

An hourglass-shaped graphic with a globe inside. The top bulb is dark blue, and the bottom bulb is light blue. The globe is centered in the narrow neck of the hourglass. The text is centered within the hourglass.

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Report RL34748

Developments in Oil Shale

Anthony Andrews, Resources, Science, and Industry Division

November 17, 2008

Abstract. This report takes up the progress toward commercializing oil shale development under the EAct 2005 mandates, and offers a policy perspective that takes account of current turmoil in the energy sector.

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CRS Report for Congress

Developments in Oil Shale

November 17, 2008

Anthony Andrews
Specialist, Energy and Energy Infrastructure Policy
Resources, Science, and Industry Division

<http://wikileaks.org/wiki/CRS-RL34748>



**Prepared for Members and
Committees of Congress**

Developments in Oil Shale

Summary

The Green River oil shale formation in Colorado, Utah, and Wyoming is estimated to hold the equivalent of 1.38 trillion barrels of oil equivalent in place. The shale is generally acknowledged as a rich potential resource; however, it has not generally proved to be economically recoverable. Thus, it is considered to be a contingent resource and not a true reserve. Also, the finished products that can be produced from oil shale are limited in range to primarily diesel and jet fuel. Earlier attempts to develop oil shale under the 1970s era Department of Energy (DOE) Synthetic Fuels program and the later Synthetic Fuels Corporation loan guarantees ended after the rapid decline of oil prices and development of new oil fields outside the Middle East. Improvements taking place at the time in conventional refining enabled increased production of transportation fuels over heavy heating oils (which were being phased out in favor of natural gas).

Rising oil prices and concerns over declining petroleum production worldwide revived United States interest in oil shale after a two-decade hiatus. In addition to technological challenges left unsolved from previous development efforts, environmental issues remained and new issues have emerged. Estimates of the ultimately recoverable resource also vary. Challenges to development also include competition with conventional petroleum production in the mid-continent region, and increasing petroleum imports from Canada. The region's isolation from major refining centers in the Gulf Coast may leave production stranded if pipeline capacity is not increased.

The Energy Policy Act of 2005 (EPAct) identified oil shale as a strategically important domestic resource, among others, and directed the Department of the Interior to promote commercial development. Since then, the Bureau of Land Management (BLM) has awarded six test leases for oil research, development, and demonstration (RD&D). The ongoing program will confirm whether an economically significant shale oil volume can be extracted under current operating conditions. If so, early commercial development may directly proceed. BLM has published a final Programmatic Environmental Impact Statement (PEIS) in which approximately two million acres of oil shale lands, out of approximately 3.54 million acres total, are identified as potentially available for commercial leasing. Draft rules for commercial leases have also been issued, and final rule making is proceeding. The lease and royalties rates proposed in the draft rules appear to compare with rates charged for similar resources, but provide no unique incentive for producing oil shale.

In a previous report, CRS framed oil shale in the perspective of national energy security and reviewed the circumstances under which policies first promoted and then ended support for earlier oil shale development. This second report takes up the progress toward commercializing oil shale development under the EPAct 2005 mandates, and offers a policy perspective that takes account of current turmoil in the energy sector.

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Developments in Oil Shale

Background

Declining domestic production, increasing demand, and rising prices for petroleum have underscored the United States' dependence on imported oil. In response, proponents of greater energy independence have argued that the huge undeveloped oil shale resource in the Rocky Mountain region should be opened for commercial development.¹ Those concerned over repeating past mistakes and compromising the environment, however, have urged caution and deliberation in proceeding.

Earlier attempts to develop oil shale had received direct funding support under the 1970s era Department of Energy (DOE) Synthetic Fuels (SynFuels) program and the later Synthetic Fuels Corporation loan guarantee program. Private sector interest in oil shale all but ended after the rapid decline of oil prices and the development of new oil fields outside the Middle East in the early 1980s. Federal support ended by the mid-1980s with the commissioning of the Strategic Petroleum Reserve. Also at the time, improved refining processes enabled conversion of petroleum residuum into high-value transportation fuel. The residuum (figuratively, the bottom of the petroleum barrel) had been processed into low-value heavy heating oil, which was being replaced by cleaner burning and increasingly available natural gas. Then, as now, oil shale was considered a strategic resource. However, its strategic value more recently had been tied to producing defense-related jet fuel, which now appears to be an uncertain prospect. Oil shale shows better potential as a resource for commercial transportation fuels — jet and diesel. However, it faces regional competition from conventional petroleum resources and their wider distribution, and thus use may be constrained by infrastructure limitations. For information on the history of oil shale under the Synthetic Fuels Program refer to CRS Report RL33359, *Oil Shale: History, Incentives, and Policy*.

In 2005, Congress conducted hearings on oil shale to discuss opportunities for advancing technology that would facilitate “environmentally friendly” development of oil shale and oil sand resources.² The hearings also addressed legislative and administrative actions necessary to provide incentives for industry investment, as well as exploring concerns and experiences of other governments and organizations and the interests of industry.³ The subsequent Energy Policy Act of 2005 (EPAAct —

¹ U.S DOE/EIA. *Monthly Energy Review January 2006, Table 1.7, Overview of U.S. Petroleum Trade*, [http://www.eia.doe.gov/emeu/mer/pdf/pages/sec1_15.pdf].

² Oil sands yield a bitumen substantially heavier most crude oils and shale oil.

³ *Oversight Hearing on Oil Shale Development Effort*, Senate Energy and Natural Resources (continued...)

P.L.109-58) included provisions under Title III *Oil and Gas* that promoted the development of oil shale, tar sands, and other strategic unconventional fuels.⁴ Section 369 of EPAct directed the Department of the Interior (DOI) to offer test leases for research, development and demonstration (RD&D); prepare a programmatic environmental impact statement (PEIS); issue final rules for commercial oil shale leasing; and commence commercial leasing. EPAct also directed the Department of Defense (DOD) to develop a strategy for using fuel derived from oil shale (among other unconventional resources).

Oil Shale Resource Potential

Oil shales exist in several states in the United States. Their kerogen content is the geologic precursor to petroleum. The term *shale oil* is used in this report to refer to the liquid hydrocarbon products that can be extracted from the shale. The most promising oil shales occur in the Green River formation that underlies 16,000 square miles (10.24 million acres) of northwestern Colorado, northeastern Utah, and southwestern Wyoming (**Figure 1**). The most geologically prospective oil shale areas make up ~3.5 million acres. The Bureau of Land Management (BLM) administers approximately 2.1 million acres. Another 159,000 acres is made of BLM administered split estate lands. These are areas where the surface estate is owned by Tribes, states, or private parties, but the subsurface mineral rights are federally-owned.

Estimates of oil shale's resource potential vary. The DOE Office of Naval Petroleum and Oil Shale Reserves estimates that ~1.38 trillion barrels of shale oil are potentially recoverable from the roughly 7.8 million acres of federal oil shales (**Figures 2 and 3**).⁵ The Rand Corporation conservatively estimates that only 800 billion barrels may be recoverable.⁶ Though Utah represents the greatest areal extent of federally managed oil shale land, Colorado's shale may offer a greater potential for recovery because of the resource richness.

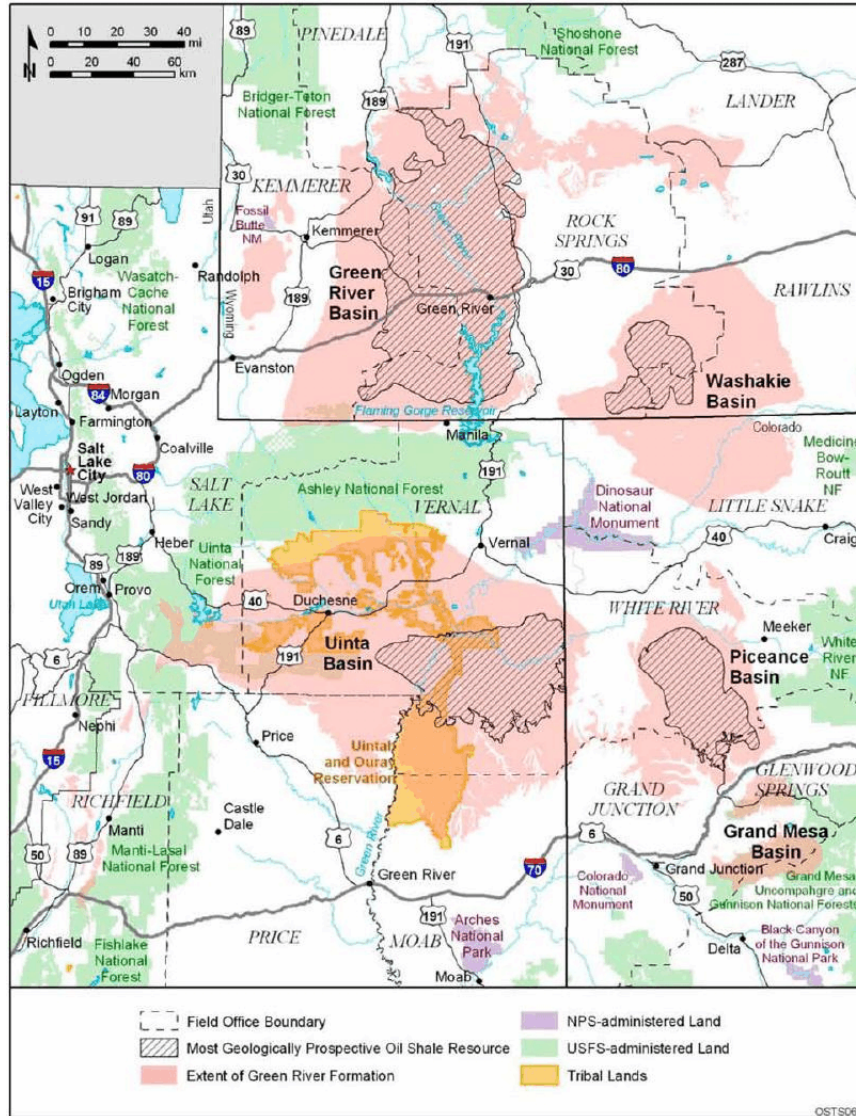
³ (...continued)
Committee, April 12, 2005.

⁴ EPAct Section 369 Oil Shale, Tar Sands, and Other Strategic Unconventional Fuels; also cited as the Oil Shale, Tar Sands, and Other Strategic Unconventional Fuels Act of 2005.

⁵ U.S. DOE, Office of Petroleum and Oil Shale Reserves, *National Strategic Unconventional Resource Model*, April 2006.

⁶ J. T. Bartis, T. LaTourrette, L. Dixon, D.J. Peterson, and G. Cecchine, *Oil Shale Development in the United States Prospects and Policy Issues* (MG-414-NETL), RAND Corporation, 2005.

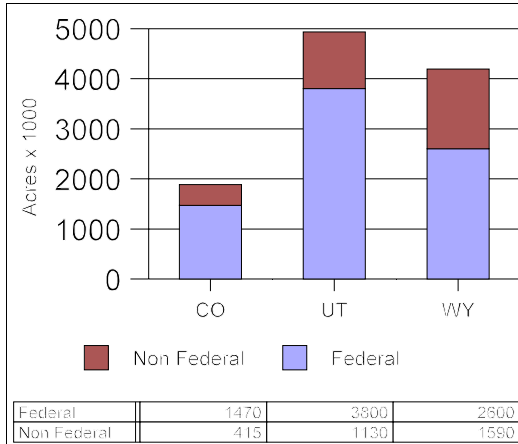
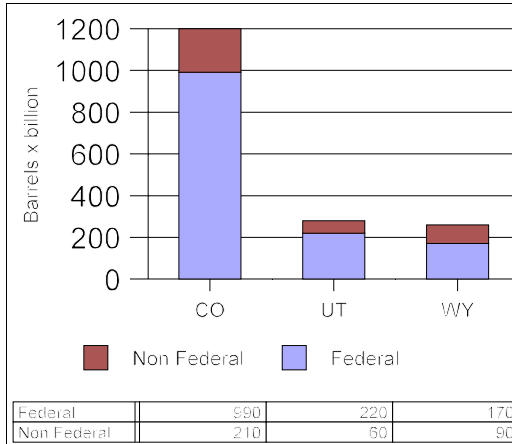
Figure 1. Most Geologically Prospective Oil Shale Resources within the Green River Formation of Colorado, Utah, and Wyoming



St	Geologic Basin	Basin Size	Geologically Prospective Areas		
			Total Area Size	BLM Administered Lands	Split Estate Lands
CO	Piceance	1,185,700	503,342	319,710	41,940
UT	Uinta	2,977,900	840,213	560,972	77,220
WY	Green River & Washakie	4,506,200	2,194,483	1,257,680	39,406
Total Acres		8,669,800	3,538,038	2,138,361	158,566

Key: NPS: National Park Service; USFS: U.S. Forest Service

Source: Bureau of Land Management, Draft Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Programmatic Environmental Impact Statement, December 2007.

Figure 2. Oil Shale Acreage**Figure 3. Shale Oil Volume**

Source: DOE Office of Petroleum and Oil Shale Reserves, National Strategic Unconventional Resource Model, April 2006.

The amount of shale oil recoverable depends on extraction technology and resource “richness.” The richest oil shales occur in the Mahogany zone of the Green River formation and could be expected to produce more than 25 gallons/ton (~ $\frac{2}{3}$ barrel). At that richness, one acre-foot would hold 1,600 to 1,900 barrels of shale oil.⁷ The Mahogany zone can reach 200 feet in thickness in the Uinta Basin of Utah, and thus could represent a technical potential of producing from 320,000 to 380,000 barrels of shale oil per acre if that volume of shale were fully exploited. The ultimate yield would depend on extraction technologies being evaluated under the RD&D program and the land area made available by the preferred leasing alternative selected in the final PEI (discussed below). The potential yield would rival the ~1,400 barrels/acre-foot yields of Canada’s oil sand.⁸ It could well exceed the 50 to 1,000 barrels/acre-foot yields of North America’s now-depleted giant oil fields.⁹

As oil shales have not yet “proved” economically recoverable, they may be considered contingent resources and not true reserves. The United States’ conventional proved oil reserves amount to less than 22 billion barrels with the Arctic National Wildlife Refuge Coastal Plain potentially adding up to 17 billion barrels of oil, as estimated by the U.S. Geological Survey. In comparison, Saudi Arabia’s reserves are reportedly 262 billion barrels according to the Energy Information Administration.

⁷ CRS assumes an oil shale density of 125 to 150 lbs/ft³. 1 acre-foot = 43,560 ft³.

⁸ Reported as $\frac{1}{2}$ barrel per ton. See *Oil Sand Facts*, Government of Alberta. [<http://www.energy.gov.ab.ca/OilSands/790.asp>]. CRS assumes an oil density of 131 lbs/ft³.

⁹ Conventional petroleum reservoirs may only yield 35% of the oil in place, while enhanced oil recovery may increase the total yield up to 50%. See: *Geology of Giant Petroleum Fields*, American Association of Petroleum Geologists, 1970.

Challenges to Development

Oil shale has long been proposed as a source of synthetic or substitute crude oil. However, the organic content (kerogen) of oil shale is only a petroleum precursor. The extracted oil lacks the lower boiling-range hydrocarbons that make up natural gasoline, and the heavier hydrocarbons that refineries crack to make gasoline. It does yield hydrocarbons in the middle-distillate fuels boiling range — naphtha, kerosene, jet fuel, and diesel fuel. Thus, it may face challenges as a substitute for conventional crude oil. It may also face competition from conventional petroleum resources under development in the Rocky Mountain region and Canadian exports to the region.

Oil shale production continues to face unique technological challenges. The kerogen occurs in the shale as a solid and is not free to flow like crude petroleum. The shale must be heated or “retorted” to extract petroleum-like distillates. Retorting oil shale involves destructive distillation (pyrolysis) in the absence of oxygen. Pyrolysis at temperatures above 900° F is needed to thermally break down the kerogen to release the hydrocarbons. Two basic retorting processes have been used — above-ground retorting and in situ (underground) retorting. The above-ground retort is typically a large cylindrical vessel based on rotary kiln ovens used in cement manufacturing and now used by Canada’s oil sands industry.¹⁰ The in situ process involves mining an underground chamber that functions as a retort. Both concepts were evaluated under the former DOE Synfuels program.

Both in situ and above-ground retorting processes have been plagued with technical and environmental problems. A plentiful water supply is considered necessary for above-ground retorting. Above-ground retorting also depends on underground or open-pit mining to excavate the shale. While either mining method is well-practiced, the expended shale that remains after retorting would present a disposal problem. In the case of open-pit mining, overburden rock had to be removed and set aside to expose the shale. Above-ground retorts also faced frequent problems from caked-up shale, which led them to shut down frequently. Apart from the problem of sustaining controlled combustion underground, in situ retorting also caused groundwater contamination.¹¹

New approaches aim to avoid the past drawbacks associated with in situ extraction methods by adapting enhanced oil recovery methods such as horizontal drilling, long term heating, and freezwall technology (a geotechnical engineering method for stabilizing saturated ground). The proposed technologies are discussed in further detail below (see RD&D Program).

¹⁰ For further information see CRS Report RL34258, *North American Oil Sands: History of Development, Prospects for the Future*.

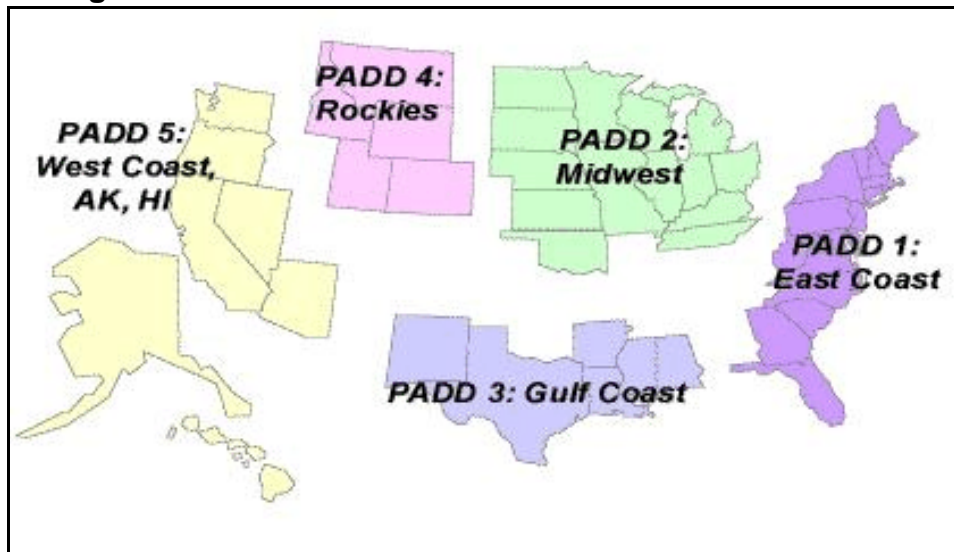
¹¹ For further information see CRS Report RL33359, *Oil Shale: History, Incentives, and Policy*.

Competition With Regional Resources

The Green River oil shales are located in the Rocky Mountain Petroleum Administration for Defense District (PADD 4 — **Figure 4**). PADDs were delineated during World War II to facilitate petroleum allocation. In the past, petroleum pipeline infrastructure left PADD 4 isolated from the other districts, a situation that may slowly improve with the emphasis on new production in the region.

With recent record-high crude oil price, crude production has increased in PADD 4, as has local refining of this production. PADD 4 produced roughly 577 thousand barrels/day over 2007-2008 (**Table 1**). An estimated 588 million barrels of undiscovered technically recoverable conventional oil and natural gas liquids are estimated to underlie the Uinta-Piceance Basin of Utah-Colorado and an additional 2.9 billion barrels are estimated to underlie southwestern Wyoming.¹² Conventional undiscovered technically recoverable resources are those hydrocarbon resources that, on the basis of geologic information and theory, are estimated to exist outside of known producing fields. They are resources that are considered producible using current technology without regard to economic profitability. Natural gas, in particular, has also been undergoing extensive development in Rifle, Colorado (the focal point for the 1980s oil shale boom and bust).

Figure 4. Petroleum Administration for Defense Districts



The Bakken Formation, part of the larger Williston basin, is estimated to hold from 3 to 4.3 billion barrels of oil, according to a recent delineation of the U.S. Geological Survey (USGS).¹³ The formation covers 529 square miles split between

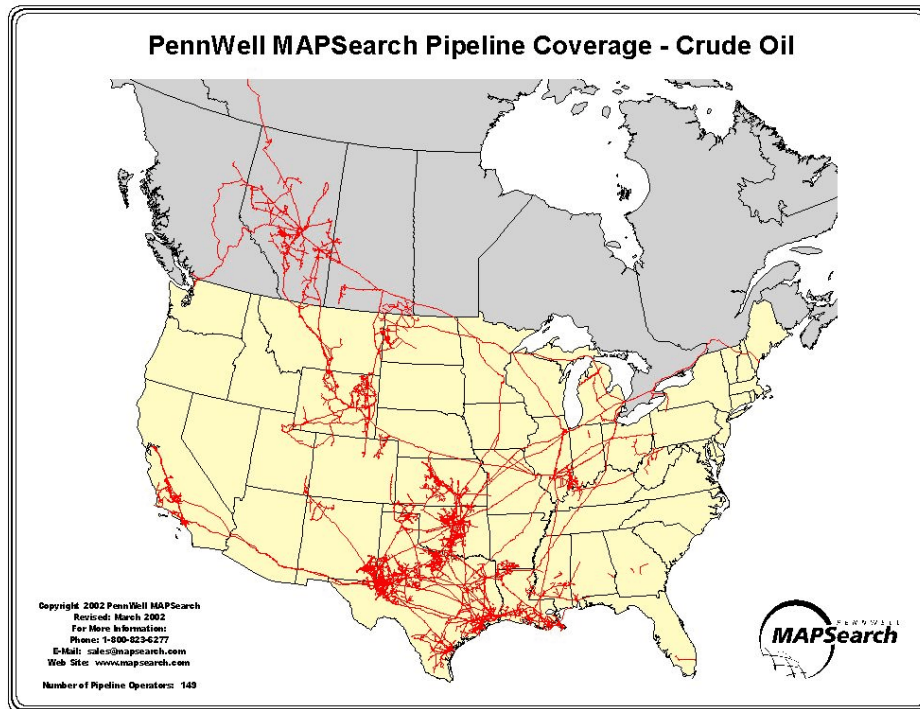
¹² U.S. DOI, *Inventory of Onshore Federal Oil and Natural Gas Resource and Restrictions to Their Development, Phase III Inventory — Onshore United States*, 2008, See Tables 3-8 & 3-15. [http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/EPCA_III.html]

¹³ U.S.G.S, *National Assessment of Oil and Gas Fact Sheet: Assessment of Undiscovered Oil Resources in the Devonian-Mississippian Bakken Formation, Williston Basin Province*, (continued...)

Montana (PADD 4) and North Dakota (PADD 2). The USGS estimate places the Bakken ahead of all other lower 48 states oil assessments, making it the largest “continuous” oil accumulation ever assessed by the USGS. A “continuous” oil accumulation means that the oil resource is dispersed throughout a geologic formation rather than existing as discrete, localized occurrences. Bakken production is increasing and is likely to add to PADD 4 production.

PADD 4 has also been a destination for oil exported from western Canada, derived from both oil sands and conventional petroleum reservoirs (**Figure 5**). Canada ranks as the largest crude oil supplier to the United States, exporting 1.6 million barrels per day. Subsequently, refiners in PADD 4 are taking less western Canadian crude supplies in order to run the readily available and heavily discounted Wyoming sweet and sour crude oils. The large discount is in reaction to aggressive Canadian crude pricing, a shortage of refinery capacity, and the lack of pipeline capacity to move the crude oil to other markets.

Figure 5. United States and Canada Crude Oil Pipelines



Supply and Disposition

Supply and disposition, as tracked by the Energy Information Administration (EIA), is an indication of petroleum production, consumption and movements between districts. Over 2007-2008, PADD 4 consumed an average 682,000 barrels/day of supplied products. Refiners and blenders in the district could only

¹³ (...continued)

Montana and North Dakota, 2008.

produce roughly 593,000 barrels/day (**Table 1**). Its roughly 174,000 barrels/day in distillate production placed PADD 4 behind the other districts.¹⁴ This also left it short of meeting the regional distillate demand of 195,000 barrels/day.¹⁵

**Table 1. Crude Oil and Petroleum Products by PADD
(2007-2008)**

	Supply (thousand barrels/day)					Disposition (thousand barrels/day)			
	Field Production	Refinery and Blender Net Production	Imports	Net Receipts	Adjust- ments	Stock Change	Refinery and Blender Net Inputs	Exports	Products Supplied
PADD 1	41	2,592	3,332	2,767	130	-47	2,507	147	6,256
PADD 2	775	3,533	1,254	2,756	208	-36	3,343	89	5,129
PADD 3	4,006	8,257	7,004	-5,446	180	-79	7,720	982	5,380
PADD 4	577	593	362	-254	-18	-4	577	5	682
PADD 5	1,448	3,019	1,516	177	153	17	2,852	209	3,235
U.S.	6,847	17,994	13,468	n.a.	653	-148	16,999	1,433	20,680

Source: EIA Petroleum Supply Annual, Volume 1, July 28, 2008

Notes:

Field Production represents crude oil production on leases, natural gas liquids production at natural gas processing plants, new supply of other hydrocarbons/oxygenates and motor gasoline blending components, and fuel ethanol blended into finished motor gasoline.

Refinery Production represents petroleum products produced at a refinery or blending plant. Published production of these products equals refinery production minus refinery input. Negative production will occur when the amount of a product produced during the month is less than the amount of that same product that is reprocessed (input) or reclassified to become another product during the same month. Refinery production of unfinished oils, and motor and aviation gasoline blending components appear on a net basis under refinery input.

Imports represents receipts of crude oil and petroleum products into the 50 States and the District of Columbia from foreign countries, Puerto Rico, the Virgin Islands, and other U.S. possessions and territories.

Net Receipts represents the difference between total movements into and total movements out of each PAD District by pipeline, tanker, and barge.

Stock Change represents the difference between stocks at the beginning of the month and stocks at the end of the month. A negative number indicates a decrease in stocks and a positive number indicates an increase in stocks.

Exports represents shipments of crude oil and petroleum products from the 50 States and the District of Columbia to foreign countries, Puerto Rico, the Virgin Islands, and other U.S. possessions and territories.

Product Supplied approximately represents consumption of petroleum products because it measures the disappearance of these products from primary sources, i.e., refineries, natural gas processing plants, blending plants, pipelines, and bulk terminals. In general, product supplied of each product in any given period is computed as follows: field production, plus refinery production, plus imports, plus unaccounted for crude oil, (plus net receipts when calculated on a PAD District basis), minus stock change, minus crude oil losses, minus refinery inputs, minus exports.

¹⁴ U.S. DOE/EIA, *This Week in Petroleum. Four-Week Average for 08/22/08 through 09/05/08*. [http://tonto.eia.doe.gov/oog/info/twip/twip_distillate.html]

¹⁵ Reported as 8,190.8 thousand gal/day. See U.S. DOE EIA, *Prime Supplier Sale Volumes*. [http://tonto.eia.doe.gov/dnav/pet/pet_cons_prim_a_EPDED_K_P00_Mgalpd_a.htm].

Processing

With the increasing competition from other petroleum resources produced and refined in PADD 4, shale oil appears to face stiff competition. However, the roughly 20,000 barrels/day distillate production shortfall could represent an opportunity. Distillate production (kero-jet fuel, kerosene, distillate fuel oil, and residual fuel oil) makes up 38% of PADD 4 refining output, compared to 42% for the United States on average (**Table 2**). For every barrel of distillate produced, almost three barrels of crude oil must be refined. Increasing distillate production by 4% in the Rocky Mountain region could make up the distillate deficit (at the expense of cutting back on gasoline production).

Table 2. Refinery Yield by PADD
(percent)

	PADD1	PADD2	PADD3	PADD4	PADD5	U.S.
Liquefied Refinery Gases	3.2	3.9	5.0	1.5	2.8	4.1
Finished Mogas	45.5	49.8	43.2	46.3	46.6	45.5
Finished Avgas	0.1	0.1	0.1	0.1	0.1	0.1
Kerosene-Type Jet Fuel	5.0	6.1	9.4	5.4	15.6	9.1
Kerosene	0.5	0.1	0.3	0.3	0.0	0.2
Distillate Fuel Oil	29.4	28.2	26.0	29.8	20.8	26.1
Residual Fuel Oil	7.2	1.7	4.1	2.6	6.3	4.2
Naphtha Petro Feed	1.1	0.9	1.9	0.0	0.0	1.3
Other Oils	0.0	0.2	2.4	0.1	0.3	1.3
Special Naphthas	0.0	0.1	0.5	0.0	0.0	0.3
Lubricants	1.0	0.4	1.7	0.0	0.6	1.1
Waxes	0.0	0.1	0.1	0.0	0.0	0.1
Petroleum Coke	3.2	4.3	6.0	3.4	5.8	5.2
Asphalt and Road Oil	5.0	5.3	1.3	8.9	1.8	2.9
Still Gas	3.9	4.2	4.3	4.2	5.4	4.4
Miscellaneous Products	0.2	0.4	0.5	0.3	0.4	0.4
Processing Gain(-) or Loss(+)	-5.1	-5.8	-6.9	-3.0	-6.4	-6.3
Middle Distillate Average	43.2	37.2	44.6	38.2	43.0	42.5

Source: Table 21. EIA Petroleum Supply Annual 2007, Volume 1.

For now, the most likely option for upgrading shale oil into finished products is by conventional refining. However, shale oil does not fully substitute for conventional crude oil. A typical refinery separates middle distillates during atmospheric distillation — the first pass in the refining process — and then removes sulfur and nitrogen by hydrotreating. The remaining heavier fraction (residuum) is “cracked” then into gasoline through advanced refining processes. Shale oil consists of middle distillate boiling-range products, and a typical refinery would not be

configured to crack the middle distillates into gasoline. In fact, some refineries find it more profitable to increase middle distillate production (diesel and jet fuel) at the expense of gasoline. There may be no economic rationale to crack shale oil into gasoline.

Given the operating refineries in the PADD 4 (**Table 3**), any one refinery might be hard pressed to expand capacity or shift production to make up the regional deficit in distillate supply. The economics of constructing and operating a shale oil plant may be uncertain but may also be outweighed by the cost of expanding operating refinery capacity. As a reference case, the CountryMark refinery in Mount Vernon, Indiana, is spending \$20 million to add 3,000 barrels/day in diesel fuel capacity. The expansion will increase throughput from 23,000 barrel/day to 26,000 barrels/day.¹⁶ CountryMark is a specialty refinery that makes diesel fuel for agriculture use.

Table 3. Atmospheric Crude Oil Distillation Capacity of Operable Petroleum Refineries in PADD 4

Refinery	City	ST	Bbls/Day
Colorado Refining Co	Commerce City	CO	27,000
Suncor Energy (USA) Inc	Commerce City	CO	60,000
Cenex Harvest States Coop	Laurel	MT	55,000
ConocoPhillips	Billings	MT	58,000
ExxonMobil Refining & Supply Co	Billings	MT	60,000
Montana Refining Co	Great Falls	MT	8,200
Big West Oil Co	North Salt Lake	UT	29,400
Chevron USA Inc	Salt Lake City	UT	45,000
Holly Corp Refining & Marketing	Woods Cross	UT	24,700
Silver Eagle Refining	Woods Cross	UT	10,250
Tesoro West Coast	Salt Lake City	UT	58,000
Frontier Refining Inc	Cheyenne	WY	46,000
Little America Refining Co	Evansville (Casper)	WY	24,500
Silver Eagle Refining	Evanston	WY	3,000
Sinclair Oil Corp	Sinclair	WY	66,000
Wyoming Refining Co	Newcastle	WY	12,500
	Total		587,550

Source: EIA, As of January, 2005.

¹⁶ CountryMark, *CountryMark Refinery Expansion to Increase Diesel Fuel Supply*, April 3, 2008. [<http://countrymark.com/node/320>].

The economic prospects of building a shale oil upgrading plant are uncertain. A new refinery has not been built in the United States since the late 1970s, as operators have found it more efficient to expand the capacity of existing refineries to yield more gasoline. Refineries increase gasoline yield by processes downstream from atmospheric distillation that crack residuum with heat, pressure, catalysts, and hydrogen. Overall refinery throughput though is limited by the atmospheric distillation capacity. A shale oil plant would process a narrower boiling range of hydrocarbons than a conventional refinery, and thus would not require the suite of complex processes. Shale oil's high nitrogen and sulfur content was considered problematic, but the hydrotreating processes now used by refineries to produce ultra-low sulfur diesel fuel can overcome that drawback. The hydrogen required for hydrotreating may be made up in part from shale oil's high hydrogen content and the lighter volatile gases devolved during processing. A less-complex facility making a limited slate of products compared to conventional refinery may prove less burdensome to permit. The approval process for new refinery construction has been estimated to require up to 800 different permits, notwithstanding anticipated legislation mandating carbon capture and sequestration.¹⁷

Congress has recognized that increasing petroleum refining capacity serves the national interest and included provisions under Title III of EPAct (Subtitle H — Refinery Revitalization) to streamline the environmental permitting process. A refiner can now submit a consolidated application for all permits required by the Environmental Protection Agency (EPA). To further speed the permit's review, the EPA is authorized to coordinate with other federal agencies, enter into agreements with states on the conditions of the review process, and provide states with financial aid to hire expert assistance in reviewing the permits. Additional provisions under EPAct Title XVII (Incentives for Innovative Technologies) guarantee loans for refineries that avoid, reduce, or sequester air pollutants and greenhouse gases if they employ new or significantly improved technology. It should be noted that permitting would be a secondary consideration for new construction, if refining was an unfavorable investment.

Short of building new pipelines, expanding pipeline capacity to export either crude or refined products from the Rocky Mountain regions appears to be an apparent alternative. As shown in Figure 5, PADD 4 is relatively isolated from refining centers in the Gulf Coast and does not serve the western states. To accommodate increased crude oil imports from Canada, the Mobile Pipe Line Company reversed its 858 mile crude oil pipeline that historically ran from Nederland, Texas, to Patoka, Illinois. The pipeline now takes Canadian crude oil delivered to the Chicago region to Gulf Coast refineries.

Carbon Emissions

Congress is considering various bills aimed at reducing and stabilizing greenhouse gas emission. The Energy Independence and Security Act of 2007 (EISA — P.L. 110-140) amends the Energy Policy Act of 2005 with research and development programs to demonstrate carbon capture and sequestration, and restricts

¹⁷ *Investor's Business Daily*, "Crude Awakening," March 28, 2005.

the federal government's procurement of alternative fuels that exceed the lifecycle greenhouse gas emissions associated with conventional petroleum based fuels. Title II of EISA directs the EPA to establish "baseline life cycle greenhouse gas emissions" for gasoline or diesel transportation fuel replaced by a renewable fuel.¹⁸ The Lieberman-Warner Climate Security Act (S. 3036) would have established a program to decrease emissions.

Until ongoing oil shale research development and demonstration projects are completed (discussed below), and environmental impact statements are prepared for permitting commercial development, adequate data to assess baseline emissions is not available. Greenhouse gas emissions, primarily carbon dioxide (CO₂), associated with oil shale production can originate from fossil fuel consumption, and carbonate minerals decomposition.

A 1980 analysis concluded that retorting Green River oil shales and burning the product could release from 0.18 tons to 0.42 tons CO₂/barrel of oil equivalent, depending on retorting temperatures.¹⁹ A large portion of the CO₂ released would be due to decomposition of carbonate minerals in the shale. The analysis concluded that equivalent of 1½ to 5 times more CO₂ could be emitted by producing fuels by retorting and burning shale oil than burning conventional oil to obtain the same amount of usable energy.

An "In Situ Conversion Process" being tested by the Shell Oil Company (discussed below) is projected to emit from 0.67 to 0.81 tons CO₂/barrel of refined fuel delivered.²⁰ The analysis concluded that the in situ retorting process could produce 21% to 47% greater greenhouse gases than conventionally produced petroleum-based fuels.

Petroleum refining alone, accounts for approximately 0.05 tons CO₂/barrel refined of oil. In 2005, U.S. refineries emitted 306.11 million tons of CO₂ to produce 5,686 million barrels of petroleum products.²¹ However, from a life-cycle perspective, these emissions do not account for the CO₂ emitted by expending fossil energy for drilling, lifting (production), and transporting crude oil by tanker ship and

¹⁸ EISA Title II — Energy Security Through Increased Production of Biofuels. Section 201. Definitions.

¹⁹ Originally reported as 30 kg carbon as CO₂ per MBTtu for low-temperature retorting and 70kgC/MBtu for higher temperature retorting. CRS assumes a product equivalent of to No.2 diesel w/net heating value = 5.43 MBtu/barrel. See Eric T. Sundquist and G. A Miller (U.S.G.S.), *Oil Shales and Carbon Dioxide*, Science, Vol 208. No. 4445, pp740-741, May 16, 1980.

²⁰ Originally reported as 30.6 and 37.1 g_{Cequiv}/MJ refined fuel delivered. (1 metric ton carbon equivalent = 3.67 metric tons carbon dioxide, and assumes refined fuel equivalent to No. 2 diesel in heating value.) See Adam R. Brandt, *Converting Oil Shale to Liquid Fuels: Energy Inputs and Greenhouse Gas Emissions of the Shell in Situ Conversion Process*, American Chemical Society, August 2008.

²¹ Mark Schipper, *Energy-Related Carbon Dioxide Emissions in U.S. Manufacturing* (DOE/EIA-0573), 2005.

pipeline. The practice in some parts of the world of flaring (burning) “associated natural gas” that can’t be delivered to market also contributes to emissions.

As a benchmark, CO₂ emissions associated with Canadian oil sand production reportedly range from 0.08 tons CO₂/barrel for in situ production to 0.13 tons CO₂/barrel for mining/extraction/upgrading.²² Starting at 0.15 tons CO₂/barrel in 1990 the oil sand industry expects to nearly halve its average CO₂ emissions by 2010 to ~0.08 tons/barrel for all processes.

Water

Depending on the depth of the oil shale and the extraction methods used, demands on water resources may vary considerably. Utah’s shallower oil shale may be more suited to conventional open-pit or underground mining, and processing by retorting. Colorado’s deeper shale may require in situ extraction. The DOE Office or Petroleum Reserves expects that oil shale development will require extensive quantities of water for mine and plant operations, reclamation, supporting infrastructure, and associated economic growth.²³ Water could be drawn from the Colorado River Basin or purchased from existing reservoirs. Oil shale has a high water content, typically 2 to 5 gallons/ton, but as high as 30 to 40 gallons/ton. In situ methods may produce “associated water,” that is, water naturally present in the shale.

EPAct 2005 Section 369 (r) is clear on not preempting or affecting state water law or interstate water compacts when it comes to allocating water. Water rights would not be conveyed with federal oil shale leases. The law of water rights is traditionally an area regulated by the states, rather than the federal government. Depending on the individual state’s resources, it may use one of three doctrines of water rights: riparian, prior appropriation, or a hybrid of the two. Under the riparian doctrine, which is favored in eastern states, a person who owns land that borders a watercourse has the right to make reasonable use of the water on that land.²⁴ Traditionally, users in the riparian systems are limited only by the requirement of reasonableness in comparison to other users. Under the prior appropriation doctrine, which is favored in western states, a person who diverts water from a watercourse (regardless of his location relative thereto) and makes reasonable and beneficial use of the water acquires a right to that use of the water.²⁵ Typically, under a prior appropriation system of water rights, users apply for a permit from a state administrative agency which limits users to the quantified amount of water the user

²² Reported as 439.2 kg/m³ and 741.2 kg CO₂/m³ respectively. *Appendix Six, Canada’s Oil Sands: Opportunities and Challenges to 2015*, National Energy Board of Canada, May 2004. [<http://www.energy.gov.ab.ca/OilSands/793.asp>]

²³ U.S. DOE/Office of Petroleum Reserves, *Fact Sheet: Oil Shale Water Resources*. [http://www.fe.doe.gov/programs/reserves/npr/Oil_Shale_Water_Requirements.pdf]

²⁴ See generally A. Dan Tarlock, *Law of Water Rights and Resources*, ch. 3 “Common Law of Riparian Rights.”

²⁵ See generally *ibid.* at ch. 5, “Prior Appropriation Doctrine.”

secured under the permit process. Some states have implemented a dual system of water rights, assigning rights under both doctrines.²⁶

One of the most controversial areas of oil and gas production operations today is the handling, treatment, and disposal of produced water.²⁷ Water produced in association with mineral extraction (including oil and gas) typically contains high levels of contaminants, and it usually must be treated before it can be safely used or discharged. As clean water is a scarce resource, treating produced water may have significant economic use, such as irrigation, washing, or even drinking. A recently completed plant in the Power River basin in Wyoming treats 30,000 barrel/day water produced from coal-bed methane (CBM) wells, and is expected to discharge 120,000 barrels/day to the basin within the next year without affecting water quality.²⁸

The Produced Water Utilization Act of 2008 (H.R. 2339) would encourage research, development, and demonstration of technologies to utilize water produced in connection with the development of domestic energy resources.

Defense Fuels

EPAct Section 369 (q) directed the Department of Defense (DOD) and DOE with developing a strategy for using fuel produced from oil shale (among other unconventional resources) to help meet DOD's requirements when it would be in the national interest. EPAct Section 369 (g) also charged a joint Interior/Defense/Energy task force with coordinating and developing the commercial development of strategic unconventional fuels (including oil shale and tar sands). DOD's earlier "Assured Fuels Initiative" and later "Clean Fuels Initiative" considered oil shale, but shifted emphasis to jet fuels produced by Fisher-Tropsch synthesis from coal and gas.

Under the provisions of EPAct Section 369 (h), the BLM established the Oil Shale Task Force in 2005, which in turn published the report "Development of America's Strategic Unconventional Fuel Resources" (September 2006). The Task Force concluded that oil shale, tar sands, heavy oil, coal, and oil resources could supply all of the DOD's domestic fuel demand by 2016, and supply upwards of seven million barrels of domestically produced liquid fuels to domestic markets by 2035.

Under Section 526 of EISA 2007, DOD is restricted in buying a fuel derived from oil shale or any other unconventional fuel unless the procurement contract specifies that the lifecycle greenhouse gas emission associated with the fuel's production is less than conventional petroleum derived fuel. Section 334 of the National Defense Authorization Act for FY2009 (S. 3001), however, directs DOD

²⁶ For further information, see CRS Report RS22986, *Water Rights Related to Oil Shale Development in the Upper Colorado River Basin*, by Cynthia Brougher.

²⁷ *Oil & Gas Journal*, "Produced water management: controversy vs. opportunity," May 12, 2008.

²⁸ *Oil & Gas Journal*, "Custom-designed process treats CBM produced water," July 14, 2008.

to study alternative fuels in order to reduce lifecycle emissions with the goal of certifying their use in military vehicles and aircraft.

Restrictions to Leasing

EPA Act Section 364 amended the Energy Policy and Conservation Act of 2000 (EPCA — 42 U.S.C. 6217) by requiring an inventory of all oil and gas resources underlying onshore federal lands, and an identification of the extent and nature of any restrictions or impediments to their development. The study areas were delineated by aggregating oil and/or natural gas resource plays within the provinces as defined by the U.S. Geological Survey (USGS) *National Assessment of Oil and Gas Resources*.

Certain lands within the oil shale resource areas are excluded from commercial leasing on the basis of existing laws and regulations, Executive Orders, administrative land use plan designations as noted below, or withdrawals. As a result, commercial leasing is excluded from all designated Wilderness Areas, Wilderness Study Areas (WSAs), other areas that are part of the National Landscape Conservation System (NLCS) administered by the BLM (e.g., National Monuments, National Conservation Areas (NCAs), Wild and Scenic Rivers (WSRs), and National Historic and Scenic Trails), and existing Areas of Critical Environmental Concern (ACECs) that are currently closed to mineral development. Within the oil shale areas, 261,441 acres are designated as Areas of Critical Concern (ACEC), and thus closed to developments (Colorado - 10,790; Utah - 199,521; Wyoming - 51,130).

A significant portion of public land within the most geologically prospective oil shale area is already undergoing development of oil, gas and mineral resources. BLM has identified the most geologically prospective areas for oil shale development on the basis of the grade and thickness of the deposits: in Colorado and Utah, deposits that yield 25 gallons of shale oil per ton of rock or more and are 25 feet thick or greater; in Wyoming, 15 gallons/ton or more, and 15 feet thick or greater.

CRS has overlain a profile of the most geologically prospective oil shale resources of the Green River formation over maps of access categories prepared for the EPCA inventory (**Figure 6**). The Uinta basin in Utah is shown as being subject to standard lease terms. The Piceance basin in Colorado is more subject to short term lease of less than three months with controlled surface use. Approximately 5.3 million acres (40%) of the federal land in the Uinta-Piceance study area is not accessible. Currently a total of ~5.2 million federal acres are under oil and gas lease in Colorado, ~4.7 million acres in Utah, and ~12.6 million acres in Wyoming.

In Colorado, BLM administers approximately 359,798 federal acres of the most geologically prospective oil shale deposits, of which 338,123 acres (94% margin of error is +/-2%) are already under lease for oil and gas development.²⁹

²⁹ Personal communication with Jim Sample, U.S. BLM Colorado State Office, September 24, 2008.

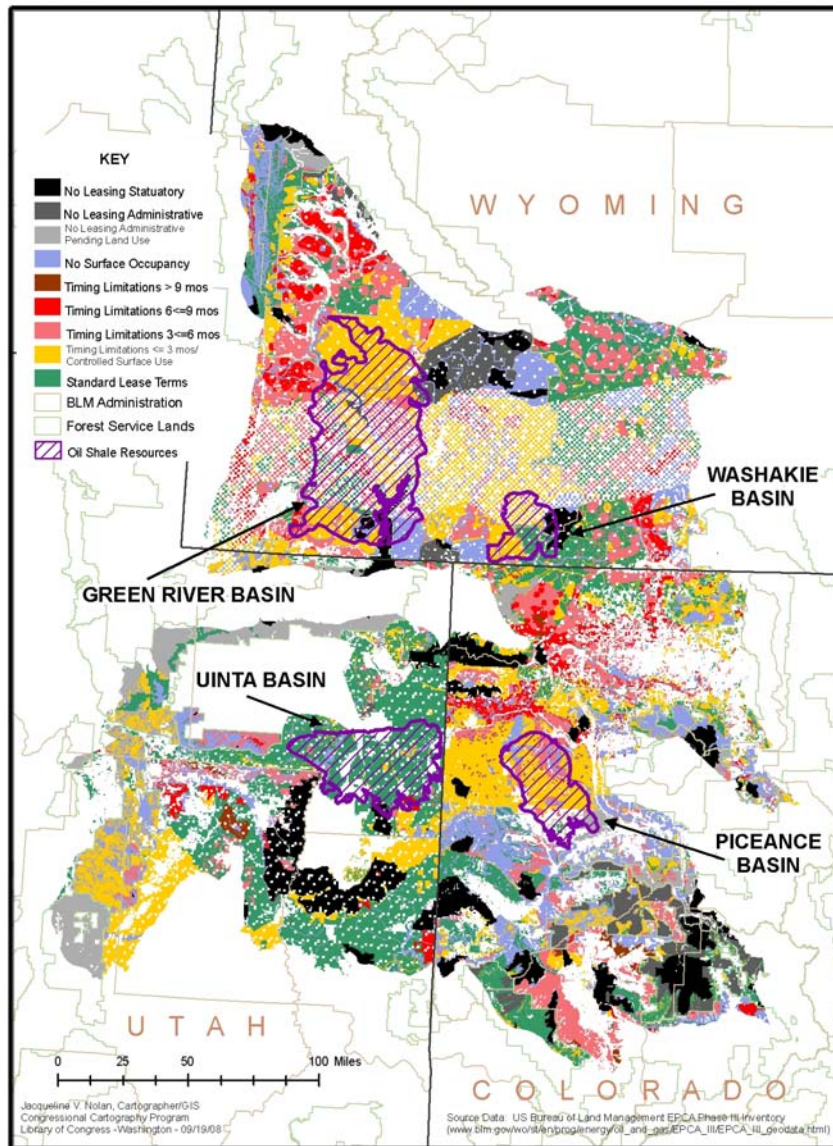
In Utah, BLM administers approximately 638,192 federal acres of the most geologically prospective oil shale deposits, of which approximately 529,435 acres (83%) are currently leased for oil and gas development.³⁰

In Wyoming, BLM administers approximately 1,297,086 acres of the most geologically prospective oil shale deposits, of which approximately 917,789 acres (71%) are currently leased for oil and gas development.

BLM's policy is to resolve conflicts among competing resources when processing potential leasing action. However, BLM considers the commercial oil shale development technologies currently being evaluated (see discussion below) as largely incompatible with other mineral development activities and would likely preclude those activities while oil shale development and production are ongoing. EPL Act Sec. 369 (n) authorizes the Interior Secretary to consider land exchanges to consolidate land ownership and mineral rights into manageable areas.

³⁰ Personal communication with Barry Rose, U.S. BLM, October 7, 2008.

Figure 6. Federal Land Access for the Most Geologically Prospective Oil Shale



http://wikileaks.org/wiki/CRS-RL34748

State	BLM Administered Oil Shale Lands acres	Land Leased for Oil and Gas Development acres
Colorado	359,798	338,123
Utah	638,192	529,435
Wyoming	1,297,086	917,789

Commercial Leasing Program

RD&D Program

EPAct Sec 369 (c) directed the Secretary of Interior to make land available within each of the States of Colorado, Utah, and Wyoming for leasing to conduct research, development, and demonstration (RD&D) of technologies to recover liquid fuels from oil shale. In a November 2004 Federal Register notice (prior to EPAct's enactment in August 2005), the BLM sought public input on the terms to be included in leases of small tracts for oil shale research and development within the Piceance Creek Basin in northwestern Colorado, the Uinta Basin in southeastern Utah, and the Green River and Washakie Basins in western Wyoming.³¹ BLM followed in June 2005, with a solicitation for three nominations of parcels to be leased for research, development, and demonstration of oil shale recovery technologies in Colorado, Utah, and Wyoming.³² BLM received 20 nominations for parcels in response to its Federal Register announcement, and rejected 14 nominations. On September 20, 2005, the BLM announced it had received 19 nominations for 160-acre parcels of public land to be leased in Colorado, Utah, and Wyoming for oil shale RD&D. On January 17, 2006, BLM announced that it accepted eight proposals from six companies to develop oil shale technologies; the companies selected were Chevron Shale Oil Co., EGL Resources Inc., ExxonMobil Corp., Oil-Tech Exploration LLC, and Shell Frontier Oil & Gas.³³ Five of the proposals will evaluate in situ extraction to minimize surface disturbance. The sixth proposal will employ mining and retorting. Environmental Assessments (EA) prepared for each proposal prepared under the National Environmental Policy Act (NEPA) resulted in a Finding of No Significant Impact. In addition to the 160 acres allowed in the call for RD&D proposals, a contiguous area of 4,960 acres is reserved for the preferential right for each project sponsor to convert to a future commercial lease after additional BLM reviews.

To date, BLM has issued six RD&D leases granting rights to develop oil shale resources on 160-acre tracts of public land (see **Table 4**). The leases grant an initial term of 10 years and the possibility of up to a 5-year extension upon proof of diligent progress toward commercial production. RD&D lessees may also apply to convert the leases plus 4,960 adjacent acres to a 20-year commercial lease once commercial production levels have been achieved and additional requirements are met. The RD&D projects are summarized below, and locations shown in **Figure 7**.

³¹ Federal Register, *Potential for Oil Shale Development*; Vol. 69, No. 224 / Monday, November 22, 2004 / Notices 67935.

³² Federal Register, *Potential for Oil Shale Development; Call for Nominations — Oil Shale Research, Development and Demonstration (R, D & D) Program*; Vol. 70, No. 110 / Thursday, June 9, 2005 / Notices 33753.

³³ U.S. DOI/BLM, *BLM Announces Results of Review of Oil Shale Research Nominations*, January 17, 2006. [http://www.blm.gov/nhp/news/releases/pages/2006/pr060117_oilshale.htm]

Table 4. RD&D Leases

Lessee	State	Locale	Technology
OSEC	UT	Vernal	Underground mining and surface retorting
Chevron	CO	Piceance Basin, Rio Blanco	In situ/ heated gas injection
EGL	CO	Piceance Basin, Rio Blanco	In situ/ steam injection
Shell	CO	Oil Shale Test Site (1); Piceance Basin, Rio Blanco	In situ Conversion Process (ICP) using self-contained heaters.
Shell	CO	Nahcolite Test Site (2); Piceance Basin, Rio Blanco	Two-Step ICP using hot water injection
Shell	CO	Advanced Heater Test Site (3); Piceance Basin, Rio Blanco	Electric-ICP using bare wire heaters

Source: Final Environmental Assessment [http://www.blm.gov/co/st/en/fo/wrfo/oil_shale_wrfo.html], [<ftp://ftp.blm.gov/blmincoming/UT/VN/>].

Notes: OSEC — Oil Shale Exploration Co., LLC; EGL — EGL Resources, Inc.; Shell — Shell Frontier Oil and Gas Inc.

OSEC. The Oil Shale Exploration Co., LLC (OSEC) RD&D project will evaluate developing oil shale by underground mining and surface retorting using the Alberta-Taciuk (ATP) Process — a horizontal rotary kiln retort. The first phase would consist mainly of hauling stockpiles of oil shale to a retorting demonstration plant in Canada. The second phase would consist of moving a demonstration retort processing plant to the former White River Mine area, processing stockpiles of oil shale that are on the surface, and eventually reopening the White River Mine, and the commencement of mining of oil shale. The third phase would involve an upscaling of the retort demonstration plant, continuation of mining, and the construction of various supporting facilities and utility corridors.

OSEC currently intends to use the Petrosix process (a patented retort process) as the technology to process the mined oil shale into shale oil at the White River Mine. The Petrosix process has been under development since the 1950s and is one of the few retorting processes in the world that can show significant oil production while remaining in continuous operation. This retort technology is owned by Petrobras and has been operational in Brazil since 1992. Petrosix is an externally generated hot gas technology. Externally generated hot gas technologies use heat, transferred by gases which are heated outside the retort vessel. As with most internal combustion retort technologies, the Petrosix retort processes oil shale in a vertical shaft kiln where the vapors within the retort are not diluted with combustion exhaust. The world's largest operational surface oil shale pyrolysis reactor is the Petrosix

thirty-six foot diameter vertical shaft kiln which is located in São Mateus do Sul, Paraná, Brazil. This retort processes 260 tons of oil shale per hour.³⁴

Chevron. Chevron's research focuses on oil shale recovery using conventional drilling methods and controlled horizontal fracturing technologies to isolate the target interval, and to prepare the production zone for the application of heat to convert the kerogen to oil and gas.³⁵ The intent of the Chevron proposal is to prove an in-situ development and production method that would apply modified fracturing technologies as a means to control and contain the production process within the target interval. The use of conventional drilling methods is aimed at reducing the environmental footprint and water and power requirements compared to past shale oil extraction technologies. The project will evaluate shale oil within the oil-rich Mahogany zone, an oil shale deposit that is approximately 200 feet thick. It will be conducted in a series of seven distinct phases that would entail drilling wells into the oil shale formation and applying a series of controlled horizontal fractures within the target interval to prepare the production zone for heating and in-situ combustion.

EGL. EGL's research will gather data on oil shale recovery using gentle, uniform heating of the shale to the desired temperature to convert kerogen to oil and gas.³⁶ The intent of the EGL proposal is to prove an in-situ development and production method using drilling and fracturing technology to install conduit pipes into and beneath the target zone. A closed circulation system would circulate pressurized heating fluid. The methodology requires circulating various heating fluids through the system. EGL plans to test the sequential use of different heating fluids during different phases of the project. Field tests will involve introducing heat near the bottom of the oil shale zones to be retorted. This would result in a gradual, relatively uniform, gentle heating of the shale to 650-750 °F to convert kerogen to oil and gas. Once sufficient oil has been released to surround the heating elements, EGL anticipates that a broad horizontal layer of boiling oil would continuously convect hot hydrocarbon vapors upward and transfer heat to oil shale above the heating elements. The oil shale that would be tested by EGL at the nominated 160-acre tract is a 300-foot-thick section comprising the Mahogany zone (R-7) and the R-6 zone of the Green River formation, the top of which is at a depth of approximately 1,000-feet. The affected geologic unit would be approximately 1,000 feet long and 100 feet wide.

Shell. Shell Frontier Oil and Gas, Inc. (Shell) intends to develop three pilot projects to gather operating data for three variations to in-situ hydrocarbon recovery from oil shale.³⁷ At the Shell Oil Shale Test (OST) site (Site 1), testing of in-situ

³⁴ OSEC. [<http://www.oilshaleexplorationcompany.com/tech.asp>]

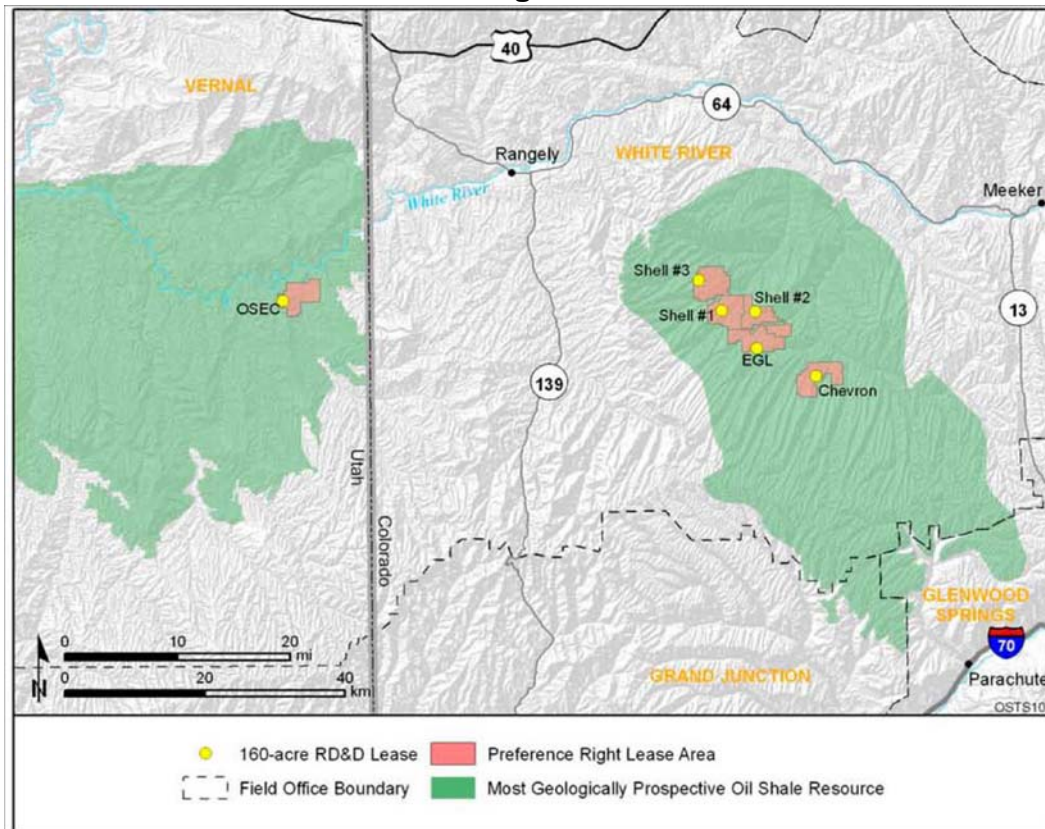
³⁵ U.S. DOI/BLM, *Environmental Assessment — Chevron Oil Shale Research, Development & Demonstration CO-110-2006=120-EA*, November 2006.

³⁶ U.S. DOI/BLM, *Environmental Assessment — EGL Resources, Inc., Oil Shale Research, Development and Demonstration Tract CO-110-2006-118-EA*, November 2006.

³⁷ U.S. DOI/BLM, *Environmental Assessment — Shell Frontier Oil and Gas Inc., Oil Shale Research, Development and Demonstration Pilot Project CO-110-2006-117-EA*, November (continued...)

extraction process components and systems will demonstrate the commercial feasibility of extracting hydrocarbons from oil shale. The Second Generation In-situ Conversion Process (ICP) test at Site 2 will determine the practicability of combining already developed nahcolite extraction methods with in-situ hydrocarbon extraction technology.³⁸ The electric-ICP (E-ICP) or advanced heater technology test at Site 3 will assess an innovative concept for in-situ heating. The sites identified by Shell overlie high grade oil shale yielding more than 25 gallons/ton of shale and a valuable nahcolite resource.

Figure 7. Locations of the Six RD&D Tracts and Associated Preference Right Lease Areas



Source: Draft OSTs PEIS. December 2007

Programmatic Environmental Impact Statement

EPA Act Sec. 369 (d)(1) directed the Interior Secretary to complete a programmatic environmental impact statement (PEIS) for an oil shale and tar sands commercial leasing program on the most geologically prospective lands within each

³⁷ (...continued)
2006.

³⁸ Nahcolite is a carbonate mineral currently mined for its economic value.

of the States of Colorado, Utah, and Wyoming.³⁹ The *Notice of Availability of Proposed Oil Shale and Tar Sands Resource Management Plan Amendments To Address Land Use Allocations in Colorado, Utah, and Wyoming and Final Programmatic Environmental Impact Statement* was published September 5, 2008.⁴⁰

In the final PEIS, the BLM proposes to amend 12 land use plans in Colorado, Utah, and Wyoming to provide the opportunity for commercial oil shale leasing. The existing resource management plans within the PEIS study area are:

Colorado.⁴¹

- Glenwood Springs RMP (BLM 1988b, as amended by the 2006 Roan Plateau Plan Amendment [BLM 2006a, 2007])
- Grand Junction RMP (BLM 1987)
- White River RMP (BLM 1997a, as amended by the 2006 Roan Plateau Plan Amendment [BLM 2006a, 2007])

Utah.⁴²

- Book Cliffs RMP (BLM 1985)
- Diamond Mountain RMP (BLM 1994)
- Grand Staircase–Escalante National Monument RMP (BLM1999)
- Henry Mountain MFP (1982)
- Price River Resource Area MFP, as amended (BLM 1989)
- San Rafael Resource Area RMP (BLM 1991a)
- San Juan Resource Area RMP (BLM 1991b)

Wyoming.⁴³

- Great Divide RMP (BLM 1990)
- Green River RMP (BLM 1997b, as amended by the Jack Morrow Hills Coordinated Activity Plan [BLM 2006b])
- Kemmerer RMP (BLM 1986)

Three alternatives to commercial leasing were presented in the draft PEIS, and in the Final PEIS, BLM selected Alternative B as the proposed plan amendment. The alternatives are:

- *Alternative A — No Action Alternative.* Under this alternative, approximately 294,680 acres in Colorado (White River) and 58,100 acres in Utah (Book Cliffs) are currently classified as available for leasing under existing land use plan. No amendments would be made to the plans to identify additional lands for commercial oil shale leasing.

³⁹ In accordance with section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)).

⁴⁰ Federal Register / Vol. 73, No. 173 / Friday, September 5, 2008 / Notices.

⁴¹ BLM. [www.blm.gov/co/st/en/BLM_Programs/land_use_planning/rmp.html]

⁴² BLM. [<http://www.blm.gov/ut/st/en.html>]

⁴³ BLM. [<http://www.blm.gov/rmp/WY/>]

- *Alternative B.* Under this alternative, BLM is designating 1,991,222 acres available for leasing by amending nine land use plans. This would include BLM-administered lands and split-estate land that the federal government owns mineral rights within the most geologically prospective oil shale areas. Land exempted by statute, regulation, or Executive Order would be excluded.
- *Alternative C.* This alternative would exclude additional land from commercial leasing under Alternative B, reducing the land available to 830,296 acres. The additionally excluded lands require special management or resource protection under existing land use plans.

BLM administers 2,138,361 acres of the most geologically prospective oil shale lands (**Table 1**). Alternative B makes 93% available for leasing. As discussed below, a significant portion of these lands are already under lease for oil and gas development.

Mineral Leasing Act Amendments

Advocates of oil shale development claimed that restrictions on lease size hindered economic development. EPLA Section 369 (j) amended Section 241(a) of the Mineral Leasing Act (30 U.S.C. 241(a)) by increasing the size of an individual oil shale lease from 5,120 acres to 5,760 acres (9 square miles), but limiting the total acreage that an individual or corporation may acquire in any one state to 50,000 acres (78.125 square miles).⁴⁴ Under the act, federal oil and gas lessees may hold to 246,080 acres (384.5 square miles).

Commercial Lease Sale and Royalty Rates

EPLA Section 369 (e) directs a lease sale of oil shale within 180 days of publishing the final lease rules if sufficient interest exists in a state, and Section 369(o) directs BLM in establishing royalties and other payments for oil shale leases that: “(1) Encourage development of the oil shale and tar sands resources; and (2) Ensure a fair return to the United States.”

Proposed Leasing Rules. EPLA Section 369 (d)(2) directed the DOI to publish a final regulation establishing a commercial lease program not later than 6 months after the completion of the PEIS. Now expired, Section 433 of the 2008 Consolidated Appropriations Act (P.L. 110-161) stipulated that “None of the funds made available by this Act shall be used to prepare or publish final regulations regarding a commercial leasing program for oil shale resources on public lands pursuant to section 369(d) of the Energy Policy Act of 2005 (Public Law 109-58) or to conduct an oil shale lease sale pursuant to subsection 369(e) of such Act.” Section 152 of the Consolidated Security, Disaster Assistance, and Continuing Appropriations Act of 2009 (P.L. 110-329) rescinds the Section 433 spending

⁴⁴ 30 USC 241 (4) “For the privilege of mining, extracting, and disposing of oil or other minerals covered by a lease under this section ... no one person, association, or corporation shall acquire or hold more than 50,000 acres of oil shale leases in any one State.”

prohibition effectively through March 2009. In the mean time, BLM published proposed regulations to establish a commercial leasing program of federally owned oil shale on July 28, 2008.⁴⁵

In an advance notice of proposed rulemaking (ANPR), the BLM requested comments and suggestions to assist in the writing of a proposed rule to establish a commercial leasing program for oil shale.⁴⁶ Section 369(j) set the annual rental rate for an oil shale lease at \$2.00/ acre. Since the statute sets the rental rate, the BLM has no discretion to revise it.

In response to ANPR, BLM received comments expressing various ideas concerning minimum production amounts and requirements ranging from no minimum production to a minimum rate of 1,000 barrels/day. BLM considers the minimum production requirement for 1,000 barrels/day too inflexible a standard because it does not allow for differences in shale quality and differences in extraction technology. A minimum annual production requirement would apply to every lease, and payments in lieu of production beginning with the 10th lease-year. The BLM would determine the payment in lieu of annual production, but in no case would it be less than \$4.00/acre. Payments in lieu of production are not unique and are requirements of other BLM mineral leasing regulations, as the BLM believes they provide an incentive to maintain production. A payment in lieu of production of \$4.00/acre for the maximum lease size of 5,760 acres equals a payment of \$23, 040/year.

Proposed Royalties. BLM would establish a royalty rate for all products that are sold from or transported off of the lease area. BLM recognizes that encouraging oil shale development presents some unique challenges compared to BLM's traditional role in managing conventional oil and gas operations. BLM has not yet settled on a single royalty rate for this proposed rule, but instead proposes two royalty rate alternatives in the proposed rule, and may also consider a third alternative, a sliding scale royalty rate.

BLM assumes that the market demand for oil shale resources based on the price of competing sources (e.g., crude oil) of similar end products is expected to provide the primary incentive for future oil shale development. Additional encouragement for development may be provided through the royalty terms employed for oil shale relative to conventional oil and gas royalty terms, but BLM recognizes that such incentives must be balanced against the objective of providing a fair return to taxpayers for the sale of these resources. The range of royalty options BLM initially examined through the ANPR process are summarized in **Table 5**.

⁴⁵ Federal Register, *Oil Shale Management - General*, Vol. 73, No. 142 / Wednesday, July 23, 2008 / Proposed Rules.

⁴⁶ Federal Register, *Commercial Oil Shale Leasing Program*, Vol. 71, No. 165 / Friday, August 25, 2006 / Proposed Rules.

Table 5. Proposed Options for Oil Shale Royalty Rates

Proposed Rates	Notes
12.5%	on the first marketable product
12.5%	on value of the mined oil shale as proposed in 1983
8% initial 1% annual increase 12.5 % maximum	on products sold for 10 years, similar to the rates established by the State of Utah in 1980
2% initial 5% maximum	production encouragement, infrastructure established
0%-12.5% Sliding scale	tied to time frames
0%-12.5% Sliding scale	tied to production
Sliding scale	tied to the of crude oil price
1% of gross profit before payout 25% of net profit after payout	based on old Canadian oil sands model
¢ / ton	proposed in the 1973 oil shale prototype program
% / Btu	as compared to crude oil

For comparison, the proposed standard lease terms for for oil and gas, tar sands, and coal are provided below.

Standard Federal Lease and Royalty Terms. Oil and gas in public domain lands are subject to lease under the Mineral Leasing Act of 1920, as amended (30 U.S.C. 181 et seq.) with certain exceptions.⁴⁷ All lands available for leasing are offered through competitive bidding, including lands in oil and gas leases that have terminated, expired, been cancelled or relinquished.⁴⁸ A lessee has the right to use so much of the leased lands as is necessary to explore for, drill for, mine, extract, remove, and dispose of all the leased resource in a leasehold subject to certain stipulations.⁴⁹ The maximum lease holding in any one state is limited to 246,080 acres, and no more than 200,000 acres may be held under an option. Alaska's lease limit is 300,000 acres in the northern leasing district and 300,000 acres in the southern leasing district, of which no more than 200,000 acres may be held under option in each of the two leasing districts. The annual rental for all leases issued after December 22, 1987, is \$1.50/acre or fraction thereof for the first five years of the lease term and \$2/acre or fraction for any subsequent year (**Table 6**). Generally, a 12½% royalty is paid in amount (royalty-in-kind) or value of the oil and gas produced or sold on mineral interests owned by the United States.⁵⁰ A 16⅔% royalty is paid on noncompetitive leases. In order to encourage the greatest ultimate recovery of oil

⁴⁷ 43 CFR 3100 Oil and gas Leasing.

⁴⁸ 43 CFR 3120 Competitive Leases.

⁴⁹ 43CFR 3101.1-2 Surface Use Rights.

⁵⁰ 43 CFR 3103.3-1 Oil and Gas Leasing Royalty on Production.

or gas, the Secretary of the Interior may waive, suspend, or reduce the rental or minimum royalty or reduce the royalty on a portion or the entire leasehold. For heavy oil leases producing crude oil less than 20° on the American Petroleum Institute (API) scale, the royalty may be reduced on a sliding scale from 12½% for 20° API to ½% for 6° API.⁵¹

Table 6. Federal Standard Lease and Royalty

	Lease Rate (\$/acre)	Lease Terms	Royalty (percent)
Federal Oil & Gas	\$1.50 to \$2.00	Competitive	12½
Federal Oil & Gas		Non-competitive	16⅔
Heavy Oil			12½ to ½
Tar Sands	\$2.00	10 years	12½
Coal surface	\$3.00		12½
Coal underground	\$3.00		8

In special tar sand areas, combined hydrocarbon, oil and gas, or tar sand leases are offered competitive bonus bidding.⁵² (The terms “tar sands” and “oil sands” are sometime used interchangeably, but here tar sands refers to resources in the United States, and oils sands to Canada.) If no qualifying bid is received during the competitive bidding process, the area offered for a competitive lease may be leased noncompetitively. Combined leases may be awarded, or leases may be awarded exclusively for oil and gas or tar sand development. Combined hydrocarbon leases or tar sand leases in Special Tar Sand Areas cannot exceed 5,760 acres. The minimum acceptable bid is \$2.00/acre. Special tar sands area leases have a primary term of 10 years and remain in effect as long as production continues. The rental rate for a combined hydrocarbon lease shall be \$2.00/acre/year. The rental rate for a tar sand lease is \$1.50/acre for the first 5 years and \$2.00/acre for each year thereafter. The royalty rate on all combined hydrocarbon leases or tar sand leases is 12½% of the value of production removed or sold from a lease.

Coal leases may be issued on all federal lands with some exceptions including oil shale.⁵³ Lease sales may be conducted using cash bonus — fixed royalty bidding systems or any other bidding system adopted through rulemaking procedures. The annual rental cannot be less than \$3.00 per acre on any lease issued or readjusted.⁵⁴ A coal lease requires payment of a royalty of not less than 12½% of the value of the

⁵¹ 43CFR 3103.4-3 Heavy oil royalty reductions.

⁵² 43 CFR 3140 Leasing in Special Tar Sand Areas.

⁵³ 43 CFR 3400 Coal Management: General.

⁵⁴ 34 CFR 3473.3-1 Coal Management Provisions and Limitations.

coal removed from a surface mine and a royalty of 8% of the value of coal removed from an underground mine.⁵⁵

Private Lease Terms. Although information on lease terms for privately held oil shale is unavailable, comparison can be made with terms for private and state-owned land above natural gas-producing shales; for example, the Marcellus and Barnett shales.⁵⁶ Bonus payments and royalties received by state and private landowners in West Virginia, Pennsylvania, New York, and Texas are shown in **Tables 7** and **8**. Rents are not included because nearly all of the information available reports on signing bonuses and royalties. Further, rents are often rolled into signing bonuses, and paid upfront or paid quarterly as a “delay rental.” Rents appear to be much less significant to small landowners who lease a few acres. On state and private leases, as with federal leases, rents would be paid until production commences, at which time royalties are paid on the value of production. All Marcellus shale lessors have shown significant increases in the amounts paid as signing bonuses and increases in royalty rates. But there are still several lease sales as reported by the Natural Gas Leasing Tracking Service, that record signing bonuses in the range of \$100 to \$200/acre because of greater uncertainty and less interest among natural gas companies and/or the lack of information among landowners on what the land is worth.⁵⁷

<http://wikileaks.org/wiki/CRS-RL34748>

⁵⁵ 43 CFR 3473.3-2 Royalties.

⁵⁶ Prepared by Marc Humphries, Analyst in Energy Policy, Congressional Research Service.

⁵⁷ *Natural Gas Leasing Offer Tracking*, Natural Gas Lease Forum for Landowners. [http://www.pagaslease.com/lease_tracking_2.php]

Table 7. Shale Gas Bonus Bids, Rents, and Royalty Rates on Selected State Lands

	Statutory Minimum or Standard Royal Rate	Royalty Rate Range	Bonus Bids (per acre)	Comments
West Virginia ^a	12.5%	-	-	No state shale gas leases
Pennsylvania ^b	12.5%	12.5-16%	\$2,500	In many cases bonus bids were in the \$25-\$50 per acre range as recent as 2002. A royalty rate of 12.5% was most common.
New York ^c	12.5%	15-20%	about \$600	Bonus bids ranged from \$15-\$600 per acre around 1999-2000 and most royalty rates were at 12.5%.
Texas	12.5%	25%	\$350-\$400 (Delaware Basin) \$12,000 (river tracts)	Bonus bids have been relatively consistent in recent times (within the past 5 years). Royalty rates were more common at 20%-25% about 5 years ago. Most state-owned lands are not considered to be among the best sites for shale gas development.

- a. Personal communication with Joe Scarberry in the WV Department of Natural Resources, October 2008.
- b. Personal communication with Ted Borawski in the PA Bureau of Forestry, who provided information on shale gas leases on both state and private lands, October 2008.
- c. Personal communication with Lindsey Wickham of the NY Farm Bureau and Bert Chetuway of Cornell University, discussed lease sales on state and private land, October 2008.

Table 8. Shale Gas Bonus Bids, Rents, and Royalty Rates on Private Land in Selected States

	Royalty Rates Range	Bonus Bids (per acre)	Comments
West Virginia ^a	12.5-18%	\$1,000-\$3,000	Bonus payments were in the \$5 per acre range as recently as 1-2 years ago. Royalty rates were 12.5%
Pennsylvania	17-18%	\$2,000-\$3,000	
New York	15-20%	\$2,000-\$3,000	
Texas	25-28%	\$10,000-\$20,000	Bonus bids were in the \$1,000 range around 2000-2001. Royalty rates were in the 20-25% range.

- a. Personal communication with David McMahon, Director of the WV Surface Owners Rights Organization, October 2008.

Conclusion and Policy Perspective⁵⁸

Shale oil is difficult and expensive to extract and has not competed well with conventional oil supplies in the past. The major barrier has been cost, but additional barriers are potential environmental damage during development, and the cost of refining and transportation from the interior western United States.

The recent spike in crude oil price has once again stirred interest in oil shale. As in the past, however, the rapid runup in prices (to a high of \$145/barrel) was soon followed by a rapid and precipitous drop in prices (\$64/barrel at the time of this writing). Although the major oil companies have reaped record profits, such price volatility discourages investment in contingent resources such as oil shale. Oil price volatility has produced patterns of boom and bust for oil shale, as seen in the interest in oil shale development in the early 1980s, followed by the cancellation of Exxon's \$5 billion Colony Oil Shale Project in 1982, and the cancellation of loan guarantees under the Synthetic Fuels Corporation.

Volatility in the price of oil affects all contingent or marginal hydrocarbon resources. After considerable investment in unconventional oil sand resources, Canadian producers have announced cutbacks in capital spending and are scaling back or cancelling plans for expansion altogether. While OPEC cuts oil output to prop up prices, the major and super-major oil companies continue to use an oil price of \$32/barrel for their business planning. In this climate, the development of oil shale seems difficult indeed. While oil shale development faces continuous

⁵⁸ With contributions by Gene Whitney, Energy and Minerals Section Research Manger, Congressional Research Service.

challenges, the exploration and production of conventional oil and gas grows steadily in the region.

The regional isolation of the massive oil shale deposits of western Colorado, eastern Utah, and southwestern Wyoming provides both opportunity and challenges for developing shale oil there. Shale oil is best used to produce middle distillate diesel and jet fuel, commodities in high demand in the region. Additionally, the oil and product pipeline infrastructure into and out of the region is limited, so moving shale oil to another region for refining is difficult, and importing refined product is equally difficult. This isolation provides an opportunity for shale oil as long as regional refining capacity is available.

An additional point of uncertainty is introduced by the government's changes in rules. A recent spending moratorium on finalization of the commercial leasing rules had added considerable uncertainty to oil shale development. Without a final rule, no developer could attract investors or plan for full development of the oil shale resources. The subsequent rescission of the spending moratorium now allows final rule making to be completed before the 111th Congress convenes. In the meantime, much of the land surface that might be leased for oil shale development has already been leased for conventional oil and gas development, adding further complication to the leasing process.

The oil shale boom-bust cycles are part of the cause of, and also the result of, an exodus of skilled labor and technical talent from the Rocky Mountain region. Whole communities grew up around the oil shale development of the 1980s, only to disappear again when the projects stopped. The uncertainty surrounding the viability of oil shale development, combined with competition from the conventional oil and gas industry and from other regions, makes it difficult to recruit and keep skilled labor for oil shale development.

Finally, the draft leasing rules are silent on CO₂ emission requirements; and yet oil shale development may be accompanied by troublesome emission of CO₂ as a result of the retorting process. Full analysis of CO₂ emissions from oil shale development must wait until the research and development phase of shale oil production is completed. Such an analysis would probably be part of the environmental impact statement required for permitting commercial development. Canada's oil sands industry has demonstrated that emission concerns may be addressed over time as technology develops.

Oil shale, along with other unconventional and alternative energy sources, will continue to struggle as long as oil prices are volatile. Sustained high oil prices will likely be required to motivate oil shale developers to make the massive investments required for ongoing production of oil from shale. Although the quantities of hydrocarbons held in oil shale is staggering, its development remains uncertain.