core measurements (next page).\(^{32}\) The TOC log was converted to a Fischer assay yield log using a correlation derived independently by AMSO scientists. The Fischer assay log exhibited excellent correlation with Fischer assay tests performed on cores (above right). This technique employing geochemical logs, along with the complementary method using nuclear magnetic resonance logs, provides reliable, efficient means to characterize shale oil yield without having to resort to core measurements.

**Heating Elements**

One of the most fundamental issues for oil shale retorting is how to get the heat into the oil shale. After early testing, steam injection was abandoned as other, more efficient techniques were discovered. In situ combustion has also been tried, but is difficult to control. Electric heaters, electrically conductive proppant and downhole gas burners have all been evaluated and reported to be effective with varying degrees of efficiency.

Another concept, heating by downhole radiofrequency (RF) transmitters, has also been modeled and has undergone laboratory testing.\(^{33}\) Advantages of the RF method are that it heats the interior of the formation instead of the borehole, and it can be controlled to customize heating rate. But like all electrical methods, it sacrifices efficiency, losing about half the heating value of the fuel originally burned to produce the electricity.

It is important to note that all the current projects to produce shale oil by in situ heating methods are in test and pilot stages; none have demonstrated large-scale commercial production. Operators are still working to optimize their heating technologies. For a given oil shale, the
heating history—how much heat and for how long—determines the amount and content of the resulting fluids. By controlling the heat input, companies can fine-tune the output, essentially designing a shale oil of desired composition.

Beyond heating methods, there are other aspects of oil shale operations that have yet to be fully addressed. Mechanical stability of the heated formation is not well understood. All the in situ heating techniques rely on some thermo-mechanical fracturing within the shale to release matured organic material and create additional permeability for the generated fluids to escape the formation. With many oil shales containing 30% or more kerogen, most of which leaves the rock after in situ retorting, treated formations may not be able to support their newfound porosity. Overburden weight can help drive production, but may also cause compaction and subsidence, which in turn can affect wellbore stability and surface structures.

It is also unclear how to deal with the CO₂ generated along with other gases. Companies retorting oil shale in situ may need to investigate ways to capture and use the CO₂ for enhanced oil recovery or sequester it in deep storage zones. An alternative, being explored by AMSO, is mineralization of CO₂ in the spent shale formation. This option exploits the chemical properties of the heat-treated shale. AMSO scientists expect the depleted formation to have sufficient porosity to accommodate all the generated and reinjected CO₂ as carbonate minerals.

Work also remains to understand the kerogen-maturation process. To optimize heating programs, operators would like to know when the shale has been heated enough and if the subsurface volume has been heated uniformly. To this end, scientists are conducting laboratory experiments to monitor the products of kerogen pyrolysis. To understand when the process should be modified or stopped, researchers plan to analyze the composition of an oil shale and its hydrocarbons as they evolve with time. In the future, it may be possible to control and monitor oil shale heating and production to obtain oil and gas of desired compositions.

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