CHAPTER 12.26

Oil Shale

Bruce Peachey

As indicated in other chapters, it is unlikely that use of hydrocarbons, including fossil fuels, will disappear from use any time soon. The energy and hydrocarbon building blocks contained in these resources are too valuable to our modern society. Only limited amounts of carbon are available for recycle through short-term biomass resources, and those resources are often too dispersed and of low quality to meet our energy needs. Impurities in raw biomass also make their use for petrochemicals (plastics, etc.) more difficult and energy intensive to use. Meanwhile, the earth's biosphere has been capturing carbon from the atmosphere and oceans, turning it into organic matter and then processing biomass into higher-quality hydrocarbons for billions of years. Once thermally and/or biologically upgraded, this resource constitutes an extremely large and valuable natural source of energy and carbon. One of the largest bodies of partially upgraded natural hydrocarbon resources are found in oil shales.

DEFINITION

Shales are generically defined as "rock formed by deposition of colloidal particles of clay and mud, and consolidated by pressure" (Schwartz 2016). Shale is fine grained and has a laminated structure, usually containing large amounts of sand, which are colored by metal oxides. Unlike sandstones, however, shales are not usually porous, most shales being hard, slate-like rocks. "Oil shale is a hard shale with veins of greasy solid known as kerogen, which is oil mixed with organic matter. Oil shales are widely distributed in many parts of the world and are regularly distilled in most of the countries of Europe" (Brady and Clauser 1991). The yield varies from 60 to 380 L/t (liters per metric ton).

KEROGEN

The organic material *kerogen* is contained in oil shales. When exposed to heat in a retorting process (sometimes referred to as *destructive distillation* or *pyrolysis*), kerogen yields hydrocarbons that can be processed into synthetic crude oil. Oil shales are often called *immature shales* and differ from tight oil-bearing shales, sands, or carbonate formations from which liquids (formed in *mature* shales) or gaseous petroleum (formed in *overmature* shales) are extracted by drilling, fracturing, and pumping for production of liquids. Once the kerogen has been converted to oil or gas, it can migrate into subsurface geologic traps that have higher permeability and generally comprise *conventional* crude oil or natural gas resources. Recently, other *unconventional* shale oil and gas formations have begun to be developed that contain oil or gas already generated from the kerogen, but which remain trapped in the source rock. Potentially mobile oil found in shales is generally referred to as *shale oil*, while similar formations only containing precursor kerogen and/or bituminous material are referred to as *oil shale*. Exact delineation of these two types of resources is made difficult, as many shale formations contain mature oil or gas, as well as some immature kerogen material.

FORMATION

Oil shale rocks containing organic carbon-rich sediments were deposited with inorganic matter when the rocks were formed by microscopic organisms and algae sinking to the bottom of relatively stagnant bodies of water, along with very fine mineral particles. These types of deposits are still forming in deep waters in the Gulf of Mexico and other water bodies that have poorly mixed, low-oxygen (anaerobic), and low-temperature environments, where decomposition is slowed and the recycle of carbon into the active carbon cycle is prevented. Carbon in these source rocks can only be naturally released by (1) weathering, where tectonic forces push the rocks to the land surface and where rainfall, organisms, or direct oxidation can return the carbon to active circulation over billions of years (slow carbon cycle); (2) thermal conversion to liquid or gaseous hydrocarbons (oil and gas) by heat and pressure from deep burial, through subduction into the earth (millions of years); or (3) biogenesis, which is biological conversion to natural gas through slow, in situ biological activity after burial.

Oil and gas produced by thermogenesis or biogenesis over time may return to the surface and the active carbon cycle by migrating through porous rocks. At least some of those fluids and gases are trapped in shallower geologic formations and become reservoirs of conventional oil and gas, and even more is retained in the nonporous shale as shale oil

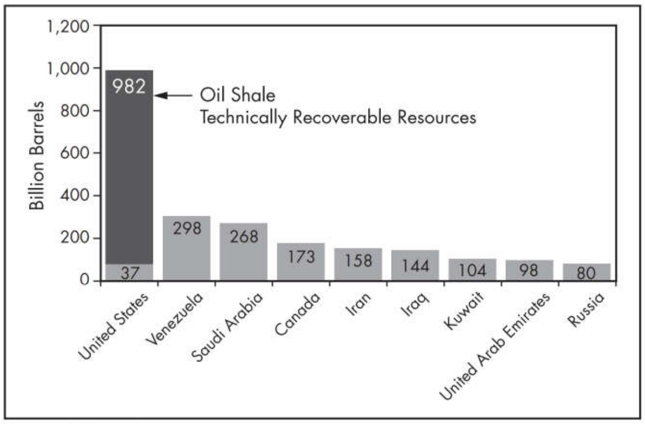
Bruce Peachey, President & Senior Consultant, New Paradigm Engineering Ltd., Edmonton, Alberta, Canada

and gas. As stated earlier, oil shales are generally considered to be a different resource than the shale oil found in source rocks in geologic petroleum systems. The shale oil found in deeper formations, such as the Bakken and Eagle Ford shales, has formed naturally through subduction and heating but has remained trapped within the shale layers, which must be hydraulically fractured to extract the oil. Conversely, in oil shales, much of the carbon remains in the form of kerogen.

Estonia, China, and Brazil today produce commercial quantities of products derived from oil shales and/or electric power from these types of deposits; and Australian deposits have been, and are continuing to be, developed. Commercial production has yet to be attained in the United States, although the largest delineated oil shale deposits in the world exist in Colorado, Utah, and Wyoming. U.S. Geological Survey estimates of technically recoverable oil shale resources in the United States range as high as 2.6 trillion barrels, while an estimated 1.0 trillion barrels may be technically and economically recoverable (reserves are dependent on oil price), making these oil shale reserves potentially four times larger than remaining conventional oil reserves in Saudi Arabia (Dyni 2006). Any figures on oil shale resources should be considered with caution:

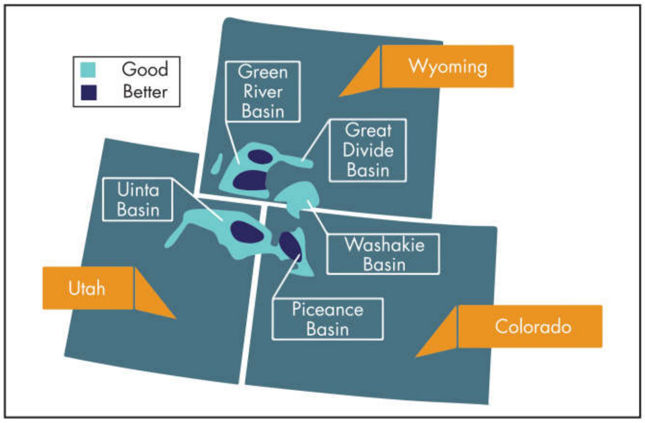
- Many potential oil shale formations around the world have not been evaluated.
- Initial estimates tend to be low to be conservative.
- Proven recovery methods have only been applied in a few specific types of deposit and, thus, may not be technically viable in all situations.
- Economic viability is a function of oil price and recovery costs, which are highly variable over time and geographic regions.

Figure 1 is a comparison of the potential size of technically and economically recoverable oil shale reserves in the United States and the remaining conventional oil reserves in the United States and other major producing countries. Figure 2 shows the location of major oil shale deposits in the United States. As one of the largest consumers of oil in the world, the United States has done considerably more work assessing its oil shale resources than other countries have done, so there is considerable uncertainty in global estimates. Often, few wells have been drilled into shales in some countries, so there is little data on which to estimate potential resources.



Source: EIA, n.d.

Figure 1 U.S. oil shale resources versus foreign oil reserves



Source: Intek 2011

Figure 2 Major U.S. oil shale resources

KEROGEN TO PETROLEUM AND NATURAL GAS

The kerogen in oil shales is an organic material, whose properties vary depending on where the original organic material was deposited, how the resulting oil shales formed, and what geologic temperatures, pressures, and other conditions they were exposed to over geologic time. The type of kerogen, and the relative composition of the kerogen regarding hydrogen, carbon, and oxygen content, impact the type of petroleum that can be produced from it, either naturally or through processing the oil shale. Recognized generic kerogen types and general properties are shown in Table 1.

Table 1 Kerogen types based on source material

Kerogen Type	Source Material, Composition, and Natural Hydrocarbons Formed	General Environment of Deposition
I	Mainly algae; rich in hydrogen, low in oxygen; oil or gas	Lacustrine (lake)
II	Mainly plankton, some contribution from algae; rich in hydrogen, low in carbon; oil or gas	Marine
II-S	Mainly plankton, some contribution from algae; rich in hydrogen, low in carbon, contains sulfur compounds; sour oil or gas, generation begins earlier (lower temperature)	Marine
III	Mainly higher plants; lower hydrogen, higher oxygen; gas prone	Terrestrial
IV	Reworked, oxidized material; high carbon, hydrogen poor; low potential to generate oil and gas	Varied

Adapted from McCarthy et al. 2011

Natural Maturation Process

Natural thermal maturation of kerogen proceeds through three stages over geologic time as the shales are buried deeper and geothermal temperatures increase. Following is a summary of these stages:

1. **Diagenesis.** At temperatures below 50°C, oxygen, other chemical reactions, and potentially some conversions to methane by methanogenic bacteria gradually convert the organic material to kerogen and smaller amounts of bitumen.

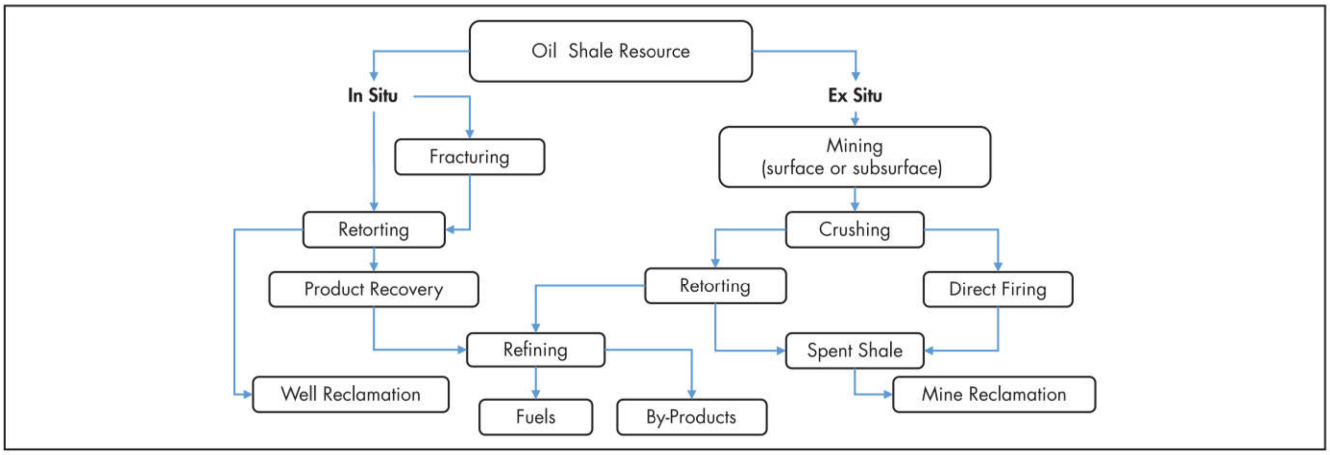


Figure 3 General processes for extracting energy

2. **Catagenesis.** At temperatures between 50° and 150°C, chemical bonds are broken and petroleum is generated in an *oil window*. Further temperature increases and secondary *cracking* of the oil produce wet gas and condensates.
3. **Metagenesis.** Further heating to 150°–200°C converts any remaining kerogen into a solid carbon residue and dry methane, which may also contain carbon dioxide (CO_2), nitrogen (N_2), and hydrogen sulfide (H_2S).

Processing to Energy Streams

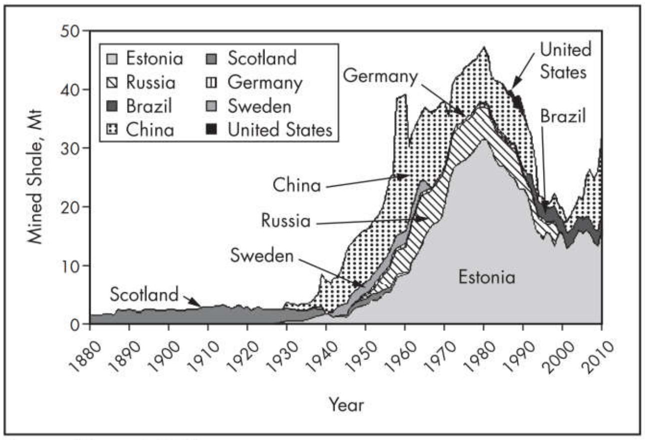
Generation of petroleum and gas through natural processes obviously takes a considerable length of time. Even in rocks at temperatures hot enough for conversion to occur, only a small percentage of the kerogen is converted, and it is still difficult to generate enough permeability (through fracturing) for the products to flow into a trap or well. Artificially enhancing the maturation process of the kerogen, either in or ex situ after mining, can accelerate and enhance the natural process and generate higher petroleum yields from a given volume of oil shale. As in nature, processing the kerogen to get liquid, gaseous, and solid fuels is accomplished mainly by heating the oil shale. The heat energy added replaces the natural energy applied to the petroleum source rock deposits over geologic time. The quality and quantity of produced fuels depend not only on the shale properties but also on the retorting process used. Each shale in a given process produces different products and volumes, depending on the type of kerogen it contains, its composition, and the degree of natural maturation that has already occurred. Numerous retorting processes have been developed and categorized into general types based on the method of exposing the raw shale to retorting temperatures. The synthetic crude oil obtained from retorting oil shale is transported to refineries as an acceptable substitute for conventional crudes to produce commercial fuels and petrochemical feedstocks.

The two main categories of oil shale processing are differentiated by how the oil shale is being accessed, with some shallower deposits accessed by mining (surface strip mining or underground mining), but most of the resource requires the use of in situ processing methods if they are too deep and hazardous to mine. Mine-based processes have been the most common methods used to date on oil shales that locally outcrop at surface or near surface, and they have been used for hundreds of years. More recently, a great deal of effort has been devoted by some major oil and gas producers to assess various in situ retorting methods that can be applied to shale oil and oil shale formations after initial depletion of any naturally matured petroleum or gas. Figure 3 shows the difference in the two basic options of in and ex situ extraction. They may proceed to similar end points as refined petroleum products, but they have significantly different technologies, economics, and environmental and sustainability impacts and are applied to oil shale resources at different depths. Ex situ processes are preferred for shallow oil shale resources, while in situ processes tend to be favored for deeper deposits.

EX SITU PROCESSING

Basic extraction of shallow oil shale resources has traditionally focused on mining from either surface (open pit mines) or underground mines. The criteria used to decide on the type of mine operations is similar to that used for coal resources and is a function of ore depth, seam thickness and quality, and the ratio of overburden to ore, which drives mining economics. Historically, oil shale has been mined and used as fuel and/or petrochemicals for centuries, but usually cannot compete economically with lower-cost coal and oil energy resources. Currently, all commercial oil shale operations are based on mining, with ~70% of those operations located in Estonia, with other commercial operations found in China and Brazil, and new large-scale operations actively being considered for Jordan. There have been a range of smaller pilot and demonstration projects in the United States, Australia, and other countries; however, the recent development and rapid growth of hydraulic fracturing to produce shale oil, and the subsequent drop in international oil prices, have reduced interest in oil shales in many locations (Figure 4).

Estonia is unique in that it has few coal, oil, or gas resources of its own, and the low-lying and flat topography of this small country makes hydropower and many other renewable energy sources uneconomic. It does, however, have extensive oil shale deposits that have been exploited since before World War II and have allowed it to be independent of energy imports. In 1997, oil shale provided more than 75% of the country's total primary energy supply, primarily for electrical power generation through direct firing, with smaller volumes of oil shale directed toward production of liquid distillates and



Source: Allix et al. 2010

Figure 4 Oil shale production from 1880 to 2010

Table 2 Size ranges for crushed shale by ex situ process

Process	Crushed Particle Size Range or Description
Oil shale circulating fluidized-bed boiler	Small, 6–12 mm
Kiviter	Coarse oil shale
Fushun	10–75 mm
Petrosix	Lump shale, 12–75 mm
Galoter	Fine, <25 mm
Alberta Taciuk	Fine, <25 mm
Tosco II	<13 mm
Lurgi–Ruhrgas	Fine, 6–13 mm
Chevron staged-turbulent-bed retorting	Small
Union	3–50 mm
Superior multimineral	First stage, <200 mm; second stage, 76 mm for retort feed

petrochemicals through surface retorting processes of various types (U.S. Department of Energy 2003). Like Estonia, China's commercial oil shale operations began in the 1930s for liquid fuels but were largely displaced with the discovery of conventional oil resources from domestic oil fields and imported from the Middle East and other sources. The oil price increases in the 1990s encouraged China to restart oil shale production in 1992, and it is now the largest producer of petroleum from oil shale. Brazil's national oil company, PetroBras, started commercial production of liquid fuels by retorting oil shales in 1992.

Crushing

Crushing of the mined ore is a common feature of ex situ oil shale plants; however, different processes have been designed based on different particle sizes or size ranges, so crushing is a key process consideration. The various oil shale utilization processes are discussed later in this chapter; Table 2 indicates the particle sizes commonly used in those processes.

Power Plants

The largest single use of oil shales globally is for power generation in Estonia, where more than 2,000 MW of capacity of shale oil–fueled power-generation capacity is installed. Originally, the plants were pulverized combustion plants, at medium or high pressure, which used oil shale in a manner similar to coal-fired plants in the rest of Europe. The high mineral content of the shale produced greater volumes of fly ash, some of which was initially used for other purposes, while the high concentration of limestone in the oil shale helped to moderate sulfur oxide (SO_x) emissions. In a drive to increase the economic and environmental performance of power generation, a modified circulating fluidized-bed (CFB) boiler technology was developed for oil shale in Estonia, with commercial operation starting in 2005 (Figure 5).

Retorting Plants

The other commercial processes utilizing oil shale feed are all aboveground retorting operations of various types. These processes often have to be custom designed to match the properties of a specific shale source. Commercial plants currently in operation are classified as either

1. Internal combustion units,
2. External hot gas,
3. Hot recycled solids, or
4. Some hybrid form of those three basic types.

Following are descriptions of the four commercial processes and other systems that are in the demonstration or piloting stage of development.

Internal Combustion

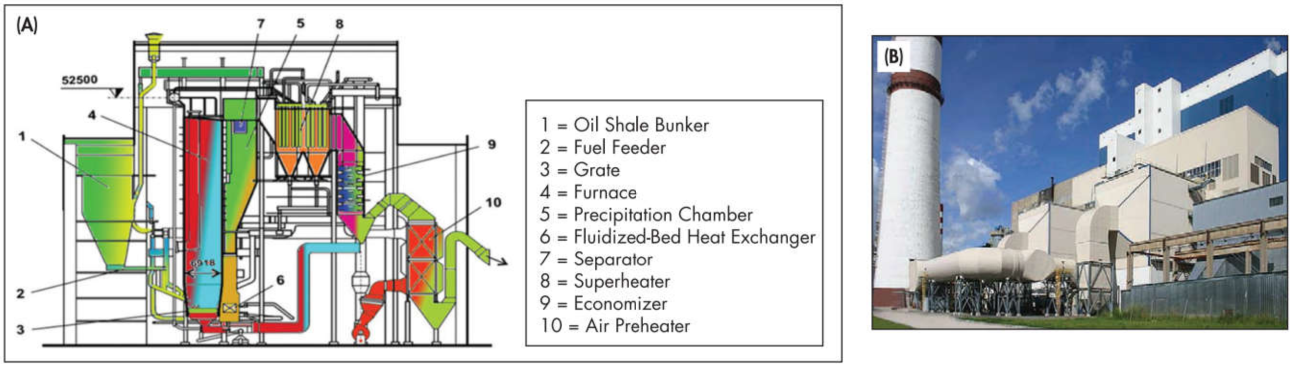
For internal combustion processes, crushed or pulverized feed is fed into the top of a retort and the raw oil shale is heated by the combustion of produced gas and spent residue within the retort at the bottom of the reactor. The vapors generated are condensed, with noncondensable gases fed back into the reactor as fuel. The two commercial oil shale retort processes of this type were developed and first used in the 1920s (Estonia) and 1930s (China), as were some of the first large-scale commercial uses of oil shale.

Kiviter process. Used in Estonia in many retorts, the Kiviter process was previously used for oil shale processing in Russia. The largest unit processes about 960 t/d (metric tons per day) of oil shale (Figure 6).

Fushun process. Similar to the Kiviter process but with a slightly different hot gas flow direction, the Fushun process has some aspects of an external hot gas process. It was developed in China in the 1920s and first commercialized in the 1930s. At one point, there were more than 250 retorts in operation in the 1950s, producing 100–200 t/d of shale oil. Once heavy oil was discovered in China, oil shale production became less economic and was shut down in the 1990s, but was soon restarted and grew to where China is the largest shale oil producer in the world from mined oil shales.

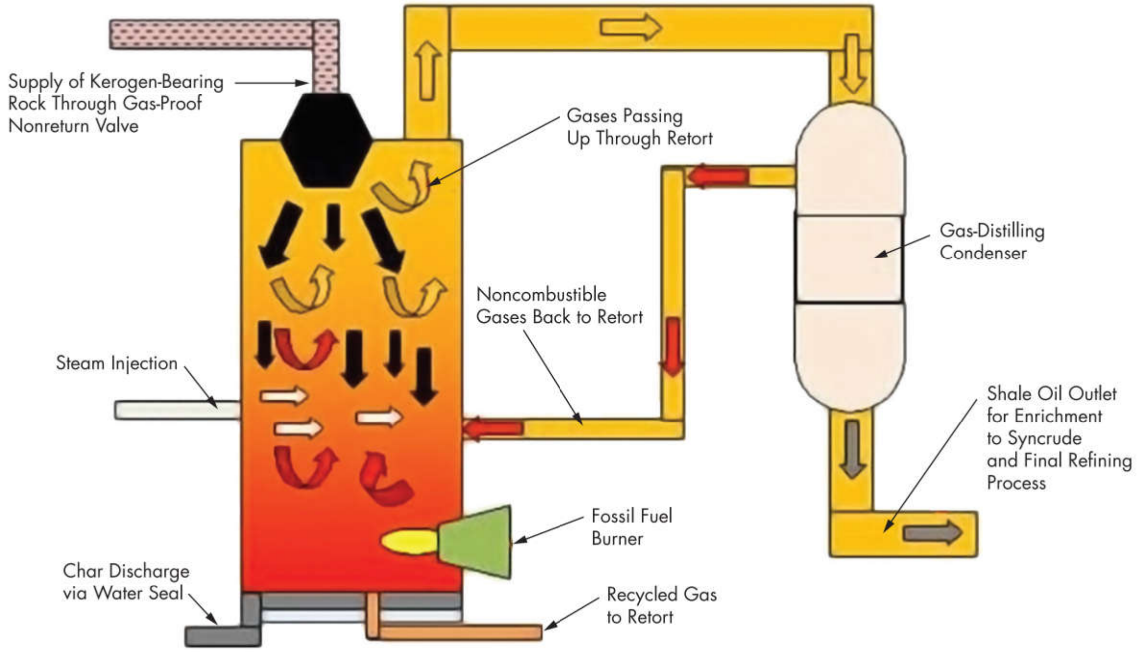
Externally Generated Hot Gas

Externally generated hot gas retort processes are based on generating hot gases at 600°C in an external process unit and injecting these hot gases into the midpoint of the retort vessel for pyrolyzing the oil shale. Another cool gas stream is injected into the bottom of the retort vessel to recover heat from the spent shale before the solids are discharged. Oil and gases are removed from the top of the retort vessel where oil droplets are collected in a precipitator. The gas is used to heat



Courtesy of Al Qamer

Figure 5 (A) Circulating fluidized-bed boiler process at (B) AS Narva power plant, Estonia



Note: This is a basic Kiviter-type pyrolysis retort that produces 40 t/h of shale oil from kerogen-bearing rock.

Source: Scott 2011

Figure 6 Kiviter process

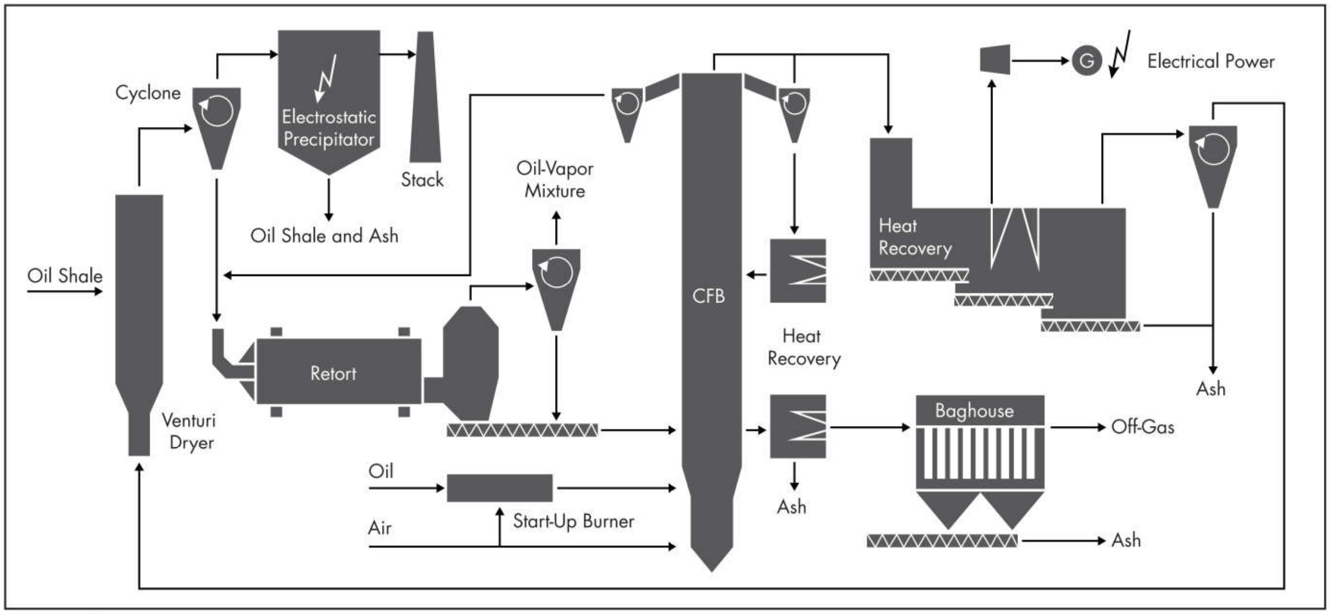
and cool the retort process, while a side stream of the gas is further cooled to produce naphtha, liquefied petroleum gas, sulfur, and fuel gas for the process. A downside of this process is that the energy in the char in the spent shale is not recovered.

Petrosix, or Petro6, process. Petrobras' Petrosix operation has the world's largest pyrolysis retort vessel with an 11-m-diameter vertical shaft kiln. Work on this process started in the 1950s, with an initial limited commercial operation starting in 1980 and the current large unit brought into commercial operation in 1992. The dual reactors in the plant process 8,500 t/d of shale on a combined basis to produce petroleum products and sulfur.

Hot Recycled Solids

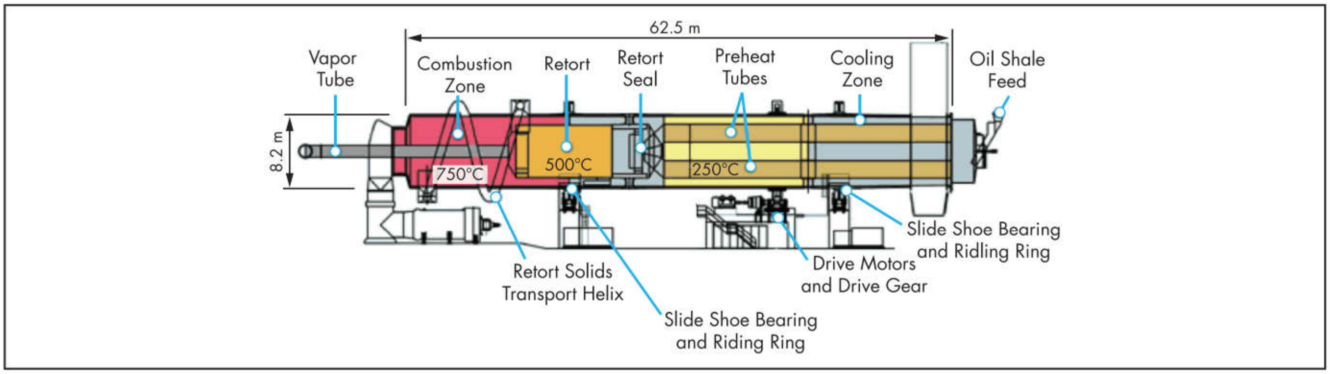
In hot recycled solids processes, much of the energy transfer is accomplished through cross exchange of input ore with hot recycled spent shale. Many processes are based on this concept to increase efficiency and conversion. The commercial operations using this basic method are located in Estonia, but they incorporate some variations and modified processes in the commercial plants.

Galoter or Petroter retort process. The Galoter retort process uses an inclined hot cylindrical rotating kiln as the retort vessel. Solid oil shale particles are separated from the dried crushed feed in a cyclone separator. A mixing chamber combines the feed with hot recycled ash from combustion of the spent shale. Then the mixture is added to the kiln where



Courtesy of Outotec

Figure 7 Enefit variation of the Galoter process



Source: U.S. Department of Energy 2004

Figure 8 Alberta Taciuk processor

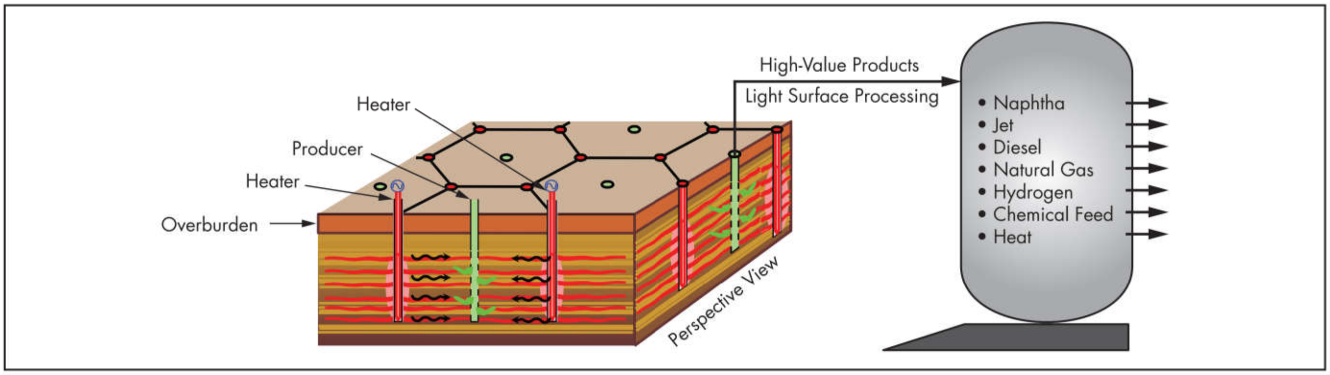
the oil and gas vapors are removed and condensed to products. The spent shale is burned in an external furnace with some solids returned to the mixer while the remainder are cooled and sent to disposal. The hot gases from combustion are used to dry and preheat the feed stream. The process has a high thermal efficiency and high oil recovery. Commercial-scale units were first online in the 1950s and 1960s, but were shut down and replaced with two larger 3,000-t/d units in 1980. Between 2009 and 2015, three additional units with slight modifications were built but were called Petroter plants. All units are in Estonia.

Outotec Enefit retort process. The Enefit280 process (Figure 7) was developed based on the Galoter process by combining it with a CFB combustor to replace the spent shale furnace in the Galoter process. One 280-t/d unit is in operation in Auvere, Estonia, which is colocated with the two 140-t/d Galoter units.

Other Noncommercial Retorting Technologies

The three basic retorting processes have been discussed; however, other processes have been proposed, piloted, or demonstrated to attempt to either improve conversion efficiency, reduce costs by reducing the number of units and complexity, or process lower-quality or more variable feeds or end products. Most of these have been piloted or demonstrated at some level and are briefly described in the following paragraphs. The only one that is discussed in a bit more detail is the Alberta Taciuk processor (ATP), which has been widely tested with a range of feedstocks and may be on the verge of being commercialized on a larger scale.

Alberta Taciuk process. Originally developed for minable oil sands in Alberta, Canada, the ATP went through extensive development and testing in the late 1970s. Its first commercial use in the late 1980s was for cleanup of contaminated soils. From 1999 to 2004, it was used at the Stuart Oil Shale Project in Australia, but the plant has since been closed and dismantled. The process has been considered for many other applications in Estonia, China, and Jordan. The ATP is



Courtesy of Colorado Geological Survey

Figure 9 In situ conversion process and wells

a hot recycled solids method and its main feature is that most of the process steps occur within a single rotating horizontal retort, through the use of multiple chambers. This provides energy efficiency and high yields with process simplicity and a robust design (Figure 8).

Tosco II process. A hot recycle solids technology, Tosco II uses hot ceramic balls to transfer energy from the heater to the retort vessel, which is a rotating kiln. The process was tested near Parachute, Colorado (United States), in the late 1960s to early 1970s.

Lawrence Livermore National Laboratory (LLNL) hot recycled solids (HRS) process. The LLNL HRS process uses a vertical retort vessel but with hot spent shale and feed mixed in a fluidized-bed mixer. It was tested in Parachute, Colorado, in the mid-1980s.

Lurgi–Ruhrgas process. An HRS technology, the Lurgi–Ruhrgas process is also used for lignite coal liquefaction and was developed in the 1940s. Plants liquefying coal operated in Japan, Germany, the United Kingdom, Argentina, and Yugoslavia, with the plant in Japan also cracking petroleum. Pilot-plant runs using oil shales were done in Frankfurt in the late 1960s and early 1970s.

Kentort II. An HRS concept, the Kentort II was developed by the Center for Applied Energy Research at the University of Kentucky (United States) in the mid-1980s. It is unique in using four cascaded fluidized-bed vessels.

Chevron staged-turbulent-bed (STB) retorting process. An HRS technology, the Chevron STB process uses a vertical fluidized bed as a retort vessel.

Paraho process. With an internal combustion method similar to the Kiviter and Fushun retorts, the Paraho process has different designs for the feed system, gas distribution, and solids discharge. It has direct and indirect heating modes. Pilot operation is located near Rifle, Colorado, and a unit was put into operation in 2011 at the Stuart Oil Shale Project in Australia.

Union process. With a vertical shaft retort, similar to Kiviter and others, the main difference in the Union process is that a *rock pump* is used to add feed shale from the bottom of the retort vessel. It can be heated with direct (Union A) or indirect (Union B) heat. It was developed by Unocal in the 1940s. Union A was tested in the late 1950s, and Union B was tested in Colorado in the late 1980s.

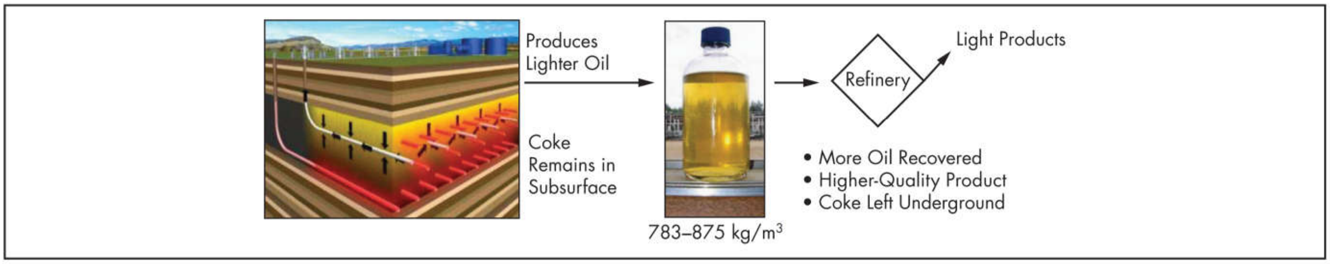
Superior multimineral process. Also known as the *McDowell-Wellman process*, shale oil production is combined with minerals processing to recover aluminum, sodium bicarbonate, and sodium carbonate. Minerals are separated after an initial crushing stage, with the oil shale crushed further prior to the retort vessel. The retort vessel is shaped like a donut with horizontal segments and a traveling grate.

IN SITU PROCESSING

The second major option for accessing and converting oil shales is through in situ (in-place) methods, which are a more recent development, beginning about the 1980s. These methods target deep, thick shale formations that may initially produce shale oil but still contain large amounts of kerogen and shale oil trapped by residual kerogen blocking the fine pores in the shale rock. Directionally, these methods provide access to a much larger volume of oil shale, can be applied incrementally because there is no major investment in mine development, and should result in lower land, air, and water impacts. None of these processes are yet commercial, so it is unclear which process is most likely to proceed. The Shell in situ conversion process (ICP) seems to be furthest along and has been piloted in both oil shale and oil sands formations, with pilot activities still underway. This section provides a basic description of the main processes being considered; however, there may be other methods under development. As with surface processes, all methods require heating the in situ kerogen to temperatures above 300°–350°C to accelerate maturation of the kerogen in the oil shale rock. Temperatures needed are generally lower than surface retorts because residence time and vessel size are not as critical to the economics.

In Situ Conversion Process

The main characteristic of the ICP method is the use of electric heaters in drilled wells, which heat the surrounding oil shale (Figure 9). Initial trials of the process in the Piceance Basin in the United States started in 2004. A unique aspect of the project is the use of subsurface *ice walls* to isolate the test volume from surrounding groundwater aquifers and to allow the shale to be dewatered before heating begins. The ice walls require surface refrigeration systems on relatively close spacing. Vertical wells are then drilled within the ice wall perimeter, and heaters are installed to heat the rock to ~350°C. This slowly converts the kerogen into shale oil and gases, which can then be produced from a pattern of producing wells. With vertical heating and producing wells in close proximity, the initial pilot had a large footprint. ICP requires further development to address issues related to shales, such as low permeability and water impacts.



Adapted from Shell Canada Limited 2014

Figure 10 In situ upgrading project

In 2004–2010, Shell tested a similar process at their Viking pilot in the Peace River oil sands in Alberta, Canada, which the company called an "in situ upgrading project." This was followed by a pilot in the Grosmont bitumen-in-carbonate formation, also in Alberta (Shell Canada Limited 2014). In this case, ice walls were not required and heaters were installed in layers of horizontal wells alternating with layers of producing wells (Figure 10). A second project in the Grosmont carbonate bitumen formation has continued work mainly on developing and proving downhole heater technology while upgrading bitumen to lighter fractions. This work, in parallel with the oil shale work, should be complementary but may result in bitumen conversion moving ahead before oil shale conversion.

Electrofrac Process

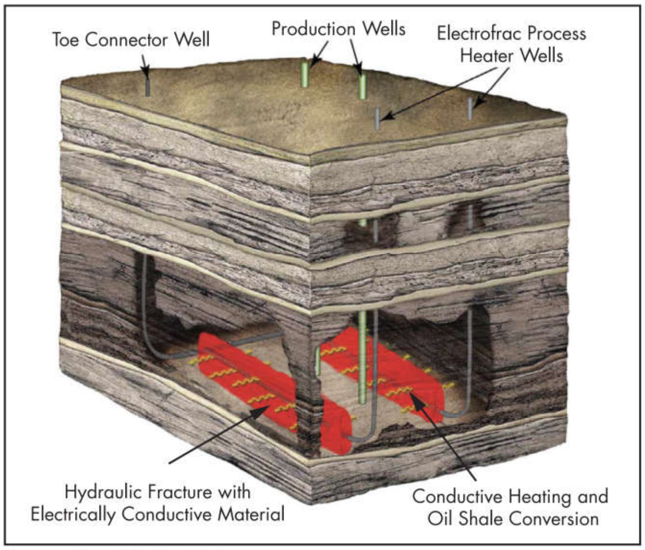
ExxonMobil's candidate technology for in situ oil shale retorting is the Electrofrac process (Figure 11). The process is designed to heat oil shale by creating hydraulic fractures in the oil shale and propping the fractures open and injecting a proprietary electrically conductive material. Electricity flowing through the conductive medium turns the fracture into a resistive heating element which gradually heats the shale and converts the kerogen into oil and gas that can then be produced by conventional means. This process is supported by ongoing research and technology development for production of shale oil and gas. ExxonMobil indicates that field tests have been initiated to test the concept, but it will be many years before the technology can be shown to be technically, environmentally, and economically feasible.

CRUSH Process

*C*hevron's technology for the *R*ecovery and *U*pgrading of oil from *SH*ale (CRUSH) is based on fracturing, or preferably *rubblizing*, the shale to increase the surface area of oil shale kerogen exposed to flow through the fractures (Figure 12). High-temperature gas, preferably carbon dioxide, is injected through the fractures, then reheated at surface or by being passed through previously depleted portions of the shale zone. There does not appear to be much recent activity on this technology, and Chevron appears to be mainly focused on shale oil developments.

RETORTING BY-PRODUCTS

Some retorting processes can produce by-products from the retorting process that may be of value. All retorting processes produce ash from the combustion of spent shale, which could be used in cement as was done for many years in Estonia. Depending on the composition of the oil shale, other by-products may be natural gas, carbon dioxide, sulfur, aluminum, ammonia, asphalt, or other hydrocarbons.



Source: ExxonMobil 2007

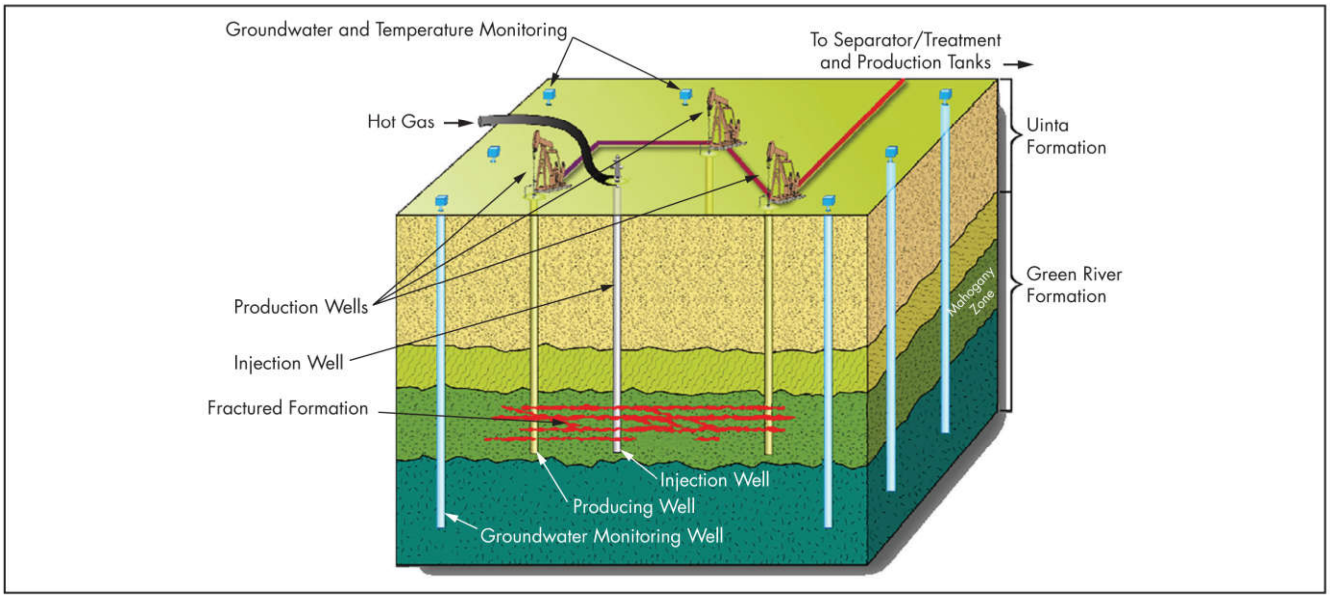
Figure 11 Electrofrac process

ENVIRONMENTAL IMPACTS

Production and processing of oil shales can have significant environmental impacts depending on the shale composition, the extraction process used, and the region in which the operation occurs.

Greenhouse Gas Emissions

Greenhouse gas (GHG) emissions vary widely depending on the process. Power generation in Estonia is treated the same as a coal power plant when compared to European emissions. Limestone in the oil shale feed can reduce SO_x emissions but increase CO_2 emissions. One analysis (using oil shale with an average grade of 125 L/t) shows GHG emission ranges, in kilograms of CO_2 per cubic meter of product, for six processes of 264–918 kg/m^3 for combustion; 0–2,214 kg/m^3 as a result of carbonate; and 69–88 kg/m^3 for the pyrolysis step, resulting in an overall total CO_2 range of 352–2,906 kg/m^3 (Burnham and McConaghy 2006). The low end of the range provided is for the Shell ICP process, assuming downhole methane burners are used for heating. This could be lower if electrical heaters were used with power from nuclear or renewable sources. These numbers do not include the life-cycle emissions for



Source: Crawford et al. 2012

Figure 12 CRUSH technology

mining the oil shale or drilling access wells, and thus give an indication of relative GHG emissions only. As with other large-point emission sources, carbon capture technologies might be utilized to mitigate these impacts.

Other Air Emissions

Depending on the shale, processing may produce SO_x emissions, volatile organic compounds, and high-particulate emission levels into the air, which could impact workers, nearby residents, and other industries. These may, in some cases, be similar to coal power plant emissions, other types of mines, refineries, or in situ production operations. They may be better or worse than other energy processes, so there is no clear generic statement that can be made about air emissions from oil shale operations.

Water Use and Contamination

The impact on water use and contamination varies widely across the various shales and extraction processes. All oil shale mining operations tend to impact groundwater and surface drainage. Power-generation water use is likely similar to an equivalent-sized coal-fired plant. Internal combustion retorting plants tend to use a lot of water for quenching the spent shale, and minerals found in the spent shale can also contaminate the water. In contrast, the hot recycled solids processes mostly operate dry, so there is little water consumption, and minerals in the spent shale are less soluble when contacting water at lower temperatures. For in situ conversion processes, the main water concerns are with any water used for hydraulic fracturing, flow-back treatment, and the protection of underground aquifers if the shale is shallow or as a result of potential well failures because of high temperatures and corrosive conditions in the production wells and gathering lines.

Land Impacts

As with other energy resource operations, oil shale operations have land impacts from mining and well development footprints, as well as the processing units, truck haulage, pipelines, and waste disposal operations associated with the chosen extraction method. Land impacts are also affected by the geographic location of the operations. Sensitive landscapes or ecosystems should be considered when looking at potential impacts.

REFERENCES

Allix, P., Burnham, A.K., Fowler, T., Herron, M., Kleinberg, R., and Symington, B. 2010. Coaxing oil from shale. *Oilfield Rev.* 22(4):4–15.

Brady, G.S., and Clauser, H.R. 1991. *Materials Handbook*, 13th ed. New York: McGraw-Hill.

Burnham, A.K., and McConaghy, J.R. 2006. Comparison of the acceptability of various oil shale processes. Presented at the 26th Oil Shale Symposium, Golden, CO, October 16–18.

Crawford, P.M., Dean, C., Stone, J., and Killen, J.C. 2012. Assessment of plans and progress on U.S. Bureau of Land Management oil shale RD&D leases in the United States. www.energy.gov/sites/prod/files/2013/04/f0/BLM_Final.pdf. Accessed September 2018.

Dyni, J.R. 2006. *Geology and Resources of Some World Oil-Shale Deposits.* U.S. Geological Survey Scientific Investigations Report 2005-5294. Reston, VA: U.S. Geological Survey.

EIA (U.S. Energy Information Administration). n.d. International energy statistics. www.eia.gov. Accessed September 2018.

ExxonMobil. 2007. *Financial and Operating Review*. Irving, TX: ExxonMobil.

Intek. 2011. *Secure Fuels from Domestic Resources: Profiles of Companies Engaged in Domestic Oil Shale and Tar Sands Resource and Technology Development*, 5th ed. Report for the U.S. Department of Energy, Office of Petroleum Reserves, Naval Petroleum and Oil Shale Reserves. Arlington, VA: Intek.

McCarthy, K., Rojas, K., Niemann, M., Palmowski, D., Peters, K., and Stankeiwicz, A. 2011. Basic petroleum geochemistry for source rock evaluation. *Oilfield Rev.* 23(2):32–43.

Schwartz, M. 2016. *Encyclopedia and Handbook of Materials, Parts, and Finishes*, 3rd ed. Boca Raton, FL: CRC Press.

Scott, W. 2011. Crude oil from unconventional sources. www.brighthubengineering.com/manufacturing-technology/68900-crude-oil-from-unconventional-sources/. Accessed September 2018.

Shell Canada Limited. 2014. *Field Production and Heater Test Project—Amended Experimental Scheme Approval 11487A Progress Report: Long Horizontal Heater Test (LHT)—2013 Performance Review to AER.* www.aer.ca/documents/oilsands/insitu-presentations/2014AthabascaShellGrosmont11487.pdf. Accessed September 2018.

U.S. Department of Energy. 2003. An energy overview of the Republic of Estonia. www.geni.org/globalenergy/library/national_energy_grid/estonia/EnergyOverviewofEstonia.shtml. Accessed September 2018.

U.S. Department of Energy. 2004. *Strategic Significance of America's Oil Shale Resource*. Vol. II, Oil Shale Resources, Technology and Economics. Washington, DC: U.S. Department of Energy.