Assessment of Plans and Progress on US Bureau of Land Management Oil Shale RD&D Leases in the United States

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Purpose

This paper describes the original plans, progress and accomplishments, and future plans for nine oil shale research, development and demonstration (RD&D) projects on six existing RD&D leases awarded in 2006 and 2007 by the United States Department of the Interior, Bureau of Land Management (BLM) to Shell, Chevron, EGL (now AMSO), and OSEC (now Enefit American, respectively); as well as three pending leases to Exxon, Natural Soda, and AuraSource, that were offered in 2010. The outcomes associated with these projects are expected to have global applicability.

I. Background

The United States is endowed with more than 6 trillion barrels of oil shale resources, of which between 800 billion and 1.4 trillion barrels of resources, primarily in Colorado, Wyoming, and Utah may be recoverable using known and emerging technologies. (Figure 1[1]) These resources represent the largest and most concentrated oil shale resources in the world. More than 75 percent of these resources are located on Federal lands managed by the Department of the Interior.

BLM is responsible for making land use decisions and managing exploration of energy and mineral resource on Federal lands. In 2003, rising oil prices and increasing concerns about the economic costs and security of oil imports gave rise to a BLM oil shale research, development and demonstration (RD&D) program on lands managed by BLM in Colorado, Utah, and Wyoming.

The purpose of the program was to address uncertainties concerning the economic and technical readiness of oil shale technologies, and potential environmental and socio-economic impacts of oil shale development on affected communities. The scope of the program was to lease small tracts of Federal lands to privately owned energy companies for the purpose of conducting long term oil shale RD&D.

In 2005, the United States Congress passed and the President signed into law the 2005 Energy Policy Act (Pub.L. 109-58). This Act incorporated BLM's RD&D program into subsection 369 pertaining to unconventional resources.

Since then, BLM has conducted two rounds of RD&D leasing. In the first round, which was completed in 2007, six leases were awarded to four different lessees; lessee RD&D activities have been underway since then. The second round was initiated in 2010, which resulted in a determination to award three leases to three lessees. The second round award process is still in progress.

The main criteria for awarding RD&D leases were:

- The potential for advancing technological understanding and developing effective technologies.
- The potential for economic viability.
- The potential for environmental and social sustainability.

A summary of BLM RD&D leasing activities is provided in Table 1 below. Table 2 provides a summary of the terms of the RD&D leases for each of the two rounds of leasing. Table 3 provides a summary of the projects, ongoing and proposed, for all nine BLM RD&D leases.

Table 1: Summary of Major BLM Oil Shale RD&D Lease Activities[2]	
Date	**BLM Action**
2003	BLM initiates review of Oil Shale leasing.
November 2004	BLM seeks public input on the terms for small tract (40 ac) RD&D leasing in CO, WY, & UT.
June 2005	BLM solicits nominations of parcels for RD&D leasing in CO, UT, and WY (first round).
August 2005	Energy Policy Act of 2005 is enacted.
September 20, 2005	BLM announces receipt of 19 nominations for 160-acre leases with a 4,960 acre preference right to convert to a 20 year commercial lease after demonstration.
January 17, 2006	BLM accepts 8 proposals from 6 companies for further consideration: NEPA Environmental Assessments (Eas) result in Finding of No Significant Impact
December 2006 to June 2007	Awards six RD&D leases to: Chevron Shale Oil Co.; EGL Resources Inc (now AMSO); Oil Shale Exploration Company (now Enefit); and Shell Frontier Oil & Gas (3 leases)
January 15, 2009	BLM Federal Register Notice (74 FR 2611) calls for nominations for a second round of RD&D leasing;
February 27, 2009	BLM withdraws 1/15/09 Call for Nominations and requests Public Comments (74 FR 8983) on RD&D leasing.
November 3, 2009	BLM solicits nominations for RD&D leases in CO, UT, WY (second round)
January 2010	BLM selects three nominations for further consideration, pending BLM NEPA analysis: ExxonMobil (CO); Natural Soda Holdings (CO); and AuraSource (UT).

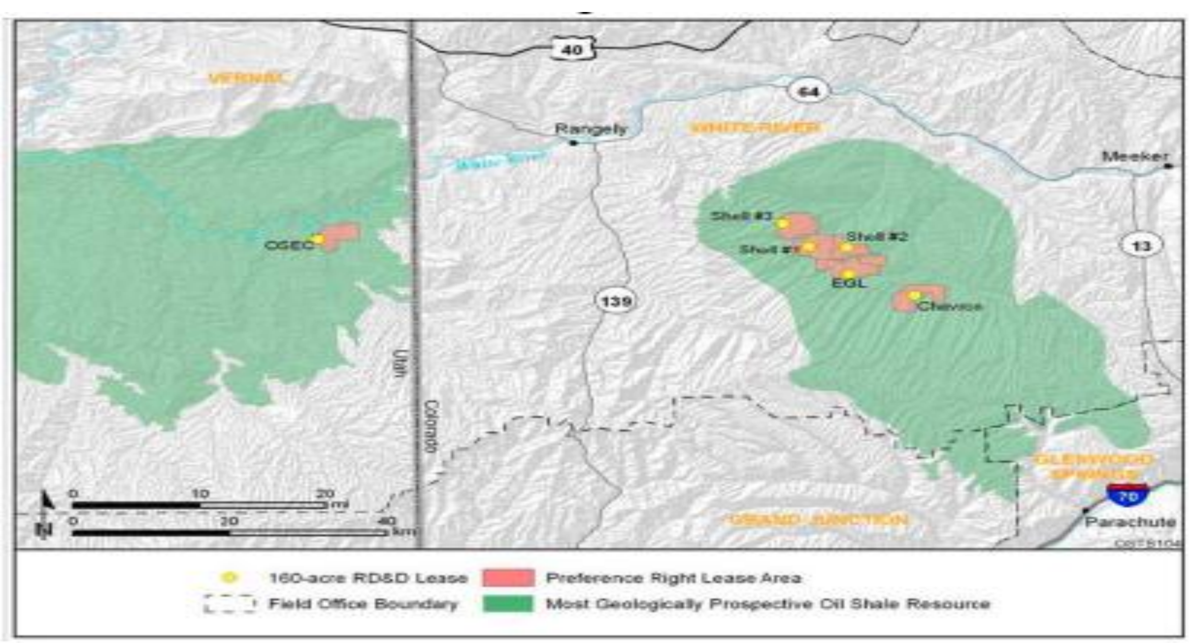
Table 2: 1st Round and 2nd Round RD&D Lease Terms		
Term	**1st Round**	**2nd Round**
RD&D Lease Size (Ac)	160 ac	160 ac
Preference Area (Ac)	4,960 ac	480 ac
Application Fee ($)	$2,000	$6,500
Lease term	10 years, with 5 yr extension	10 years, with 5 yr extension
Diligence Requirements	Based on Plan of Operations approved by BLM	Plan of development within 9 months State & local permits within 18 months Infrastructure deployment in 24 months Quarterly progress reports
Rental	$.050/ac Mineral Lease Act / $2.00/ac under EPAct'05	$.050/ac Mineral Lease Act / $2.00/ac under EPAct'05
Royalty	Waived during RD&D period	Waived during RD&D period
NEPA	Completion of Environmental Assessment (EA)	Additional environmental studies required
Selection criteria	Potential to advance technology understanding Potential for economic viability Potential for environmental and social sustainability.	Same as 2005 plus: Information about water, GHG emissions & carbon capture, and minimization of surface & wildlife impacts.
Other	Addenda allow lessees to choose which regs govern conversion if new commercial lease regs are issued.	Rents and royalties to be paid per regulations in effect at time of conversion Limit 1 application per company

Table 3. Summary of BLM RD&D Projects			
Company / Lease Date	**Setting**	**Location**	**Technology**
Projects on Six First Round Active Leases (Awarded 2006-2007)			
EGL Resources Inc (now AMSO) 12/15/06	In-Situ	Rio Blanco Co. CO; Piceance Basin	Originally: Heated gas injection Current: - Conduction, Convection, Reflux (CCR) process using thermo-mechanical fracturing and boiling oil
Chevron Shale Oil Co. 12/15/06	In-Situ	Rio Blanco Co, CO; Piceance Basin	Rubblization of formation followed by heated gas injection
Enefit American Oil (formerly OSEC) 6/21/07	Surface	Vernal, UT / Uintah Basin	Mining w Surface retorts: Original Alberta Taciuk Processor (ATP) Considered Petrosix VSR Current: Enefit 280
Shell Frontier Oil & Gas (Site 1) 12/15/06	In-Situ	Rio Blanco, CO, CO; Piceance Basin	ICP w/ downhole encased heaters
Shell Frontier Oil & Gas (Site 2) 12/15/06	In-Situ	Rio Blanco, CO, CO; Piceance Basin	Hot water leaching of Nahcolite w/ICP
Shell Frontier Oil & Gas (Site 3)	In-Situ	Rio Blanco, CO, CO; Piceance Basin	E-ICP w bare wire electric heaters
Projects on Three Second Round Pending Leases (11/09Applications)			
Aura Source	Surface	Vernal, UT; Uintah Basin , UT	Surface mining / Chinese surface retort
ExxonMobil	In-Situ	Rio Blanco Co, CO; Piceance Basin	Electric heating with charged conductive material (ElectroFrac)
Natural Soda Holdings	In-Situ	Rio Blanco Co, CO; Piceance Basin	Chemical leaching with natural lift

II. Projects on Six First Round Active Leases

There are six active RD&D leases on BLM lands, as shown in Figure 2.[3] Five of the six active RD&D projects on BLM leases (all in Colorado) seek to demonstrate the technical, environmental, and economic viability of in-situ (subsurface) heating of oil shale to convert kerogen to hydrocarbon liquids and gases and produce them to the surface The sixth is a surface retorting project in Utah

Figure 2: Locations of the Six Active RD&D Tracts and Associated Preference Right Areas



A. American Shale Oil LLC (Formerly EGL Oil Shale LLC)

1. Original Plans

Resource: On December 15, 2006, BLM issued a RD&D lease to EGL Oil Shale LLC to test the use of an in-situ retorting technology in a 300-foot-thick section of the Mahogany and R-6 Zones in the Green River Formation in the Piceance Basin.[4] (Figure 3) The tract is located approximately 27 miles northwest of Rio Blanco, CO, on a ridge at elevations between 6,795 and 6,965 feet above sea level. The shale in these zones is estimated to have a recoverable oil content of approximately 25 gallons/ton.[5] EGL Oil Shale LLC was subsequently sold to IDT Corporation and the company was renamed American Shale Oil, LLC. The company is now owned 50/50 by Total and Genie Energy. In October 2011, Genie was spun off from IDT and is now a separately traded public company (NYSE: GNE).[6,7] Genie Energy is the operating partner through the demonstration phase of the AMSO LLC oil shale RD&D project.

Proposed Technology and Approach: In its original proposal, EGL (hereafter referred to as AMSO) proposed to test the potential of a closed-loop passive heating technology. The approach envisioned a closed piping system through which a heated fluid would be circulated to heat the formation to pyrolysis temperature. The fluid would be heated at the surface, using natural gas or propane in the RD&D period and eventually produced hydrocarbon gases. The heating pipes would be drilled vertically from the surface to the base of the R-6 formation, then horizontally through the formation and then rise vertically back to the surface in a "U" shape. The produced hydrocarbons would be brought to surface using multi-lateral "spider" production wells. The developers anticipated the need to dewater the heating zone to prevent groundwater contamination.

The developers anticipated a six to seven year work program summarized in Table 4 to: conduct lab work, bench tests and modeling; investigate drilling and completion methods; and investigate various forms of heating. This would be followed by a six-year period to plan and complete a commercial demonstration.

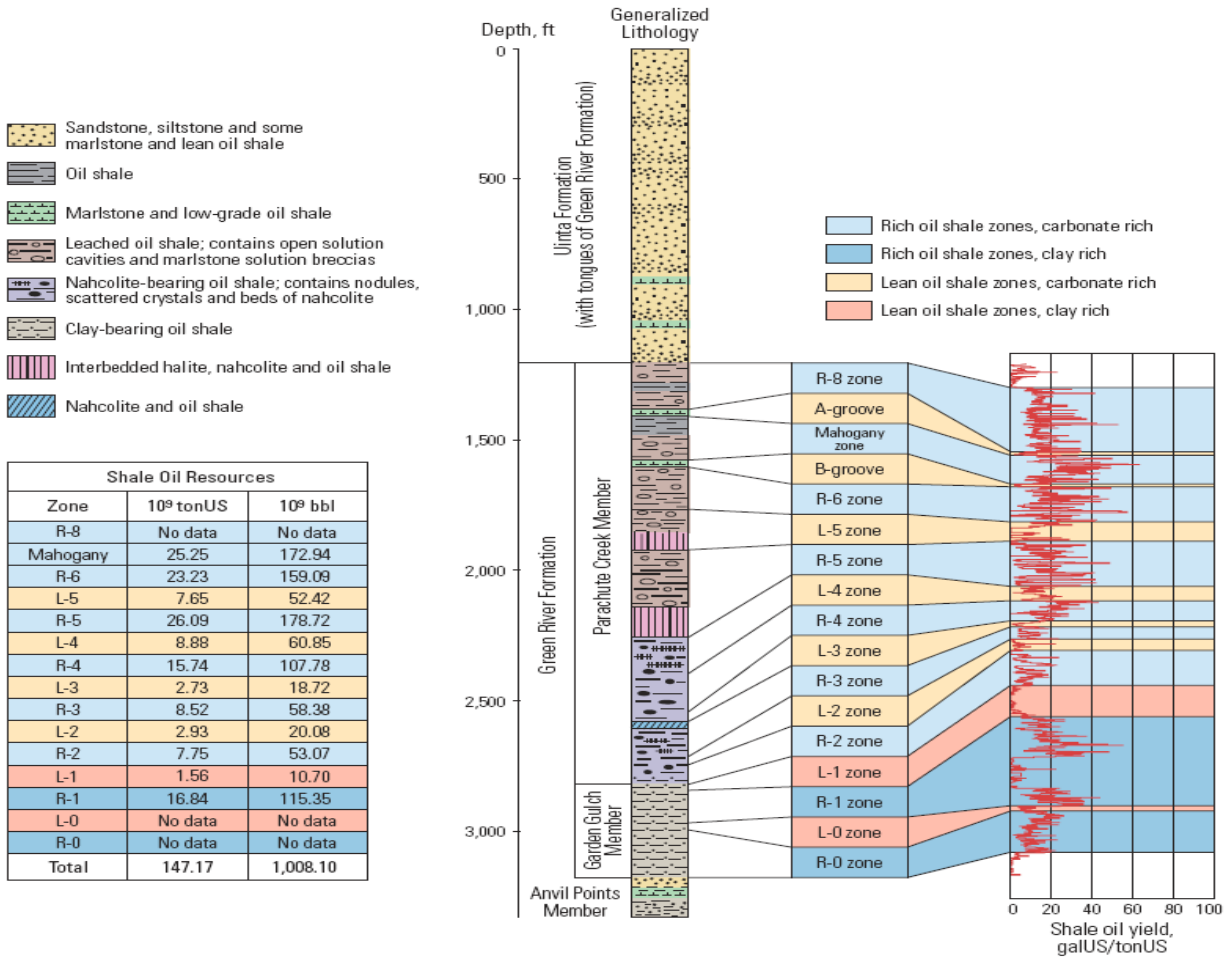
Table 4: Initial EGL RD&D Plan, Objectives and Milestones (As Proposed)

Six Planned Phases	Research Goals and Field Objectives
Analysis (01/06 – 06/06)	• Operations Plan and Environmental Assessment
Research (01/06 – 06/07)	• Planning; lab tests; field studies; field test design; monitor well tests
Field Testing (06/07 – 12/15) • Resource characterization • Energy delivery systems • Product recovery systems • Reservoir hydraulic fracturing and other stimulation methods • Optimization of energy recovery • Operations and environmental protection/reclamation	• Directional drilling techniques for injection wells below R6 • Methods of placing heat injection pipe in wells & securing casings • Methods for allowing thermal expansion of injection piping system • Directional drilling for "spider" production wells – (4 spider wells) • Demonstration of hydraulic fracturing to establish fracture zone between injection holes and production zone for flow and refluxing of hydrocarbons. • Methods of placing gravel or sand in the spider wells to maintain a zone in which reflux of hydrocarbons can occur. Design of surface condensers, tanks, separators, heater-treaters, etc. • Design of surface condensers, tanks, separators, heater-treaters, etc.
Commercial Design (06/12 – 06/13)	
Commercial Demo (06/13 – 06/18)	
Comm. Production (06/15 –6/20)	

2. Progress and Accomplishments

Since the submission of the initial Plan of Operations, AMSO has made two major modifications to its RD&D program as a result of its preliminary research and analysis phases. These major changes relate to the target formation for initial pilot testing and significant modifications to the technology to employ a downhole heater. An amended Plan of Operation has been approved by the BLM.

Figure 3: Oil Shale Bearing Formations and Aquifers in the Piceance Basin



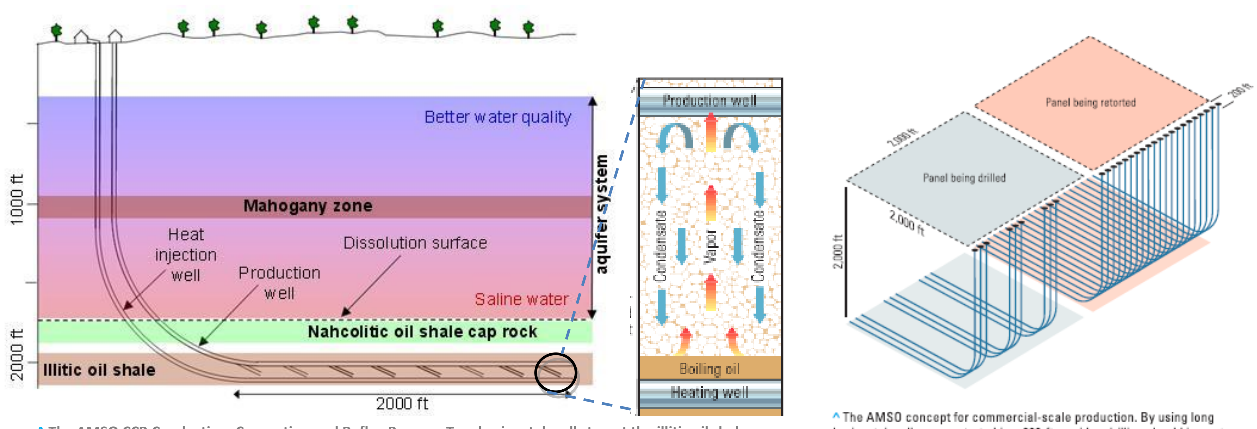
Shale Oil Resources		
Zone	10⁹ tonUS	10⁹ bbl
R-8	No data	No data
Mahogany	25.25	172.94
R-6	23.23	159.09
L-5	7.65	52.42
R-5	26.09	178.72
L-4	8.88	60.85
R-4	15.74	107.78
L-3	2.73	18.72
R-3	8.52	58.38
L-2	2.93	20.08
R-2	7.75	53.07
L-1	1.56	10.70
R-1	16.84	115.35
L-0	No data	No data
R-0	No data	No data
Total	147.17	1,008.10

New Target Formation for Development: Concerns about groundwater intrusion and protection of groundwater quality in the R-6 zone and nearby aquifers led to a major decision to target a deeper oil shale formation. The illite shale resources lay below the L-3 saline water bearing zone in the R-1 and R-0 zones and are isolated from ground water intrusion by a Nahcolite-rich oil shale layer that serves as a caprock. This target zone is the depositional equivalent of the Garden Gulch member of the Green River Formation (Figure 3).[8] This change will eliminate the requirement for a freezewall or other methodology to prevent groundwater intrusion during the RD&D phase. Water bearing zones above the target zone will be isolated using conventional well technologies. AMSO intends to demonstrate the isolation of the retort zone by the intervening nahcolitic oil shale.[9]

Modification to Proposed In-Situ Heating Technology: The developers have made a significant modification to the proposed heating technology. AMSO observed that in nahcolite recovery operations in the Green River Formation "a thermally fractured zone can propagate at least 100 feet from the heating well." "Free-volume for continued spallation is created by removal of the nahcolite."[10] AMSO hypothesized that by analogy the same effect could be achieved in oil shale operations by pyrolysis of the embedded kerogen.[11] This thermo-mechanical fracturing eliminates the need for hydraulic fracturing of the shale formation before heating. Rather than using surface equipment to heat the circulated fluids, a downhole heater, fueled by produced hydrocarbons will be used. This technology reduces heat loss between the surface facilities and the target formation and also protects the quality of the intervening groundwater.

The new "Conduction, Convection, Reflux" or "CCR" process combines the use of horizontal wells heated downhole (via downhole burner) and other horizontal or vertical wells, which provide both heat transfers through refluxing of generated oil and a means to collect and produce the oil. Two parallel wells are drilled vertically to the base of the formation and then laterally in an "L" shape. The lower well is the heater well and the upper well gathers the produced gases and vapors for production to the surface. The only fluids to be injected are recycled fractions of the produced oil in order to optimize the properties of the in-situ oil pool for refluxing. In this configuration, AMSO expects to achieve an energy return on investment of 4 to 5 times the energy invested. The process is expected to use less than one barrel of water per barrel of oil produced. In a commercial scale application, the facility is like to deploy array of horizontal wells 30 feet apart going 2,000 feet long, as shown in Figure 4. (Note: In the test area, the water table is about 650 ft, and the salinity is low, slightly increasing down to the nahcolitic oil shale.)

Figure 4. Conceptual Views of AMSO's CCR Technology



^ The AMSO CCR Conduction, Convection and Reflux Process. Two horizontal wells target the illitic oil shale below a nahcolitic caprock. The heating well is at the base and the production well is at the top of the shale (left). As heat causes the kerogen to decompose, the lighter products rise and condense (right), efficiently heating a large volume of rock. Hydrocarbon fluids are produced via the production well.

^ The AMSO concept for commercial-scale production. By using long horizontal wells concentrated in a 200-ft corridor, drilling should impact less than 10% of the surface area. While one 2,000-ft square panel is being heated and converted in situ, wells will be drilled in an adjacent panel. The operation is projected to produce about 1 billion bbl of shale oil over a 25-year period.

AMSO's revised schedule of phases and major activities, reflecting its modified Plan of Operations, is shown in Table 5.

Figure 5: AMSO's RD&D and Commercialization Schedule (As of October 2011)

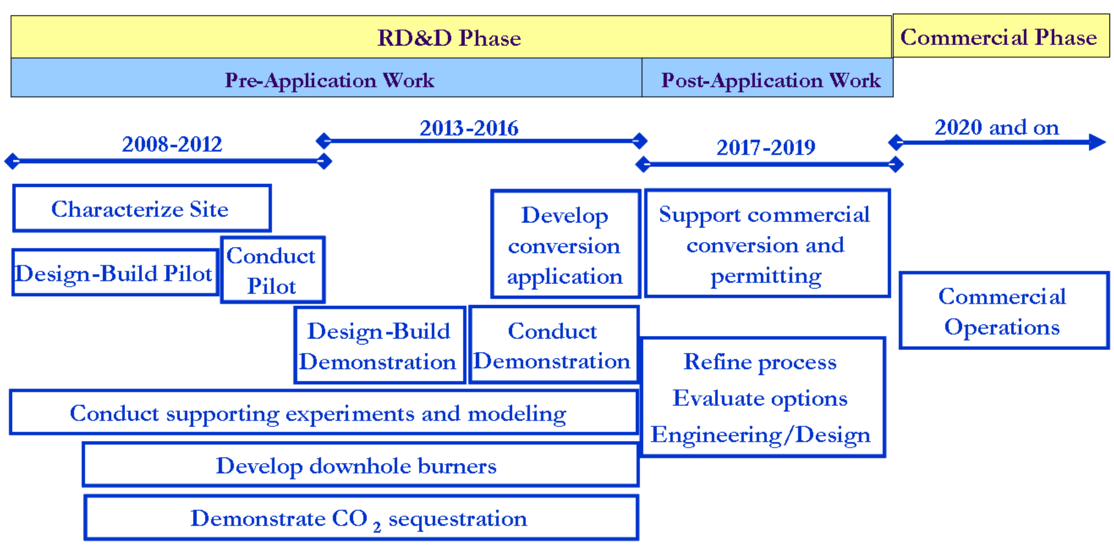


Table 5: AMSO – In-Situ Project in Colorado (Lease Issued 01/01/07)

Revised Plan Elements	Progress Relative to Revised Plan
A. R&D Goals **Phase I: Site Characterization and Baseline** • Determine hydrology baseline • Determine resource geology and geochemistry • Develop a process model **Phase II:** • Conduct one or more retort tests to refine AMSO' understanding of the process • Improve process modeling • Demonstrate lease conversion criteria **Phase III:Transition to Commercial Lease** • Continue small scale operations to enhance process and reclamation technologies • Conduct engineering analyses to design a commercial process	• Established baseline water chemistry at three depth intervals in wells surrounding the retort area • Determined oil shale grade and mineralogy as a function of depth through the entire Green River formation • Conducted pyrolysis and rock mechanics experiments • Developed process models with varying degrees of completeness • Developed a downhole electric heater for the pilot test. • Conducted small-scale experiments on downhole burners and carbon sequestration
B. Milestones & Activities	
1. Characterize site by 2010	• Completed 2010
2. Design Pilot by 2009	• AMSO's initial design for surface heating was scrapped and a new downhole heater (CCR) was designed and tested; target zone shifted from R-6 to R-1 • Design of surface and downhole facilities was completed in 2010
3. Conduct Pilot by 2011	• Planned field pilot by 2012 • Progress delayed by additional engineering and permitting issues • All permits have been received • Plan of Development for Pilot approved • Pilot facilities are installed • Heating initiated, stopped, to resume late Spring 2012
4. Start design semi-works by end of 2011	• Will depend on pilot plant results • Additional pilot could be required based on outcome
5. Start semi-works by end of 2014	• May still be on track, pending pilot
6. Develop downhole burners by end of 2014	• Progress in small-scale lab tests
7. Demonstrate CO_2 sale or sequestration by end of 2014	• Laboratory experiments in progress

3. Current Status and Future Plans

Current Status (As of April 2012):

- All of the analysis phase operations planning and environmental assessment work is complete.
- Site characterization and baseline establishment activities were completed by drilling and studies.
- All BLM permits had been received to allow site development and pilot testing.
- Surface facilities for pilot plant operations were constructed, instrumented, and commissioned.
- Six tomography wells were drilled.
- Heater and production wells were drilled and near completion.
- Instrumentation was designed, constructed, and installed in heater, monitor, and production wells.
- Cementing and testing of the production well casing was completed.
- Problems identified with downhole equipment during an initial test in late 2011 delayed initiation of the full pilot test.

Next Steps:

The pilot facility is expected to begin heating the formation in late Spring 2012.[12]

- The pilot test will measure the efficiency and robustness of transferring heat into a boiling oil pool and determine the need for surface refluxing.
- Multi-week testing segments at different pressures will determine the effect of pressure on oil properties and rates of heat penetration as a function of retort size.
- Geophysical and temperature measurements will measure relative directional growth rates.
- Additional experiments will be defined based on the results of the initial pilot testing.

Retort RD&D and Commercial Conversion Application (2009 - 2016): Between now and 2016 AMSO will heat the reservoir and test the performance of its CCR technology while measuring environmental impacts relative to the established environmental baseline and early engineering-based estimates of surface, subsurface and other impacts. Based on the results of the pilot, AMSO will build and operate a pilot plant and subsequently expects to build larger scale production facilities that will demonstrate the commercial viability of its process. At the conclusion of this phase, upon meeting all lease requirements for commercial conversion, AMSO plans to apply for a commercial lease.

Transition from Commercial Conversion Application to Commercial Lease Issuance: A third phase will include continued R&D at this site that would be conducted as needed to enhance the conversion to commercial operations, including improving process and reclamation technology. AMSO expects that the primary commercial operations will be started several miles from the RD&D Tract, but some small-scale commercial operations may be conducted at the RD&D tract. Once RD&D is complete, facilities not required for commercial operations will be decommissioned and the affected areas will be reclaimed.

B. Chevron Oil Shale Company

1. Original Plans

Chevron Oil Shale's BLM RD&D lease is located closer to the center of the Piceance Basin, southeast of the other four active RD&D leases, in Section 5/T3s/R97W).[13,14] The proposed resource target is the oil-rich Mahogany zone, an oil shale deposit that is approximately 200 feet thick.[15] Chevron estimates that the deposit has an estimated 280 million barrels in place (using 35 gallons per ton minimum cut-off grade). The estimated volume of recoverable resources is dependent on the technology and is as yet unknown.[16]

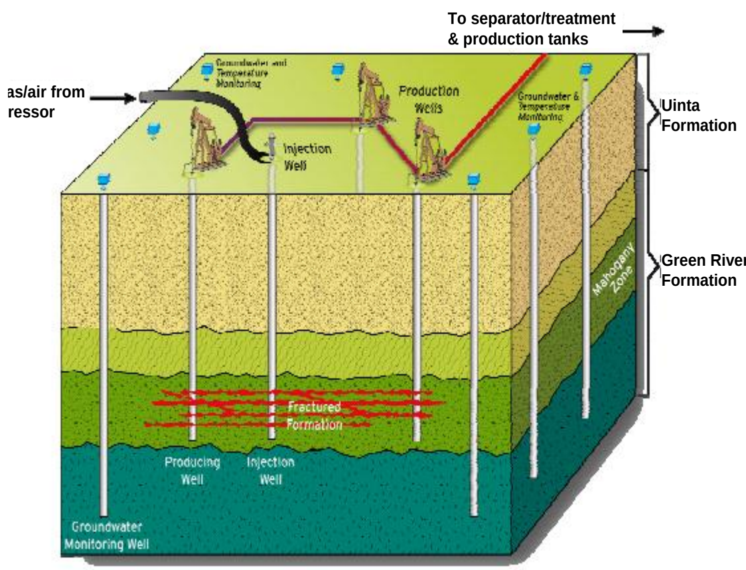
Proposed Technology

Chevron proposed to test and 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 approach is aimed at reducing the environmental footprint and water and power requirements compared to past shale oil extraction technologies. Chevron plans to target shale beds capped by impermeable geological formations that can permanently prevent groundwater from seeping through the contaminated rubble.[17]

In contrast to steady heating approaches being developed by Shell and AMSO, Chevron is working with scientists from Los Alamos National Laboratory and the University of Utah to investigate a variety of methods to use chemistry to produce oil from the rock. Thus far, the preferred technology appears to be Chevron's CRUSH (Chevron's Technology for the Recovery and Upgrading of Oil from Shale), which involves rubblizing rich swaths of shale with precisely controlled chemical explosions before injecting a solvent (such as super-critical carbon dioxide) to separate the kerogen from the shale. Once dissolved by the chemical reaction, the energy-rich hydrocarbons in the kerogen could be pumped out using a conventional production well. (Figure 6)

Chevron expects CRUSH to use less energy and water than other in situ methods. The process also sequesters CO_2 in-situ reducing greenhouse gas emissions. Chevron expects CRUSH to be net "producer" of water.[18] Upon completion of production in a zone, in-situ combustion of the residual carbon is induced by hot air injection. This will consume immobilized or un-extracted hydrocarbons. The hot combustion gases will be used as a heat source for adjacent un-retorted areas.[19]

Figure 6. Chevron's CRUSH Technology



RD&D Approach and Activities

Chevron's RD&D goals are to:

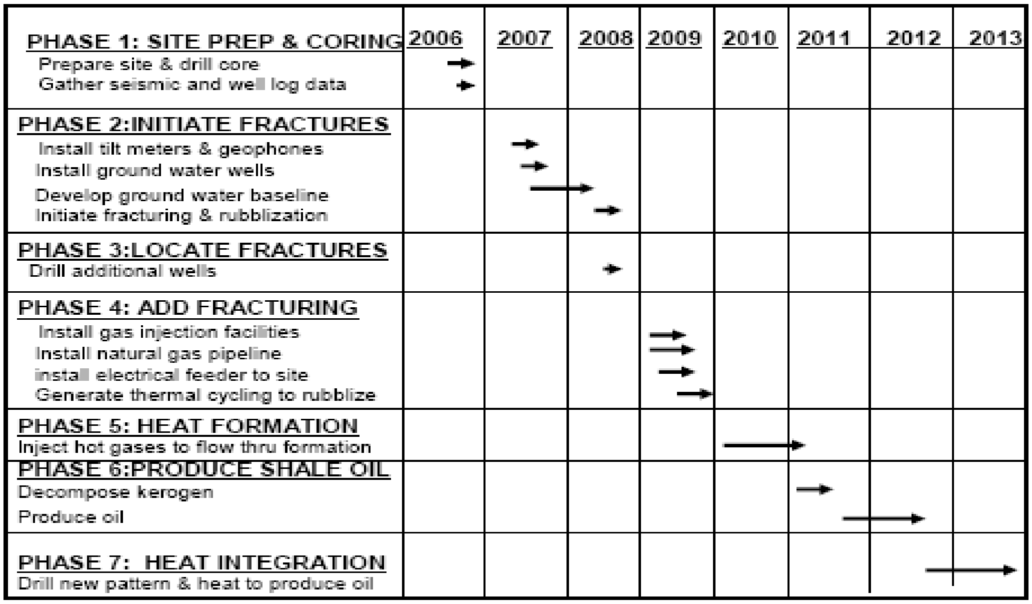
- Maximize use of potential resources within the oil shale formation without disrupting the surrounding environment.
- Demonstrate feasibility of in-situ combustion of the residual organic material left in the formation after the initial kerogen heating and recovery process to achieve 90+% recovery of the total energy in the target zone of the formation.
- Evaluate processes to recover the waste heat in the liquids produced from the formation. (Both the produced water and shale oil will contain residual heat as these streams leave the oil / water separator.)
- Conduct additional research into determining if byproducts from the shale oil can be economically recovered. (Both minerals (multi-minerals) and chemical by products will be considered.)
- Conduct a pilot test of two 5 spot patterns (each pattern uses 4 injectors, 1 producer).[20]

Schedule and Milestones

Chevron's proposed a research and pilot testing plan consisting of seven distinct phases (Figure 7) that would entail drilling wells into the formation and applying a series of controlled horizontal fractures within the target interval to prepare the production zone for heating and in-situ combustion.

- **Phase 1:** Analyze core from 2,800 feet (mahogany zone). Upon completion convert the well into a ground water monitoring well (with others) to establish baseline conditions, and begin a groundwater and aquifer characterization program.[21]
- **Phase 2:** Drill well to test Chevron's fracturing method. Additional wells will then be drilled for the installation of 20-25 tilt meters and 2 geophones to monitor the formation during the fracture process. The initial well will be turned into an injector at the end of the phase.[22]
- **Phase 3:** Drill 1-4 additional fracture test well to confirm results, each 100 feet apart. [23,24]
- **Phase 4:** The shale will have additional fracturing through thermal cycles of gas (CO2) injections into the formation, testing the flow between the connected fracture wells. [25,26]
- **Phase 5:** Slowly heat formation with pressurized gases (CO_2) that are reheated and recycled into the formation. Formation heating is supported by Radio-frequencies through inserted rods, spaced many meters apart. [27,28]

Figure 7. Chevron's Technology Development Schedule for BLM Lease



- **Phase 6:** The heating of the shale formation will continue to the point where the kerogen begins to decompose.[29] The oil and water will be separated, stored, and trucked to pre-tested processing facilities.
- **Phase 7:** Process is repeated with the drilling of a new well pattern adjacent to the first. This will include pressuring air into the depleted portion of the formation to create in situ combustion of the residual organic material remaining in the oil shale, which is used in the heating of the newly fractured zone. CO_2 is recovered for re-use. [30,31]

2. Progress and Accomplishments

Chevron's progress in implementing its planned R&D activities on its BLM lease are listed below ans summarized in Table 6.

- In 2006, Chevron teamed up with the Los Alamos National Laboratory to help in the simulation and modeling of its oil shale research.[32]
- Analyses conducted by the Lawrence Livermore National Laboratory estimated potential CO_2 emissions to be 230 kg/bbl and estimated CO_2 mitigation to cost $6.90/bbl.
- In 2007 Chevron presented analytical results of the mineralogy of the site to the Colorado School of Mines Oil Shale Symposium; geological and hydrological tests continued.[33]
- By 2009 Chevron had performed geological and hydrological tests on the RD&D site.
- In 2011, Chevron reported that it had drilled, logged and cased one core hole; completed core studies and geological tests; drilled 15 ground water monitoring wells, and performed various low temperature recovery tests.[34] Chevron was continuing to analyze cores obtained from its Federal core hole 397-5-1. Chevron was also continuing to process crosswell tomography data to better understand rock mechanics, fracture characteristics and potential anisotropy, and was developing a basin wide hydrology model.

Table 6: Chevron – In-Situ Project in Colorado (Lease Issued 01/01/07)

Plan Elements	Progress Relative to Plan
A. Research Goals • Recover 90+% of total energy in target zone by in-situ combustion of residual organic matter after pyrolysis • Recovery and use of waste heat from produced fluids (oil; water) • Economic recovery of byproducts (mineral and chemical)	• Chevron testing processes for efficient heating, heat recovery, and heat transfer, and production of hydrocarbons and byproducts
B. Milestones and Activities	
1. Site Prep & Coring by EOY 2006 (2007)	• Didn't receive lease until 1/1/07 • Completed 2010
2, Initiate Fractures by EOY 2008 (2009) (geophones, monitoring wells, groundwater baseline; initiate fracturing)	• Geological and hydrological tests continued through 2009, • Reported this activity complete in 2011
3. Locate fractures by drilling more coreholes: EOY 2008 (2009)	• Crosswell tomography ongoing to understand rock mechanics and fracture characteristics ongoing -- Not clear whether completed as of 10/11
4. Additional Fracturing: gas injection facilities; gas pipeline; electric feed; begin thermal cycling to rubblize by EOY 2009 (2010)	• May be off schedule by 1 year or more;
5. Heating the Formation: Hot gas injection into formation by Early 2011 (2012)	• Technology development underway at Chevron labs and at LANL • Chevron says some low-temperature heating tests have been conducted, but not clear whether this was done in the lab or in the formation • Unclear whether the proposed 2 5spot patterns have been drilled. Does not appear to have been initiated as of 10/11 • May be off schedule by 1 year or more
6. Produce Shale Oil – Expected by end of 2012 (2013)	
7. Heat Integration: Drill new pattern to heat/ produce oil (EOY 2013 (2014)	• Progress unknown

3. Future Plans

Next Steps

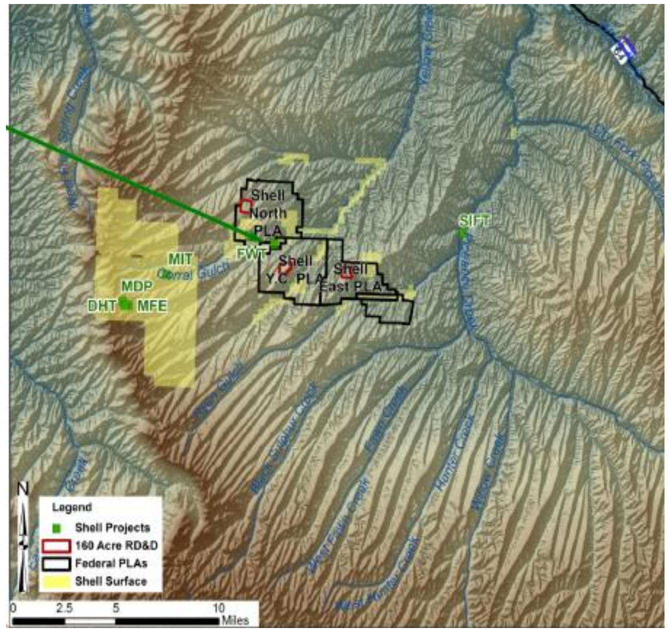
Chevron has taken a long term approach to oil shale with a budgeted, but mostly part-time, research team dedicated to enhancing the technology to commercialization.[35]

In March 2012, Chevron announced that while its research activities had yielded new information and valuable insights, the company would discontinue lease activities and divest its BLM lease. It is not yet clear whether the lease will be relinquished back to BLM or transferred to another operator.

C. Shell Frontier Oil & Gas Company (3 Leases)

1. Original Plans

Figure 8. Shell RD&D Leases and Project Sites



On December 15, 2006, the BLM issued three (3) RD&D leases to Shell Frontier Oil and Gas to test and demonstrate three variations of Shell's "In-Situ Conversion Process" (ICP). The three lease sites are adjacent to one another in the northwest portion of the Piceance Basin, as shown in Figure 8. The Shell lease sites contain high grade oil shale resources that are estimated to yield more than 25 gallons/ton of shale as well as other valuable minerals, including Nahcolite. Research and pilot testing at Sites 1 and 3, containing 300 million and 274 million barrels of oil equivalent (BOE), respectively, will target resources in the R-2 through R-7 zones in the Parachute Creek member of the Green River Formation, as shown in Figure 3 above. Work at Site 2, containing some 356 million barrels, will target the R-3 through R-7 zones.

Proposed Technology and Approach

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. All three of the proposed research and pilot test projects involve the application of the Shell In-Situ Conversion Process (ICP).

Figure 9. Shell In-Situ Conversion Process (ICP)

In this process, the target zone is isolated from groundwater intrusion (where necessary) by construction of a freezewall or by natural geologic containment. Downhole heaters are inserted in heater holes drilled to the base of the target formation and the target resource is slowly heated until embedded kerogen is converted to hydrocarbon gases and liquids. Naturally occurring fractures and those created by the heating process facilitate resource heating and the communication of produced liquids and gases to production wells. (Figure 9)

Oil Shale Test at Site 1: Shell proposed to conduct an Oil Shale Test (OST) project to test the in-situ extraction process components and systems, and to demonstrate the commercial feasibility of extracting hydrocarbons from oil shale. This test would employ the same cased electric heaters that Shell has used in ICP tests on its private lands. Once the hydrocarbons have been produced, the subsurface area will be reclaimed by flushing the heated zone with water, allowing the freezewall to thaw, plugging and abandoning the wells, and decommissioning and removing surface facilities.

ICP Nahcolite Test at Site 2: Shell proposed to conduct an In-situ Conversion Process (ICP) test that would demonstrate the technical feasibility of combining conventional Nahcolite solution mining (using hot water) and extraction methods with the ICP hydrocarbon extraction technology.[36]

E-ICP at Site 3: Shell proposed to conduct an electric-ICP (E-ICP) or advanced heater technology test to assess an innovative heater technology concepts for in-situ heating. 1,950 foot long bare electrode heaters concentrating heat output in the bottom 1000 feet could reduce well costs, improve energy efficiency, and make more Piceance Basin oil shale resources commercially viable.[37]

Research Goals

The initial RD&D goals proposed by Shell for each of these projects are summarized in Table 7, below.[38]

Table 7: Shell RD&D Goals for Three BLM Oil Shale Leases

RD&D Goals	Site 1: Oil Shale Test	Site 2: ICP / Nahcolite	Site 3: E-ICP
Demonstrate the In-Situ Conversion Process	●	●	●
Gather additional operating data and information	●	●	●
Allow testing of components and systems to demonstrate the commercial feasibility of recovering hydrocarbons from oil shale	●	●	●
Experiment with lift systems for use in producer holes	●		
Install heaters in lower oil shale resource (R-4 to top of R-2)		●	
Determine practicality of combining Nahcolite flushing with ICP		●	
Test and demonstrate desalting and distillation technology		●	
Evaluate air mist fluid or aerated fluid drilling for freeze wall			●
Test use of alternative heater technology vs. cased heaters			●
Expected Production Volume during R&D period	~1000 BOE/d at peak	~1500 Bbls Untreated Condensate	600 – 1500 Bbl/d
Revised Production Volume Estimates Per 2008 BLM Approved Plan Addenda	~1500 Bbls (10-30 bpd)	~1500 Bbls (10-30 bpd)	~1500 Bbls (10-30 bpd)

2. Progress and Accomplishments

Shell Research on Private Lands (non-BLM Lease):

Shell has conducted an extensive program of research, development, and pilot testing of its ICP technology and freezewall technology on a small scale on its own lands (e.g. not on BLM leases) in the Piceance Basin (Figure 8).[39] Shell has conducted six (6) oil shale heating/heater tests (Red Pinnacle, SIFT, MFE, MTE/DHT, MDPo, MDPs, & MIT) and two (2) freeze wall tests(MIT and FWT). Three of these tests, described below, provide important information and insights about in-situ heating, fracturing, groundwater control, and subsurface reclamation from heating and freeze wall operations.

Mahogany ICP Demonstration (South) Test: This project sought to demonstrate high volume in-situ hydrocarbon production (> 1,000 bbls) and recovery efficiency by the ICP process. On a 30 x 40 foot testing area, Shell successfully recovered 1,860 barrels of high quality light oil plus associated gas from shallower, less-concentrated oil shale layers. Post production coring confirmed the recovery to be approximately 60% of Fischer Assay, as predicted.

Mahogany Isolation Test (MIT) (2002-2004). In this project, Shell sought to demonstrate the freezewall technology, and its use the in-situ heating and extraction of hydrocarbons, and site reclamation technique. In this test, Shell successfully formed a freezewall by circulating chilled calcium chloride brine through 18 freeze holes in a 50 foot diameter ring. Two heater holes and one production well were drilled in the center of the ring. This test confirmed the ability to precision drill freezer holes for the entire depth and the ability to form and close a single impermeable subsurface freezewall. A heating phase demonstrated the conversion of in-situ kerogen to oil and gas, containment of the heated area by the freezewall, and facilitated a subsequent demonstration of post-production reclamation approaches in the heated area. [40]

Freezewall Test (FWT) (2005-2009). In this test, Shell sought to demonstrate the freezewall technology and its ability to form it over the entire commercial interval as well as the ability to detect and quickly repair any breaches in the freeze wall. Shell successfully formed a freezewall across the entire commercial interval by circulating chilled aqua ammonia through 136 freeze wells. By deliberately breaching the freezewall, Shell determined that freezewall breaches can easily be detected by use of pressure monitoring and later pinpointed via temperature logs. Breaches can be re-sealed quickly via pressure equalization across the freeze wall.[41] [42]

MIT Reclamation Test. Following the successful Mahogany Isolation Test (MIT), Shell also sought to demonstrate that injection of water into the heated formation after hydrocarbon production could result in successful flushing of non-hydrocarbon contaminants to pre-freeze wall levels. Data indicated that the inorganics did not require reclamation and no regulated inorganics were increased by heating. As for the organics, only seven regulated were ever detected reliably (even prior to active reclamation/flushing). Active flushing from Nov 2003 to Aug 2004 reduced the only constituent above regulatory standard to benzene (toluene, ethylbenzene, xylenes were detected, but below drinking water standards). Natural attenuation and decay has since further reduced the BTEX concentrations. By 2011, benzene was the only contaminant still above the desired standard and continues to be remediated. [43]

Lessons learned from these efforts will be applied to design pilot tests to be conducted on BLM leases.

Progress on BLM Leases:

Shell has continued to correlate both analytical data and geophysical log information to support development of its three RD&D leases, and has been assessing baseline groundwater quality across the Piceance Basin of Colorado.[44] Tables 8-10 summarize Shell's progress on its three BLM leases.

Table 8: Shell Site 1: Oil Shale Test (OST) (Lease Issued 01/01/07)

Plan Elements	Progress Relative to Plan
A. R&D Goals: • Demonstrate ICP (w/ freezewall) • Gather additional operating information and data • Allow integrated testing of systems and components to demonstrate commercial feasibility • Experiment with lift systems for production holes • Produce ~1500 BOE (20-30 bbl/d at test peak).	• Shell has not initated OST RD&D activities on Site 1 • Between 2002 and 2004, Shell tested ICP heating, pyrolysis and production on Shell lands in the Basin. • The Mahogany Isolation Test (MIT) successfully demonstrated the freezewall, heating pyrolysis and production, and active reclamation. • FWT test confirmed ability to establish and maintain freeze wall over entire commercial oil shale interval." • Continued monitoring indicates positive reclamation results; only benzene remains above the regulatory standard and requires further remediation. • Shell may propose a pilot test on Site 1 RD&D lease.
B. Milestones & Activities	
Phase 1 – Site Preparation early Year 2 (3/08)	• Not conducted on BLM lease
Phase 2 – Subsurface Prep (21 months) (09/08)	• Not conducted on BLM lease
Phase 3 - Production: 24 mo after Ph. 2. (09/10)	• Not conducted on BLM lease
Phase 4 – Reclamation: 11 yrs post Ph. 3 (09/21)	• Not conducted on BLM lease

Shell's first project on a BLM RD&D Lease site will be its proposed ICP/Nahcolite co-production project on Site 2, described in Table 9, below.

Table 9: Shell Site 2: Nahcolite/ ICP Oil Shale Test -- East RD&D (Lease Issued 01/01/07)

Plan Elements	Progress Relative to Plan
A. R&D Goals: • Demonstrate ICP (w freezewall) • Gather operating info and data • Allow testing of systems and components to demonstrate commercial feasibility • Install heaters in lower oil shale resource from top of the R-4 to top of the R2 pending research • Determine practicality of combining Nahcolite with ICP • Determine practicality of airmist fluid drilling or aerated fluid drilling for freezewall • Produce 1,500 bbls untreated synthetic crude at peak of test	• Plan has been modified to target the saline zone below the R-4 zone to allow testing in the Nahcolite zone without a freezewall • No freezewall • No change - Produce 500 – 1000 tons Nahcolite to develop permeability; 1500 bbls cum. oil
B. Milestones & Activities	
Phase 1 – Design & Permitting Preparation (Schedule undetermined)	• Conducted full environmental baseline • Shell completed the research, design and permitting phase in 2011 – 12 acre permit • 13 heaters, 2 producers, 6 observers with a central leach well in a hex pattern
Phase 2 – Equipment Fabrication and Field Construction	• Equipment fabrication is in progress; field construction expected to begin early 2012
Phase 3 - Execution Freeze wall (1 year) Nahcolite solution mining (12-15 months) Dewatering inside freezewall (9-12 months) ICP heating & recovery (5-6 years) Groundwater reclamation (5 years) Thaw freeze wall (1.5 – 3 yrs)	• NA - No freezewall will be constructed per 2008 Addendum. Project will utilize and test Natural Geologic Containment. • Natural cooling in lieu of thaw • Down gradient groundwater monitors • Total project 3.5 – 4.5 years (2016-17)
Phase 4 – Decommissioning and Site Reclamation (12-18 months)	• Reduced due to 12 ac footprint, no freezewall, and minimal site facilities

Table 10: Shell Site 3: E-ICP Oil Shale Test (Lease Issued 01/01/07)

Plan Elements	Progress Relative to Plan
A. R&D Goals: • Demonstrate ICP (w freezewall) using 1,950' bare wire electrode heaters; combine thermal electric and ohmic heating to improve project economics by reducing heater well capital costs; make applicable to lower richness shale • Gather operating info and data • Test systems and components to demonstrate commercial feasibility • Install 1,950' heaters in lower oil shale zone between the R-7 and R-2 zones pending R&D • Determine practicality of airmist fluid drilling or aerated fluid drilling for freezewall	• Progress unknown

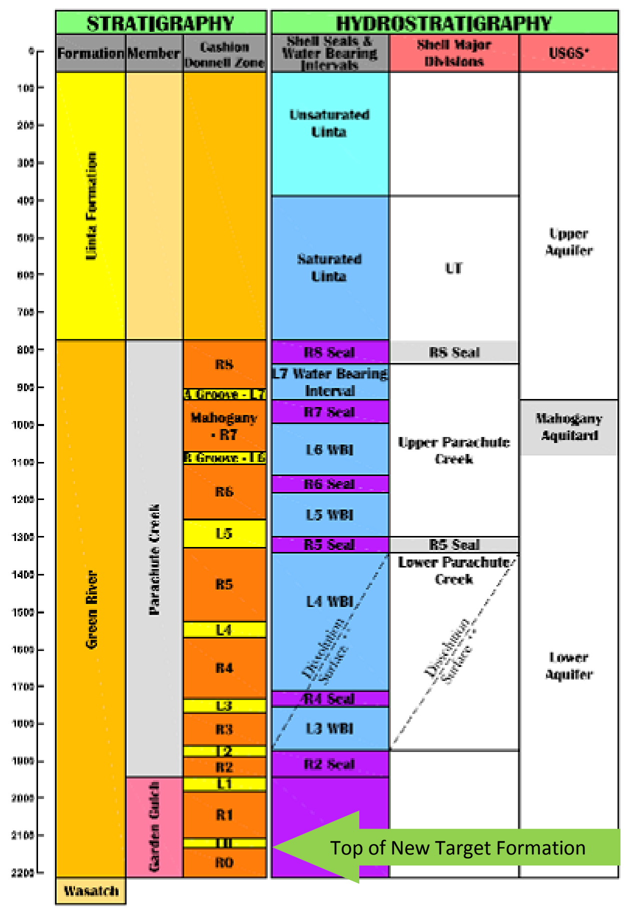
• Produce 1,500 bbls (10-30 bpd) at test peak)	
B. Milestones & Activities	
Phase 1 – Design & Permitting Preparation (Schedule undetermined)	• Progress unknown • Process R&D ongoing at Shell labs
Phase 2 – Equipment fabrication and field construction	• Progress unknown
Phase 3 - Execution Freeze wall (1 year) ICP heating & recovery 5-6 years Groundwater reclamation (5 years) Thaw freeze wall (1.5 – 3 yrs) depending on reclamation program	• No field execution initiated
Phase 4 – Decommissioning and abandonment (12-18 months)	• NA

3. Future Plans

Next Steps:

Site 2 – ICP/Nahcolite Project: Shell has completed the design of a 3.5 to 4.5 year ICP-Nahcolite RD&D project that will be conducted on its East BLM RD&D lease (Site 2), beginning early in 2012. The three phase project includes leaching of Nahcolite, pyrolysis and production of oil shale and hydrocarbon products, and reclamation.[45]

Figure 10: New Target Zone for Site 2 Test.

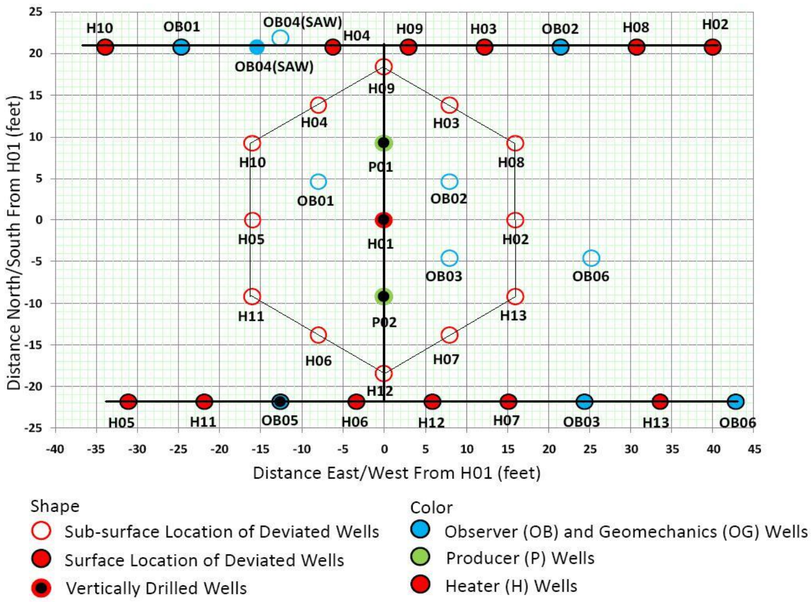


The presence of Nahcolite (sodium bicarbonate) in the portions of the Piceance Basin has limited the applicability of the ICP process. Removal of the Nahcolite from the formation by solution mining with heated water prior to in-situ heating could improve the permeability and porosity of the rock matrix in the target formation, and the thermal efficiency of the process by exposing more surface area for heating and by preheating the shale with hot water. Further, in commercial scale operations, the solution water can be heated using waste heat transferred from adjacent ICP-heated zones. Shell plans to demonstrate these benefits and efficiencies.[46]

New Target Formation: When applied in oil shale bearing zones contacted by groundwater, a freezewall would be used to isolate the zone to be solution mined and ICP-heated. In a deviation from its initial plan, however, Shell now intends to conduct the Nahcolite test pilot project in a deeper zone of the Green River formation. The top of new target zone – the Greeno Bed -- is at a depth of approximately 2145 feet, approximately 130 feet below the dissolution surface in the Saline Zone, and extending to the base of the T1 bed at a total depth of approximately 2,285 feet (Figure 10).[47] This setting will allow for natural geologic containment of the test without the need for a freezewall. All of the wells will be packed off using conventional technologies to protect groundwater bearing zone between the surface and the target zone.

Modified Drilling Plan**:** For this pilot, Shell plans to drill 13 heater holes, 2 production wells, and 6 observation and geomechanical monitoring wells on a permitted 12 acre area. For access and safety purposes, these wells will be configured in an H pattern at the surface and result in a hex pattern subsurface using a combination of vertical and deviated wells (Figure 11).[48]

Figure 11: Drilling Plan for Nahcolite / ICP Test



In the central leaching well, which will later be converted to a central heater well, a "nitrogen blanket" will be placed in the tubing-casing annulus to minimize thermal losses during leaching. All of the wells will be drilled prior to initiation of the 6-9 month leaching phase. Most surface facilities will also be constructed prior to leaching, with only minimal facility conversion required as the project moves into the 2 year pyrolysis and production phase.

Shell expects to produce approximately 500 to 1,000 tons of Nahcolite by hot water leaching. The central leaching well will later be converted to a central heating well. The removal of this mineral will develop permeability in the shale formation. Upon completion of leaching operations, the central leaching well will be converted to a heater. Heating and pyrolysis is expected to yield about 10 to 30 barrels of oil per day or a total of 1,500 barrels over the life of the pilot test.

Shell expects that reclamation will be achieved by natural cooling in the formation after heaters are turned off. A complete environmental baseline has already been developed. Shell will continuously monitor surface and subsurface environmental conditions before and during construction and operations and following reclamation of the site. If this pilot is successful, Shell hopes to convert the RD&D project to a commercial lease.

Sites 1 and 3 – The R&D goals established for Site 1 have largely been accomplished on private Shell lands. The likely next step would be a larger demonstration on the RD&D lease.

D. Enefit American Oil – (Former OSEC BLM Lease)

1. Original Plans

On June 21, 2007 the BLM awarded Oil Shale Exploration Company (OSEC) an oil shale RD&D lease for a 160 acre tract located in Uintah County, Utah at Township 10 S, Region 24 E, S22/27. This lease includes "Tract Ua" and the White River Mine which were development candidates under the Prototype Oil Shale Leasing Program in the 1970s. As part of the lease, OSEC agreed to make oil shale available to other researchers from the remaining stockpile of the White River Mine and to investigate the feasibility of re-opening the mine to supply a surface retorting project. OSEC was owned and operated by a group of private investors. The company was recently acquired by Enefit American Oil Company.

Initial RD&D Goals:[49]

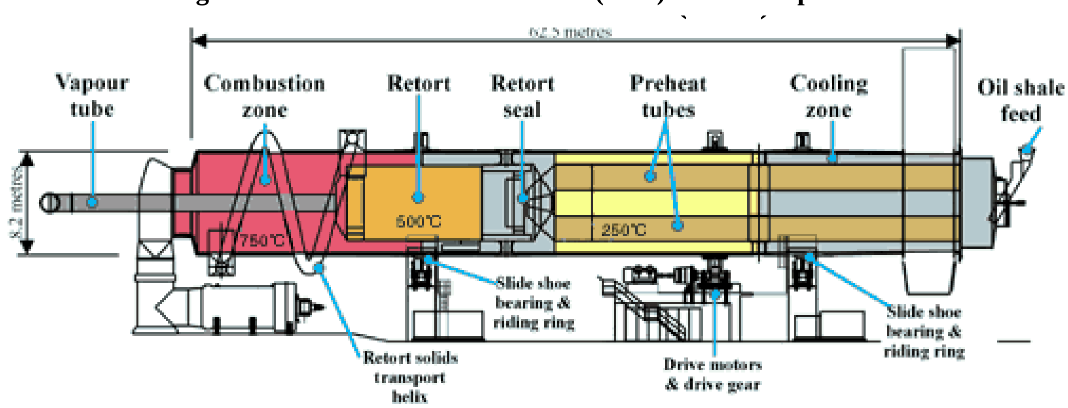
OSEC proposed to:

- Conduct research to achieve a demonstration project that will inform and advance the knowledge of commercially viable production, development and recovery technologies consistent with sound environmental management.
- Demonstrate surface retort through the Alberta Taciuk Process (“ATP”) to study, test and demonstrate that it is a viable method for thermally processing crushed oil shale.
- Apply a three phase approach to assess the technical feasibility and economical and environmental impacts of shale oil production.
- Develop an understanding of how high volumes of spent shale can be disposed of at the surface in a manner that is economical, environmentally acceptable in the very long term.
- Research how the ATP technology could be improved to achieve: (a) predictable and safe air emissions; (b) predictable and complete extraction of recoverable hydrocarbons, and (c) a consistent spent shale waste stream.
- Investigate spent shale handling and disposal methods to minimize leaching impacts.
- Identify new revenue source and minimize waste disposal on-site.

Proposed Technology

Alberta Taciuk Processor “ATP”: The ATP is a surface based rotating horizontal kiln retort. The ATP retort has four internal zones for: (1) preheating incoming shale; (2) pyrolysis of the oil shale under anaerobic conditions; (3) combustion of coked solids to provide process heat; and (4) cooling of combustion products by heat transfer to the incoming feed (Figure 12).[50,51]

Figure 12: Alberta Taciuk Processor (ATP) Surface Report Schematic



Proposed RD&D Approach and Schedule

OSEC initially proposed a three phase RD&D approach:

Phase 1: Remove stored shales from site. Crush locally to transport via truck to Canada for processing through a 4-ton/hour ATP pilot plant producing 650 barrels of shale oil. (11 months from start)

Phase 2: Relocate pilot ATP plant from Calgary to the White River Mine. The on-site pilot will use stock pile shale to process 6,000 barrels shale oil. (14 months following Phase 1)

Phase 3: Permit and build a demonstration plant to process 250 tons/hour or 1.5 million tons of shale per year, for over two years. During this time the mine will be re-opened and the new source of shale. (Two years following Phase 2)

2. Progress and Accomplishments

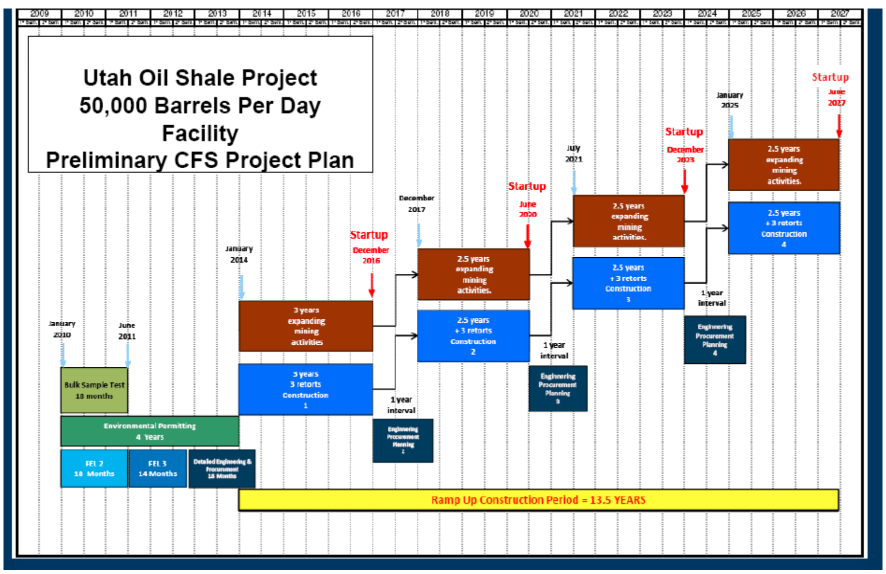
Shortly after the BLM lease was signed, OSEC sent samples of the White River shale to three laboratories for study. OSEC also shipped 300 tons of crushed shale from Utah to Calgary, Alberta for test processing in the ATP demonstration plant. Although initial indications for the Alberta Taciuk Process were favorable, OSEC determined it to be prudent to conduct an evaluation of other surface retorting technologies for the White River site.

In 2008, seeking additional oil shale resources OSEC acquired Cliffs Synfuels. OSEC also formed a Joint Venture with Petrobras & Mitsui. Petrobras is the owner and licensor of the Petrosix vertical shaft retort technology that has been in commercial operation in Brazil for more than 300 years. Mitsui offered an expanded source of private investment capital for the next project phase.

Consistent with the BLM RD&D Plan of Operations and the joint venture terms, the joint venture partners planned and initiated a comprehensive, 15-part technical, economic and environmental feasibility study that included a comprehensive assessment of retort technology alternatives, including the Petrosix. This study was completed in 2009. As part of this effort, OSEC constructed an air quality monitoring station and developed a comprehensive environmental baseline for the RD&D site and the significant block of oil shale leases and properties acquired since the BLM lease.

The results of the study included a 15 year development plan for a commercial oil shale facility to include the Petrosix retort as the primary technology, potentially supported by an ATP retort to be used to process the fines that could not be processed by the Petrosix design (Figure 13).[52] OSEC also began discussions with an Estonian oil shale company, Enefit, about using its' E-280 technology. .

Figure 13 – OSEC Development Plan for 50,000 B/d Surface Retort Facility



In late 2010, Mitsui and Petrobras decided not to continue their investment in the project. OSEC began to seek other private investors to continue the project. On March 31, 2011, OSEC's shares, assets, and leases were wholly acquired by Enefit American Oil Company, the US subsidiary of Estonia's state-owned oil shale company Eesti Energia, with the approval of BLM and the US government. OSEC and Enefit's progress related to its BLM RD&D lease is summarized in Table 11.

3. Current Status and Future Plans

Current Status

The acquisition of all shares, property, leases and intellectual property of OSEC by Enefit American Oil (EAO) initiates a new chapter in the development plan and outlook for the BLM lease**.** EAO intends to build on the prior operators' resource acquisition, site development planning, permitting, and environmental assessment accomplishments. Enefit will use the combined sites, including the BLM RD&D lease, to demonstrate the commercial feasibility of its proprietary surface retort technology, a scale up of the Enefit 280 circulating fluidized bed retort. In addition to the approximately 545 million barrels of resources on the BLM lease and preference right extension, Enefit now controls an additional 2 billion barrels of resource on state and private leases and holdings in the Uintah Basin.

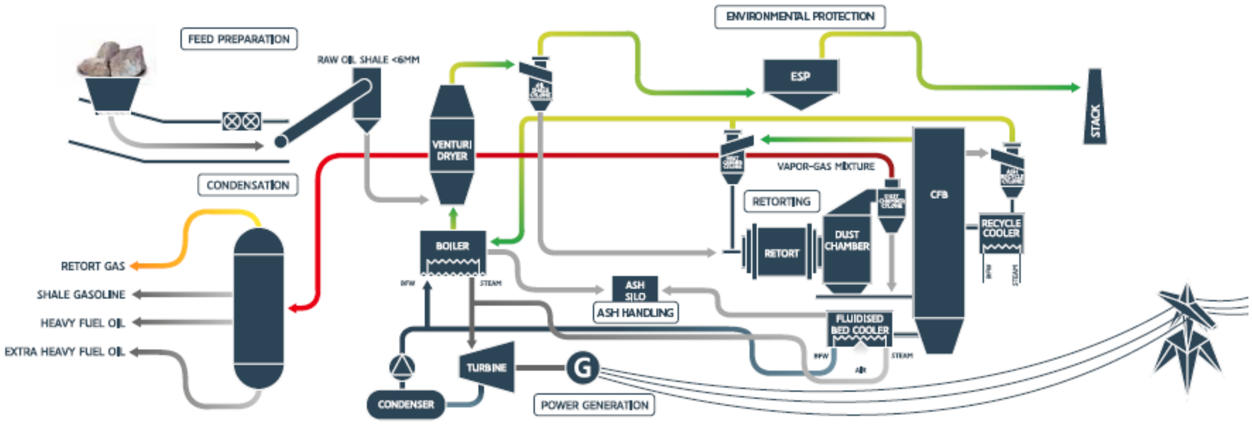
Table 11: Enefit American Oil - Utah Surface Retort (Lease Issued to OSEC 07/01/07)

Plan Elements	Progress Relative to Plan
A. R&D Goals: • Demonstrate surface retorting using ATP • Determine technical, economic, and environmental feasibility in Utah • Understand how spent shale can be managed environmentally • Improve ATP for predictable and safe emissions and products	• OSEC investigated ATP as well as Petrosix and Enefit 280 – prior to sale to Enefit • Completed comprehensive feasibility and development plan • Developed shale management plan • Unknown • The new ownership and technology will require a new feasibility study and commercialization plan.
B. Milestones & Activities	
1. Shale Preparation and Testing in ATP (11 months) e.g. June 2008	• Sent shale to 3 labs, including Calgary for testing. • OSEC acquired additional lands via purchase of Cliffs Synfuels • Formed JV with Petrobras and Mitsui to consider Petrosix alternative to ATP
2. Relocate ATP Pilot to Utah for testing (14 months after Ph. 1) (Aug-Sep 2009)	• Relocated ATP to Utah • Initiated 15 part feasibility study using Petrosix w/ ATP as a fines retort with positive results • Prepared 15 yr development plan. • Mitsui & Petrobras cease investment (late 2010.
3. Permit and build a 250 ton/hr demo plant in Utah Reopen White River mine (24 months after Phase 2) (Sep 2011)	• OSEC sold to Enefit American Oil (EAO) (03/11) • Enefit American Oil is planning a new project using Enefit 280 surface retort technology. • Reaching agreement with BLM on a new and different Plan of Operations for the RD&D period (and updates Demonstration Plan for Enefit tech) • EAO will demo E-280 technology in Estonia • Test Utah oil shale samples in Germany • Conceptual study completed 2011 • New environmental baseline (1.5 years) • Planning for EIS underway • Mine development plan underway • Design and build Utah Phase I commercial plant • Initiate production 2020 (25K bbl/d) with a second unit in 2025.

Future Plans

New Technology: Enefit American proposes to conduct oil shale retorting operations using a scale up of the second generation of Enefit's surface retorting technology, the Enefit 280 ton per hour plant. A commercial scale project employing this technology is currently under construction in Estonia with commissioning expected in 2012. Enefit will also evaluate a further scale up of the Enefit 280 plant to achieve its US production goals. Produced oil will be upgraded to either synthetic crude oil for regional markets or end-use diesel fuel. The Enefit 280 (Figure 14) employs an enhanced solid heat carrier

Figure 14. Enefit 280 Surface Oil Shale Solid-Heat Carrier Retorting Technology

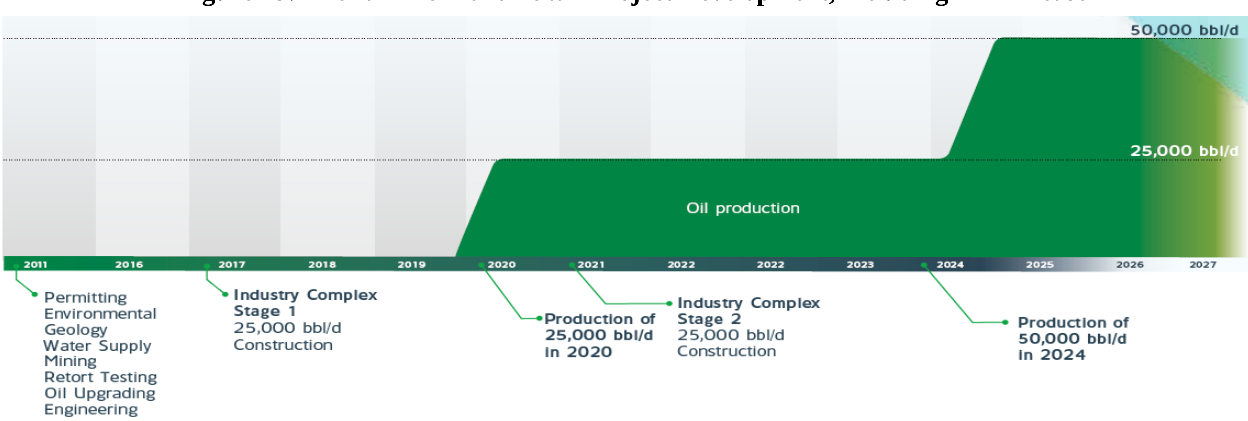


retorting technology surrounding horizontal kiln retort.[53] Major enhancements engineered in collaboration with the Finnish firm Outotec have increased on-stream time ~70 percent. By recovering heat from both the hot spent shale ash and flue gases and reusing it in the process, the energy efficiency of the process is significantly improved. Combustion of the residual carbon on the spent shale in a circulating fluidized bed boiler results in cleaner flue gases.

Next Steps

Enefit intends to conduct RD&D activities on the BLM lease to commercialization its Enefit 280 technology. Enefit hopes to accelerate development goals to initiate oil shale production in 2020 at a level of 25,000 bbl/d and implement a second retort to achieve full capacity of 50,000 Bbl/d in 2024 (Figure 15). Enefit is finalizing a new lease development plan with BLM for the RD&D period.

Figure 15: Enefit Timeline for Utah Project Development, including BLM Lease



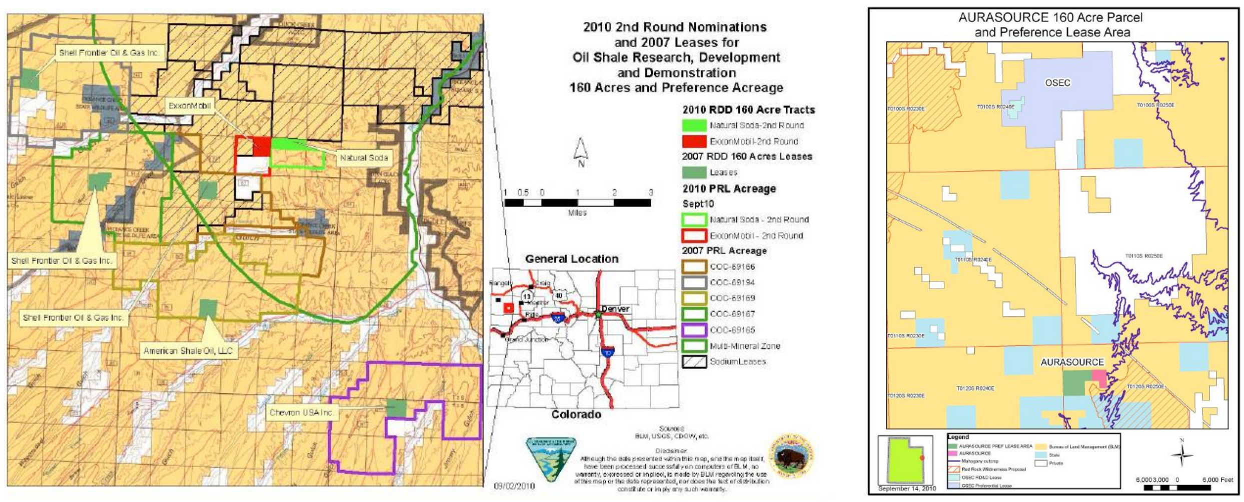
To achieve its goals, Enefit American Oil will:

- Conduct a Conceptual study – Completed in 2011
- Develop Baseline for Environmental Study (1.5 years)
- Plan and preparation for EIS (started)
- Drill additional cores and model the resource; Ship samples to Germany for bench / pilot testing
- Create 30 MM t/yr surface/underground mine plans to support planned 50,000 bbl/d oil output.
- Build Enefit Technology on-site including the new Enefit280 plant.

III. 2nd Round BLM Oil Shale Leases Pending NEPA Review and Approval

The BLM received three proposals in response to its November 3, 2009 "second round" request for oil shale RD&D lease nominations. All three were given preliminary approval, pending affirmative outcome of NEPA reviews currently being performed. The locations of the three pending and six active BLM oil shale RD&D leases are shown in Figure 16.[54] The RD&D goals, proposed technologies, and activity plans for each of these pending leases are discussed below.

Figure 16: BLM 2010 RD&D 2nd Round Nominations in Colorado (l) and Utah (r)



A. AuraSource

1. Plans

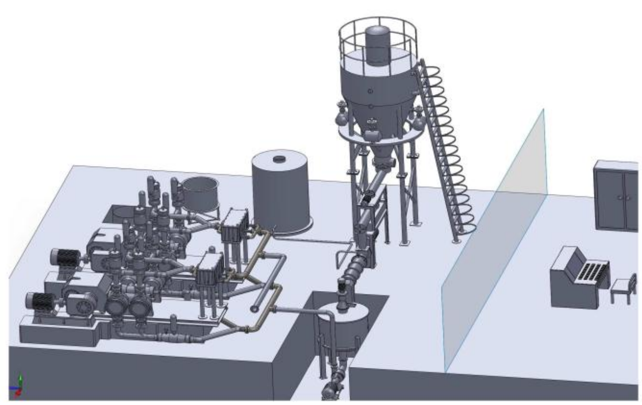
In January 2010, BLM selected AuraSource's nomination of a 160 acre parcel and an associated preference lease area of 480 contiguous acres located in Uintah County in Eastern Utah (Figure 16). The lease is situated south of the White River near the Colorado border.[55] AuraSource proposes to use the proposed lease to test the use of a surface process that "cooks" crushed shale at a low temperature to release the kerogen.[56] A subsequent commercial scale facility would include a refinery for processing up to 1 million tons of oil shale annually from BLM and other shale resources within the region.[57]

Proposed Technology and Approach

AuraSource hopes to replicate in Utah the success it has achieved in China, using same the licensed technology and development plan. AuraSource plans on using an ultra-fine grinding and separation process called AuraFuel.[58]

The technology was developed by Pengchuang Tech and licensed to AuraSource by Beijing Pengchuang Technology Co., Ltd in 2010. In this process, an above ground injector creates fluid shock waves in the target zone (Figure 17). The zone is ground into an ultra-fine slurry that is lifted for separation. The slurry is pressurized to ~145 psi[59] causing particles to

Figure 17: Design for AuraCoal in China



collide and shear to smaller particles.

Separation Technology

AuraSource plans on using a gravity separation system to separates particles with different densities in the ultra-fine slurry. This technology enables particles separation by applying a large amount of gravitational force. Thus impurities and unwanted substances (such as ash or sulfur in coal) can be removed.

Retort Technology

A low temperature chemical conversion of oil shale for feedstocks in the petrochemical industry was licensed from the China Chemical Economic Cooperation Center. The corporate website claims the technology is: energy self-sufficient, requires minimal water usage, and produces high oil yields of 21-28% by weight and 8-15%, by weight, of dry gas.

2. Progress and Accomplishments

In 2010, AuraSource broke ground on 1 million ton oil shale processing plant in China. The project was formed as a joint venture called the China Quinzhou KaiYuYuan New Energy Co., Ltd. The joint venture is between AuraSource, Mongolia Energy, and Kaiyuyan Miner Investment Group. Financing is being provided by the Kaiyuyan Miner Investment Group. AuraSource is managing the plant development located in Qinzhou, China and is providing the AuraSource Process license for the retort technology.[60]

3. Future Plans

Next Steps

As of December 2011 BLM reports the lease to be at risk of not passing the NEPA review due to lack of filing activity by AuraSource.[61] BLM will make a decision on the NEPA process and lease in 2012.

B. Natural Soda Holdings

1. Plans

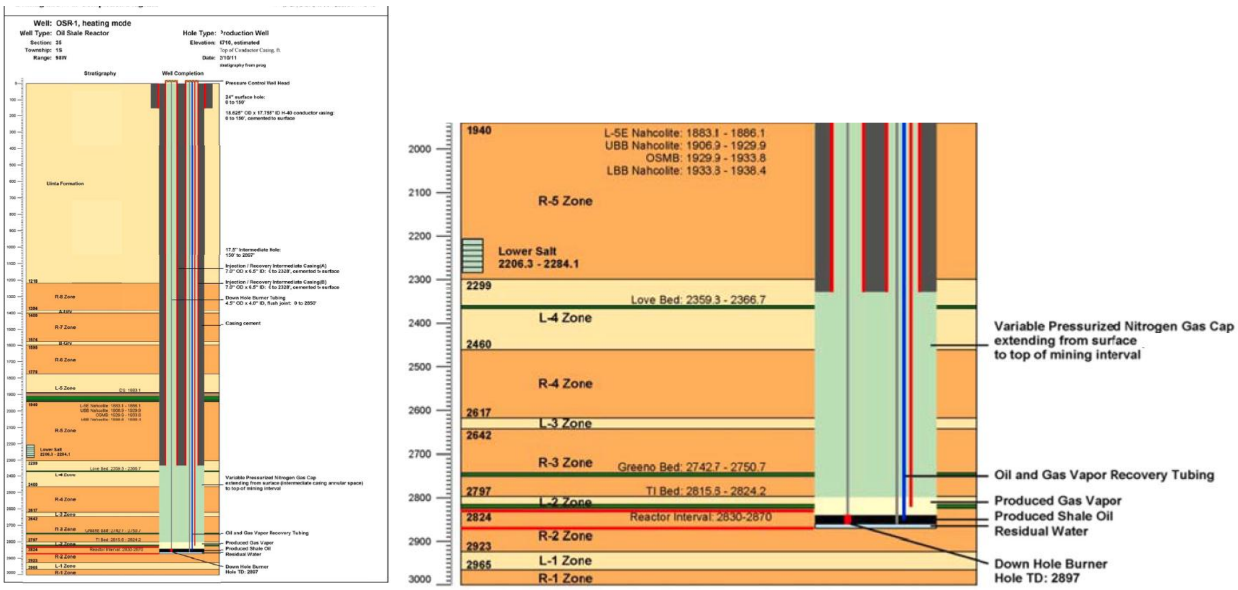
Natural Soda Holdings, Inc., an established producer of Nahcolite by solution mining in the Piceance Basin, has nominated a 160 acre RD&D oil shale lease tract with an associated preference lease area of up to 480 contiguous acres in Rio Blanco County, Colorado (Figure 14). Situated between the Stake Springs and Ryan Gulch drainages, the tract lies almost 41 miles southwest of Meeker. The RD&D lease is located adjacent the company's Federal sodium lease which will allow access to utilities.

Natural Soda proposes to use the RD&D lease to test an application of the company's coal liquefaction process on oil shale as an in-situ chemical conversion process. As with several other in-situ projects on RD&D leases, Natural Soda will bypass the rich upper Mahogany Zone and target the saline zone of the Parachute Creek Member from the R5 down to the L2 zones. This zone contains an estimated 300 million barrels of oil equivalent in the form of kerogen embedded in Nahcolite, dawsonite, and halite.[62]

Stated Research Goals

Natural Soda's stated research goal is to produce an amount of shale oil by the proposed process and to define the parameters, and economics required for commercial operation. The scale and scope of research and development is largely dependent upon the initial and continued success of the proposed leaching and chemical conversion technology. Natural Soda intends to drill and complete a single Oil Shale Reactor (OSR) production well to test the effectiveness of the technology on a small scale.[63] Natural Soda will complete a – 40 ft reactor interval at the base of the Saline Zone for the initial test - which should produce 100 bbls of oil. If successful, additional reactor intervals targets higher in the Saline Zone will be selected.

Figure 18. Natural Soda Planned Well Completion Shown During Production Phase



Technology to be Utilized

Natural Soda proposes to utilize high-temperature supercritical (or near supercritical) water in conjunction with carbon monoxide, sodium bicarbonate, and sodium aluminate to break the chemical bonds of the oil shale. The process is derived from research conducted at Monash University in Australia to enhance the liquefaction of low rank coals, such as Victorian Brown coal—which have similar reactive chemical bonds and structural features to those found in oil shale kerogens. Research is on-going at Monash University on samples of oil shale from the Piceance Creek basin to guide the process development.

The leaching and chemical conversion process will utilize the abundance of saline minerals (Nahcolite, and to a lesser extend, Disunite) to create porosity and permeability and to potentially catalyze, the chemical conversion process. Development activities are to take place low in the Saline Zone which is devoid of any water and acts as a highly confined interval, avoiding complications associated with groundwater and highly fractured rock (Figure 18).

Proposed RD&D Approach and Activities

Natural Soda has defined a three phase RD&D program consisting of seven distinct steps. (Table 12) Progression to each successive step and Phase is contingent upon the results of the prior step(s).

Table 12: Natural Soda RD&D Objectives and Milestones (As Proposed)	
Three Planned Phases	**Research Goals and Field Objectives**
Phase 1 - Pre-Conversion Leaching: 1. Drill / complete initial production well 2. Leaching 3. Design and construct facilities 4. Install heating elements and recovery infrastructure	• Use conventional vertical well technology • Solution mine the Nahcolite • Form an in-situ reactor interval • Process sodium bi-carbonate-enriched brine on adjacent facility • De-water L1 zone
Phase 2 - Oil Shale Liquefaction: 5. Operate (pre-production)	• Liquefy kerogen through chemical conversion, • Equip well with downhole burner and pressure control system • Heating to 300-350 degrees centigrade. • Avoid approaching fracture pressure • Test for natural thermal mixing • Lift occurs from downhole pressure or downhole pump (if needed) • Lift occurs in semi-continuous basis as walls dissolve

	• Vent processed gas, scrub if necessary • Develop temperature, pressure, and timing parameters
Phase 3 - Oil Shale Extraction: 5. Continue Operations (production) 6. Expansion and replicate 7. Plugging, abandonment, reclamation	• Inject recycled hydrocarbons to solubilize heavy end liquids and provide extraction medium. • Analyze produced oil • Distill oil and test fractions • Analyze performance in hydrotreating operations and products. • Identify the economic life of producer wells

Phase 1 - Pre-Conversion Leaching: In Phase 1, Natural Soda will use conventional vertical well technology to drill and complete one production well, and install the heating and recovery infrastructure. Once installed the target zone will be leached and then de-watered to extract minerals and create porosity and permeability. Surface facilities will be designed and constructed and the downhole heater will be installed. This phase has the most uncertainty.

Phase 2 - Oil Shale Liquefaction: In Phase 2, testing will focus on thermal mixing, natural lifting, temperature/pressure requirements, and timing parameters. A downhole burner will heat the zone to liquefy the kerogen and will be monitored for proper temperature/pressure. The operating plan calls for thermal mixing to occur once optimal temperature is achieved. If thermal mixing is inadequate Natural Soda may preheat the water and gases that are injected. Natural Soda will endeavor to liquefy the embedded kerogen through a chemical conversion, heating the formation to 300-350 degrees centigrade. Lift to produce the hydrocarbon resources generated downhole will be provided by a combination of downhole pressure or a downhole pump. This phase consists of the operational step (5)

Phase 3 - Oil Shale Extraction: Phase three will liquefy the kerogen through a chemical conversion process and extract the oil and gas through natural lift. Extraction requires the injection of recycled oil to solubilize heavy end liquids which will provide an extraction medium for the super heated liquids and gases. The oil will be accumulated for testing and the gas will be vented (Figure 16). If successful, step six (expansion and replication will follow.) If not, step 7, (plugging and abandonment) will occur, followed by reclamation of the site. Processing of the sodium bicarbonate will occur on the neighboring facilities. The produced oil will be shipped to a laboratory for analyses. The lab will analyze and then distill the oil. The fractions will then be analyzed for quality and usability. After production the well will be abandoned. Abandonment will occur once the downhole temperature decreases the pressure which is below the natural lift pressure point. This self-limiting approach will require an economic analysis to validate the commercial scaling is economical.

2. Progress and Accomplishments

The BLM is currently in the process of the NEPA Analysis, if approved the nominated lease will be granted. Meanwhile the processing capabilities at the adjacent Nahcolite lease is being increased. The company recently increased the Rifle, Colorado processing plant by 30,000 tons a year and doubled its heating abilities. In 2012, the firm is building a new processing facility costing $34 million.[iii] Upon completion of NEPA and award of the RD&D lease, Natural Soda will implement its work plan (above).

C. ExxonMobil

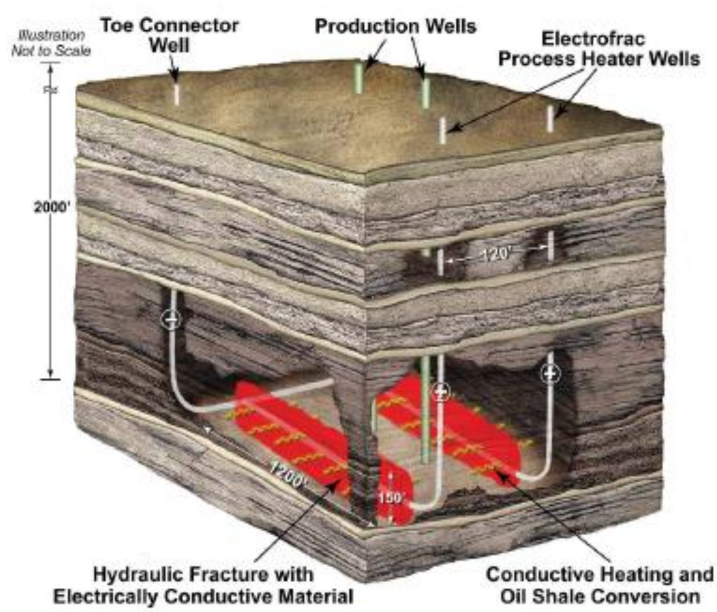
1. Plans

In response to the Nov. 3, 2009 BLM Federal Register Notice, ExxonMobil nominated a tract located in Garfield and Rio Blanco Counties situated on the north sloping ridge separating Ryan Gulch from Yellow Creek within the White River Basin. The average elevation of this tract is approximately 6,642 ft with average 1,280 feet depth to the top of the Mahogany Zone. The resource interval of interest for oil shale development lies within the Green River Formation from the top of the Mahogany zone to the base of the R1 zone. The lease is estimated to contain 0.6 billion barrels of oil in place. The estimated shale oil resource in the proposed preference right lease area is 1.7 billion barrels of oil in place. In addition the RD&D lease area also has 87 million tons nahcolite and 30 million tons of dawsonite.[64]

Proposed Technology and Approach

ExxonMobil has proposed testing a in-situ hydraulic fracturing and heating technology called Electrofrac. The process applies an in-situ hydraulic fracturing technology that fills fractures with an electrically conductive material -- a mixture of calcined coke and cement. Electricity is conducted from one end of the fracture to the other, in effect making it a resistive heating element, similar to that in a toaster. (Figure 19) The heat flows from the fracture into the oil shale formation, gradually converting the solid organic matter of the oil shale into oil and gas.[65] The oil and gas are produced to the surface by conventional methods.

Figure 19: ExxonMobil ElectroFrac Technology



ExxonMobil will design the operations to contain the pyrolysis zone in a low-permeability envelope of unheated oil shale as their groudwater mitigation strategy.[66] ExxonMobil plans a five phase approach to developing the RD&D lease to commercialization as seen in Table 13. Initial work will build the site and fracture the target zone. Fractures are built by fracturing the construction holes and filling the fractures with a non-hazardous electrically conductive material.

The horizontal section of the construction holes will be cased with electrically nonconductive pipe (likely fiberglass tubular designed for downhole use), 5.5-in. in diameter. The net result will be to create a series of parallel planer heaters causing thermal diffusion (red area of Figure 17) to convert the kerogen into oil and gas.[67] In Phase II the site will produce enough oil for testing. Phase III will see an increase in production until the lease reaches a commercial status and testing will continue, to include minerals recover: Work during this phase will include:

- Conversion of producer wells to water injection wells
- Injection of water into the fracture network to dissolve the sodium-bearing minerals
- Production of the water recovery of the sodium-bearing minerals
- Recovered natrite conversion to sodium bicarbonate, as needed, with the addition of CO_2.
-

Table 13: ExxonMobil RD&D Objectives and Milestones (As Proposed) [68]		
3 Planned Phases	**Research Goals and Field Objectives**	**Operations**
Phase 1- Design / permit operations on RD&D lease (Years 1-3)	• Successfully building an electrically conductive fracture in the zone • Determine minimum in situ stress direction.	• Design and build infrastructure • Drill 3 appraisal wells • Determine location for future experiments • Drill ~48 groundwater monitor wells for baseline data. • Apply for permits • Construct two or more small Electrofrac fractures • Verify electrical continuity
Phase 2 - Electrofrac operation at depth (Year 4)	• Create small scale production from Electrofrac process. • Produce approximately 40 barrels of oil per day, 350 thousand standard cubic feet per day of gas, and 20 barrels of water per day.	• Electrify existing fractures • Assess fluid properties of shale oil and gas • Assess groundwater protection measures. • 8 production wells; 12 a monitoring holes. • 400 kW of electrical power • Heating will last for ~6 months • Test recovery of sodium minerals by flushing • Determine if groundwater remediation is required.
Phase 3 - Pilot scale testing (Years 5-10)	• Increase production to pilot scale. • Test technology to recover sodium-bearing minerals.	• Test two Electrofrac fractures, one connector well, and 12 production and monitoring wells. • 7 MW of electric power. • Heat the formation for 2 to 5 years • Produced volumes are estimated to be 400 – 700 BOPD, 1 – 6 Mscfd of gas, and 200 – 300 BWPD.
Phase 4/5: Commercial lease	• Convert to commercial or anbandonAchieve commercial lease status.	• Convert RD&D lease to a commercial lease, and/or • Abandon and reclaim site

Data presented at the Colorado School of Mines' 31st Oil Shale Symposium and in a subsequent ExxonMobil paper indicates modifications to the original RD&D Lease proposal. During Phase 2, production estimates have increased from 40 barrels of oil per day to 75-175; water production increased from 20 barrels per day to 40-80 barrels per day; Additionally in Phase 2, up to 1.7 MW of power will be delivered to each of up to two heating elements. During Phase 3, the amount of power delivered to the heating elements drops from 7 MW of electrical power to 4 MW. Also, the estimated range of gas produced decreases slightly from 1 – 6 Mscfd to 350 Kscfd – 6 Mscfd.[69]

2. Progress and Accomplishments

ExxonMobil had already done lab, modeling, and field testing of the technology prior to the 2010 BLM RD&D lease application. Field testing occurred at the Colony Oil Shale Mine in Piceance Basin, Co, a private lease that ExxonMobil has used for testing. Two ElectroFracs (EF1/EF3) were drilled and tested at low temperature, successfully proving that[70]

- Electric continuity can be maintained.
- Fractures remained conductive over the operating ranges tested

Time Line of Pre-BLM RD&D Progress: [71,72,73]

2008: Two ElectroFracs were drilled and pumped with a calcined coke and cement slurry.
2009: Graphite was injected into fractures creating power connections to the ElectroFracs and the EF3 well was heated for 90 days at a low temperature.
2010: The EF1 well was heated for seven months at a low temperature. The massive amounts of data from the experiments were used for modeling.
2011: Ongoing thermal modeling

Accomplishments: [74,75]

- Water usage reduced to 1-2 (1.5) Bbls water to produced oil.
- The energy ratio is 3:1
- Detailed hydrology study
  a. Minimum flow to water table is 10 years.
  b. Dilution of several thousand times will occur first.
  c. No surface discharge occurs at Colony Mine.

3. Future Plans

Next Steps

Several more years of testing will help ExxonMobil reach commercialization (production) within 10-24 years:

- Continue development of advanced simulators
- Continue field research at the Colony mine
- Execute the appraisal and groundwater monitoring program at the proposed RD&D lease.

IV. Conclusions

Progress is being made to implement RD&D plans on active BLM oil shale leases. In several cases, preliminary research and assessments have resulted in significant refinements and modifications of the original RD&D plans. In all of these cases, the modifications demonstrate a commitment to focus RD&D activities on efforts that will advance geoscientific understanding of the oil shale and mineral resource base of the target basin and formation, advance designs and performance of fracturing, pyrolysis, and recovery technologies, and improved protection of the environment, including remediation of development impacts. Pre-lease work on two of the three new projects proposed for second round RD&D leases also demonstrate substantial industry research and investment into new and promising technologies to produce hydrocarbon resources while protecting the environment.

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