Responsible Development of Oil Shale

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Abstract

Economic progress, especially in developing countries, will drive global energy demand higher despite substantial efficiency gains. Oil, natural gas, and coal are indispensable to meeting this demand, even with rapid anticipated growth in renewable energy sources. Oil shale represents a significant unconventional hydrocarbon resource, with estimates of the total volume of oil-in-place in oil shale formations in the U.S. exceeding 1.5 trillion equivalent barrels.

With advances in technology and a responsible regulatory framework, oil shale may contribute significantly to global oil supplies. We present various ways in which responsible development of oil shale can be achieved. Topics include: surface footprint, water use and supply, groundwater protection, energy balance and carbon footprint, and multimineral development of oil shale together with nahcolite and deep gas.

Introduction

ExxonMobil has researched various oil shale technologies for decades. Our leading technology, the proprietary Electrofrac™ process, is an energy-efficient method to convert oil shale to producible oil and gas. The Electrofrac™ process is designed to heat oil shale *in situ* by building a hydraulic fracture (a conventional oilfield technology) in the oil shale and filling the fracture with an electrically conductive material. Electricity is conducted from one end of the fracture to the other, making it a resistive heating element. Heat transfers from the fracture into the oil shale formation, gradually converting the solid organic matter of the oil shale (kerogen) into oil and gas. The oil and gas are produced by conventional methods, as illustrated by the schematic in Figure 1. If successful, Electrofrac™ has the potential for cost-effective recovery with less surface disturbance than either mining and retorting or competitive *in situ* processes. Several years of research and development are required to demonstrate technical, environmental, and economic feasibility of the process.

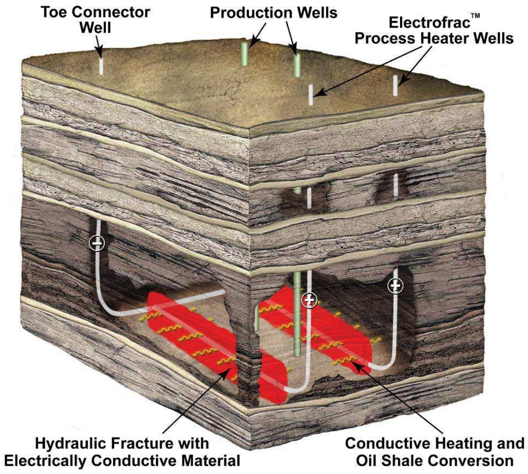

Figure 1. Electrofrac™ is a potential process for the subsurface conversion of oil shale into producible hydrocarbons.

ExxonMobil is committed to responsible development of energy sources, which includes good stewardship of the associated environmental resources. We have demonstrated this in our operations around the world. We will bring the same environmentally responsible project management to the research and development of oil shale.

In this paper, we present our current thinking on several critical issues associated with the development of oil shale. While additional research and development is required to fully address these issues, this paper is intended to be a starting point for dialogue. We believe that responsible development of oil shale can provide affordable energy while protecting the environment. We address the following specific topics:

- Reduced surface footprint of fracture heaters
- Reduced use of fresh water
- Groundwater protection
- Multimineral development: nahcolite, tight gas
- Energy efficiency and CO_2 emissions

ExxonMobil's research program has included laboratory work, computer modeling, and field testing of Electrofrac™ process elements at our Colony site in Colorado (Symington *et al*., 2006; Symington *et al*., 2009). Environmental elements are a prominent part of our current and future research program.

Reduced Surface Disturbance

ExxonMobil's Electrofrac™ technology has a reduced surface footprint compared to either mining and retorting methods or to alternative *in situ* oil shale technologies. Electrofrac™ should require only one or two heater wells per acre, which is an order of magnitude fewer heater wells than vertical *in situ* wellbore heaters. Figure 2 shows a schematic representation comparing the surface footprint; production wells are not shown for either scenario. We will strive to reduce the surface footprint further by drilling multiple wells from a single pad.

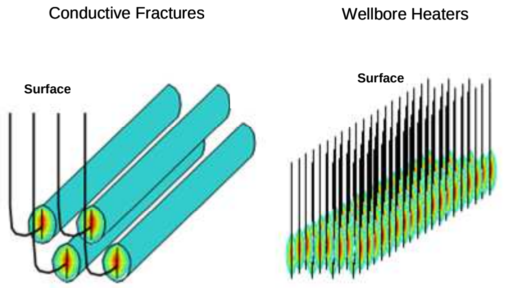

Figure 2. Surface footprint of Electrofrac™ heaters compared to vertical wellbore heaters for a notional 240-ft by 1200-ft (73-m by 366-m) development area.

Water Use and Supply

While the actual water requirements for the Electrofrac™ process are not fully known, it is expected that water requirements will be lower than 1980s estimates of 2 to 5 bbl of water per bbl of oil produced for mining and retorting operations (Bartis *et al*., 2005). The consumptive water requirements to cool and reclaim spent shale do not apply to *in situ* methods like Electrofrac™. Water will be needed for construction and drilling activities, shale oil processing, water flushing for remediation and sodium mineral recovery, and power generation. Instantaneous water requirements will vary depending on the nature of on-going operations (drilling, initial heating, production, nahcolite recovery, and reclamation). To the extent practical, ExxonMobil will treat water for reuse and will plan field operations in phases such that peak requirements for water are moderated.

ExxonMobil's current estimates of water use for commercial Electrofrac™ operation are provided in Table 1. This includes both direct water use for drilling, processing, and water flushing as well as indirect water use for power generation estimated for Electrofrac™ operation.

Table 1. Water Use Estimates for Commercial *In Situ* Oil Shale Development, bbl water used per bbl oil produced

Use	Unmitigated Estimates	Mitigated Estimates
Drilling, dust control	0.1	0
Post-production flushing	1.7	0-1
Oil stabilization	1	1
Power generation	1-3	0.1
Total	4-6	1-2

The first column in the table provides a first-pass estimate of water use, unmitigated except for the use of a wastewater treatment plant for water reuse in the flushing process. Water use for drilling, fracturing, and dust control is relatively modest, estimated at 0.1 bbl water per bbl oil. The initial estimate of water use for post-production flushing assumes one pore volume of fresh water to fill the pyrolized zone and recycle from a wastewater treatment plant for subsequent fills (with typical plant recycle efficiencies). We anticipate that the shale oil produced from *in situ* conversion will require some stabilization prior to pipeline transport; mild hydrotreating to stabilize olefins would require a hydrogen plant with water use of approximately 1 bbl of water per bbl of oil. Indirect water use for power generation depends strongly on the type of power plant: conventional gas-fired power plants use about 1 bbl of water per bbl of oil, and coal-fired power plants use about 3 bbl of water per bbl of oil (URS Corporation, 2008).

The second column is an estimate of water use if alternative water sources and current water-use-reduction technologies are employed. One alternative source to displace fresh water use might be the use of water coproduced from ExxonMobil's tight gas operations. Such water would require treatment prior to many of the uses for *in situ* oil shale production, and the planned wastewater treatment plant could accept the tight gas coproduced water as influent. One currently available technology that could substantially reduce the indirect water use is air-cooled power plants. Several such plants have been built around the world, and the technology is well developed (Wurtz and Peltier, 2008).

By utilizing the currently available measures discussed here, water use for *in situ* oil shale development may be reduced from the first-pass, unmitigated estimate of 4-6 bbl water used per bbl oil produced to approximately 1-2 bbl water used per bbl oil produced. With additional research, new technologies may be developed that enable even further reduction of fresh water use.

It is important to recognize that there is an environmental (surface footprint, energy, carbon emissions) and economic cost for such measures to mitigate fresh water use. However, options exist, and trade-offs for their application can be evaluated at the time of development.

If we assume that 1.5 bbl water used per bbl oil produced is a reasonable estimate, let us consider what this means for a commercial scale project and a potential oil shale industry. Table 2 provides estimates for a commercial project producing 50,000 bbl of oil per day and an industry of ten such projects. The estimated water used by the 500,000 bbl/d industry is 35,000 ac-ft/yr. To help put this value in context, the annual water usage for the State of Colorado in 2005 was 15,300,000 ac-ft/yr (Kenny *et al.*, 2009).

Table 2. Estimated Industry Water Demands

Scope	Oil Production bbl/d	Water Demand bbl/d	Water Demand ac-ft/yr
One Commercial Project	50,000	75,000	3500
Industry (10 projects)	500,000	750,000	35,000

ExxonMobil anticipates use of a wastewater treatment plant to reduce fresh water consumption. This facility would be used to treat and recycle produced water during the post-production flushing, and it could also be used to treat alternative water sources to make them acceptable for project use. A process flow diagram of the proposed facility is shown in Figure 3. The process comprises the following steps.

1. Oil-Water Separator: Free oil will be removed using a dissolved air flotation (DAF) system. If required, an API oil-water separator may be used ahead of the DAF unit.
2. Activated Sludge Biological Treatment: An activated sludge process will be used to break down organic compounds.
3. Clarification/Filtration: Effluent from the Activated Sludge process will be settled in a clarifier and effluent will be filtered using a dual-media filter to remove suspended solids.
4. Hot-Lime Softening: The filtered water will be sent to a hot-lime softening unit to quantitatively remove hardness and some alkalinity.
5. Reverse Osmosis: The softened water will be demineralized using a reverse osmosis system.

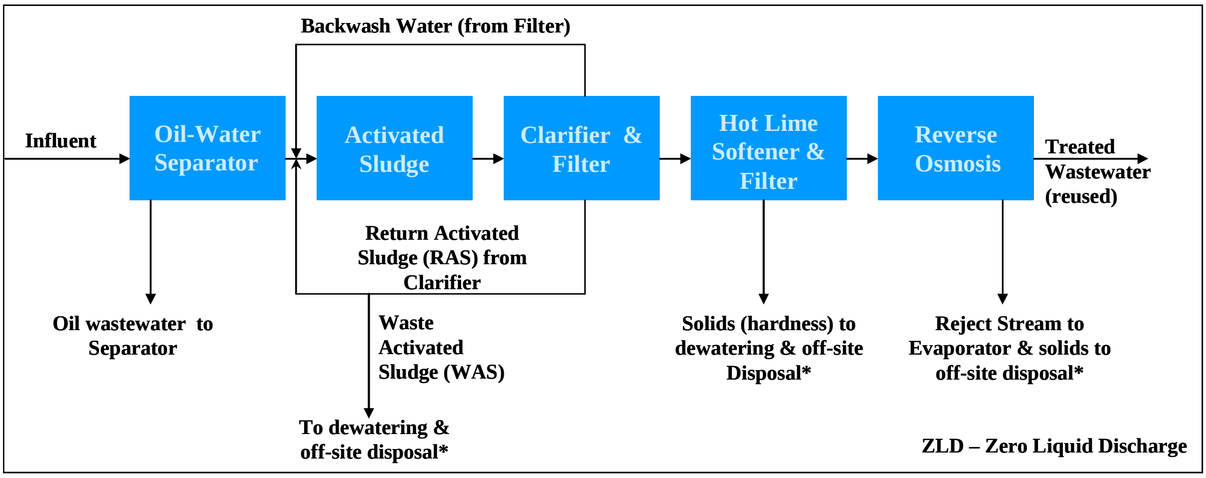

Figure 3. Wastewater treatment plant

ExxonMobil has water rights on both the Colorado and White river systems. ExxonMobil's water rights consist of agricultural and industrial rights together with augmentation plans, including a 6,000-acre-ft storage right in the Ruedi Reservoir (which ExxonMobil has made available in the past to agricultural users during drought conditions).

In summary, ExxonMobil will meet water requirements through a combination of fresh water obtained from its water rights, alternative water sources, and wastewater treatment and reuse. ExxonMobil has sufficient water resources included within decreed augmentation plans to support an *in situ* oil shale project, conventional natural gas development, and the development of the Colony Shale Oil Project with mining and retorting methods. ExxonMobil also anticipates that it will have water available, if needed, to assist municipalities in meeting water demands arising from an increase in population as workers relocate to the area for these projects.

Groundwater Protection

ExxonMobil's strategy to protect proximate groundwater (and, by extension, the surface water streams in communication with groundwater) will be to design the operations to contain the

Electrofrac™ zone in a low-permeability envelope of unheated oil shale below the aquifer systems. The effectiveness of this strategy will be evaluated throughout the research and development program with comprehensive groundwater monitoring.

ExxonMobil will target the tight, saline zone below the aquifers. Hydraulic fracturing will be controlled to prevent fractures from extending beyond the developed volume. Geomechanical modeling indicates that an Electrofrac™ process volume can be surrounded by cold pillars of oil shale such that subsidence and associated faulting could be mitigated, preventing connection to over- or underlying aquifers. Thus, an impermeable seal will be maintained around the developed volume as shown in Figure 4. Such a development strategy should preclude contact between proximate groundwater sources and the Electrofrac™ pyrolysis volume.

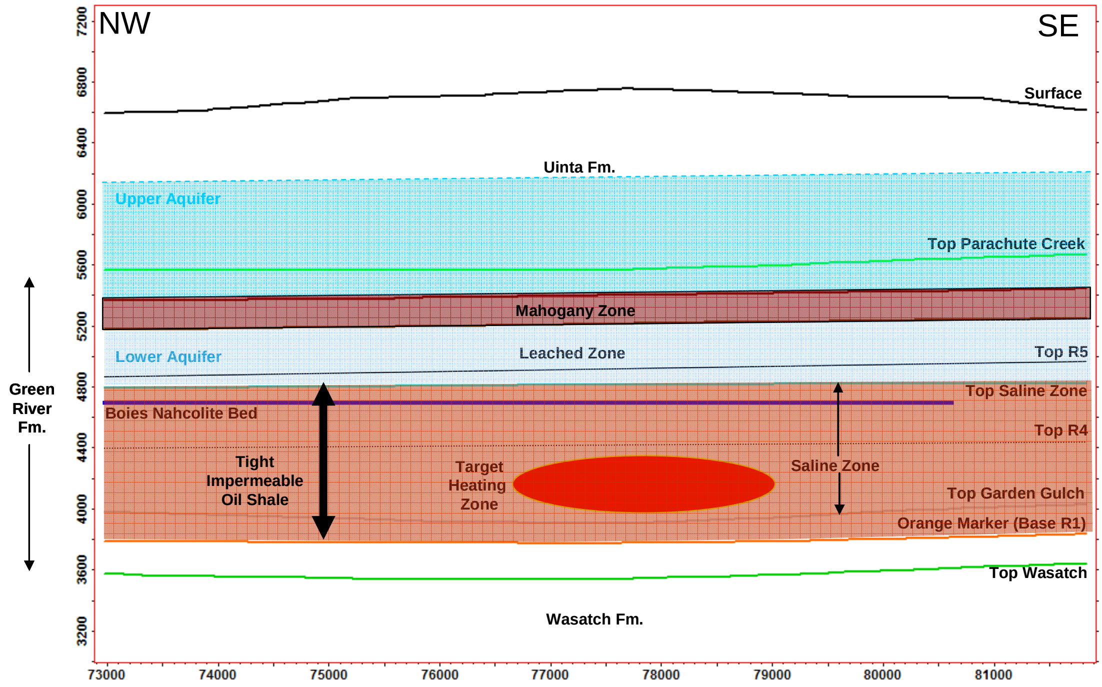

Figure 4. Hydraulic isolation of pyrolysis volume below aquifers.

Post-Production Flushing and Nahcolite Recovery

While we anticipate that the tight, saline oil shale formation will seal the heated volume on the time scale of production, groundwater monitoring results may indicate that it is prudent to flush the heated volume to remove residual hydrocarbons prior to abandonment. This post-production flushing could serve a dual purpose: groundwater remediation and recovery of nahcolite.

Nahcolite, $NaHCO_3$, occurs as beds, nodules, and finely disseminated crystals within and between beds of oil shale within the Parachute Creek member of the Green River formation. Dyni (1974) estimated that 85% of the nahcolite is intimately mixed with oil shale as either nonbedded crystalline aggregates or finely disseminated crystals.

ExxonMobil's Electrofrac™ technology will preserve and perhaps enhance sodium-mineral value (Yeakel *et al.*, 2007). Chemical-equilibrium modeling and experimental work indicate that pyrolysis of oil shale will result in the transformation of nahcolite (sodium bicarbonate or baking soda) to sodium carbonate (natrite or soda ash). Like nahcolite, sodium carbonate is a water-soluble mineral. After oil shale recovery is complete, water injection into the pyrolysis zone can be an effective method for recovering the sodium carbonate. The enhanced permeability of the pyrolyzed oil shale will make access to the sodium minerals more efficient and may result in increased recovery. This synergistic process is illustrated in Figure 5.

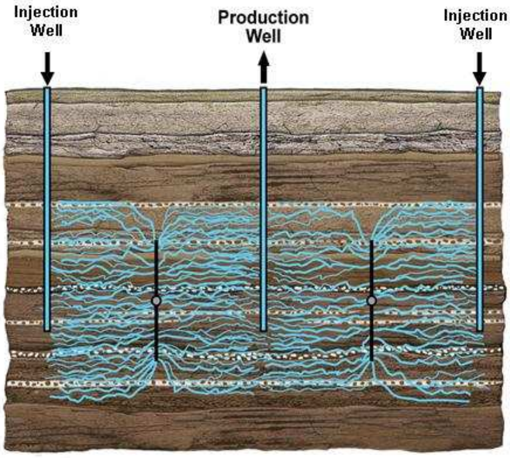

Figure 5. Synergistic post-production flushing removes residual hydrocarbons and recovers sodium minerals.

Codevelopment with Tight Gas

The Piceance basin of Colorado is a rich petroleum system. It contains up to 10,000 ft of Late Jurassic to Paleocene Age fluvial and marine strata: the Mancos, Mesaverde, and Wasatch Formations. The Eocene Green River Formation overlies the Wasatch Formation. The Wasatch Formation is a mature gas producer, and the Mesaverde Formation is in active development for gas production. ExxonMobil operates several tight gas wells in the Mesaverde Formation.

ExxonMobil has identified methods that enable concurrent development of *in situ* oil shale and the underlying tight gas resource. We have used geomechanical modeling to demonstrate that cold pillars of oil shale can effectively mitigate subsidence. Such cold pillars also provide a conduit for wells to access the tight gas resource as shown in Figure 6. The yellow pads indicate surface locations of the Electrofrac™ heater wells. The blue pads indicate surface locations of the tight gas wells. Current tight gas drilling practices include pad drilling of deviated wells. By planning these wells with kick-off points below the Green River Formation as shown, the gas wells can be restricted to cold pillars within the oil shale.

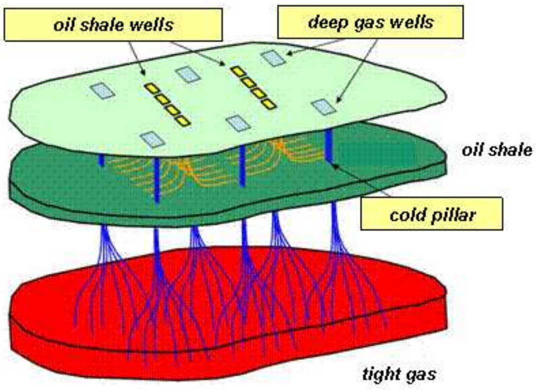

Figure 6. Codevelopment of *in situ* oil shale and underlying tight gas.

Additional synergies may exist between oil shale and tight gas development. There is potential to share some infrastructure and reduce surface disturbance. As previously mentioned, the water that is coproduced with the tight gas may be treated and used as an alternative water source to reduce fresh water use for oil shale development.

Energy Efficiency and CO_2 Emissions

The life-cycle greenhouse gas emissions of potential commercial oil shale development depend on the thermal efficiency of the retorting method and on the type of energy source used to heat the shale.

For commercial development, ExxonMobil envisions application of Electrofrac™ to an *in situ* oil shale resource that is several hundred feet thick. Such a development might include multiple layers of Electrofrac™ heaters to maximize thermal efficiency as described by Symington *et al*., (2006), and Symington and Spiecker, (2008). By developing a thick section of rich oil shale, the fraction of heat lost to overburden and underburden is minimized, and the *in situ* thermal efficiency is optimized.

ExxonMobil is looking at several options for supplying electrical power to the Electrofrac™ heaters. The most likely commercial development scenario is to use gas coproduced from the oil shale to fuel an energy-efficient, combined-cycle gas power plant. Gas-fired power plants emit less than 60% of the CO_2 emissions of coal-fired power plants (Energy Information Administration, 2009).

For the thermally efficient *in situ* heating and gas-fired power plant, preliminary estimates of the energy efficiency of the Electrofrac™ process indicate an energy ratio of at least 3 to 1 (that is, 3 bbl of oil equivalent of energy are produced for each bbl of oil equivalent of fuel input to the power plant).

For this scenario with a power plant fueled by produced gas, essentially all of the carbon dioxide produced, either from the *in situ* conversion process or from the power plant combustion, ends up in the power plant flue gas. If cost-effective methods are developed to capture and sequester CO_2 from power plant flue gas streams, such methods could be applied to the Electrofrac™ power plant.

ExxonMobil strives to continually improve energy efficiency in all of our operations. By applying new energy-efficient technologies, we use less energy to run our business, extend the life of the world's energy reserves, and reduce greenhouse gas emissions. Since 2004, we have invested more than $1.5 billion in activities to increase energy efficiency and reduce greenhouse gas emissions. As we invest in new facilities, such as those that would be constructed for oil shale development, we employ energy-efficient technologies.

Summary

Oil shale comprises an important domestic resource that has the potential to help us meet U.S. energy demand and diversify supply.

Laboratory work, modeling, and early field tests support technical feasibility of ExxonMobil's Electrofrac™ process. The method has significant potential for technical, environmental, and economic success.

ExxonMobil envisions environmentally and socially responsible development of oil shale with

- Reduced surface disturbance, water use, and CO_2 emissions
- Groundwater protection
- Multimineral development.

Going forward, we will proceed with a thoughtful, phased approach that allows for prudent technical, environmental, and social planning and execution. We look forward to working with all appropriate local, state, and federal agencies to develop viable options.

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