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Potential Ground Water and Surface Water Impacts from Oil Shale and Tar Sands Energy-Production Operations

Environmental Science Division

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Potential Ground Water and Surface Water Impacts from Oil Shale and Tar Sands Energy-Production Operations

for
Ground Water Protection Council
Oklahoma City, OK

by
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Chapter 1 – Introduction

Background

The United States ranks among the largest oil and gas producers in the world but is also by far the largest consumer of oil and gas. At present, the nation is therefore unable to supply its own petroleum needs. The U.S. reserves of conventional oil and gas and most unconventional sources are not large enough to meet current demands. In light of the present high crude oil and natural gas prices, the nation is looking at other domestic sources of petroleum that have not been produced in the past because of economic considerations. The United States hosts substantial oil shale reserves and some additional tar sands reserves. The U.S. Department of Energy (DOE), U.S. land management agencies, and some of the western states are already focusing attention on producing oil from oil shale and tar sands in ways that are economically viable and protective of the environment.

Current U.S. Efforts Relating to Oil Shale and Tar Sands

In August 2005, Congress passed the Energy Policy Act of 2005, Public Law 109-58 (H.R. 6). Section 369 of the Energy Policy Act of 2005 is also known as the Oil Shale, Tar Sands, and Other Strategic Unconventional Fuels Act of 2005. In the opening sentences of Section 369, Congress declares that it is the policy of the United States that:

> *(1) United States oil shale, tar sands, and other unconventional fuels are strategically important domestic resources that should be developed to reduce the growing dependence of the United States on politically and economically unstable sources of foreign oil imports;*
> *(2) the development of oil shale, tar sands, and other strategic unconventional fuels, for research and commercial development, should be conducted in an environmentally sound manner, using practices that minimize impacts; and*
> *(3) development of those strategic unconventional fuels should occur, with an emphasis on sustainability, to benefit the United States while taking into account affected States and communities.*

Section 369 focuses on a variety of programs to stimulate development and production of oil shale and tar sands. One of the key requirements directs the Secretary of the Interior to prepare a programmatic environmental impact statement (PEIS) for a commercial leasing program for oil shale and tar sands (OSTS) resources on public lands in Colorado, Utah, and Wyoming (see Figure 1). Through the *Oil Shale and Tar Sands Resources Leasing PEIS*, the U.S. Department of the Interior (DOI), Bureau of Land Management (BLM), will evaluate decisions regarding which public lands will be open for leasing in the three-state area and under what constraints. The PEIS will analyze and document the environmental, social, and economic issues associated with alternative approaches for leasing OSTS resources. The PEIS also will amend BLM Resource Management Plans (RMPs) in each of the three states.

Information about the PEIS is available at the Oil Shale and Tar Sands Leasing Programmatic EIS Information Center (http://ostseis.anl.gov/index.cfm). In addition to containing current information on oil shale and tar sands, this website provides online access to the previous comprehensive environmental impact statement (EIS) for oil shale leasing released by DOI in 1973. This is a detailed, six-volume document containing in excess of 3,000 pages of information about the state of the oil shale industry at that time. Much of this information is still valid because little oil shale development has occurred since the early 1970s. Volumes 1 and 3 of the 1973 EIS (DOI 1973a, b) are referenced throughout this report.

In addition to the large PEIS effort, BLM is moving forward with reviewing several specific proposed oil shale projects in Colorado. The BLM Colorado State Office and White River Field Office have selected five proposed projects from three companies (E.G.L Resources, Chevron U.S.A., and Shell Frontier Oil & Gas). Environmental assessment documents for the projects are available at http://www.co.blm.gov/wrra/nepa.htm. Public comments on the proposals were due to BLM during September 2006.

Purpose of This Report

The Ground Water Protection Council (GWPC) is a national association of state ground water and underground injection control agencies whose mission is to promote the protection and conservation of ground water resources for all beneficial uses, recognizing ground water as a critical component of the ecosystem. The GWPC recognizes the need for and supports U.S. production of oil and gas but wants to ensure that ground and surface water resources are not compromised by hydrocarbon production. Because these resources have not previously been produced in the United States in economic quantities, only a limited amount of information is readily available. The U.S. Environmental Protection Agency (EPA) and state oil and gas and environmental agencies have little or no experience with regulating production of oil shale and tar sand. The GWPC asked Argonne National Laboratory to make a preliminary evaluation of the impacts to ground water, including impacts to surface water as it interacts with ground water, which could result from the mining and in-situ production of oil from oil shale and tar sands. Agencies responsible for regulating these types of production activities would benefit from current information as they develop suitable control mechanisms.

Contents of Report

This report is intended to be a preliminary overview identifying issues and compiling relevant literature on the relatively narrow subject of ground water and surface water impacts. Several other recent reports sponsored by DOE provide much more detail and cover a broad range of issues (RAND Corporation 2005; DOE 2004a, b). References to relevant sections of those documents are found throughout this report. The draft PEIS described above will be a useful current reference when it becomes available. This report is organized as follows:

- Chapter 2 provides definitions and describes the processes used to recover oil from oil shale and tar sands.
- Chapter 3 discusses the potential impacts to ground water and surface water from oil shale and tar sand production.
- Chapter 4 describes the regulatory requirements for several U.S. states that host oil shale or tar sands reserves.

- Chapter 5 reviews the experience of producing oil from oil sands (the Canadians' preferred term for tar sands) in the Province of Alberta, including the regulatory guidelines that companies must follow.
- Chapter 6 discusses research needs, regulatory gaps, and proactive steps that can help to prevent ground water and surface water impacts from oil shale and tar sands development.
- The report also contains a bibliography of references on oil shale and tar sand production, with a special emphasis on ground and surface water issues.

Chapter 2 – Oil Shale and Tar Sands – Resources and Technologies

The technology descriptions in this chapter are intended to be overviews. They are provided to help readers gain a general understanding of the major steps in producing oil shale and tar sands. In-depth descriptions of the different alternative oil shale technologies are not included here; they can be found in DOI (1973a), DOE (2004a, b), RAND (2005), and the draft PEIS (when completed). Unfortunately, we were unable to identify reports with comparable levels of details on tar sands production technologies.

Oil Shale Resources

Oil shale is a fine-grained sedimentary rock that yields substantial quantities of oil when heated to high temperatures in a closed retort (destructive distillation). Kerogen is the solid, insoluble, organic material in the shale that can be converted to oil and other petroleum products by pyrolysis and distillation. Oil shale was formed millions of years ago by deposition of marlstone and silt and organic debris on lake beds and sea bottoms. Over long periods of time, heat and pressure transformed the materials into oil shale in a process similar to the formation of conventional oil. However, in the case of oil shale, the heat and pressure were not as great, and the form of the hydrocarbon is different. Oil shale generally contains enough oil that it will burn without any additional processing. However, oil shale does not release liquid oil at ambient temperatures; it requires additional processing to separate the kerogen from the shale.

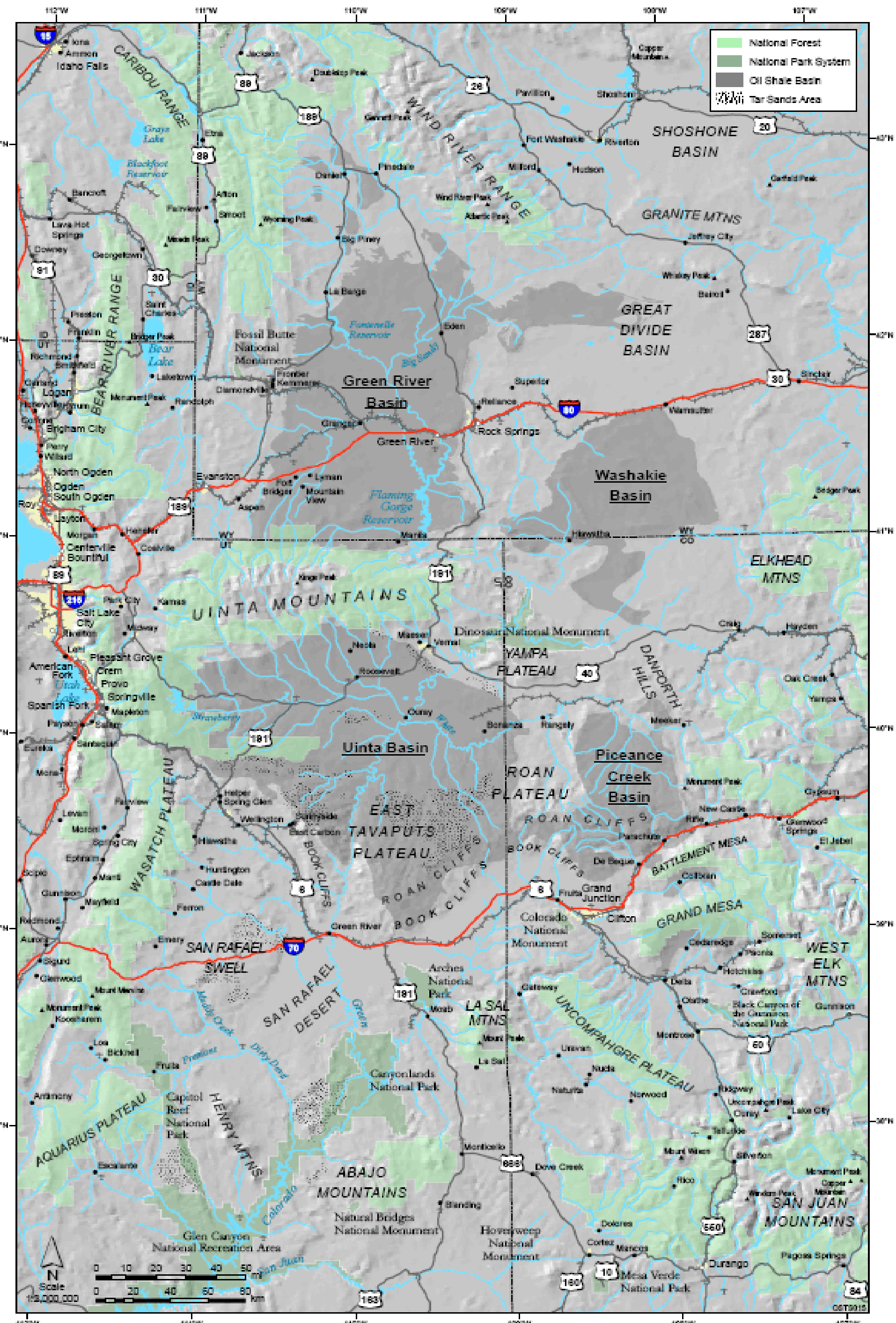
A recent U.S. Geological Survey report provides a very thorough review of worldwide oil shale resources (Dyni 2006). Oil shale occurs in at least 33 countries worldwide. The global oil shale resource base is believed to contain about 2.8 trillion barrels, of which the vast majority, about 2 trillion barrels, is located within the United States (including eastern and western shales). The most economically attractive deposits, containing an estimated 1.2 to 1.8 trillion barrels (with an oil content of more than 10 gallons/ton), are found in the Green River Formation of Colorado (Piceance Basin), Utah (Uinta Basin), and Wyoming (Green River and Washakie Basins) (DOE 2004b). Figure 1 shows the locations of these basins.

Not all resources in place are recoverable. Nevertheless, the oil shale deposits of the Green River Formation have been extensively studied and overshadow all other deposits on the basis of both abundance and richness. More than 70% of the total oil shale acreage in the Green River Formation, including the richest and thickest oil shale deposits, is under federally owned and managed lands. Thus, the federal government directly controls access to the commercially attractive portions of the oil shale resource base.

Outside the Green River Formation, the Elko Formation of Nevada is another smaller but still attractive oil shale deposit. It contains in excess of 200 million barrels of fairly high-grade oil shale beds averaging at least 15 gallons/ton over a 15-foot thickness (RAND 2004).

In the eastern United States, black, organic-rich shales, produced during the Devonian period, underlie portions of Kentucky, Indiana, Ohio, and Tennessee. However, when heated, the organic matter of the Devonian shales yields only about half as much oil as the organic matter in the Green River Formation shales. Because of considerations of grade, yield, and processing costs, eastern oil shale deposits are at present not likely candidates for development.

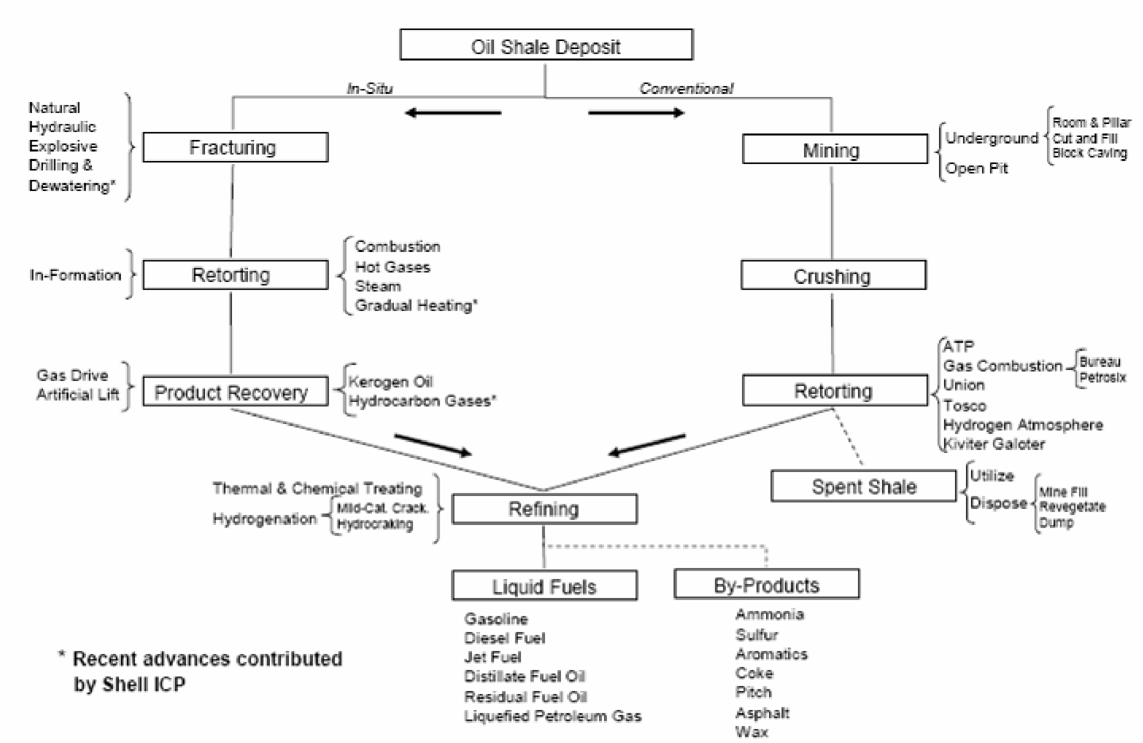
Figure 1 – Oil Shale Basins and Tar Sands Deposits in Colorado, Utah, and Wyoming (as shown on http://ostseis.anl.gov; oil shale basins defined by Rand 2005)



Oil Shale Production Technology

Conventional production of oil from oil shale involves three steps – mining, retorting (heating to release the kerogen from the shale), and upgrading the kerogen to refinery feed quality. An alternative in-situ production method combines the first two steps by fracturing or rubblizing the formation and heating in place to produce products that can be upgraded in hydrocarbons. These processes are described below. Figure 2 (from DOE 2004b) shows the steps for converting oil shale to finished products.

Figure 2 – Generalized Processes for Conversion of Shale to Fuels and By-products
Source: DOE (2004b)



Mining: Oil shale can be mined by using conventional mineral mining methods. Where deposits are relatively shallow, strip mining or open-pit mining allows removal of a large percentage of the resource. The large surface area disturbed by these mining methods can result in environmental concerns that must be properly managed. Where deposits are deeper, underground mining methods can be used. The most common form of underground mining is the room-and-pillar method, in which large pillars of the mineral are left in place to support the roof of the mined-out rooms. Because of the need for the pillars, 25% or more of the mineral resource is left in the mine.

After mining, the oil shale may be crushed to achieve a uniform size. It is then sent to an aboveground retort.

Retorting: After being mined, the oil shale must be heated to a high temperature (900–1,000°F) to separate the kerogen from the oil shale. The process is known as pyrolysis. Alternative retort technologies are differentiated by how they produce and deliver the heat needed for pyrolysis. Technologies include both direct and indirect heating of the oil shale. Some examples of above ground retorts include:

- Union Oil B (DOI 1973a; DOE 2004b; RAND 2005)
- TOSCO II (DOI 1973a; DOE 2004b; RAND 2005)
- Gas Combustion Retort (DOI 1973a; DOE 2004b)
- Alberta Taciuk Processor (ATP) (DOE 2004b; RAND 2005)
- Paraho (DOE 2004b)
- Lurgi-Ruhrgas (DOE 2004b)
- Petrosix Vertical Shaft Retort (DOE 2004b).

Upgrading: The different retorting processes yield shale oils having different properties. Independent of the specific process used for retorting, the shale oil is likely to require further processing or upgrading before becoming attractive to oil refineries as feedstocks for conventional fuels. Upgrading is designed to increase the relative proportion of saturated hydrocarbons over unsaturated hydrocarbons in the crude shale oil recovered from retorting and to eliminate those other compounds present that can interfere with further refining of the crude shale oil into conventional middle distillate fuels (primarily, compounds containing nitrogen or sulfur atoms). The upgrading steps are comparable to those used in refining (e.g., distillation, delayed coking, catalytic hydrogenation, and hydrogen production).

In-Situ Retorting: An alternative approach extracts the crude shale oil directly from the ground rather than first mining the shale and retorting it at the surface. This so-called in-situ retorting involves heating oil shale in place, extracting the liquid from the ground, and transporting it to an upgrading facility. The early versions of the technology involved burning a portion of the oil shale underground to produce the heat needed for retorting the remaining oil shale. Later versions of in-situ retorting mine a cavity near the base of the retort zone and rubblize the above and adjacent shale by a series of staged explosions. This process provides improved access for the air needed for combustion. The rubblized shale is retorted in place, and the mined shale is sent to surface retorts.

Retorting techniques can include controlled combustion of rubblized shale or formation heating by alternative means such as the introduction of electromagnetic energy, hot air, or steam. Product recovery techniques have included steam leaching, chemically assisted or solvent leaching, and displacement by high-pressure gas or water injection. Some of these formation sweeping techniques also can be seen as aiding or promoting additional refining of the initial retorting products.

Shell Oil has developed an in-situ retorting process known as thermally conductive in-situ conversion process (ICP). The process involves heating underground oil shale by using electric heaters placed in deep vertical holes drilled through an entire vertical section of oil shale. The volume of oil shale is heated over a period of two to three years, until it reaches 650–700°F, at which point oil is released from the shale. The released product is gathered in collection wells positioned within the heated zone.

For its Colorado project currently being reviewed by the BLM, Shell proposes pumping refrigerated fluid through a series of wells drilled around the perimeter of the extraction zone to establish an underground barrier called a freeze wall. A series of 150 holes approximately 8 feet apart would be drilled where the freeze wall would be created. The freeze holes would be drilled to a depth of approximately 1,850 feet. A chilled fluid (–45ºF) would be circulated inside a closed-loop piping system and into the holes. The cold fluid would freeze the nearby rock and ground water and, in 6 to 12 months, create a wall of frozen ground. The freeze wall would be maintained during both the production and reclamation phases of the ICP project (BLM 2006). The freeze wall would prevent groundwater from entering the extraction zone and keep hydrocarbons and other products generated by the in-situ retorting from leaving the project perimeter. Before the heating process begins, the ground water inside the freeze wall will be pumped out and injected into a nearby aquifer.

Shell proposes to conduct tests of three separate variations of its process (BLM 2006). The first test would involve the process as described above. The second test is called two-step ICP. Some of the shale formations in that portion of Colorado have extensive deposits of nahcolite (sodium bicarbonate) that interferes with production of the shale oil. In the two-step version, Shell would first inject hot water into the shale to remove the nahcolite through solution mining. Then the hydrocarbon could be removed through ICP. The third test would use bare electrode heaters, an alternate method of heating the shale, to reduce the cost of heating.

In an interesting twist to the in-situ conversion approach, an engineer from Oak Ridge National Laboratory proposes to use nuclear energy as an alternate source of energy to heat the oil shale beds (Oil & Gas Journal 2006). The proposed process would reduce the generation of greenhouse gases and have lower costs.

Tar Sand Resources

Tar sands (also referred to as oil sands in Canada) contain clay, sand, water, and bitumen, which is a heavy, black, and viscous type of oil. The bitumen in tar sands cannot be pumped from the ground in its natural state. Tar sands can be mined and processed to extract the oil-rich bitumen for subsequent refining. Bitumen can also be produced through in-situ underground heating or other tertiary recovery processes.

According to the Province of Alberta's website (http://www.energy.gov.ab.ca/88.asp), Canada has the world's second largest proven crude oil reserves (15% of world reserves), after Saudi Arabia. The majority of these reserves are found in Alberta's oil sands – over 174 billion barrels. After processing, this translates into 140 to 148 billion barrels of crude oil equivalent. Several commercial operations aimed at recovering bitumen from this resource are currently underway. Alberta's oil sands underlie 54,363 square miles of primarily northern Alberta – an area larger than the state of Florida.

In the United States, tar sands resources are primarily concentrated in Eastern Utah, mostly on public lands (see Figure 1). The in-place tar sands oil resources in Utah are estimated at 12 to 20 billion barrels.

Tar Sands Production Technology

Although tar sands are in a different form than oil shale, the basic technologies for producing oil from tar sands follow the same pattern as those for oil shale. Tar sands can be mined and processed at the surface or can be produced in situ. The resulting bitumen generally needs upgrading before it can serve as a refinery feedstock. The United States has very little experience with producing oil from tar sands, so the following descriptions are based on the active Canadian tar sands industry processes.

The properties and composition of the tar sands and the bitumen significantly influence the selection of recovery and treatment processes and vary among deposits. In the so-called "wet sands" or "water-wet sands" of the Canadian Athabasca deposit, a layer of water surrounds the sand grain, with the bitumen partially filling the voids between the wet grains. The bitumen can be separated from the sand by using water. Utah tar sands lack the water layer; the bitumen is directly in contact with the sand grains without any intervening water and is sometimes referred to as "oil-wet sands." Processing beyond water washing is needed to recover the bitumen (Daniels et al. 1981).

Mining: Tar sands deposits near the surface can be recovered by open-pit mining techniques. These systems use large hydraulic and electrically powered shovels to dig up tar sands and load them into enormous trucks that can carry up to 320 tons of tar sands per load. For example, the Syncrude and Suncor oil sands operations near Fort McMurray, Alberta, use the world's largest trucks and shovels to recover bitumen. The trucks haul the tar sands to crushers that break up lumps and remove rocks. Photos of the operations there can be found at http://ostseis.anl.gov/guide/photos/index.cfm.

Processing: After mining, the tar sands are transported to an extraction plant, where a hot water process separates the bitumen from sand, water, and minerals. The separation takes place in separation cells. Hot water is added to the sand, and the resulting slurry is piped to the extraction plant where it is agitated. The combination of hot water and agitation releases bitumen from the oil sand. The bitumen forms into a froth layer that floats to the top of the separation vessel where it is skimmed off. Further processing removes residual water and solids. The bitumen is then transported and eventually upgraded into synthetic crude oil. About two tons of tar sands are required to produce one barrel of oil. Roughly 75% of the bitumen can be recovered from sand. After oil extraction, the spent sand and other materials are then returned to the mine, which is eventually reclaimed.

In-Situ Production: In-situ recovery is used for bitumen deposits that are buried too deeply for mining to be practical. Most in-situ bitumen and heavy oil production comes from deposits buried more than 400 meters below the surface of the earth. Some of the production methods that have been used or proposed include:

- Cyclic steam stimulation (CSS), also called “huff and puff,”
- Steam-assisted gravity drainage (SAGD),
- Vapor extraction process (VAPEX),
- Toe-to-heel air injection (THAI) or a variant known as CAPRI,
- Cold heavy oil production with sand (CHOPS), and
- Pressure pulsing technology (PPT).

These involve different combinations of injecting steam or solvents through horizontal or vertical wells. Some description of these technologies can be found in NEB (2006), Alberta COR (2004), and Dusseault (2002).

Bitumen requires additional upgrading before it can be refined. Alberta COR (2004) notes that essentially all of the bitumen mined in Alberta is upgraded. The process involves two steps. The first step uses coking and catalytic conversion processes. The second step uses hydroprocessing to increase the hydrogen content of the synthetic crude oil.

After upgrading, the synthetic crude oil is piped to a refinery. Because it is so viscous, bitumen normally requires dilution with lighter hydrocarbons to make it transportable by pipelines.

Chapter 3 – Impacts on Ground and Surface Water

Oil shale and tar sands production will involve either mining large tracts of land, which results in surface disturbance, or drilling of numerous injection and recovery wells for in-situ production. Both methods have the potential to cause impacts to ground and surface water resources. In addition, large-scale production of either type of resource will require local availability of large volumes of water to support the production process. This chapter discusses some of the water quantity and quality issues that could result from oil shale and tar sands production.

<u>Water Quantity</u>

Most of the areas in the United States with significant oil shale or tar sands resources are historically arid regions. DOI (1973a) indicates that most U.S. oil shale areas receive between 7 and 24 inches of rainfall per year, and many of the local streams are ephemeral. Local supplies of ground water occur in the oil shale areas. The yield of wells in these areas generally will be small or moderate, except where large draw-downs are required to maintain a dry mine. The chemical quality of the ground water differs from place to place and is different at different depths depending upon the type of aquifer, the quality of recharge water, and the geologic formations. Any large withdrawals of ground water will probably eventually become saline, although initial withdrawals in some areas would be of good quality (DOI 1973a).

The available water resources are subject to complicated water rights provisions. Producers would need to obtain water rights allowing them to proceed with development. Even several decades ago, water was identified as a limiting resource for producing oil shale. Ely (1968) wrote an early paper that evaluates the water budget for the Colorado, Utah, and Wyoming oil shale industry. He estimated that production of 2 million barrels per day (bpd) of oil would require 1.2 times that volume of water for processing, retorting, and upgrading. The resulting volume, 2.4 million bpd of water, can be converted to other common volumetric units through the following conversion factors:

a) 1 barrel = 42 gallons

b) 1 acre-foot = 325,851 gallons = 7,760 bpd

c) 1 million bpd = 47,085 acre-feet per year = 42 million gallons per day (MGD)

d) 1 MGD = 3.07 acre-feet = 24,000 bpd.

Therefore, 2.4 million bpd is equivalent to about 100 MGD or about 113,000 acre-feet per year. Ely (1968) adds that if the produced shale oil is refined locally, the water requirement could increase to 200,000 acre-feet per year. He also suggests that indirect water demands related to the population of persons constructing and operating the production facilities and related infrastructure could increase the total water demand to 500,000 acre-feet per year. The paper then discusses some of the water compacts, treaties, and other legal requirements that pose barriers to acquiring new, large water supplies. Although this paper was written nearly 40 years ago, it highlights one major challenge to developing oil shale and tar sands in the United States. Water availability has become even more problematic in the ensuing decades.

DOI (1973b) contains extensive discussion of water requirements at a hypothetical 100,000-bpd oil shale plant associated with a surface mine and a 50,000-bpd plant associated with an underground mine. DOI (1973a) compiles these two examples plus comparable data for three other types of oil shale plants. This information is shown in Table 1.

Table 1 – Water Requirements for Different Types of Oil Shale Plants (in acre-feet/year)
Source: DOE (1973b)

Shale Oil Production (Barrels per day)

	50,000 Underground	100,000 Surface Mine	50,000 In Situ	400,000 Technology Mix[2]	1,000,000 Technology Mix[2]
PROCESS REQUIREMENTS					
Mining and Crushing	370- 510	730-1,020	---	2,600- 3,600	6,000- 8,000
Retorting	580- 730	1,170-1,460	---	4,100- 5,100	9,000-12,000
Shale Oil Upgrading	1,460-2,190	2,920-4,380	1,460-2,220	11,700-17,500	29,000-44,000
Processed Shale Disposal	2,900-4,400[3]	5,840-8,750[3]	---	20,400,30,900	47,000-70,000
Power Requirements	730-1,020	1,460-2,040	730-1,820	5,800- 9,200	15,000-23,000
Revegetation	0- 700	0- 700	0- 700	0- 4,900	0-12,000
Sanitary Use	20- 50	30- 70	20- 40	200- 300	1,000- 1,000
Subtotal	6,060-9,600	12,150-18,420	2,210-4,780	44,800-71,500	107,000-170,000
ASSOCIATED URBAN					
Domestic Use	670- 910	1,140-1,530	720-840	5,400-6,900	13,000-17,000
Domestic Power	70- 90	110- 150	70- 80	500- 600	1,000- 2,000
Subtotal	740-1,000	1,250-1,680	790-920	5,900-7,500	14,000-19,000
GRAND TOTAL	6,800-10,600	13,400-20,100	3,000-5,700	50,700-79,000	121,000-189,000
AVERAGE VALUE	8,700	16,800	4,400	65,000	155,000

1/ Assumes the same technologies as those used to develop Table III-2.
2/ Assumes development schedule as those shown in Table III-2.
3/ Water used is 20% by weight of the disposed spent shale.

Although water supplies are needed to produce oil shale, some steps in the process actually generate water. Water is an inherent by-product of oil shale retorting. It may be produced at a rate as high as 10 gallons per ton of shale retorted; but more typically, it will range from 2 to 5 gallons per ton. It will contain a variety of organic and inorganic components (DOI 1973a). Before it can be reused or discharged, it will require treatment.

As part of the mining process, ground water intercepted by the excavation will be pumped out of the mine in order to continue producing the oil shale. Depending on the quality of the aquifer, the water may or may not require treatment before being used in the process or discharged to surface water.

Different authors over the years have made different estimates of water requirements for oil shale development. Table 2 compares some of those estimates.

Table 2 – Comparison of Water Requirements Estimated by Different Authors

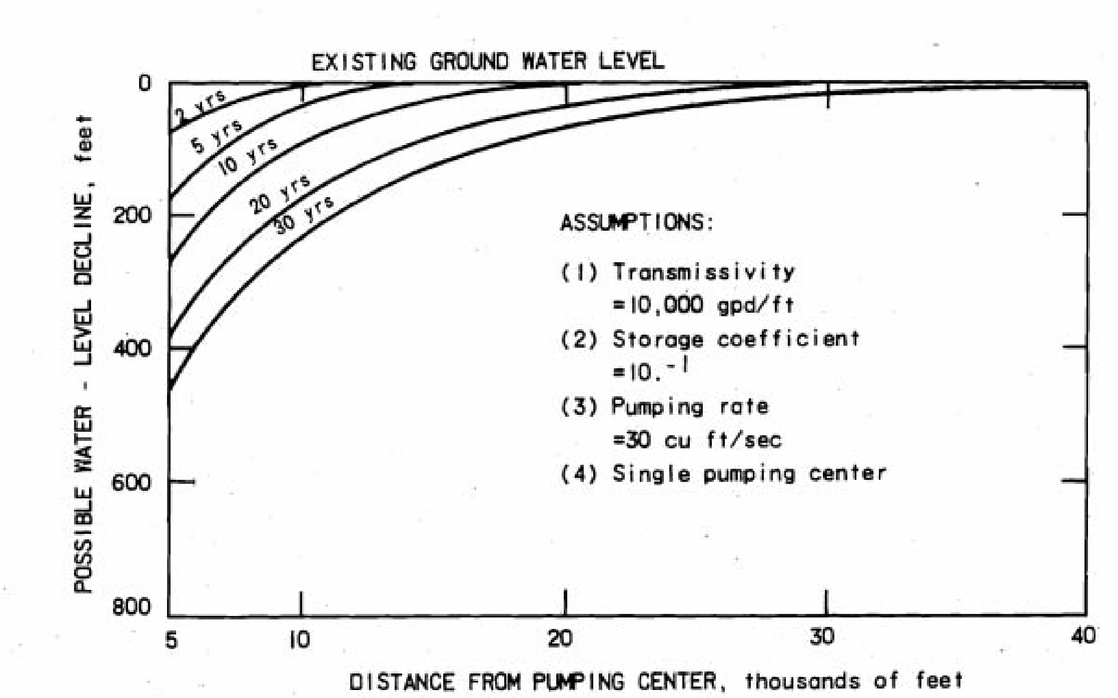
Source	Oil Production (bpd)	Water Required (acre-feet/year)	Water Requirement Scaled to 100,000 bpd Oil Production (acre-feet/year)
Prien (1954)[a]	1 million	227,000 diverted 82,500 consumed	22,700 diverted 8,250 consumed
Cameron and Jones (1959)[a]	1.25 million	252,000 diverted 159,000 consumed	20,000 diverted 13,000 consumed
Ely (1968)	2 million	500,000	25,000
DOI (1968)[a]	1 million	145,000 diverted 61,000-96,000 consumed	14,500 diverted 6,100-9,600 consumed
DOI (1973a)	50,000 underground mine	8,700	17,400
	100,000 surface mine	16,800	16,800
	50,000 in-situ	4,400	8,800
	400,000 technology mix	65,000	16,300
	1 million technology mix	155,000	15,500
McDonald (1980)	1.5 million	200,000	13,300
RAND (2005)	No specific value given; assume 3 bbl of water per 1 bbl of oil		14,125

[a] These references were not specifically viewed by the authors of this report. The data were published in DOI (1973a).

The estimates vary somewhat. The water required for in-situ production is substantially less than that required for surface or underground mining followed by surface retorting. Nevertheless, the estimates published over 50 years with varying assumptions are all in the same order of magnitude.

Dewatering to support mining of oil shale is projected to cause depression of local ground water levels. For a site in Colorado, DOI (1973b) estimated that ground water could decline by more than 400 feet near the pumping location. Figure 3 portrays the decline at different distances from the pumping location and at different times after pumping begins.

Figure 3 – Estimated Decline of Ground Water Levels at Different Times and Distances
Source: DOI (1973b)



McDonald (1980) suggests that the average net water consumption for oil shale production would be 200,000 acre-feet per year for oil shale production of 1.5-million bpd. He also explores the concept of using ground water as a water source for oil shale production. He concludes:

> Perhaps the most important aspect of utilizing ground water as a source of supply is that relatively large rates of pumping would lead to mining of the ground water resource. The use of such waters, which have been stored over geologic time, represents an irrevocable decision to deplete an essentially nonrenewable resource. The question in all such instances is whether benefits would be maximized by using the resource now as opposed to using it at some point in the future.

<u>Ground Water Quality</u>

Types of Impacts: Several aspects of oil shale and tar sands production are likely to cause changes in ground water quality. Surface mining removes overburden rock and exposes it to precipitation and atmospheric oxygen. Chemical changes may occur, and the resulting leachate can affect ground water.

In underground mining, operators must continuously pump the excavation to allow access to the shale seams. In addition to causing a lowering of ground water levels (described in the previous section), this can allow possible influx of ground water from lower aquifers. The lower aquifers generally have poorer water quality (e.g., they are high in total dissolved solids) that can mix with the shallower, higher-quality aquifers.

For surface retorted shale, the spent shale is either stockpiled on the surface, where it can come in contact with precipitation, or is placed back into the mine. Spent shale will have more pore space than the original shale, thereby allowing a much greater opportunity for infiltration of precipitation or ground water. The resulting leachate can contaminate aquifers. Spent tar sands require disposal following processing. Like the spent shale, they may result in leaching to ground water.

For in-situ shale retorting, the spent shale is left in place, but its porosity is greater than that of the natural oil shale. Leaching of contaminants is likely. For in-situ tar sands production, the formations are likely to be in contact with steam or solvents that will eventually reach the ground water in the area.

The upgrading process should not cause much impact on ground water. Retorted hydrocarbons from either surface or in-site production methods are sent to a separate upgrading facility on the surface. The upgrading process takes place in an industrial facility similar to a refinery. Unless the upgrading facility allows incoming or processed shale oil to leak or spill, there is little opportunity for ground water impacts.

Discussion of Impacts: One of the best documented examples of the effect of oil shale mining on regional ground water quality is described in a doctoral thesis (Erg 2005). This document describes ground and surface water conditions in an area of Estonia that has produced oil shale from underground mines since the early 1900s. Some of the conclusions reached by Erg include:

- Human influences have changed the hydrochemical conditions of surface water and shallow ground water.
- The hydrogeological regime in oil shale mines is controlled by the thickness of the aeration zone, tectonic faults and fractures, and an alteration of hydraulic gradients causing a change in flow direction and rate.
- After mines were closed and pumps were turned off, the mine water level returned to pre-mining level in about three years.
- Closing and flooding of underground mines has radically changed the ground-water-forming conditions in the area.
- Prior to the start of mining, the ground water quality was primarily influenced by precipitation. During the mining period, sulfate content increased up to 50 times as high as it was under natural conditions (2–10 mg/L).
- Following the end of mining, as the mines fill with water, the sulfate content increases several fold to as high as (1,200 mg/L) during the first two years. After four years, the concentration decreases to 150–200 mg/L.
- The water quality of closed mines generally meets Estonian drinking water standards.

Erg (2005) contains very little information about pH levels following mining. Although the report contains chemical equations that indicate acid conditions would be formed along with the sulfate, no data or discussions are included about pH. However, judging from the final conclusion listed above, low pH does not appear to be a wide-spread or long-term phenomenon.

The authors searched the Society of Petroleum Engineers (SPE) electronic database of tens of thousands of papers to look for information on ground water impacts from production of oil shale and tar sands. Although several hundred papers were found through online searches, only a small handful of them seemed relevant to this report; all were from the early 1980s. They are described below.

Ramirez and Morelli (1981) evaluated the porous media properties and the leaching capacity of spent oil shale to develop input parameters for future modeling efforts. They found that each type of spent shale had a unimodal distribution of pore sizes. The leachate research showed that some chemical parameters showed a continuous smooth leaching rate, while others made a discontinuous jump in leaching rate as they reached their solubility limit.

Several of the SPE papers described efforts to develop grout by using spent shale products. Mallon (1982) describes development of a grout by using finely ground spent shale. A mixture of grout and coarse shale showed a permeability of 0.4 md (millidarcies). This compares to permeabilities in the kerogen-rich Mahogany zone of the Green River Formation in the Piceance Basin in Colorado of 200 md horizontal and 0.5 md vertical.

Watson et al. (1982) discuss laboratory and pilot-scale tests to evaluate the feasibility of injecting grout into completed modified in-situ retorts to seal them from leaching. The grout would be based on spent shale ash from surface retorts. They demonstrate that grout can be formulated by using spent shale ash, but that some chemical additives are needed to ensure a good seal. By varying the types of additives, the permeability and strength can be varied. The experimental grouting system would require a large volume of water when used on a commercial scale.

Persoff (1984) was able to develop an effective grout by using spent shale ash along with fly ash and lignosulfonate. The permeability of the cured grout depended on the in-situ conditions but was generally low enough to reduce the flow of ground water through abandoned in-situ retorts. Persoff noted that any water that does permeate through grouted retorts would leach significant quantities of minerals from the grout.

Bethea et al. (1983) discuss the results of a series of laboratory experiments that investigated the leachate quality from a simulated in-situ oil shale retort. They found that:

- The factor having the greatest effect on leachate composition was retort temperature.
- The presence of carbon dioxide during high-temperature retorting suppressed the amounts of base-forming materials generated.
- All leachates were affected significantly by the quality of the ground water used. As expected, more material was leached from the shale when the higher-purity ground water was used.
- The effect of leaching temperature on leachate composition was minor.

- Bentonite was only moderately effective as a pH modifier, although it did decrease the solubility of several ions.
- Capillary forces are an important mechanism in the initial movement of water through spent oil shale. Subsequent movement of water through the oil-shale matrix may be stopped after a short time because of reductions in matrix permeability.

Surface Water Quality

Types of Impacts: Surface water impacts can result from several aspects of oil shale and tar sands development. The need for large volumes of water is likely to draw down local stream levels such that aquatic habitats may be diminished. Stormwater runoff from disturbed surface area at mines, spent shale and tar sands piles, access roads, and supporting facilities will carry contaminants into surface waters. Removal of surface vegetation can change runoff rates and increase erosion.

The retorting and upgrading steps of the process can contribute chemical-laden wastewater. Dewatering of mines will require disposal of large amounts of water. The increase in local population associated with the work force will generate sewage and other domestic and commercial wastewater. To the extent that these wastewaters are inadequately treated before discharge to surface waters, they can cause water quality impacts.

Discussion of Impacts: In addition to metal and organic contaminants that may be part of discharged oil shale or tar sands wastewater or runoff, salinity is an important consideration. Most of the oil shale and tar sands resources are located within the Colorado River watershed. Excess salinity is a major concern in the Colorado River, and eliminating it is one of the key water goals of the Bureau of Reclamation. Oil shale production would contribute to increased salinity.

Chapter 4 – Regulatory Programs in the United States

Federal

Section 369 of the Energy Policy Act of 2005 (EPAct 2005), Pubic Law 109-58, signed into law on August 8, 2005, establishes the "Oil Shale, Tar Sands, and Other Strategic Unconventional Fuels Act of 2005." Section 369(d) directs the Secretary of the DOI to prepare a PEIS for a commercial leasing program for oil shale and tar sands resources on public lands administered by the BLM, with an emphasis on the most geologically prospective lands within Colorado, Utah, and Wyoming. The PEIS process under the National Environmental Policy Act is underway. Section 369(n) also directs the DOI to consider the use of land exchanges where appropriate and feasible to consolidate land ownership and mineral interests into manageable areas to facilitate the recovery of oil shale and tar sands. It further requires DOI to focus on public lands containing oil shale and tar sands within the Green River, Piceance, Uintah, and Washakie basins. Section 369(j) amends the Mineral Leasing Act (MLA) to expand the size of oil shale and tar sand leases from 5,120 to 5,760 acres and to set the minimum lease bid at $2.00 per acre.

On June 9, 2005, the BLM published in the *Federal Register* (FR) a notice soliciting nominations for oil shale, research, development, and demonstration for oil shale recovery technologies in Colorado, Utah, and Wyoming (70 FR 33753). BLM's notice allows leasing of up to 160 acres to be used to demonstrate the economic feasibility of oil-shale extractive technologies. On October 7, 2005, the BLM issued an interim final rule on leasing on special tar sand areas (70 FR 68610). The interim rule authorizes BLM to issue separate leases for exploration for and extraction of tar sand, separate leases for exploration and development of oil and gas, and combined hydrocarbon leases for any area that contains any combination of tar sand and oil or gas.

The BLM conducts its operations in accordance with the Federal Land Policy and Management Act (FLPMA) and all applicable statutes, regulations, and standards. Moreover, Executive Order (EO) 12088, "Federal Compliance with Pollution Control Standards" (1978), requires federal agencies, including the BLM, to comply with applicable administrative and procedural pollution control standards established by, but not limited to, the Resource Conservation and Recovery Act (RCRA), Toxic Substances Control Act (TSCA) of 1976, Clean Air Act (CAA), Noise Control Act of 1972 (NCA), Clean Water Act (CWA), and Safe Drinking Water Act (SDWA).

Federal requirements for oil shale and tar sands activities depend on the specific project-related activity. For example, siting of a project facility in wetland areas must comply with the applicable requirements governing the discharge of dredge and fill material (see Section 404 of the CWA). Wastewater and stormwater discharges are subject to all applicable permitting requirements of the National Pollutant Discharge Elimination System (NPDES) (see Section 402 of the CWA).

Injection wells used for in-situ recovery of oil shale and tar sands must comply with all applicable requirements of the Underground Injection Control Program (UIC) authorized by the SDWA (EPA 1999). Defined by EPA's implementing regulations as Class V wells in Title 40 of the *Code of Federal Regulations* (40 CFR 146.5(e)(16)), they are currently not governed by tailored regulations but are subject to the UIC regulations covering all Class V wells. Owners and operators of all injection wells are subject to the prohibition on movement of fluid into underground sources of drinking water (40 CFR 144.12(a)). Owners or operators of Class V wells are required to submit basic inventory information. In general, Class V wells are authorized by rule, unless they are specifically required to obtain a permit. Authorization by rule terminates upon the effective date of a permit or upon proper closure of the well. In the past, such wells have primarily operated in Colorado and Wyoming (EPA 1999).

In addition to Class V UIC requirements, BLM (2006) suggests that in Shell's two-step ICP test, it will use solution mining to remove nahcolite before producing the shale oil. Most solution mining projects are regulated through the UIC Class III program. EPA protects underground sources of drinking water from contamination from Class III wells (40 CFR 146.5(c)(3)) through UIC regulations requiring operators to case and cement their wells to prevent the migration of fluids into an underground drinking water source; never inject fluid between the outer-most casing and the well bore; and test the well casing for leaks at least once every five years. Colorado and EPA officials will determine the necessary requirements if the proposed twos-step ICP test project moves forward.

<u>States</u>

As noted in Chapter 2, oil shale and tar sands resources are located in various parts of the country. The most significant resources are located in Colorado, Wyoming, and Utah. The regulatory programs for these three states are described in the following sections. In addition to these resource-rich states, several states in the eastern half of the country also have resources that, while less promising, may be developed in the future. For the sake of completeness, we include descriptions of the regulatory programs relating to oil shale in those states too.

Colorado

Contacts: Ron Cattany, Colorado Division of Minerals and Geology (Department of Natural Resources); Brian Macke and Thom Kerr, Colorado Oil and Gas Conservation Commission (Department of Natural Resources)

In Colorado, the Department of Interior is the primary landowner for most exploration sites. In the early 20th Century, two oil shale reserves were set aside on federal lands in Colorado to ensure the Navy's petroleum supply. Naval Oil Shale Reserve Number 1 (NOSR #1), measuring 36,406 acres, and Naval Oil Shale Reserve Number 3 (NOSR #3), measuring 20,171 acres, are located 8 miles west of Rifle, Colorado, in Garfield County. NOSR #1 has been estimated to contain more than 18 billion barrels of shale oil in place. As much as 2.5 billion barrels of oil may be recoverable from shale yielding 30 gallons of oil or more per ton. NOSR #3 is not considered to have commercial value.

During the late 1970s and early 1980s, the oil industry poured billions of dollars into oil shale projects in western Colorado. Notwithstanding the high oil prices of the day, oil shale remained prohibitively expensive. The boom ended abruptly on May 2, 1982 (referred to as Black

Sunday), when a major oil company pulled out and announced that it would close its $5 billion Colony II project near Parachute, Colorado.

In terms of state regulatory involvement in oil shale operations, the Division of Minerals and Geology within the Department of Natural Resources (DNR) is taking the lead. Under state law, the definition of "mineral" includes oil shale. All moneys from sales, bonuses, royalties, leases, and rentals of oil shale lands received by the state pursuant to the federal Mineral Lands Leasing Act shall be deposited by the state treasurer into a special fund for appropriation to state agencies, school districts, and political subdivisions of the state affected by the development and production of energy resources from oil shale lands, primarily for use by such entities in planning for and providing facilities and services necessitated by such development and production and secondarily for other state purposes. All moneys earned from the investment of the oil shale special fund shall then be deposited into a separate special fund for appropriation.

Any actual mining activity would require a permit from the Division of Minerals and Geology. Operations would need to comply with all applicable water quality control and water quantity laws and regulations.

Wyoming

Contact: Don Likwartz, Wyoming Oil and Gas Conservation Commission

If a Wyoming project was similar to Colorado projects, the Wyoming Oil and Gas Conservation Commission (WOGCC) would have some involvement. Otherwise, if operations would resemble the Canadian oil sand projects, the WOGCC would defer completely to the Wyoming Department of Environmental Quality (DEQ). The Senior Assistant Attorney General of WOGCC is researching the issue of statutory authority over oil shale operations. The WOGCC has no authority over the processing operations.

Utah

Contact: John Baza, Utah Division of Oil, Gas and Mining (Department of Natural Resources)

Utah has become a focal point of interest for new oil shale and tar sands development. Several promoters and speculators have contacted the Division of Oil, Gas and Mining (OGM) with questions, but until now, very little on-the-ground activity is occurring. Some pilot testing of oil shale extraction and processing is undertaken or planned for the immediate future; however, no commercial projects have been launched at this time. The same is true for tar sands extraction.

The majority of land area in Utah is federally owned. At present, no unique state statutes and regulations tailored to this specific type of mineral extraction are in place. Activities are covered under OGM's general mining laws and rules for all mineral (or noncoal) types of mining activity within OGM's Minerals Regulatory Program (http://ogm.utah.gov/minerals/default.htm). Utah regulations define "deposit" or "mineral deposit" to include oil shale and bituminous sands extracted by mining operations (R647-1-106).

Some suggest that Utah oil shale/tar sands resources are large in magnitude; however, their characteristics are different than those of resources in the surrounding Rocky Mountain states. The bulk of the prospective development activity in Utah seems to be focused on conventional mining extraction. If this is the case, OGM will be able to handle the state permitting of such activities within the existing authorities of OGM's Minerals Regulatory Program. Modifications of the regulatory structure may be required if in-situ extraction of oil shale becomes a reality. This will involve working with OGM's Oil and Gas Regulatory Program to share expertise in well drilling, production, and plugging operations. However, because of the resource characteristics of Utah deposits, no in-situ extraction is being considered for the foreseeable future. Utah has a long history of mining. OGM has a long track record for addressing mining impacts and mitigation. If the extraction methods should be different than traditional mining operations, then Utah may need to consider being more specific in the current laws and rules.

Another theme of oil shale/tar sands development involves the surface processing of mined material. This processing will undergo the type of state regulatory scrutiny from the Utah DOQ that any refinery or chemical processing plant would receive. This includes reviewing development proposals in the light of all applicable requirements governing air quality, water quality, and solid waste management compliance.

A project developer interested in conducting oil shale/tar sands extraction and processing operations in Utah would seek the appropriate approvals of the Utah Division of Water Rights for obtaining water used for extraction and processing. If future water demands are substantial, then coordination with the Division of Water Resources to assess water supply and storage potential would be required. Both divisions, along with OGM, are within the Department of Natural Resources, and coordination would occur for appropriate regulatory consideration. OGM would likely serve as the lead agency, because any actual mining activity would principally require a permit from OGM. OGM would also assess the operation for potential environmental impacts that would dictate land reclamation and bonding requirements.

Nevada

Contact: Russ Land and Valerie King, Nevada Division of Environmental Protection (Department of Conservation and Natural Resources)

In addition to the Nevada Division of Environmental Protection (NDEP), other agencies, including the Nevada Division of Minerals, Nevada Division of Water Resources, and BLM (since 80% of Nevada is public land) may enter the regulatory picture.

From the standpoint of the NDEP, existing regulations would cover the bases. The agency source adds that the determination whether additional regulations are required will be driven by the activities of the specific processes used. At this time, no tailored regulations under the NDEP's authority are in place.

Kentucky

Contact: Rick Bender, Kentucky Division of Oil and Gas Conservation (Department of Natural Resources)

Kentucky hosts considerable oil shale reserves. However, project proposals are not pending at this point in time. In Kentucky, Title XXVIII, Chapter 350, Section 350.600 of the Kentucky Revised Statutes (KRS) calls for administrative regulations for oil shale operations to minimize and prevent their adverse effects on the citizens and the environment. Implementing regulations have been codified in Title 405, Chapter 30, of the Kentucky Administrative Regulations (KAR). The Division of Mine Reclamation and Enforcement within the Department of Natural Resources is responsible for the administration of these regulations.

- 405 KAR 30:320 establishes requirements for water quality standards, effluent limitations, and monitoring.
  - In addition to all applicable federal and state requirements, discharges from areas disturbed by oil shale operations must meet, at a minimum, the following numerical limitations in mg/L (maximum one day/average over 30 days) (see chart).
  - A permit applicant must prepare and submit a surface water monitoring program subject to approval by the regulator.
  - Groundwater levels, infiltration rates, subsurface flow and storage characteristics, and groundwater quality must be monitored in a manner approved by the regulator.

Type of Discharge	Iron	Manganese	Total Suspended Solids	Settleable Solids	pH
Drainage from disturbed areas other than reclamation areas	6.0/3.0	4.0/2.0	70/35	---	6–9
Reclamation areas	--	--	--	0.5	6–9
Discharge resulting from precipitation event less than or equal to 10-year, 24-hour storm	--	--	--	0.5	6–9
Discharge resulting from precipitation event greater than 10-year, 24-hour storm	--	--	--	--	6–9

- 405 KAR 30:310 covers diversion of flows and water withdrawal.
  - Diversion requirements cover overland flow, shallow groundwater flow, ephemeral streams, and stream channels.
  - Water withdrawals transfers or diversions from public water are subject to permitting, recordkeeping, and reporting requirements (established in KRS 151.140, KRS 151.150, KRS 151.160, KRS 151.170, KRS 151.200, and 401 KAR 4:010).

- 405 KAR 30:330 governs sediment control measures.
  - All surface drainage from the disturbed area must be passed through a sedimentation pond or series of ponds. Sedimentation ponds are subject to design requirements.

- 405 KAR 30:270 establishes casing, sealing, and other management requirements for exploration holes, boreholes, wells, or other exposed underground openings created during exploration.

- 405 KAR 30:340 provides for leachate control measures.
  - The permittee shall, by using the best technology currently available, control the quantity and quality of leachate produced at an oil shale operation.
  - The regulations cover preventative measures and containment structures.

- 405 KAR 30:360 establishes waste management provisions.
  - Drainage from acid-forming and toxic-forming materials in soil, overburden, spoil, spent shale, mining waste, and other materials must be managed in accordance with the leachate control provisions.
  - Or such drainage shall be prevented from entering groundwater and surface water through various methods of prevention, including:
    - Burial or treatment of spoil;
    - Prevention or removal of water from contact with acid-producing or toxic-producing deposits;
    - Burial or treatment of all toxic or harmful materials within 30 days;
    - Burial or storage of acid-forming or toxic-forming material not in proximity to a drainage course; and
    - Appropriate covering of exposed, used, or produced acid-forming or toxic-forming materials.

- 405 KAR 30:410 provides requirements governing in-situ operations.
  - In-situ operations must be planned and conducted in a manner that minimizes disturbances to the prevailing hydrologic balance by
    - Avoiding discharge of fluids into holes or wells, other than those approved by the regulator;
    - Injecting process recovery fluids only into geologic zones or intervals approved by the regulator;
    - Avoiding annular injection between the wall of the drill hole and the casing; and
    - Preventing discharge of process fluid into surface waters.
  - Each permittee must prevent flow of the process recovery fluid
    - Horizontally beyond the affected area identified in the permit and
    - Vertically into overlaying or underlying aquifers.
  - Each permittee must restore the quality of affected groundwater in the permit area and adjacent area, including groundwater above and below the production zone, to a state that equals or exceeds the pre-mining level, to ensure that the potential for use of the groundwater is not diminished.

- Monitoring must be conducted relative to the quality and quantity of surface and groundwater and the subsurface flow and storage characteristics to measure changes in the quantity and quality of water in surface and ground water systems in the permit area and in the adjacent area.

According to the agency source, the Kentucky Division of Oil and Gas Conservation within the Department of Natural Resources could conceivably take the lead if the process was in-situ extraction through a well bore. The question of appropriate regulatory controls would need to be addressed. Well bores could be covered under existing freshwater protection rules, but other issues, including treatment methods, would need to be addressed.

Indiana

Contacts: Herschel McDivitt**,** Indiana Division of Oil & Gas (Department of Natural Resources); Kevin C. Geier, Indiana Division of Reclamation (Department of Natural Resources)

The Indiana Division of Reclamation within the Indiana Department of Natural Resources has recently received one phone call from an individual who was approached for the purpose of obtaining a lease to explore for oil shale. Back in the early 1980s, Indiana had a few oil shale permits that were basically exploratory in nature. The amount of oil shale actually mined was minimal and for test purposes only. No large-scale mining occurred.

Indiana's surface mining and regulatory statutes apply to the extraction of coal, clay, and shale, including oil shale. Title 14, Article 36, Chapter 1 of the Indiana Code (IC) governs surface mining reclamation. IC 14-36-1 provides for the proper reclamation of land subjected to surface mining for clay, shale, and shale oil, whether on land owned by the operator or on land owned by others. The Division of Reclamation is responsible for the administration of the Act. Implementing regulations have been codified in Title 312, Article 25 of the Indiana Administrative Code (IAC). Each operator seeking to surface mine coal, clay, or oil shale must obtain a permit annually. This permit remains in effect for a period of one year from the date of issuance unless suspended or revoked. Permits are typically renewed on an annual basis. Each application is accompanied by a $100 permit fee and a fee of $50 for each acre or fraction thereof as described in the application. The bond amount for each acre will range from $1,000 to $5,000 per acre. The permit application describes the area and mineral to be mined, method of operation, erosion and drainage control, backfilling and grading, refuse and debris handling, and revegetation.

The Indiana oil and gas law, administered by the Division of Oil and Gas within the Department of Natural Resources, does not contain any specific reference to oil shale. However, to the extent that oil shale's development would include the drilling or operating of wells associated with the extraction of natural gas or liquid petroleum, the wells could be regulated just as any other oil or gas well. According to one agency source, one could debate whether raw shale oil extract could be considered "liquid petroleum." However, because oil and gas statutes were not developed with oil shales in mind, the source suggests that it would seem awkward to apply some of the same provisions (for example, well spacing requirements) to the shales.

The answer to the question of how Indiana would regulate the activity from an environmental or natural resource protection perspective, would, according to the agency contact, very much depend on the specific methodology proposed by the developer (surface mine extraction, underground mine extraction, in-situ processing, and others). The Department of Natural Resources, through its Divisions of Oil and Gas and Reclamation, only regulates the process of extracting the regulated mineral from the earth and not the processing of the mineral once it is brought to the surface (except for coal processing facilities located at or near the mine itself). Any surface treatment facilities processing the extracted ore or further refining or processing the raw shale oil extract (retorting or fractionation) would be regulated under existing general environmental laws administered by the Indiana Department of Environmental Management. This means that applicants for clay, shale, and oil shale permits have to make sure they comply with all applicable requirements imposed by several regulatory agencies.

Ohio

Contact: Scott Kell, Ohio Division of Mineral Resources Management (Department of Natural Resources)

Ohio does not have statutes or regulations tailored specifically to the extraction of oil from mined shale. If an application to mine oil shale was received today, the Division would likely process it as a shale mining permit subject to the requirements of Title 15, Chapter 1514, of the Ohio Revised Code (ORC) covering "other" surface mining. The Ohio Division of Mineral Resources Management within the Department of Natural Resources has codified implementing regulations for industrial minerals in Title 1501:14 of the Ohio Administrative Code.

According to the agency source, the Ohio Division of Mineral Resources Management would be interested in seeing regulations that were tailored specifically to the process of oil shale mining. If an oil shale mining permittee proposed to discharge groundwater, as part of the operation, the applicant would be required to model the anticipated impact on the affected aquifers or to submit sufficient data to enable the Division to develop a model. The permittee would assume responsibilities to replace impacted water supplies within the area of influence.

Tennessee

Contact: Ron Zurawski, Tennessee Division of Geology

The agency source reports that shale distillation tests have been performed on more than 50 samples obtained from both east and middle Tennessee. Results ranged from 4 to 42 gallons per ton and averaged 18 gallons per ton. However, until now, the only economic use of the shale has been in producing carbon black for use in ceramic pigment, paint pigment, and cement industries.

According to the agency source, exploitation of the Chattanooga shale as an oil shale in Tennessee is not likely in the near future for a number of reasons. In upper east Tennessee, where the unit is thickest and amenable to surface mining, the overall kerogen content is very low because the relatively thin zones of black shale are separated by considerable thicknesses of barren gray shale, siltstone, and sandstone. Elsewhere in the state where the kerogen content is higher, the shale is very thin and overlain by the hard, cherty Mississippian Fort Payne Formation, making it difficult to strip mine, leaving underground mining or in-situ retorting and pyrolysis as the only available options. Since much thicker deposits of higher-grade material exist to the north and in the western United States, it seems unlikely that the Tennessee deposits would be exploited in the foreseeable future.

In light of the relatively low potential for extraction and processing operations involving the Chattanooga shale, no "tailored" statutes and regulations have been developed. The rules of the Division of Surface Mining in the Department of Environment and Conservation cover selective minerals (coal, phosphate, sand and gravel, ball clay, brick, clay and shale, and barite) but not oil shale. Nor do the rules of the State Oil and Gas Board offer oil shale regulations.

If a project did come up, general environmental requirements would come into play. For example, the Division of Water Pollution Control in the Department of Environment and Conservation issues NPDES discharge permits.

Chapter 5 – Regulatory Requirements for Oil Sands Production in the Province of Alberta

Contacts: Jim Dilay and Aaron Sellick, Alberta Energy and Utilities Board

Alberta has been regulating oil sands development for nearly 50 years. The requirements are extensive. Regulatory responsibilities are shared by the Alberta Energy and Utilities Board (EUB), the Alberta Department of the Environment (AENV), and other agencies. In addition, fisheries, navigable water, and transboundary emissions trigger federal involvement in these projects. Various agreements have been made between levels of government and between departments and agencies in the provincial and federal governments addressing the question of agency lead in cases with jurisdictional overlap. These agreements normally also explain how regulators will work together when a project raises issues under the exclusive jurisdiction of more than one regulator.

Some of the laws and regulations are specific to oil sands development, while others are more generally applicable statutes that govern oil sands development in addition to other forms of industrial development. In light of the magnitude of potential requirements, the following descriptions of statutes and regulations are by no means exhaustive. According to the agency contacts, one oil sands mining company indicated that it was required to obtain approximately 50 approvals, permits, and authorizations prior to commencing construction of its project.

<u>Oil Sands Conservation Act and Oil Sands Conservation Regulations</u>

The Oil Sands Conservation Act and Alberta Regulation 76/88, Oil Sands Conservation Regulation, are administered by the EUB for the development of oil sands resources and related facilities in Alberta.

- Oil Sands Conservation Regulation, Sections 2 to 22, govern general regulations.
  - EUB approvals are required for commencing, suspending, or abandoning
    - Oil sand sites,
    - Experimental schemes,
    - In-situ operations,
    - Mining operations, and
    - Processing plants.
  - Operators of oil sands sites require an EUB license for drilling a well and incidental or preparatory operations.
  - Drilling, completion, servicing, and production operations must comply with Alberta Regulation 151/71, Oil and Gas Conservation Regulations.

- Oil Sands Conservation Regulation, Sections 24 to 32, govern mining operations.
  - Storage or disposal of any oil sands or discard accumulated during mining or overburden removal requires EUB approval.
  - Mining operations must be carried out in a manner that ensures public safety.
  - The operator must comply with recordkeeping and reporting requirements.

- Oil Sands Conservation Regulation, Sections 33 to 47, govern in-situ operations.
  - The construction or modification of a central processing facility requires EUB approval.
  - Liquid hydrocarbon storage requires EUB approval.
  - Produced sand must be disposed of in a manner satisfactory to the EUB.
  - The operator must minimize the disposal of water and maximize the recycling of produced water.
  - The operator of a thermal in-situ operation must be able to detect and prevent casing failures in the completion and operation of wells.
  - The well operator requires EUB approval for the method to determine volumes of production from or injection into the well.
  - The operator must comply with general and daily recordkeeping and reporting requirements.
  - Information Letter IL 89-5, *Water Recycle Guidelines and Reporting of Water Use Information for In Situ Oil Sands Facilities in Alberta*, establishes goals and guidance for managing and conserving water supply.

- Oil Sands Conservation Regulation, Sections 48 to 58, govern processing plants.
  - Storage or disposal of any oil sands, coke, sulphur, precipitator ash, or other hydrogen effluent or discard associated with the processing plant requires EUB approval.
  - The operator must minimize the use of fresh make-up water and the disposal of wastewater and maximize the recycling of produced water.
  - The operator must comply with recordkeeping and reporting requirements.

<u>Mines and Minerals Act and Regulations</u>

The Mines and Minerals Act governs the management and disposition of rights in Crown-owned mines and minerals, including the levying and collecting of bonuses, rent, and royalties. The term minerals includes “bituminous sands” and “oil sands,” meaning “sands and other rock materials containing crude bitumen, the crude bitumen contained in those sands and other rock materials, and any other mineral substances, other than natural gas, in association with that crude bitumen or the sands and other rock materials.” It also includes a hydrocarbon substance declared to be oil sands. The Mines and Minerals Act, Sections 87 to 90, govern the McMurray formation, solution gas, operations to recover bituminous or oil sands, and royalty.

The Mines and Minerals Act provides for the procedures to obtain the rights for minerals and the repercussions of not complying with regulations. Enabled regulations include:

- Alberta Regulation 347/1992, Experimental Oil Sands Royalty Regulation
- Alberta Regulation 214/1998, Exploration Regulation
- Alberta Regulation 166/1984, Oil Sands Royalty Regulation
- Alberta Regulation 185/1997, Oil Sands Royalty Regulation
- Alberta Regulation 50/2000, Oil Sands Tenure Regulation
- Alberta Regulation 318/1987, Suncor Oil Sands Royalty Regulation

Alberta Environmental Protection and Enhancement Act and Associated Regulations

The Environmental Protection and Enhancement Act, Part 4, Division 1, governs the release of substances into the environment, regulating releases and creating general prohibitions with respect to substance release. The law entrusts AENV with the regulation of stormwater drainage and wastewater systems. Two regulations enable the AENV to regulate the operation of storm drainage and wastewater systems and establish standards for such facilities and their operators:

- Alberta Regulation 119/93, Wastewater and Storm Drainage Regulation, and
- Alberta Regulation 120/93, Wastewater and Storm Drainage (Ministerial) Regulation.

In November 1999, AENV issued *Surface Water Quality Guidelines for Use in Alberta* to provide guidance on evaluating surface water quality throughout Alberta.

Water Act and Associated Regulations

The Province is the owner of all water in Alberta. The Water Act and the Water Ministerial Regulation are administered by AENV.

- Water Act, Sections 36 to 45, require an approval before undertaking a construction or "activity" in a water body.
    - Activity means:
        - Placing, constructing, operating, maintaining, removing, or disturbing works; maintaining, removing, or disturbing ground, vegetation, or other material; or carrying out any undertaking, including but not limited to groundwater exploration, in or on any land, water, or water body;
        - Altering the flow, direction of flow, or level of water or changing the location of water for the purpose of removing an ice jam, drainage, flood control, erosion control, channel realignment, or a similar purpose; and
        - Drilling or reclaiming a water well or borehole.
    - Approval will contain conditions.
    - In December 2001, AENV issued the *Administrative Guide for Approvals to Protect Surface Water Bodies under the Water Act*.
    - In December 2004, AENV issued the *Guide to Requirements for Outfall Structures on Water Bodies*.

- Water Act, Sections 46 to 65, require a license for "diversion" and use of surface water and groundwater.
    - Diversion of water means:
        - The impoundment, storage, consumption, taking, or removal of water for any purpose, except the taking or removal for the sole purpose of removing an ice jam, drainage, flood control, erosion control, or channel realignment.
    - License identifies:
        - Source of water supply,
        - Location of diversion site,
        - Allocation of water to be diverted and used from the source,

    - Priority of the "water right" established by the license, and
    - Other conditions for diversion and use.
  - In February 2003, AENV issued *Groundwater Evaluation Guidelines*.
  - In January 2006, AENV issued *An Interim Framework: Instream Flow Needs and Water Management System for Specific Reaches of the Lower Athabasca River.*
    - Under conditions having potential short-term impacts on the ecosystem, project owners are asked to target their diversion rate to less than 10 percent of available flow.
    - Recent and new licenses may include conditions with mandatory incremental reductions.
    - In cases where flows are so low that withdrawal would have expected impacts on the aquatic ecosystem, water use reductions and the use of water storage would be mandatory.
  - AENV is currently developing a new *Water Conservation and Allocation Policy* to reduce or eliminate the use of freshwater for in-situ projects.
    - Water allocation licenses are to be issued for a two-year period, with subsequent licenses issued for a five-year term, if the renewal is allowed (a reduction from the previous 10-year renewal period).
    - License holders must apply for renewal under Water Act, Section 59.
    - AENV will approach the holders of permanent licenses to undertake a voluntary review of their license.

- Alberta Regulation 205/98, Water (Ministerial) Regulation, Sections 35 et seq., contain water well regulations governing, among other activities, obtaining approvals, drilling, construction, completion, and pumping.

<u>Public Lands Act and Associated Regulations</u>

Alberta Sustainable Resource Development exercises its role as a manager of public natural resources through a variety of legislation, regulations, and policies. The Public Lands Act covers the selling and transferring of public land, as well as the management of rangeland and activities permitted on designated land.

Chapter 6 – What Is Needed to Move Forward?

The previous chapters outlined the basic forms of technology used to produce oil from oil shale and tar sands, the ground and surface water issues and impacts associated with that production, and the regulatory requirements that govern the production. In this final chapter, we examine the gaps in knowledge and the research needs that will allow oil shale and tar sands production to move forward in the United States, while being protective of the environment. In the light of future information and research needs, the chapter also looks at areas in which legal requirements and regulatory programs could be enhanced to allow oil shale and tar sands production to proceed.

The comments received through the BLM PEIS scoping process (Argonne National Laboratory 2006) provide a good starting point for identifying issues that require more information and research. The BLM held public scoping meetings for the Oil Shale and Tar Sands Leasing PEIS in seven cities in Colorado, Utah, and Wyoming in January 2006. Members of the public were invited to submit comments at the meeting, by mail, or electronically. A scoping summary report is available at http://ostseis.anl.gov/scopingcomments/index.cfm, along with all of the comments received in writing. The scoping summary report covers the total breadth of topics addressed in the scoping phase; however, only those topics most relevant to the focus of this report are discussed below.

Additional issues and information needs are discussed on the basis of some of the recent documents cited throughout this report (i.e., Alberta COR 2004; DOE 2004a, b, c; NEB 2006; RAND 2005) and from the authors' own experiences. The following sections present findings in bullet format. We anticipate that as this preliminary report is reviewed and finalized, other interested parties can expand and refine the list of information and research needs.

Water Quantity and Quality Information and Research Needs

- Baseline information about ground water and surface water (including springs) quantity and quality in the region

- Development and maintenance of monitoring networks

- Accurate regional and local estimates of the amount of water that specific oil shale and tar sands development technologies would require

- In addition to total water needs, the amount or percentage of water that could be recycled or reused within the process or for other purposes

- Where those water supplies would come from, and how competing water demands would be allocated

- How the different types of production technologies would impact ground water and surface water availability and quality during and after production

- How to manage additional salty discharges to the already salinity-stressed Colorado River basin

- Hydrologic modeling that uses modern methods to predict ground water and surface water behavior during and following hydrocarbon production

- Ground water and surface water interactions in the region

- For site workers, planning for potable and general water needs and sanitary wastewater treatment

<u>Waste Generation and Management Information and Research Needs</u>

- How to manage spent shale and spent sand to minimize leaching to ground water and runoff to surface water

- Evaluation of other commercial minerals that may be present in spent shale and sands to enhance production and reduce the volume of waste to be managed

- Evaluation of reuse opportunities for waste materials

<u>Other Environmental Issues Information and Research Needs</u>

- How to minimize air emissions through process design and treatment technology

- Regional air quality monitoring and modeling

- How to minimize noise and visual impacts

- Development and refinement of techniques to stabilize and revegetate mined lands quickly and without stressing limited water resources

- How ecology and wildlife can be effectively protected

<u>Production Technology Information and Research Needs</u>

- How the different types of production technologies would impact ground water and surface water during and after production (also listed above under water needs, but bears repeating as one of the most important issues from a ground and surface water standpoint)

- How to minimize land surface disturbance while still maximizing hydrocarbon production

- More pilot-scale and small-commercial-scale trials of in-situ production and thermally conductive in-situ conversion

- Refinement of existing technologies, transfer of technologies from other industries, and "thinking outside the box" to develop innovative new technologies
- Evaluation of alternate heating/energy sources for in-situ production
- Information on how the rate of heating and the maximum formation temperature affect the quantity and quality of oil produced
- Improvements in mining and processing materials, handling of bulk materials, and maintenance

Infrastructure Information and Research Needs

- Development of adequate power supplies to produce oil shale and tar sands on a large scale
- Evaluation of the role of alternate energy sources to produce oil shale and tar sands
- How and where to site and develop roads, pipelines, power lines, water and sewer lines, materials storage areas, and maintenance areas
- How and where to site and develop temporary or permanent living accommodations and ancillary commercial facilities for workers and families

Legal and Regulatory Needs

- Clarification and possible revision of water rights law
- Preparation of an appropriate programmatic EIS (this is already underway) to be followed as necessary by site-specific environmental assessments
- Coordination of requirements between federal, state, and tribal agencies for developing oil shale and tar sands
- Provision of basic information on technologies and possible impacts to state and tribal oil and gas and/or environmental protection agencies to allow orderly development of regulatory guidelines for oil shale and tar sands production
- How to equitably allocate land access, water, and other public features to competing user groups
- Determination of whether in-situ mining techniques can be permitted through the UIC program, and, if so, how agencies would classify those injection wells

Upcoming Oil Shale Symposium

In light of the current interest in oil shale and tar sands development, it is likely that various upcoming energy and environmental conferences will have sessions dealing with these subjects. In earlier years, interested researchers gathered for a series of oil shale symposia. In October 2006, after an 11-year hiatus, the Colorado School of Mines (CSM) and the Colorado Energy Research Institute will host the 26th Oil Shale Symposium at the CSM campus. This symposium will review development of oil shale resources worldwide, including research and development, impact analysis, regulatory framework, and project and program status. Information on this meeting is available at http://www.mines.edu/outreach/cont_ed/oilshale2006.html.

Chapter 7 – References

The documents listed here are cited in this report. The report is intended to provide an overview of the subject to serve as a starting point. The project budget did not allow the authors to undertake a detailed, in-depth literature review. To supplement the key references in this list, readers are encouraged to examine the list of additional references found in Appendix A relating to oil shale and tar sands production. Although they are not specifically cited in this report, they may provide useful information. We also encourage readers to follow a "back-tracking" approach to find more useful literature. By this, we mean that readers should look at the references cited in each document in this list, then read those of interest. In iterative fashion, each additional document read can provide a wider network of literature sources for readers interested in gaining a deeper perspective.

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