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U.S. DEPARTMENT OF
ENERGY

Annual Report to Congress on Strategic Unconventional Fuels Activities and Accomplishments

November 2008

Assistant Secretary for Fossil Energy
Office of Petroleum Reserves
U.S. Department of Energy
Washington, DC 20585

This Report is submitted to the U.S. Congress in response to the requirements of Section 369 (i) of the Energy Policy Act of 2005 [P.L. 109-58]

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Executive Summary

Statutory Requirements

Section 369(h) of the Energy Policy Act of 2005 (EPACT 05), directed the Secretary of Energy to form a Strategic Unconventional Fuels Task Force (Task Force) to develop a program and make recommendations to coordinate and accelerate the commercial development of strategic unconventional fuels. Under Section 369(i) of EPACT 05, the Department of Energy (DOE), Office of Petroleum Reserves (OPR) was directed to coordinate the staff support of the Task Force; and to provide an initial report within 180 days after the date of enactment of EPACT 05 (August 8, 2005), and annually thereafter for the next five years, on DOE's efforts and activities to support strategic unconventional fuels development. This report is submitted in fulfillment of that requirement.

Activities of the Task Force Since Enactment of the Energy Policy Act of 2005

The Task Force was convened by the Secretary of Energy in January 2006, and is comprised of: the Secretaries of the Departments of Energy (DOE), the Interior (DOI), and Defense (DOD); the Governors of five key states with unconventional fuel resources; representatives of localities likely to be impacted by development; and their official representatives. These members are supported by working groups on the major unconventional resources and crosscutting issue areas.

The Task Force defined the scope of its work to include: oil shale, coal-derived liquids, heavy oil, tar sands, and oil producible by carbon dioxide (CO_2) enhanced oil recovery. During its first 180 days, the Task Force approved its charter, defined a suite of analyses required to support its efforts, and laid the groundwork for preparation of its initial findings and recommendations, supported in these efforts by OPR.

The Task Force has since held twelve full meetings, as well as numerous conference calls, work group meetings, and outreach activities. The Task Force's efforts are reflected in several reports and documents, including its *Initial Findings and Recommendations;* an *Integrated Strategy and Program Plan;* a series of *Fact Sheets* on unconventional fuels resources, technologies, economics and related issues*;* and an assortment of briefing materials that communicate its efforts and accomplishments*.* All of these materials were prepared with support provided by the DOE.

Activities of the Department of Energy in Support of the Task Force and its Recommendations

Since the enactment of EPACT 05 and the inception of the Task Force, and consistent with its charge under EPACT 05, OPR has provided technical, analytical, and management support for the activities and products of the Task Force. In addition to this support, the Naval Petroleum and Oil Shale Reserves (NPOSR), within OPR, has participated in the following activities.

In July, 2007, NPOSR issued a report summarizing the status and challenges of the domestic oil shale and tar sands industry, titled "*Secure Fuels from Domestic Resources,*" which profiled the oil shale and tar sands related efforts of over 25 companies. NPOSR subsequently updated this report, the second edition of which was issued in September 2008.

NPOSR has provided financial support of the recently resumed Colorado School of Mines Oil Shale Symposium which annually reviews global developments in oil shale resources, technology, regulation, and industry development.

OPR has facilitated an *ad hoc* steering committee comprised of representatives from industry, national labs, academia, and other organizations interested in the potential offered by oil shale and tar sands and issues that constrain their commercial development. Three meetings have been held by this group to date. This group is expected to provide recommendations for the implementation of the findings of the Task Force regarding further analysis and development efforts for unconventional fuels.

NPOSR has also supported activities of the national laboratories on unconventional fuels and will continue to support efforts to be conducted by the Idaho National Engineering Laboratory regarding water resources availability, requirements, and water quality issues associated with unconventional fuels development.

The success of unconventional fuels will depend on demonstrating the ability to accomplish concurrent development of multiple energy resources and other interrelated activities within a basin without destroying the valued attributes of the associated region. NPOSR has worked with the national laboratories and the *ad hoc* steering committee to conceptualize a major technical study to perform a regional analysis of the development potential of the Rocky Mountain Energy Corridor known as the Western Energy Corridor Initiative.

Next Steps for the Department of Energy

In June 2008, President Bush addressed the nation regarding the high price of oil and the country's inherent security risk of relying on foreign suppliers of fuel. He recommended that the Congress act quickly to remove the barriers to increasing domestic fuels supplies, specifically citing the need for oil shale resource development. Consistent with this policy, and in accordance with the directives from EPACT 05, the Department of Energy will continue activities in support of economically and environmentally responsible development of an unconventional fuels industry in the United States by conducting relevant economic and technical analysis, continuing to support the Task Force, reporting on the status of technologies and other industry progress, supporting the annual Oil Shale Symposium, working with the *ad hoc* Steering Committee, and supporting activities of the national laboratories on unconventional fuels including the Western Energy Corridor Initiative.

Conclusions

The Department of Energy has worked aggressively to fulfill the requirements of Section 369 of EPACT 05, convening the Task Force; supporting and participating in Task Force activities; giving full consideration to the Task Force's recommendations; and establishing the Western Energy Corridor Initiative that is planned to address Task Force recommendations pertaining to water, environmental, and socio-economic impacts associated with oil shale development, in a manner that is fully integrated with other development. Additional plans to address other Task Force recommendations will be forthcoming in the future.

Section I. Statutory Requirements

Section 369(h) of EPACT 05, directed the Secretary of Energy to form a Strategic Unconventional Fuels Task Force to:

- *"… develop a program to coordinate and accelerate the commercial development of strategic unconventional fuels, including, but not limited to, oil shale and tar sands resources within the United States, in an integrated manner" [Sec 369(h)(1)], [and to]*
- *"make such recommendations regarding promoting the development of the strategic unconventional fuels resources within the United States as it may deem appropriate" [Sec 369 (h)(3)]; and to*
- *"make recommendations with respect to initiating a partnership with the Province of Alberta Canada for … sharing information relating to the development and production of oil from tar sands, and similar partnerships with other nations that contain significant oil shale resources." [Sec 369 (h)(4)]*

The Act directed the Task Force to submit a report of its analyses and initial recommendations to the President and the Congress within 180 days following enactment. The Act also directs the Secretary of Energy annually to report the progress of the Department of Energy in implementing the recommendations of the Task Force. This report is submitted in response to and in fulfillment of the requirements of the Act.

Since its inception, the Task Force has been supported extensively in its activities and analyses by OPR's NPOSR, with input from other DOE offices and laboratories and from the Task Force's resource and issue-focused work groups. The activities and achievements, and proposed next steps of the Task Force are summarized below, followed by a discussion of the Department of Energy's efforts to support the Task Force and respond to its findings and recommendations.

Section II. Activities During the 180 Days Following Enactment of the Energy Policy Act of 2005 [PL 109-58]

Task Force Activities and Progress

As directed by EPACT 05, the Task Force on Strategic Unconventional Fuels was convened by the Secretary of Energy in January 2006. During the first 180 days following enactment, the structure and composition of the Task Force was determined. By statute, the Task Force is comprised of:

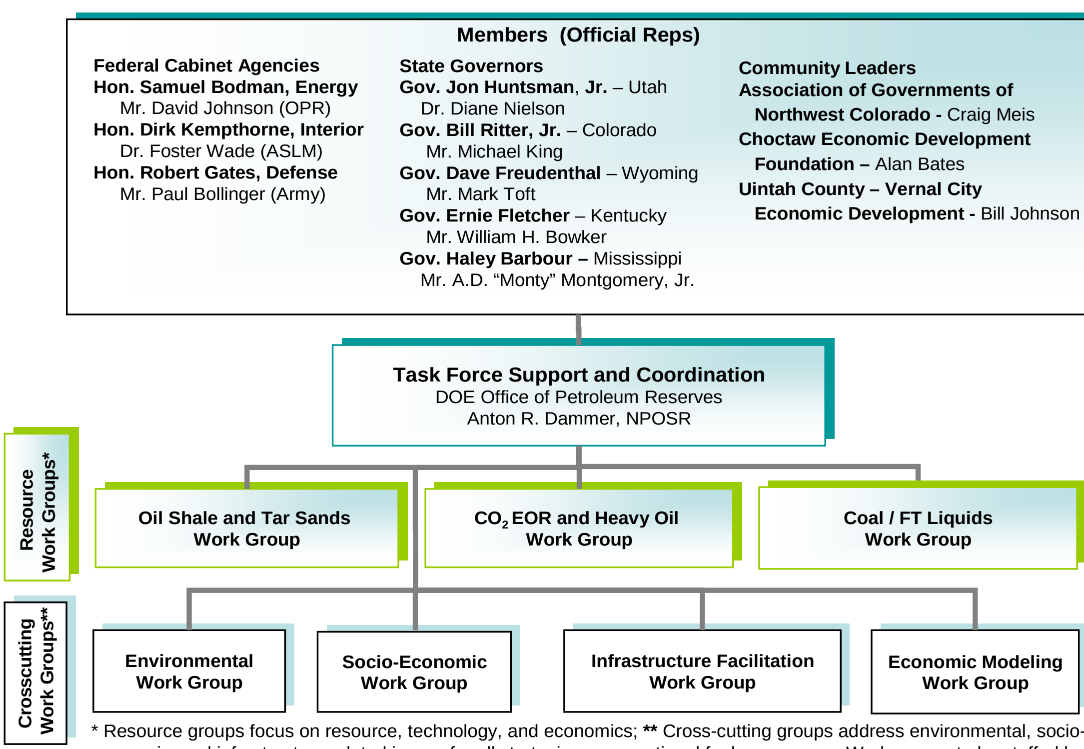
- The Secretaries of DOE, DOI, and DOD;
- The Governors of five key states with unconventional fuel resources;
- Representatives of the localities likely to be impacted by development; and
- Official Representatives, who act on behalf of the members when they cannot be present.

Since the inception of the Task Force, state and national elections, changes in the Administration, and other staff changes have resulted in changes in the roster of the Task Force. Figure 1 reflects the Task Force structure, members, and their official representatives as of January 2008.

EPACT 05 directed the Task Force to evaluate unconventional fuels including, but not limited to, oil shale and tar sands. The Task Force subsequently defined its scope to encompass a range of promising unconventional fuels resources, including: oil shale, coal-derived liquids, heavy oil, tar sands, and oil producible by carbon dioxide (CO_2) enhanced oil recovery.

During the first 180 days, the Task Force adopted a charter, planned and structured its activities, and defined and organized technical and analytical support required by the Task Force and its working groups.

Figure 1. Strategic Unconventional Fuels Task Force (as of January 2008)



* Resource groups focus on resource, technology, and economics; ** Cross-cutting groups address environmental, socio-economic, and infrastructure related issues for all strategic unconventional fuels resources; Work groups to be staffed by representatives of participating federal, state, and community organizations.

Department of Energy Activities During the First 180 Days

Having fulfilled its responsibility to convene the Task Force, NPOSR was mandated to provide technical, analytical, management, and staff support to the Task Force. During the first 180 days, NPOSR fulfilled these requirements by:

- providing logistical support for initial Task Force meetings,
- preparing drafts of the Task Force charter,
- advising on structuring options, and
- developing briefing materials on unconventional energy resources, technologies, economics, and associated environmental, socio-economic, market, and related issues and concerns.

The NPOSR management also assisted in the composition of the various working groups and prepared a structured analytical framework and operating approach for each to ensure consistency in the structure and content of subsequent work group products.

NPOSR also identified requirements for modeling and analytical support that would be required to support Task Force deliberations on initial findings and recommendations and subsequent program planning efforts and documents.

NPOSR provided the staff and contractor support for the preparation of initial and final drafts of the Task Force's report on its Initial Findings and Recommendations.

Section III. Task Force Activities and Achievements to Date

To conduct its work and fulfill its statutory mission the Task Force has held twelve full meetings, to date (listed to the right). Numerous additional conference calls, work group, and outreach meetings have been held.

Task Force Meetings

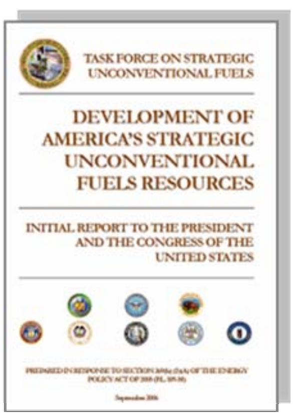
- March 22, 2006 (Denver, CO)
- May 11, 2006 (Salt Lake City, UT)
- June 28-29, 2006 (Lexington, KY)
- August 23-4, 2006 (Shepherdstown, WV)
- September 25, 2006 (Denver, CO)
- November 3-4, 2006 (Oxford, MS)
- December 6-7, 2006 (Salt Lake City, UT)
- February 6-7, 2007 (Washington, D.C.)
- June 14-15, 2007 (Washington, D.C.)
- August 28-29, 2007 (Denver, CO)
- January 24, 2008 (Denver, CO)
- May 1, 2008 (Denver, CO)

Task Force Reports

Several reports have been prepared by the Task Force and OPR, consistent with the directives of EPACT 05.

- The Task Force submitted a report of its *Initial Findings and Recommendations* to the President and Congress in August 2007.
- The Task Force completed a three volume *Integrated Strategy and Program Plan* that was released in September 2007.
- A series of *Fact Sheets* and *Briefing Materials* on unconventional fuels resources, technologies, economics and related issues have also been prepared (Appendix).

The reports summarized below, as well as a variety of background materials, fact sheets, and briefing materials are available on the Task Force website: www.unconventionalfuels.org/publications.html.



Report of Initial Findings and Recommendations: Based on its early analyses and initial findings, the Task Force crafted broad recommendations and identified a suite of options to be more thoroughly analyzed and considered for inclusion in a subsequent integrated Strategic Unconventional Fuels Program Plan. These broad recommendations were described in the Task Force Initial Report to Congress.

The Task Force found that significant opportunities exist for producing fuels from the nation's vast unconventional resources, including: oil shale and tar sands, heavy oil, enhanced oil recovery, and coal-derived liquids. Domestic production of fuels from these unconventional resources could reduce import dependence and the potential impacts and strategic risks posed by global oil supply and demand trends.

Strategic Unconventional Fuels Strategy and Program Plan: EPACT 05 directed the Task Force to "…develop a program to coordinate and accelerate the commercial development of strategic unconventional fuels." Following the completion of its report of initial findings and recommendations, the next step for the Task Force was to further analyze program and policy options to determine the goals, objectives, content, benefits, and public costs of an integrated Strategic Unconventional Fuels Program.

The Task Force subsequently completed a three-volume Strategic Unconventional Fuels Program Plan, the contents of which are summarized at right. The integrated program plan details program and subprogram objectives, program strategies, key activities, and timelines for each program element, and provides a framework for subsequent analyses and program implementation planning.

The Task Force relied on analyses performed using the National Strategic Unconventional Resources Model (NSURM) to analyze and evaluate public options for overcoming industry development hurdles and stimulating industry investment. NSURM was developed for this purposed by the DOE Office of Petroleum Reserves.

NSURM models the resource potential and economic viability of potential unconventional fuels projects and various assumptions about oil prices, technology performance, fiscal regimes, and other factors. Additional information on the NSURM Model is available on the Task Force website: www.unconventionalfuels.org

Contents of Strategic Unconventional Fuels Strategy and Program Plan

Volume I

- Fuels Situation and Program Rationale
- Program Goals / Development Objectives
- National Economic Costs and Benefits
- Commercialization Strategies
- Program Structure / Management Plan

Volume II

- ***Resource-Focused Subprogram Plans*** (Oil Shale, Oil Sands, Coal Liquids, Heavy Oil, CO_2 Enhanced Recovery and Storage)
- ***Crosscutting Program Sub-Plans*** (Carbon Management, Water, Environmental, Markets, Infrastructure, Socio-Economic)

Volume III

- ***Resource and Technology Profiles*** that characterize current resources, development technologies, economics, and development constraints for each of the five resources considered.

Section IV. Activities of the Department of Energy Supporting the Strategic Unconventional Fuels Task Force and its Recommendations

Since the enactment of EPACT 05 in August 2005, the Department of Energy has engaged in a variety of activities that directly and indirectly support activities of the Task Force and the development of unconventional fuels resources and technologies. These efforts were conducted within the Office of Petroleum Reserves and in conjunction with several national laboratories including Los Alamos National Laboratory (LANL), Idaho National Laboratory (INL), Argonne National Laboratory (ANL), Pacific Northwest National Laboratory (PNL) and the National Energy Technology Laboratory (NETL).

NPOSR has played a significant role as a leader in the areas of energy supply security and the potential of unconventional fuels, including domestic oil shale and tar sands, for a number of years.

Prior to the inception of the Task Force, NPOSR led DOE's technical support and assistance to the government of the Republic of Estonia for oil shale development. It sponsored an important study of the *Strategic Significance of America's Oil Shale and Tar Sands Resources,* in 2004, that has played an important role in renewing public awareness of the nation's extensive oil shale and tar sands resources and their potential for reducing the nation's dependence on imports of crude oil and refined products.

Consistent with its charge under EPACT 05, OPR has provided technical, analytical, and management support for the activities and products of the Task Force.. This support has included:

- The development and application of analytical tools to assess the potential of various resources under a variety of technology and policy options.
- Direct and contractor-supported assistance to the Task Force for the preparation of its various reports, presentations, fact sheets and supporting materials.
- Facilitating support and input from the Office of Fossil Energy related to heavy oil, tar sands and carbon dioxide enhanced oil recovery and carbon sequestration technologies and economics.

To address issues associated with water resources and carbon management, the Office of Petroleum Reserves engaged the expertise of the Idaho National Engineering Laboratory (INL) and Los Alamos National Laboratory (LANL) to support the Task Force in this effort.

Secure Fuels from Domestic Resources: In July, 2007, NPOSR issued a report entitled *Secure Fuels from Domestic Resources* summarizing the status and challenges of the domestic oil shale and tar sands industry. The report highlighted the significant activity of U.S. companies in oil shale and tar sands resource and technology development. The report profiles more than 25 companies investing in U.S. unconventional oil development. In July of 2008, NPOSR initiated work to complete a new edition, adding several new oil shale companies and updating the status of the world oil price and domestic energy supply.

Colorado School of Mines Oil Shale Symposia: In 2006**,** with financial support from NPOSR, the Colorado School of Mines (CSM) resumed hosting the Oil Shale Symposium series after an eleven year hiatus. The Symposium reviewed the development of oil shale resources worldwide, including conversion technologies, research and development, environmental impacts and impact reduction and mitigation strategies, regulatory framework, and project and program status. The symposium was repeated in October of 2007, updating the participants on developments in oil shale technology, policy, economics, and associated issues. The Symposia have been supplemented by field trips to oil shale deposits and pilot projects, as well as workshops (managed by NETL) to assess environmental issues and requirements and to identify technical and regulatory approaches to resource development and effective environmental protection.

***Ad Hoc* Steering Committee:** OPR has facilitated an *ad hoc* steering committee that includes representatives from industry, the national labs, academia, and other organizations interested in the extensive potential offered by oil shale and tar sands and concerned about the issues that have constrained commercial development and relevant public policy. The Steering Committee has convened periodically since 2004 to identify issues and concerns that must be addressed before these resources can be developed.

NPOSR has utilized an *ad hoc* Industry Steering Committee to elicit input from the commercial sector. In January 2008, NPOSR brought together a broad group made up of representatives from industry, local, state, and Federal governments, national laboratories, and academia, all of which are stakeholders in the development of unconventional resources. The purpose of this meeting was to gain information that would be useful in devising a strategy to further the development of unconventional fuels while concurrently addressing related issues such as national security, environmental stewardship, and economic and technical feasibility. A follow-up planning meeting, hosted by DOE's National Labs, was convened in June 2008 to discuss the concepts for the Western Energy Corridor Initiative (described below), and other DOE/NPOSR and industry efforts associated with improving our understanding of and preparing for development of unconventional fuels..

Supporting Activities of the National Laboratories on Unconventional Fuels: The Consolidated Appropriations Act for Fiscal Year 2008 for the Office of Naval Petroleum and Oil Shale Reserves allocated $2 million for environmental research and development associated with oil shale, tar sands, and other unconventional fuels to be performed by LANL. OPR has recently transferred these funds to LANL and is working closely with LANL managers to define the scope of work to be performed. Much of the required work is defined in a planning and analysis framework contained in Volume II of the Task Force's Integrated Program and Strategy Plan.

DOE continues to support efforts by INL regarding water resources availability, requirements, and quality issues associated with unconventional fuels development. The Department is considering partnering with the Province of Alberta to evaluate and consider the potential of a basin-wide resource model developed by the Alberta Energy Council (AEC) for use in development planning in the United States.

Western Energy Corridor Initiative: The Task Force identified the need to improve the understanding of the potential impacts and benefits of concurrent development of multiple energy resources in the Rocky Mountain region and to identify strategies and approaches for impact mitigation. A broad spectrum of parties interested in energy resource development in the Western Energy Corridor support the view that concurrent development of multiple conventional and unconventional energy resources needs to be evaluated and considered in an integrated manner. These parties include representatives from industry, communities, national labs and research organizations, and the environmental community

Consistent with its roles and responsibilities delineated in the EPACT 05, over the past year, NPOSR has worked with the national laboratories and the *ad hoc* steering committee to conceptualize and initiate a major technical study of the potential benefits and impacts of energy development in the Western Energy Corridor which extends through the Rocky Mountains region from Alberta, Canada through the state of New Mexico, and contains massive undeveloped unconventional hydrocarbon resources, as well as substantial conventional energy resources, including coal, natural gas, oil, uranium and other minerals, that are under various stages of development. The group has met for two out of three planned sessions in 2008 to build the study concept.

- The study will focus on the integrated development of multiple energy resources in a carbon neutral and environmentally acceptable manner.
- Emphasis will be placed on analyses of the interrelationships of various energy resource development plans and the infrastructure, employment, training, resource, and fiscal and economic demands placed on the region as a result of various development scenarios.

The study framework consists of three distinct phases (Appendix 2 provides a detailed description):

- Phase I – Resource Characterization and Modeling: The study will involve extensive resource characterization and modeling formulation.
- Phase II – Analysis of Development Characteristics and Impacts: The second phase will entail detailed regional analyses of requirements and impacts.
- Phase III – Decision Support and Analysis: The third phase will focus on establishing a regional decision-making mechanism focused on local, state, and Federal government regional benefits and costs.

A diverse joint technical team comprised of highly regarded analysts and experts, including technical and policy experts from both Alberta and Saskatchewan, have been assembled under the leadership of NPOSR and the participating national laboratories to complete this major technical study. The group includes: INL, LANL, and

NETL; OPR and NPOSR, and knowledgeable and experienced support contractors including INTEK Inc., SI Inc., and James W. Bunger and Associates Inc. This team will be expanded to provide additional expertise from several western universities, and other appropriate entities.

Section V. Next Steps for the Department of Energy

In June 2008, President George W. Bush addressed the Nation regarding the high price of oil and the country's inherent security risk of relying on foreign suppliers of fuel. He recommended that Congress act quickly to remove the barriers to increasing domestic fuels supplies, specifically citing the need for oil shale resource development.

To support this initiative, and in accordance with the directives from EPACT 05, the Department will continue its efforts to promote an unconventional fuels industry in the United States through the following activities:

Support to the Task Force: NPOSR will continue to provide management and analytical support for the Task Force, as needed to help the Task Force fulfill its mission.

Reporting on the Status of Industry: NPOSR will update the *Secure Fuels from Domestic Resources* report periodically, as industry development and associated progress warrants.

Annual Reports to Congress: The Department of Energy will prepare and submit to Congress an annual report of its activities associate with unconventional energy resources development, consistent with the requirements of Section 369 (i) of EPACT 05.

Colorado School of Mines Oil Shale Symposia: NPOSR will continue to support the Colorado School of Mines Oil Shale Symposia.

***Ad Hoc* Steering Committee:** NPOSR will continue to meet with the *ad hoc* Steering Committee to gain insight into the unconventional fuels industry.

Supporting Activities of the National Laboratories on Unconventional Fuels: NPOSR will continue to support the activities of the national laboratories in their efforts to assess unconventional fuels. In particular, NPOSR will participate in the major technical study, the Western Energy Corridor Initiative, to assess regional impacts of concurrent energy development in the western basin.

Updating and Expanding the National Strategic Unconventional Fuels Model: During the next year DOE intends to expand and update the NSURM model. New processes and technologies have been identified that must be reflected in the model in order to conduct economic, technical, and planning analyses on a basis that is reasonably representative of the recoverability of the nation's resources. Similarly, the model also needs to be updated to reflect significant changes in the economics of each of the unconventional fuels resources and technologies assessed in the model. Changes in capital costs, operating costs, royalty structures, severance taxes, and other fiscal regimes at the federal and state levels will alter the economic thresholds for all unconventional resources, as will the various proposals for carbon management via cap-and-trade and other policy options.

Conclusions

The success of unconventional fuels development in the Western Energy Corridor will depend on demonstrating the ability to accomplish concurrent development of multiple energy resources and other interrelated activities without destroying the valued attributes of the Corridor or its component basins.

Further progress toward industry development will require public actions and policies that improve knowledge and understanding; reduce technical, economic, investment, social, and environmental risks; facilitate public and private development planning; and, provide a solid foundation of science and engineering to inform public and private decision making.

The Department of Energy is actively fulfilling the directives of Section 369 of EPACT 05. The three-volume Integrated Strategy and Program Plan, published in September 2007 by the Task Force, details the potential benefits, as well as the issues and uncertainties, associated with unconventional fuels development. It sets forth a measured and deliberative approach, based in sound science, engineering, and objective analysis, to address these issues and uncertainties in an integrated manner. The Western Energy Corridor Initiative seeks to implement the Task Force approach, drawing on the resources of our national laboratories and research universities to answer critical questions and provide an effective path forward for policy makers, industry, and other stakeholders.

Additional plans to address other Task Force recommendations will be forthcoming in the future.

Appendix 1 – Fact Sheets

(Extracted From Task Force Report Dated September 2005)

Fact Sheet: U.S. Oil Shale Resources

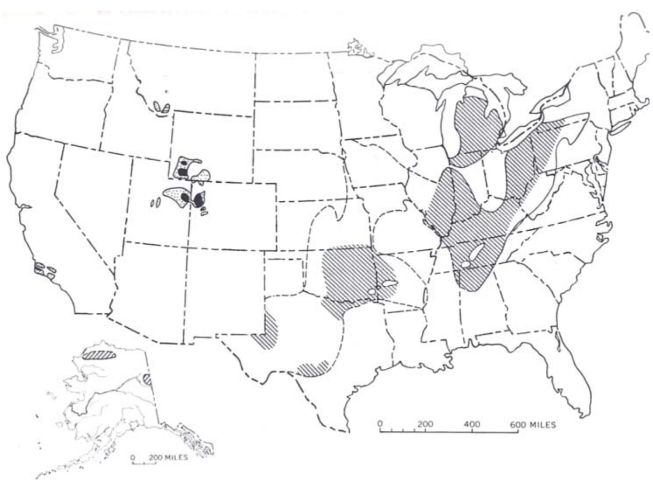
What is Oil Shale?

- U.S. western oil shale is carbonate rock generally marlstone that is very rich in organic sedimentary material called "kerogen." Eastern shales are more often silica based.
- Oil shales are "younger" in geologic age than crude oil bearing formations; natural forces of pressure and temperature have not yet converted the sediments to crude oil.
- Kerogen can be converted to superior quality jet fuel, #2 diesel and other high value by products.
- The kerogen content of "oil shale" ore can range from 10 to 60 or more gallons of oil per ton.

Where is Oil Shale?

- The richest, most concentrated deposits are found in the Green River Formation in western Colorado, southeastern Utah, and southern Wyoming.
- Other significant, less concentrated deposits exist in the Devonian, Antrim and Chattanooga shale formations in several easten and southern states and parts of Alaska. (Figure 1)

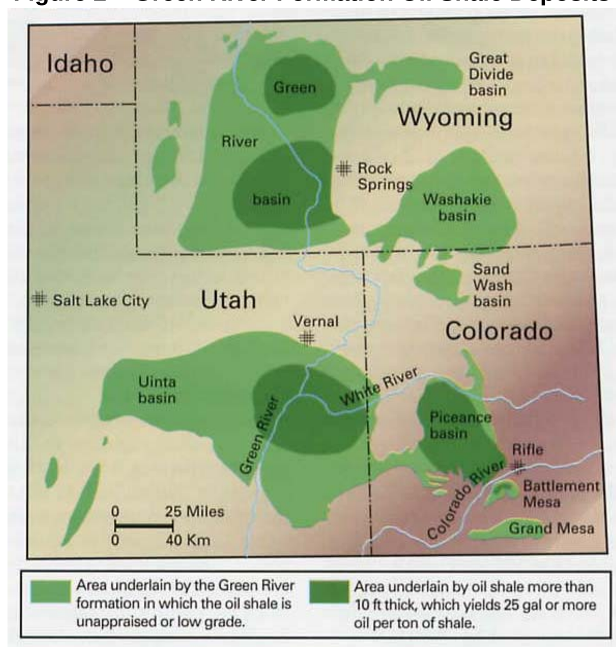
Figure 1 - Major U.S. Oil Shale Deposits



What is the Area of the Green River Formation?

- Oil shale underlies 17,000 square miles or 11 million acres in the Piceance (CO), Uinta (UT), Green River, Washakie (WY), and Sand Wash (CO) Basins. (Figure 2)[1]
- The Piceance Basin, which contains more than 80 percent of the recoverable resources of the Green River Formation, underlies a 35 mile by 35 mile (1,225 sq miles) area of western Colorado.

Figure 2 – Green River Formation Oil Shale Deposits



How Much Oil Shale Does America Have?

- America's total oil shale resources could exceed 6 trillion barrels of oil equivalent. However, most of the shale is in deposits of insufficient thickness or richness to access and produce economically.

How Much Oil Shale Could Be Recovered?

- Potentially recoverable resources are generally deemed to be at least 15 feet thick and have potential yields of 15 gallons per ton or more.
- Oil shale yields more than 25 U.S. gal/ton are generally viewed as the most economically attractive and hence the most favorable for initial development. (Table 1)
- About 1.8 trillion barrels of shale oil are thought to reside in deposits greater than 15 gallons per ton in the Colorado, Utah, and Wyoming.

Table 1: U.S. Oil Shale Resource in Place (Bil Bbls)[2]

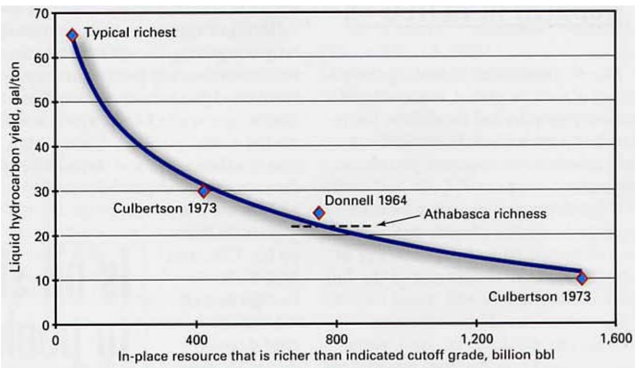
Deposits	Richness (gals/t)		
Location	5 - 10	10 - 25	25 - 100
Colorado, Wyoming & Utah (Green River)	4,000	2,800	1,200
Central & Eastern States	2,000	1,000	NA
Alaska	Large	200	250
Total	6,000+	4,000	2,000+

- The thickest and richest resources have the greatest technical recoverability and economic potential. (Table 2 and Figure 3[3])

Table 2: Potentially Recoverable Oil Shale Resources (Green River Formation)[4]

Thickness (Feet)	Yield (Gal/t)	CO	UT	WY	Total
> 100	> 30	355	50	13	418+
15 – 100>	>15	840	270	290	1,400+
Total		1,200	320	300	1,820+

Figure 3: Resource Distribution by Richness



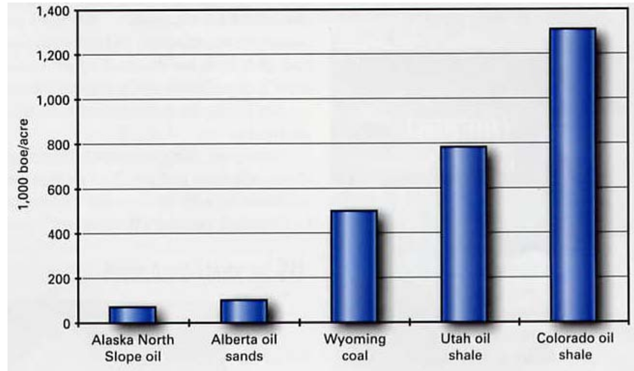
How Do We Know How Much Oil Shale Exists?

- More than a quarter million assays have been conducted on core and outcrop samples for the Green River oil shale.
- Results show that the richest zone, known as the Mahogany zone, is located in the Parachute Creek member of the Green River Formation. This zone can be found throughout the formation.
- Because of its relatively shallow nature and consistent bedding, the resource richness is well known, giving a high degree of certainty as to resource quality.

How Do U.S. Oil Shale Resources Compare with other U.S. and Canadian Energy Resources?

- U.S. western oil shales are more concentrated on a resource per acre basis than Alaskan North Slope oil or Alberta's tar sands. (Figure 4)[5]

Figure 4: Areal Density of Selected Resources



Who Owns the Oil Shale Resources?

- The U.S. Government owns and manages about 73 percent of the lands that contain significant oil shale deposits in the west. Federal lands contain about 80 percent of the known recoverable resource in Colorado, Utah, and Wyoming.
- As on 1978, private company ownership of oil shale lands in Colorado, Wyoming, and Utah totaled about:
  - -- 21 percent of the Piceance Basin (CO)
  - -- 9 percent of the Uinta Basin (UT)
  - -- 24 percent of the Green River Basin (WY)
  - -- 10 percent of the Washakie Basin (WY).[6]
- State governments and localities and Native American Tribes also own oil shale lands.

For More Information, Contact:

U.S. Department of Energy
Deputy Assistant Secretary for Petroleum Reserves
Office of Naval Petroleum and Oil Shale Reserves -- Anton R. Dammer, Director
1000 Independence Avenue, S.W
Washington, D.C. 20585

References

[1]Reproduced from *Oil & Gas Journal* "Is Oil Shale America's Answer to Peak-Oil Challenge?" Pennwell Corporation, August 9, 2004

[2] Duncan, D.C. and V.E. Swanson: "Organic-Rich Shales of the United States and World Land Areas, U.S.G.S. Circular 523, 1965; as reported in U.S. Office of Technology Assessment, "An Assessment of Oil Shale Technologies" 1980.

[3] Reproduced from Oil and Gas Journal, August 9, 2004

[4] U.S. Office of Technology Assessment "An Assessment of Oil Shale Technologies, 1980, p. 92, Table 14)

[5] Reproduced from Oil and Gas Journal, August 9, 2004

[6] U.S. Office of Technology Assessment "An Assessment of Oil Shale Technologies, 1980

Fact Sheet: Oil Shale Conversion Technology

Background

- Oil shale must be heated to temperatures between 400 and 500 degrees centigrade to convert the embedded sediments to kerogen oil and combustible gases.
- This can be achieved by mining the shale and heating it in surface retorts, or by contacting and heating the oil shale in-place (in-situ).

Surface Retorting

Numerous approaches to surface retorting were tested at pilot and semi-commercial scales during the 1970s. Two major types of surface retorts, vertical and horizontal, have offered significant promise.

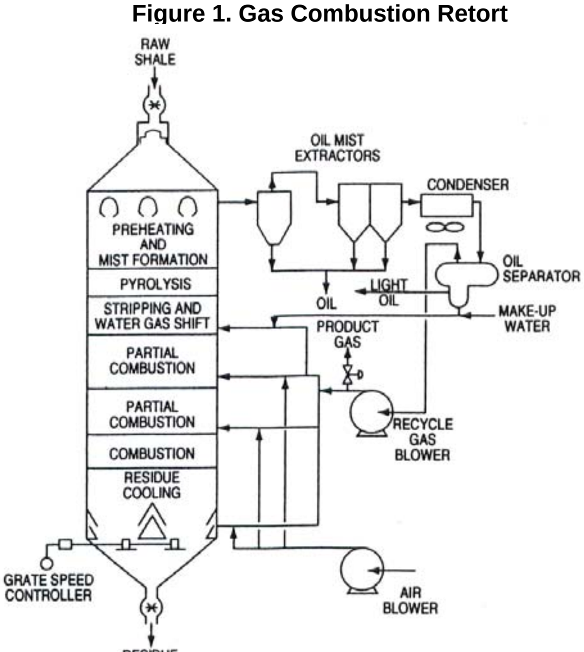
A. Vertical Retorts

Vertical shaft retorts have been used with increasing success and efficiency since the earliest days of oil shale operations in Scotland.

The Gas Combustion Retort (GCR), developed by Cameron Engineers and the U.S. Bureau of Mines is one of the most successful vertical retorts (Figure 1). GCR achieves high retorting and thermal efficiencies. GCR requires no cooling water, an important feature in semi-arid regions. A variation called Petro-Six is operating in Brazil.

- Crushed shale moves downward by gravity.
- Recycled gases enter the bottom and are heated by retorted shale. Air is injected and mixes with the rising hot re-cycle gases.
- Combustion of gases and residual carbon from the spent shale heats the raw shale above the combustion zone to retorting temperature.
- Oil vapors and gases cooled by the incoming shale leave the top of the retort as a mist.

Figure 1. Gas Combustion Retort



In another GCR variation, the **Paraho** process:

- Crushed shale (fines removed) descends by gravity.
- Zones for each step in processing the shale are maintained by managing gas flow in the retort.
- The retort can be operated in a direct or indirect combustion mode. The indirect combustion mode burns process gas in a separate furnace and hot gases carry heat to the retort.
- This technology is currently being considered for a major non-U.S. oil shale development effort.

B. Horizontal Retorts

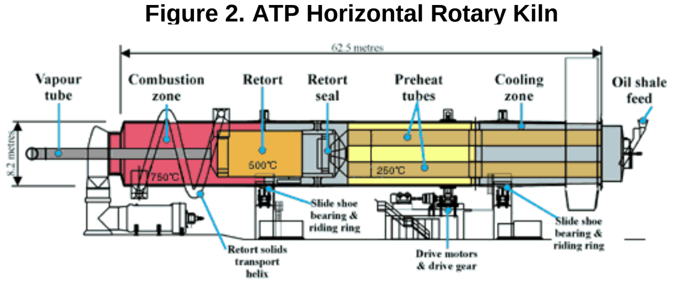
Both the TOSCO II and the Alberta Taciuk Processor (ATP) use horizontal rotating kilns for pyrolysis.

- TOSCO II, terminated in 1972, preheated shale in a bed, then circulated the shale in a hot rotating drum with heated ceramic balls.
- The ATP process combines gas recirculation and direct and indirect heat transfer from circulated hot solids in a rotating kiln.
- The ATP process is largely energy self-sufficient. Some of the hot processed shale is re-circulated in the retort with fresh shale to provide pyrolysis heat by direct, solid-to-solid heat transfer.

ATP has been reported to increase kerogen oil and gas yields, improve thermal efficiency, reduce process water needs, and minimize residual coke on spent shale, enabling environmentally-safe disposal.

ATP's ability to handle fines could be important for U.S. carbonate shales, which can disintegrate into fine particles. These particles can find their way into the shale oil and be difficult and costly to remove.

Figure 2. ATP Horizontal Rotary Kiln



ATP Caveat: Design issues and scale-up limitations have raised critical questions about ATP's viability for use in large scale commercial operations.

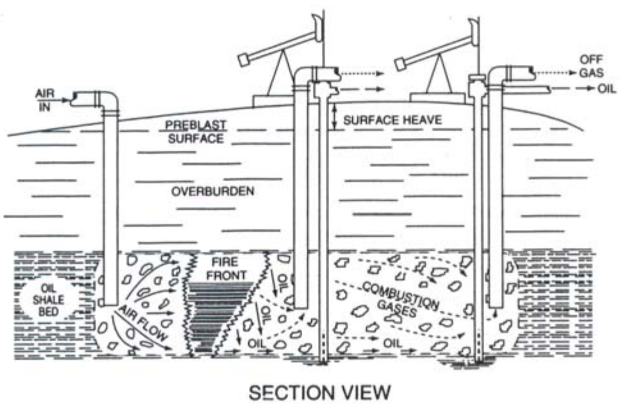
In-Situ Processes

In-situ processes can be technically feasible in deeper, richer deposits where the rock has natural permeability or where permeability can be created by fracturing.

True in-situ processes involve no mining.

- The shale is fractured, air is injected, the shale is ignited to heat the formation, and shale oil moves through fractures to production wells.
- Difficulties in controlling the flame front and the flow of oil can limit oil recovery, leaving areas unheated and some oil unrecovered. (Figure 3)

Figure 3: Conventional True In-Situ Process



Modified in-situ (MIS) may involve mining below or above the target shale deposit before heating to create void space of 20 to 25 percent.

- The shale is heated by igniting the top of the target deposit and recovering fluids from ahead of or beneath the heated zone.
- Modified in-situ processes can improve performance by heating more of the shale, improving the flow of gases and liquids through the rock formation, and increasing volumes and quality of the oil produced.

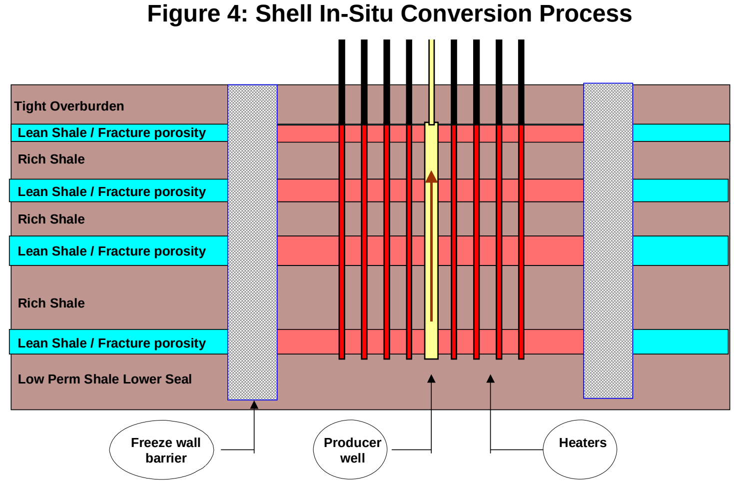
Environmental Caveat: Both true and modified in-situ processes are challenged by the potential for contamination of groundwater by pyrolized oil and other metals and toxics that may be left behind.

- **Shell ICP:** Shell's new in-situ conversion process (ICP) could produce high quality fuels in a more, economic and environmentally sound manner. In this substantial modification of the "true in-situ" process:
- Electric or gas heaters, placed in closely spaced vertical wells, slowly heat the shale for 2-4 years.
- The slow heating creates microfractures in the rock that augment natural permeability and enhance fluid flow from heated zones to production wells.
- Resulting shale oil and gases are moved to the surface by conventional wells and vapor recovery technology.
- Slow heating improves product quality; sub-sequent product treating is less complex, than for surface retorts or other in-situ approaches.
- Much more oil and gas may be recovered from a given area as shale oil and combustible gas products can be produced at greater depths than are accessible by other oil shale technologies.
- The ICP process involves no subsurface combustion of the resource, reducing environmental impacts.
- Close spacing, adjustable heat sources, and modern downhole monitoring technologies vastly improves temperature control.
- Innovative "freeze wall" technology is being tested to isolate production areas from intrusion of groundwater until shale heating, production, and post production flushing has been completed.

Shell is currently operating a modest field research effort in northwestern Colorado's Piceance Basin to test ICP's viability on the basin's world-class oil shale reserves. Critical issues include:

- Development of reliable heater technology
- Improvements of heater durability relative to down hole rock mechanics
- Validation of efficacy of freeze wall technologies.

Figure 4: Shell In-Situ Conversion Process



Fact Sheet: U.S. Oil Shale Economics

Economic Requirements for Oil Shale Feasibility

- Oil shale technologies must be demonstrated at commercial scale before definitive capital and operating costs of oil shale projects will be known.
- Oil shale projects must demonstrate capability to achieve a minimum rate of return at expected sustained average world oil prices.

What are the Major Cost Elements of Oil Shale Projects?

For Mining and Surface Retorting:

- Mine development: surface or underground
- Retorting & upgrading facilities: design, manufacture, and construction of facilities
- Infrastructure: roads, pipelines to upgrading plants and refineries, powerlines, utilities, storage tanks, waste treatment and pollution control.

For In-Situ (underground) Processing:

- Subsurface facilities: wells or shafts to access and heat the shale, recover liquids and gases, and isolate and protect subsurface environments.
- Surface facilities: production pumps and gathering systems, process controls, process power, and upgrading facilities.

How Big is a Commercial Scale Project?

- Commercial oil shale projects could range in size from 10,000 to 50,000 barrels per day for surface retorts to as much as 300,000 barrels per day for full-scale in-situ projects.

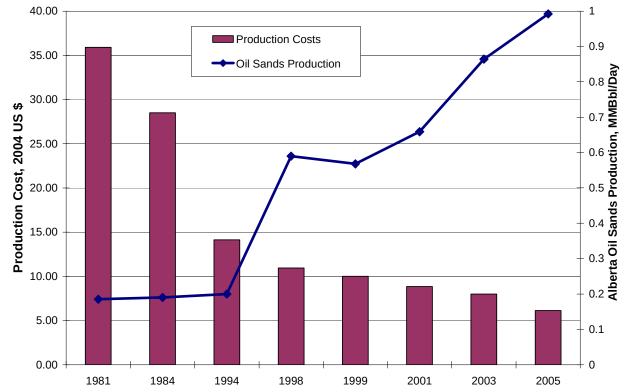
How Much Will Commercial Projects Cost?

- Cost estimates will vary according to the oil shale resource and the process selected. In the 1980s, cost estimates for a 100,000 barrel/day surface retort plant ranged from $8 - $12 billion (2005$)[1]. Capital costs are expected to be less today, i.e., $3.0 to $10.0 billion (2005$).

Can Costs be Expected to Decrease Over Time?

- Yes. Capital and operating costs can be expected to decrease over time with operating experience, improved understanding, design enhancements, and improved operating efficiencies, analogous

Figure 1 – Canadian Oil Sand Economics and Production



Production Costs: Oil & Gas Journal, July 14, 2003, V. 101.27
Production Volumes: Canadian Association of Petroleum Producers, Historical Statistics

- to the experience of the Province of Alberta in developing its oil sands resources.roduction costs in Alberta's oil sands declined by as much as 80 percent between 1980 and 2003. Oil shale cost reductions of 40 to 50 percent could occur as lessons from first of a kind facilities are learned and applied (Figure 1)[2].
- Mining capital costs have risen with the trend toward more mechanized mining operations. Mine operating costs have decreased significantly as mining efficiency has improved.
- Rapid industry growth may tax limited resources of skilled labor, materials, and manufacturing facilities for retorting technologies and mining and processing equipment, increasing costs.

What Sustained Oil Prices are Required for Oil Shale Projects to be Economic?

- First of a kind mining and surface retorting plants may eventually be economic, providing a minimum 15% rate of return, at sustained average world oil prices above $54.00 per barrel.
- In-situ processes may be economic at sustained average world oil prices above $35 per barrel.

What are the Potential Public Economic Benefits of Oil Shale Development?

- The Federal treasury, State and local governments, and the overall domestic economy stand to benefit from the direct contributions of a domestic oil shale industry and from the additional economic activity and growth that will result from industry development.
- Direct benefits can be measured in terms of: (1) Direct Federal revenues (from lease bonuses,

Federal taxes and the Federal share of royalties) (2) Direct state/local revenues (from State and local taxes and the state share of Federal royalty); (3) Contributions to Gross Domestic Product (GDP), and (4) the value of avoided oil imports.

- At a sustained production of about 2.5 million barrels of shale oil per day, the cumulative value of these benefits over a 25 year period could exceed $500 billion.
- Direct state/local revenues (from State and local taxes and the state share of Federal royalty); (3) Contributions to Gross Domestic Product (GDP), and (4) the value of avoided oil imports.
- At a sustained production of about 2.5 million barrels of shale oil per day, the cumulative value of these benefits over a 25 year period could exceed $500 billion.

With Oil Prices at $60/ Bbl, What are the Impediments to Investment in Oil Shale?

- Large initial capital requirements
- Insufficient private tracts of high-grade oil shale
- Restricted access to resources on public lands
- Oil price uncertainty and volatility
- Technology not demonstrated at commercially-representative scale
- Competing investment opportunities, including investments in other conventional and unconventional oil and gas resources

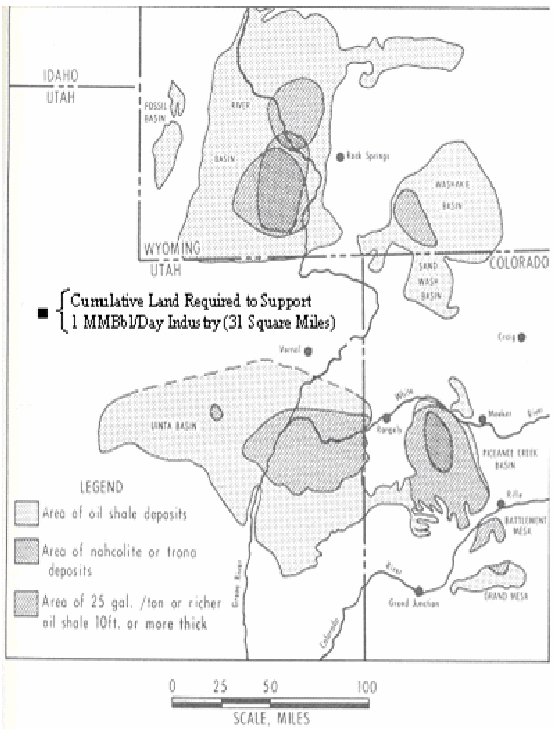
How Have Current Oil Shale Economics Been Modeled by DOE?

- DOE has performed an analysis of the economics of oil shale. DOE developed a model to evaluate project economics for the application of oil shale technologies to selected resource tracts, and the impacts of various incentives on project economics.
- As there are no commercial facilities currently operating in the United States, capital cost and production cost data used in the analyses were updated from past technology processes and from current vendor cost information to construct plausible cost scenarios.
- The analysis applied resource characterization data from surveys conducted by the U.S. Geological Survey in preparation for the 1974 Prototype Oil Shale Leasing Program.
- The economic analysis examined 27 USGS defined resource tracts, which were nominated by industry, to determine the most efficient technology approach for use at each location.
- The production cost and resource characterization data were then used to calculate minimum economic prices.
- The minimum economic price is defined as the breakeven price assuming a return on capital of 15 percent, and represents our best cost estimates for a mature industry.
- These cost estimates do not take into account research and development costs, permitting costs, land access issues, or production inefficiencies that are characteristic of first-of-a-kind plants. All of these other factors could add significantly to early development costs and have the potential to double production costs for the first plants.
- The model estimates cash flow for the various projects by evaluating plant capacity, development schedule, market prices for oil and natural gas, leasing royalty structure, operating costs, capital costs, and tax structure.
- The model determines the minimum economic cost shown and breakeven prices for a given technology for each resource tracts where it is being applied.
- Capital costs are the sum of investments needed per barrel of installed capacity. These costs include investments in mining, retorting, solid waste disposal, refining and upgrading, plant utilities, and other facilities.
- Operating costs include fuel, operating and maintenance personnel, consumable equipment and other non-capital costs for mining, retorting, refining and upgrading,The components of both capital and operating costs are different for various technologies used for mining, retorting, and upgrading. These costs were derived from information available from a variety of sources, particularly the Prototype Leasing Program in the early 1980's. These costs were escalated to 2004 dollars using Bureau of Labor Statistics data and were further validated with current vendor quotes.

References

[1] U.S. Office of Technology Assessment. "An Assessment of Oil Shale Technologies", 1980.
[2] Oil and Gas Journal, July 13, 2003.

Figure 1- Surface Area Required to Support Oil Shale Production



Source: DOI/BLM

Surface Impacts

- America's best oil shale resources are highly concentrated in several major deposits in Colorado, Wyoming and Utah. The areas are semi-arid and sparsely populated.
- Current uses include recreation, sheep and cattle grazing, mining, and oil and gas production.
- The area has considerable wildlife, including large mammals and migratory birds.
- Portions of the oil shale lands are in or adjacent to conservation and wilderness areas and scenic vistas.

How Much Land Will Be Required for Oil Shale Development?

- The richest oil shale deposits in the world are located in Colorado's Piceance Creek Basin and in the Uinta Basin, in Utah.
- Depending on depth, thickness, richness, and accessibility, oil shale may be surface mined, underground mined, or heated in-situ (i.e., in the ground). Deeper and thicker beds will likely be produced in-situ. A combination of these three approaches will likely be used.
- In 1972, the Department of the Interior estimated the cumulative surface area impacted by a domestic oil shale industry – over a 40 year period – would be ~31 square miles per million barrels of daily shale oil production capacity (MM Bbl/d). (Figure 1)[1] This figure could increase if surface processes comprise a greater share of operations than assumed in the 1972 Prototype Leasing Program, or decrease if new in-situ processes comprise a greater share.

What Land Impacts are Associated with Oil Shale?

- **Open-Pit (surface) mining** involves significant surface disturbance and can impact surface-water runoff patterns, subsurface water quality, flora, and fauna. Experience in coal mining and other mining industries has demonstrated that impacted lands can be very effectively reclaimed with minimal long-term effect.
- **Underground mining** involves much less surface disturbance. Surface impacts can be limited but will include run-off and fugitive dust emissions from shale transport and storage.
- **In-situ production** may involve limited mining to access the resource of drilling heater holes and production wells at very close spacing. Impacts will be similar to those experienced in oil and gas drilling operations. Heater holes and wells will likely require plugging and abandonment when heating and production operations cease.
- **Other surface impacts** will occur in association with construction of surface facilities, including retorting, upgrading, storage, and transportation. New pipelines, roads, and utilities, will also have surface impacts

- **Spent shale**: Surface retorts generate quantities of spent shale. Retort technology has improved to reduce residual carbon, making spent shale better suited for landfill. Backfilling will be employed in underground and surface mines. Some spent shale will be used to make commercial building materials, or landfilled. Satisfactory disposal and reclamation has been achieved in later-generation oil shale operations.

Air Quality Impacts

- Most western oil shale ore is a carbonate-based, kerogen-bearing marlstone. Heating carbonate rock to 450 to 500 degrees centigrade generates not only kerogen oil and hydrocarbon gases but also a slate of other gases, including: (1) oxides of sulfur and nitrogen, (2) carbon dioxide, (3) particulate matter, and (4) water vapor. Fugitive dust and fine particulates may also pose concern.
- Commercially available stack gas clean-up technologies, currently in use in electric power generation and petroleum refining facilities, have improved over the years and should be effective in controlling oxides and particulates emissions.
- Carbon dioxide (CO_2) will be produced in large quantities and may need to be captured, used in other commercial applications (such as improved oil recovery or coalbed methane operations), or otherwise sequestered. Depleted oil and gas reservoirs in the local area may provide effective sequestration targets.

Water Quality Impacts

- Runoff from mining and retorting operations can impact surface and groundwater. In-situ operations pose greater risks to groundwater quality. Controls will be required to protect surface and groundwater.
- Effective technologies and management processes already exist and have been demonstrated in other commercial-scale mining and chemical processing applications.
- In-situ processes have been particularly challenged to protect groundwater from contamination by kerogen oil or other produced gases and sediments.
- Promising freeze-wall technologies are being tested to isolate ground water from subsurface in-situ processing areas until post-production flushing and clean-up of the heated areas has been completed.

What Major Federal Laws and Regulations Will Apply to Oil Shale Development?

- National Environmental Policy Act (NEPA)
- Clean Air Act (CAA)
- Resource Conservation and Recovery Act
- Clean Water Act
- Comprehensive Environmental response, Compensation, and Liability Act (CERCLA)
- Emergency Planning and Community Right-to-Know Act
- Pollution Prevention Act
- Toxic Substances Control Act
- Endangered Species Act

State and local environmental standards and permitting processes must also be adhered to. In some cases, as with the Clean Air Act, the Federal regulation sets the minimum allowable standard and entrusts its implementation to the states under State Implementation Plans. The states have the latitude to apply a stricter standard than the Federal standard if they so choose.

Changes since the 1970s

- Maturation of environmental laws and regulations has resulted in more stringent standards and requirements.
- Commercial operations and environmental control technologies have advanced to improve efficiency, and reduce or better control effluents and emissions.
- Companies have implemented sophisticated environmental and safety management systems that are incorporated into project development and plant management and operations.

What is the Current Permitting Environment for Commercial Mining and Processing?

- Oil shale projects will require permits and approvals from several levels of government
- As environmental laws have matured, some permitting processes have improved, but permitting delays remain a major risk for large mining and industrial projects.
- The Energy Policy Act of 2005 establishes a prototype program for streamlining permitting processes for energy projects, in a selected group of states, including Colorado, Utah, and Wyoming.

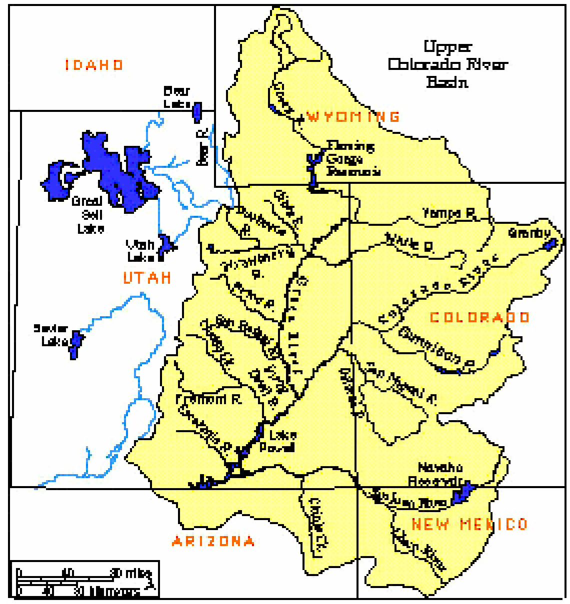
References

[1] "Final Environmental Impact Statement for the Prototype Leasing Program", U.S. Department of the Interior, Bureau of Land Management, Volume 1, 1973.

DOE Office of Petroleum Reserves – Strategic Unconventional Fuels

Fact Sheet: Oil Shale Water Resources

Figure 1. Upper Colorado River Basin Water Resources[1]



What Water Resources Will Be Needed for Oil Shale Industry Development?

- Development of Western oil shale resources will require significant quantities of water for mine and plant operations, reclamation, supporting infrastructure, and associated economic growth.
- Initial process water requirement estimates of 2.1 to 5 barrels of water per barrel of oil, first developed in the 1970s, have declined. More current estimates based on updated oil shale industry water budgets suggest that requirements for new retorting methods will be 1 to 3 barrels of water per barrel of oil[1]. Some processes may be net producers.
- For an oil shale industry producing 2.5 MMBbl/d, this equates to between 105 and 315 million gallons of water per day (MGD). (See Table 1). These numbers include water requirements for power generation for in-situ heating processes, retorting, refining, reclamation, dust control and on-site worker demands.
- Municipal and other water requirements related to population growth associated with industry development will require an additional 58 million gallons per day.
- A 2.5 MMBbl/d oil shale industry would require 0.18 million to 0.42 million acre feet of water per year, depending on location and processes used.[2]
- Water supply issues will be less critical for eastern oil shales where water supply is ample.

Where Will the Water Come From?

- In the West, water will be drawn from local and regional sources. The major water source is the Colorado River Basin, including the Colorado, Green, and White Rivers (Fig. 1)[3]. The Colorado flows between 10 and 22 million acre feet/yr.
- Water may also be purchased from other existing reservoirs. Transfers may be possible from other water basins, including the Upper Missouri.
- Western oil shale has high water content. Some oil shale contains 30-40 gallons per ton of shale. More typically it holds 2-5 gallons of water per ton. Much of this water can be recovered during processing and used to support operations. Produced water will contain organic and inorganic substances that can be removed with conventional filtering technologies.
- Recycling and re-use of process water will help to reduce water requirements.

How are Water Rights Allocated?

- Water in the West is treated much the same as other commodities – it can be bought and sold in a competitive market.
- Interstate "compacts" control the amount of river water each state is entitled to use. They allocate 5.3 to 5.9 million acre feet to the states. States are expected too use about 4.8 million acre feet of their allocations by 2020. If all industry water were withdrawn from the river, oil shale development would increase withdrawals by 0.18 to 0.42 million acre feet / year. Use of connate water and water re-use could reduce this volume.
- A system of rights and seniority has been established that allocates expected resources. Many private companies previously engaged in oil shale development retain very senior rights they obtained during the 1970s. Because Federal lands and prospective future leases will not come with water rights, some lessees may need to negotiate water purchases to advance projects.

Table 1. Estimated Water Demand for Oil Shale Production and Associated Population Growth.						
Water Requirement (Bbl Water Used/ Bbl Oil Produced)	**Oil Shale Production Rate** (Thou Bbls/d)	**Oil Shale Industry Water Demand** (Mil Gals/d)	**Projected Population Growth** (People)	**Additional Water to Support Population (mil gals/d)**	**Total New Water Demand** (Mil Gals/ d)	**Total New Water Demand** (Mil acre-ft/yr)
1-3	500	21 to 63	96,000	13	34 to 76	0.04 to 0.09
1-3	1,000	42 to 126	177,000	24	86 to 150	0.10 to 0.17
1-3	2,500	105 to 315	433,000	58	163 to 373	0.18 to 0.42

Are Available Water Supplies Adequate to Support a Domestic Oil Shale Industry?

- Initial estimates indicate that enough water will be available to support oil shale industry development in the Western states. However, variability of supply during low flow years may cause conflicts among water users.
- As the industry grows, additional water resources for human consumption and for oil shale processes will likely be required.
- The water consumption growth will slow as oil shale technologies become more efficient.
- For a mature industry, substantial water storage and water transfers may be required over time.

Allocation of Water Rights

- The overall allocation of water today is governed by the Colorado River Compact, originally agreed to on November 24, 1922. Currently there is a mix of both absolute and conditional water rights.
- Absolute rights are those that have been decreed by the state Water Court available for use.
- Conditional rights are rights that have not been through the Court process and therefore have not been decreed. They cannot be used until a decree has been granted and the rights have been determined to be absolute. Conditional rights only preserve a holder's seniority in accordance with the doctrine of first in time, first in right. In addition, conditional rights must undergo a diligence test every six years to preserve the conditional right.
- An absolute right is still subject to being curtailed (a call) in the event the water balance is insufficient for all rights and a senior right holder is being injured.
- To help assure supply, it is customary to file an Augmentation Plan which may consist of a plan for reservoir storage and release or purchase of senior rights that can be provided to a senior right holder.

A recent (October, 2003) agreement between the State of California and the Upper Basin States returns about 0.9 million-acre feet per year to the Upper Basin States that was being over-used by the State of California. This 0.8 million acre-feet/year increment could help support an oil shale industry, if the water were largely allocated to the use.[4]

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[2] Wood, Thomas "Water Resources for Oil Shale" Battelle, 2006.

[3] www.engineering.usu.edu/uwrl/atlas/ch7/ch7upcolcom.html

[4] Bunger, J.W., P.M. Crawford, and H. Johnson, *"Strategic Significance of America's Oil Shale Resource – Volume II: Oil Shale Resources, Technology and Economics"* U.S. department of Energy, Office of Deputy Assistant Secretary for Petroleum Reserves, March 2004.

Fact Sheet: U. S. Tar Sands Potential

Background

- Tar sands (referred to as oil sands in Canada) are a combination of clay, sand, water, and bitumen, a heavy, black, asphalt-like hydrocarbon.
- Bitumen from tar sands can be upgraded to synthetic crude oil and refined to make asphalt, gasoline, jet fuel, and value-added chemicals.
- U.S. tar sands tend to be lean and the mineral matter consolidated (sand grains are cemented together with minerals). While lessons may be learned from the experience in Alberta, modifications in those technologies may be necessary to cost-effectively produce synthetic oil from U.S. tar sands.

U.S. Tar Sand Resources

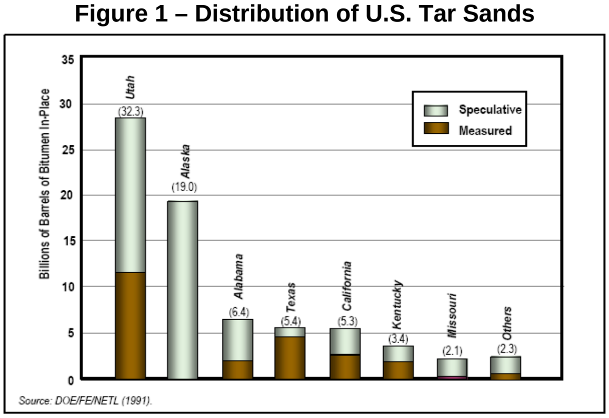
- U.S. tar sands resources are estimated at 60 to 80 billion barrels of oil; some 11 billion barrels may be recoverable[1]. The resource could support 500 M Bbl/d of production. The richest deposits are found in Utah (Table 1) and California.
- Current access, technology, and investment constraints make near-term production unlikely.
- Government action and incentives could catalyze an industry of 350,000 Bbl/d by 2035.

Table 1 - Utah Tar Sands Resources (MMBbl)

Deposit	Known Resource	Additional Potential
Sunnyside	4,400	1,700
Tar Sand Triangle	2,500	13,700
PR Spring	2,140	2,230
Asphalt Ridge	820	310
Circle Cliffs	590	1,140
Other	1,410	1,530
Total	**11,860**	**20,610**

Source: DOE/FE/NETL (1991)

Figure 1 – Distribution of U.S. Tar Sands



Tar Sands Technology

- Recovery technology options depend on grade, viscosity and depth. Shallow, colder resources are more viscous, but may be surface mineable. Deeper, warmer resources are less viscous, but may require in-situ processes to produce.
- Steam injection, including Steam Assisted Gravity Drainage (SAG-D), has been the favored in-situ method in Alberta;
- Other processes include solvent vapor, THAI, or Cold Heavy Oil Production with Sand (CHOPS).
- Bitumen may be separated from the sands by hot-water or cold-water or hot-water extraction processes, depending on the composition of the resource.
- But neither may work on U.S. tar sands that are "oil-wet", and consolidated.
- New technology solutions or adaptations of those used in Alberta may be necessary to produce oil from U.S. tar sands.
- About two tons of tar sands yield one barrel of oil - roughly 90 % of the bitumen is recovered.

Figure 2 – Cyclic Steam Injection

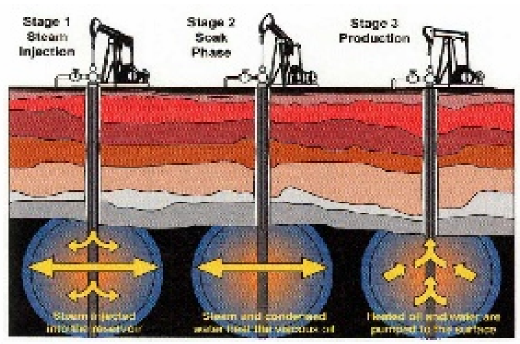
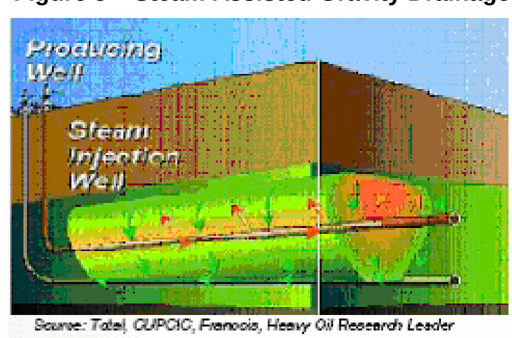


Figure 3 – Steam Assisted Gravity Drainage



Tar Sands Economics

- U.S. tar sands production costs are expected to be similar to or higher than costs in Alberta
- Costs may be higher as technologies are tailored to meet the characteristics of U.S. tar sands.
- Alberta oil sands costs declined steadily as lessons learned made project design, construction and operations more efficient.
- Projects require large capital investments. Capital costs depend on the production technology chosen. Mining is more capital intensive than alternative in-situ processes. (Table 2)
- Recently, capital and operating costs for Alberta oil sands projects have increased due to increased demand and tight supplies of skilled labor and construction materials. (Table 3)

Table 2 - Capital Costs of Tar Sands Projects in Canada ($2006 USD)	
Project Type	**Cost per Barrel of Daily Capacity**
Integrated mining, extraction and upgrading	$37,940
Mining and extraction	$17,070
Steam Assisted Gravity Drainage (SAG-D)	$11,380
Cyclic Steam Soak (CSS)	$17,070
Source: National Energy Board of Canada, An Energy Market Assessment, 2004. Costs converted to U.S. dollars and escalated to 2005 by INTEK, Inc.	

Table 3 - Alberta Oil Sands Costs / Barrel ($2006 USD)			
Process / Technology	**Product**	**Operating Costs ($/Bbl)**	**Total Supply Cost** ($/Bbl)**
Cold Production	Bitumen	4-7	9-13
Cold Heavy Oil Production with Sand	Bitumen	6-9	11-15
Cyclic Steam Stimulation	Bitumen	8-13	12-17
Steam Assisted Gravity Drainage	Bitumen	8-13	10-16
Mining / Extraction	Bitumen	6-9	11-15
Integrated Mining / Upgrading	Syncrude	11-17	21-27
** Total Supply Cost includes capital and operating expenses.			
Source: National Energy Board of Canada, An Energy Market Assessment, 2004. Costs converted to U.S. dollars and escalated to 2005 by INTEK, Inc.			

Markets for Oil from Tar Sands

- Bitumen from tar sands produced in Utah would be refined in PADD IV.
- PADD IV refining capacity (600 M Bbl/d, projected to double by 2025) could fully absorb potential Utah syncrude production if expanded.
- Refineries in the region now process 555 M Bbl/d of crude; 260 M Bbl/d from Canada.
- Utah tar sands must compete with Alberta syncrude for market share on a $/bbl basis

Tar Sands Environmental Data

Emissions

- Bitumen and syncrude manufacture produces a slate of gases that includes carbon dioxide, sulfur dioxide, and nitrous oxides.
- Technology is available to control and reduce emissions. Scrubbers on coking units can reduce sulfur emission to acceptable levels, given the bitumen is low in sulfur (~0.6 %) to begin with.

Land Disturbance

- The area of disturbance depends on mining versus in-situ processing. A 50 M Bbl/d surface operation would require 10,000 acres. Land can later be reclaimed with cleanup and rejuvenation efforts.

Water Impacts

- Depending on the process, a large volume of water may be needed to extract and process tar sands and bitumen, albeit because of favorable mineral composition, less than the 3 bbl/bbl current used in Alberta.
- Use of substantial volumes of water could affect regional water supplies.
- The release of treated water, could affect the regional water quality and supply.

References

[1] International Centre for Heavy Hydrocarbons, 1993 U.S. Bitumen Database, http://www.oildrop.org.

Fact Sheet: Coal to F-T Liquids Technology

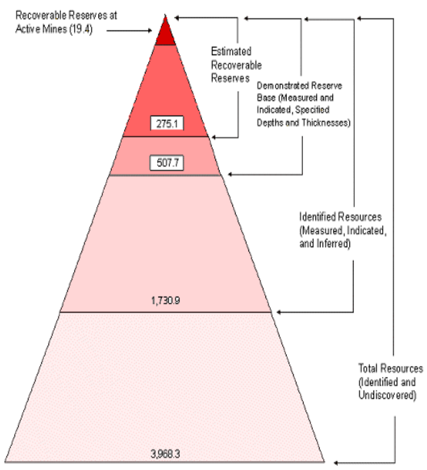
Background

- Coal-to-liquids (CTL) conversion could help increase domestic fuels production.
- America's massive coal resources could meet current U.S. coal demand, plus requirements for CTL, for another 200 years or longer.[1]

Coal Resources and Requirements

- U.S. demonstrated coal reserves exceed 507.7 billion short tons. About 45% is bituminous coal, and 55% is lower rank sub-bituminous and lignite.[2] Less than one billion tons are anthracite.
- One third is surface mineable and two thirds would require underground mining.

Figure 1 - Delineation of U.S. Coal Resources and Reserves - 2003 (Billion Short Tons)



- U.S. annual coal production reached 1.13 billion short tons in 2005, of which 90 percent was used for power generation[2].
- However, the National Coal Council estimates that with major investment and effort, domestic coal production could be doubled to exceed 2.4 billion tons by 2025.[3]
- A 32,000 Bbl/d CTL plant using bituminous coal would consume approximately 16,000 tons of coal per day or 6 million tons of coal per year. The same size plant using lignite would require twice that amount.[4]
- An 80,000 Bbl/d plant would consume about 39,500 tons per day or 14.5 million tons/year of high quality bituminous coal.[4]

Table 1 - U.S. Top Coal Reserve States (EIA 2005)

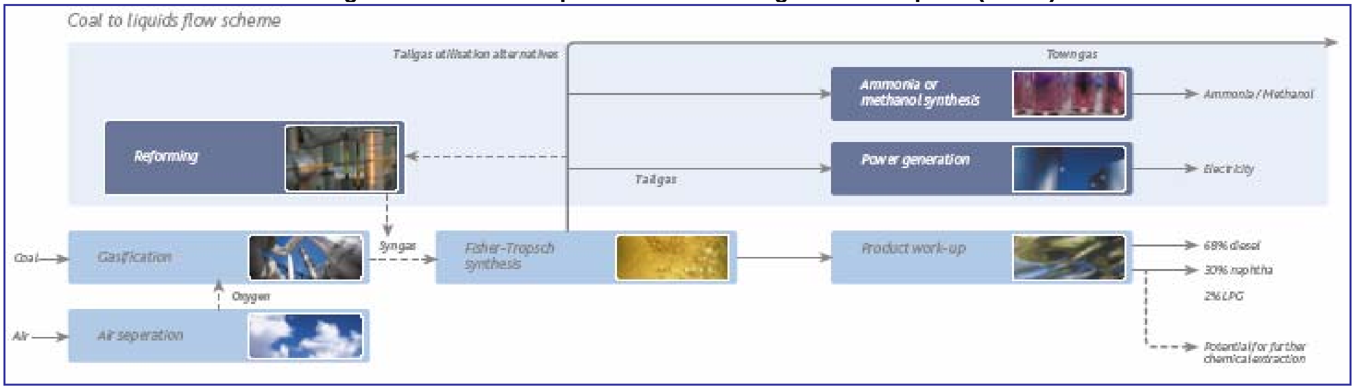
Rank	State	Demonstrated Coal Reserves (Billion Short Tons)
1	Montana	119.33
2	Illinois	104.6
3	Wyoming	64.8
4	West Virginia	33.5
5	Kentucky	30.5
6	Pennsylvania	27.8
7	Ohio	23.4
8	Texas	12.5
9	Colorado	16.4
10	Indiana	9.6

- An industry producing 2.5 million barrels/day would require thirty-three 80,000 Bbl/d plants and consume approximately 475 million tons of bituminous coal or 960 million tons of lignite per year.[5]
- An actual U.S. industry development profile would likely include more plants ranging in size from 10,000 to 30,000 Bbl/d than 50,000 to 80,000 Bbl/d.
- The Sasol Coal to Liquids plants in South Africa currently produce about 150,000 barrels of oil equivalent (BOE) per day.[5]

Indirect CTL Technology

- Coal can be gasified, using a variety of coal gasification processes, to create synthesis gas.
- Synthesis gas can be converted – through proven Fischer-Tropsch (FT) processes – to clean, high quality liquid fuels, including, primarily ultra-clean diesel and jet fuels.
- Depending on coal quality and process technology, FT processes can also yield quantities of naphtha and ammonia. The process can also be used to make methanol. (Figure 2)
- Integrated Gasification Combined Cycle (IGCC) technology can be incorporated in F-T plant design

Figure 2 – Coal to Liquids Process Using Fisher-Tropsch (Sasol)



- (and vice versa) to generate significant quantities of electricity for plant use or sale into the power grid.
- Although each of the component technologies is deemed proven, no integrated gasification, F-T synthesis and power generation plant has yet been demonstrated in the United States.

Indirect CTL Economics

- Coal Gasification, IGCC, and F-T Liquids plants are very capital intensive.[3]
- U.S. projects may be initiated at design capacities of about 10,000 to 30,000 Bbl/day, expanding over time to outputs of up to 80,000 Bbls / day.3
- Smaller plants will be more expensive on a barrel of capacity basis. Scully Capital estimates capital costs for a 32,000 Bbl/d CTL plant of between $81,000 and $92,000 / stream day barrel of output.[4] This is consistent with estimates that range from $100,000 per daily barrel for a 10,000 BPD plant to $80,000 for 80,000 BPD commercial plants.[3]
- Taking credit for the value of CO2, sold power, naphtha, and other products, and any premium for the high quality fuel, F-T liquids could compete with oil at a crude oil price of $41 to $61/ Bbl depending on plant size, coal type (bituminous v. lignite), and financial asumptions.[6]

Environmental Considerations

- Underground and surface coal mining can have significant environmental impacts. These impacts have been substantially reduced since the Surface Mining Act, adoption of more stringent Federal and state regulation, and development of best management practices and will continue to be applied in future coal mining and reclamation operations.
- Coal gasification and F-T synthesis generates significant quantities of carbon dioxide, (1.8 x petroleum refining), albeit in a concentrated form that can be captured, compressed, and sequestered.
- Depending on plant proximity to candidate fields, volumes of captured CO_2 may be injected into oil reservoirs to increase oil recovery or into coal seams to enhance coal bed methane production.
- IGCC power generation technology, combined with capture and storage of CO_2, could make integrated gasification power generation and liquid fuels production more environmentally desirable than traditional coal-fired power plants and oil refining.
- The F-T process produces superior quality diesel fuel that has virtually no sulfur, very low aromatic content and a high cetane number.[4] The naphtha produced is well suited for conversion to other fuels and/or chemicals in a refinery.

Reference

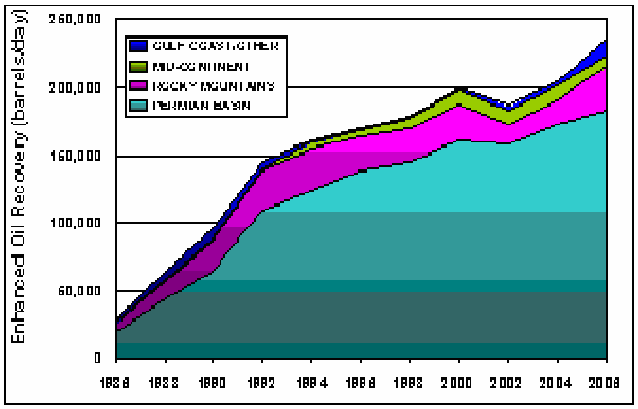
[1] BP World Statistical Survey of Energy Resources, 2005.
[2] U.S. EIA, Table 15. Recoverable Coal Reserves …" http://www.eia.doe.gov/cneaf/coal/page/acr/table15.html
[3] National Coal Council, "Coal: America's Energy Future, Volume II; A Technical Overview" March 2006 p. 59.
[4] Scully Capital "The Business Case for Coal Gasification with Co-Production " November 8, 2006.
[5] Sasol Synfuels International,Inc. "Unlocking the Potential Wealth of Coal". September 2005.
[6] Dr. David Gray, Mitretek "Presentation to National Academies Workshop on Peak Oil" Washington, D.C. - 2005.

Fact Sheet: CO_2 Enhanced Oil Recovery

Background

- Significant volumes of conventional oil remaining in known U.S. oil reservoirs could be produced by injection of carbon dioxide (CO_2).
- CO_2 enhanced oil recovery (CO_2 EOR) has been constrained by economics, technology, CO_2 supply, and pipeline infrastructure.
- Use of CO_2 EOR in additional basins and reservoirs could increase domestic oil supply and provide effective storage of CO_2 produced from unconventional fuels production.
- Current (2005) oil production from CO_2 EOR is approximately 237,000 Bbls/day.[1] (Figure 1)

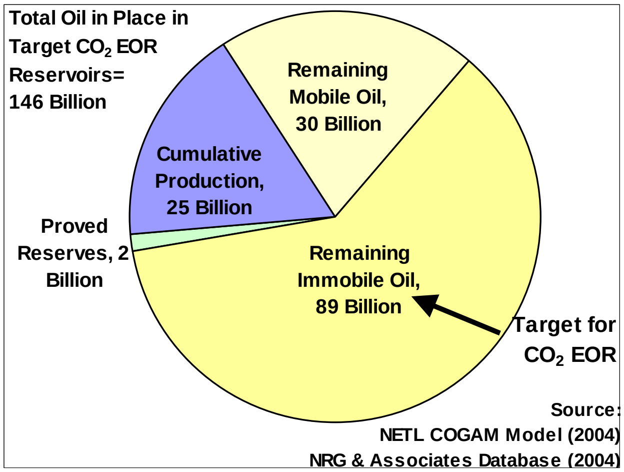
Figure 1 - U.S. CO_2-EOR Production is growing
Most Production Comes from the Permian Basin



U.S. CO_2 EOR Resources

- Based on the information available in the DOE/NETL Comprehensive Oil and Gas Analysis Model (COGAM), a total of 1,673 fields/reservoirs have been identified as candidates for CO_2-miscible flooding in the United States.
- These fields and reservoirs collectively account for 146 billion barrels of OOIP, with 65 billion barrels of remaining immobile oil as the target resource for CO_2–miscible flooding. (Figure 2)
- Application of CO_2 EOR in candidate reservoirs in other basins depends on the economic availability of CO_2 from natural or industrial sources.

Figure 2 – Potential Target for CO_2 EOR



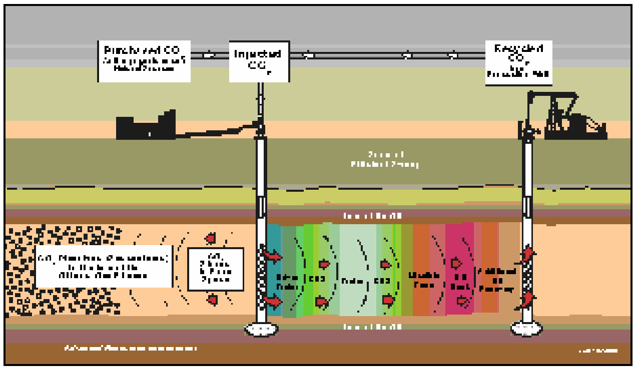
CO_2 EOR Economics

- Construction of new pipelines from CO_2 sources to target basins requires significant capital investments that must be supported by the long-term oil production potential of the target basin and by expectations of future oil prices.
- Oil price volatility is a significant deterrent to CO_2 pipeline and project investment by industry, particularly for smaller independent producers.

CO_2 EOR Technology

- CO_2 injection in conventional oil reservoirs can produce oil unrecovered by primary production or secondary water-flooding. CO_2 acts as a solvent that reduces viscosity and enables the oil to flow to the production well. (Figure 3)[2]

Figure 3 – What is CO_2 Enhanced Oil Recovery?



- Significant volumes of injected CO_2 can be recovered from producing wells and recycled by reinjection.
- When production is complete, the depleted reservoir may act as a CO_2 storage site.

CO_2 Sources and EOR Markets

- Natural sources of CO_2 now supply about 950 billion cubic feet (Bcf)/ yr (2.6Bcf/d) for CO_2 EOR projects. Approximately 75 percent is used in projects in West Texas (the Permian Basin). Other states with CO_2 EOR projects include Colorado, Wyoming, and Mississippi. (Figure 4)[3]

Figure 4 - Natural CO_2 Sources and Pipelines

- CO_2 EOR can provide a significant market for "EOR-ready CO_2", from industrial sources, including unconventional fuels projects such as shale oil, oil sands, and coal-to-liquids.
- The potential market is about 380 trillion cubic feet (Tcf,) or about 20 billion metric tons of CO_2. Future oil prices and CO_2 cost will determine how much of this market may be economically captured.[4]

CO_2 EOR Environmental Factors

Environmental concerns associated with CO_2-EOR development differ from those of other unconventional oil resources.

- Most production potential exists in already producing oil fields. So, many environmental concerns are already addressed within the existing regulatory oversight framework for these fields.
- Emissions are generally limited to gases from compressors used for CO_2 injection.
- CO_2 is captured from the production well and recycled, so CO_2 emissions are negligible if injected CO_2 is stored in the reservoir when production is complete, not vented.
- CO_2-EOR projects require significant amounts of water in order to pursue a 'water-alternating-gas," or WAG, injection processes. Much of this water will come from the oil formation itself, as it is produced with the oil.

References

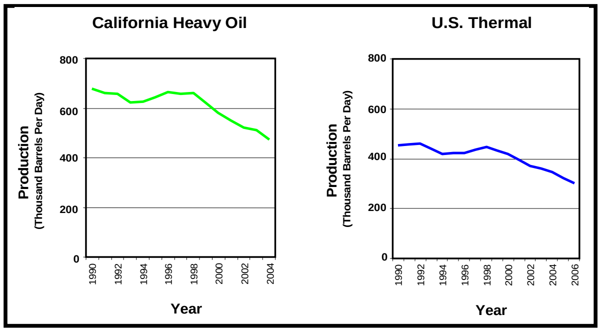
[1] Oil & Gas Journal Vol. 105.15, April 17 2006 p.40.
[2] Advanced Resources International, 2006.
[3] Oil and Gas Journal, April 2006.
[4] U.S. DOE Office of Fossil Energy,

Fact Sheet: U.S. Heavy Oil Resource Potential

Background

- "Heavy oil" is a dense, viscous crude oil that has an API gravity between 10 and 20 degrees.
- Most heavy oil has a viscosity between 100 and 10,000 centipoise (cp), and does not flow readily in the reservoir without dilution (with solvent) and/or the introduction of heat.
- Currently heavy oil production and other thermal EOR production are in decline. (Figure 1)

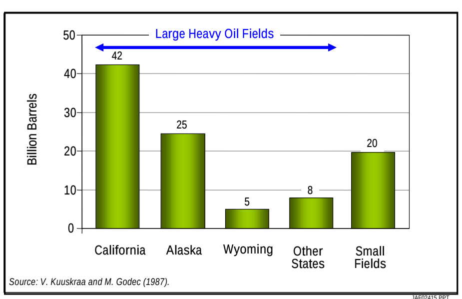
Figure 1 - California Heavy Oil and Thermal EOR Production are Declining[1]



U.S. Heavy Oil Resources

- The U.S. heavy oil resource approaches 100 billion barrels of original oil in-place (OOIP).
- The resource is concentrated in 248 large reservoirs, holding 80 billion barrels of OOIP, primarily located in California, Alaska, and Wyoming (Figure 2).
- Numerous other states, such as Arkansas, Louisiana, Mississippi and Texas, contain significant volumes.
- Some undeveloped heavy oil resources underlie public lands, including much of the heavy oil deposits in Alaska. Much of the potential exists in already producing basins.

Figure 2 - Distribution of U.S. Heavy Oil Resources



Heavy Oil Technology

- Most heavy oil recovery is by thermal methods, including steam injection and, to a lesser extent, in-situ combustion, and cyclic steam injection. Schematic diagrams of cyclic steam injection and steam flooding are shown in Figures 3 and 4.
- Thermal technologies have been applied to produce heavy oil resource in shallow (less than 3,000 feet) reservoirs, particularly in California.
- These technologies have generally been applied to large fields that can achieve higher return on investment due to lower costs per barrel of incremental oil recovered.
- Efficient thermal EOR technology could enable nearly two-thirds of the resource in-place to be recoverable from favorable shallow heavy oil fields.
- Additional production of up to 500,000 Bbl/d is possible with further development of the resource.
- Proven technology is applicable to nearly half of the remaining resource (shallower than 3000 feet).
- New technology is required to address resources deeper than 3000 feet and the more shallow but environmentally-sensitive Arctic resources.
- Current production's limited to the "best" reservoirs.

Figure 3 –Cyclic Steam Injection

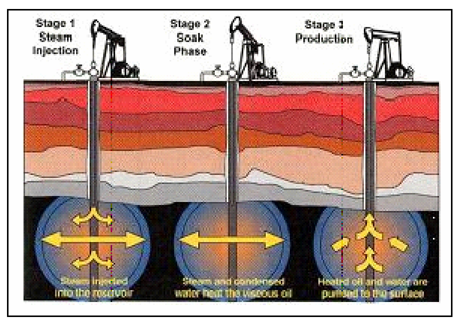
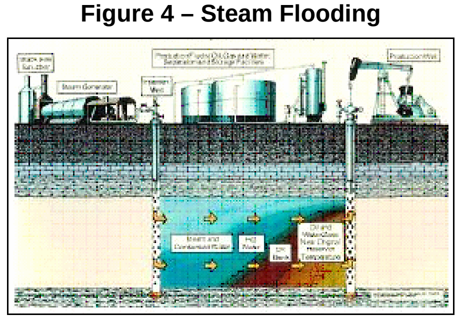


Figure 4 – Steam Flooding



Heavy Oil Economics

- Application of thermal recovery processes in heavy oil reservoirs in other basins depends largely on capital cost per barrel of steam generation.
- New cold production methods have less capital cost, but also have lower recovery efficiency.
- Oil price volatility is a significant deterrent to heavy oil project investment by industry, particularly smaller independent producers.
- Price differentials between heavy and light crude, due to crude quality, are substantial. (Figure 5)
- Expanded development is resource constrained – capital, people, investment, and "know how".

Figure 5 - Price Differential Between Light Sweet and Heavy Oils[2]

Source: Robert Heinemann, Presentation to National Academy of Sciences, 2005.[1]

Heavy Oil Environmental Factors

Environmental concerns associated with the development of heavy oil resources differ from those of other unconventional oil resources.

- Heavy oil production is controlled by current environmental laws and regulations that apply to conventional oil production. However, areas that have not experienced much oil development could face regulatory compliance and permitting challenges comparable to other unconventional sources of liquid fuels.
- Production techniques are established, but new approaches are needed to allow production of shallow Alaska North Slope (ANS) resources while protecting the permafrost.
- Air emissions challenges are associated with generation of steam for injection. Most projects use gas-fired generation to minimize emissions.
- Heavy oil projects require water for steam-generation; however, much of the water will come from the oil formation itself, as it is produced with the oil.

References

[1] Oil and Gas Journal, Vol 104.17 June 17, 2006; California Department of Oil Gas and Geothermal Resources, 2006.
[2] Robert Heinemann, Presentation to National Academy of Sciences, 2005

Fact Sheet: Energy Efficiency of Strategic Unconventional Resources

The Issues

- The three primary sources of energy are fossil hydrocarbons, nuclear, and solar in its various forms.
- Nuclear and solar are best suited for making electricity; fossil hydrocarbons are best suited for producing liquid fuels.
- Energy *production efficiency* is declining, reflecting the greater difficulty in recovering and converting energy to end-use forms.
- Reduced production efficiency increases economic costs and increases environmental impacts. These provide dual incentives to increasing the efficiency of primary production.

Definitions of Efficiency

- A rigorous, well-accepted method for calculating efficiency utilizes the "first-law of thermodynamics", which says:

  First-Law Energy Efficiency = energy output / energy input (expressed as a percent),

- Another useful measure is the Energy Return on Investment (EROI) which says:

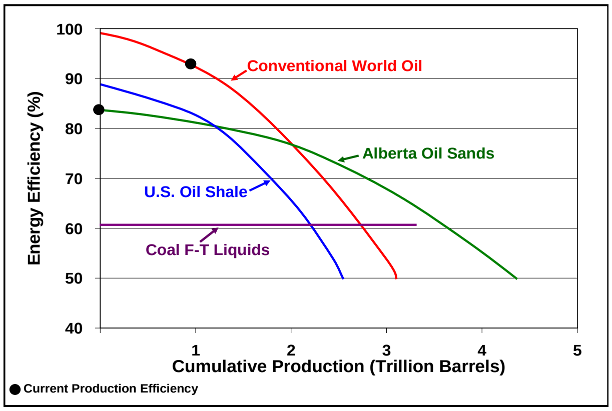
  EROI = (energy output – energy consumed) / energy consumed

- The EROI deducts the energy consumed in the process to yield the net energy produced. The higher the number, the greater the energy return for the energy invested in the process.

Efficiency of Fossil Fuels Production

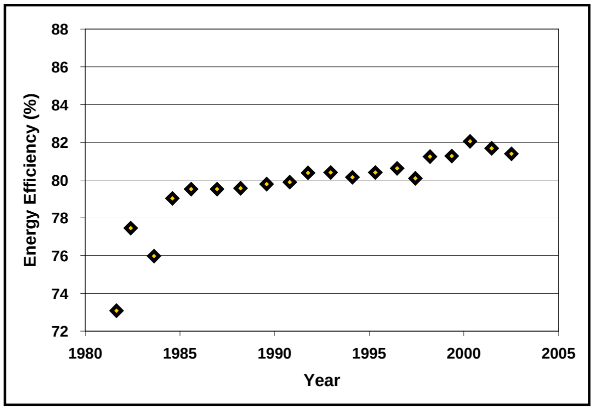
- Recovering oil from gushers in the early years of the petroleum industry required only the energy to drill the wells. Flush production was followed by pump jacks followed by enhanced oil recovery followed by exploration and development in increasing hostile environments, all of which increased energy use. Today, the world has cumulatively produced about 1 trillion barrels of conventional oil. In this process, the first-law energy efficiency has fallen from the high 90's to about 92% today (see Figure 1).
- Unconventional fuels require additional processing steps (mining, heating, upgrading) to recover and convert these resources to fuels. These steps consume energy and lower the energy efficiency relative to conventional oil.

Figure 1. Energy Efficiency vs. Cumulative Production



- Experience with the Alberta oil sands show that energy efficiency improves as the industry matures and operations improve. The average efficiency of oil sands development has improved to about 82% from the low 70's in first generation facilities. (See Figure 2).
- U.S. oil shale is richer in energy content than the Alberta oil sands. Therefore, the first-law energy efficiency for oil shale will be greater than for oil sands.
- All fossil resources will become more difficult to produce as the highest grade and most accessible deposits are produced. Additional energy will therefore be required to produce each incremental barrel. This will continue to lower energy efficiency for all conventional and unconventional fossil resources.

Figure 2. Oil Sand Efficiency Increases over Time



Calculated Efficiencies for Liquid Fuels Production

Energy efficiency and energy return on investment are summarized for various resources in Figure 3. In this calculation *only the external energy imported to the process* is used to calculate the EROI.

During initial development, conventional world oil had energy efficiency in the high 90 percent range and a EROI of 20 or more. The energy cost of deep drilling, secondary recovery, enhanced oil recovery, and the production of higher viscosity oil has reduced the energy efficiency to about 92% and the EROI to about 10.

As compared with conventional oil, all unconventional supply options have significantly lower energy efficiency and a lower EROI.

Table 1. Energy Efficiency Estimates

Resource and Process	First-Law Energy Efficiency, %	EROI, Value
Conventional petroleum E&P	92	10.5
U.S. Oil Shale (Surface)	82	>10.0
Alberta Oil Sands (Surface)	82	7.2
Alberta Oil Sands (in-situ) (similar to heavy oil)	86	5.0
U.S. Oil Shale (in-situ, non-electric heat)	89	6.9
U.S. Oil Shale (in-situ, electric heat)	78	2.5
Coal IGCC with FT synthesis	65	6.0
Ethanol from Corn (after Wang)	52	< 1.0

Source: James W. Bunger Associates, 2006.

Conclusions

- The United States must diversify its fuel supply and improve the efficiency of fuel use to meet increasing energy supply and demand challenges and to strengthen our nation's energy security.
- Fortunately, the nation has several trillion barrels of unconventional resources that can contribute to diversifying supply and increasing domestic production
- Unconventional fuels alone, however, will be insufficient to significantly *reduce* the nation's dependence on imports – improvements in end-use efficiency will also be needed to reduce liquid fuels demand.
- More energy will be required to produce fuels from unconventional resources than was required in the era of easy oil. However, unconventional fuels can be produced with substantial positive net energy gains.

"So long as oil is used as a source of energy, when the energy cost of recovering a barrel of oil becomes greater than the energy content of the oil, production will cease no matter what the monetary price may be."

-- M. King Hubbert
(as Referenced by Ivanhoe, 1982).

Fact Sheet: Carbon Management for Strategic Unconventional Resources

The Issues

- Carbon dioxide (CO_2) in the earth's atmosphere has been implicated in global warming.
- The use of fossil fuels for the energy needs of society produces emissions of CO_2.
- Production of unconventional fuels (oil shale, coal to liquids, heavy oil) produces more CO_2 than is produced when using conventional petroleum; the issues are:
  - Where CO_2 is produced in the process,
  - The concentration of the produced CO_2, and
  - The cost of capturing and sequestering it.
- Technologies are being developed and demonstrated for more efficiently capturing, concentrating, and storing or utilizing CO_2 generated in energy production processes.
- Global and national assessments of carbon sequestration potential show vast storage capacity.

Carbon Dioxide Sequestration and Utilization

- Carbon dioxide may be sequestered in deep saline formations, depleted natural gas reservoirs, depleted oil reservoirs, deep unmineable coal seams, deep saline-filled salt formations, salt caverns, and organic shales.[1]
- In April, 2007, the U.S. DOE published the first edition of the Carbon Sequestration Atlas of the United States and Canada[2]. In the Atlas, the seven regional federal/state sequestration partnerships estimate that at least 3,500 billion tons of CO_2 may be sequestered in oil and gas reservoirs, unmineable coal seams, and deep saline formations. The sequestration partnerships estimate over 1,000 years of total sequestration potential in the United States.
- The Battelle Global Energy Technology Strategy Program in 2006 reported that "assuming that other advanced energy technologies are developed and deployed along with carbon capture and storage systems, this potential storage capacity should be more than enough to address CO_2 storage for at least this century."[3]
- Enhanced oil recovery utilizing CO_2 (CO_2-EOR) is a proven technique with a long history in United States oil fields. The federal/state sequestration partnerships estimate that 89 billion barrels of oil could be recovered and 20 billion metric tons of CO_2 could be utilized using current CO_2-EOR technologies. Ultimately, as much as five times as much CO_2 could be stored and three times as much oil could be recovered using advanced technology.[4]
- Sequestration and CO_2-EOR opportunities are widespread but are not found in every locale. An extensive pipeline system may ultimately be required. CO_2 transport via pipeline is proven technology and in use in oilfields in the United States. Today, approximately 3,000 miles of dedicated CO_2 pipeline deliver CO_2 to commercial EOR projects in North America.[5]

Carbon Dioxide Sequestration Issues

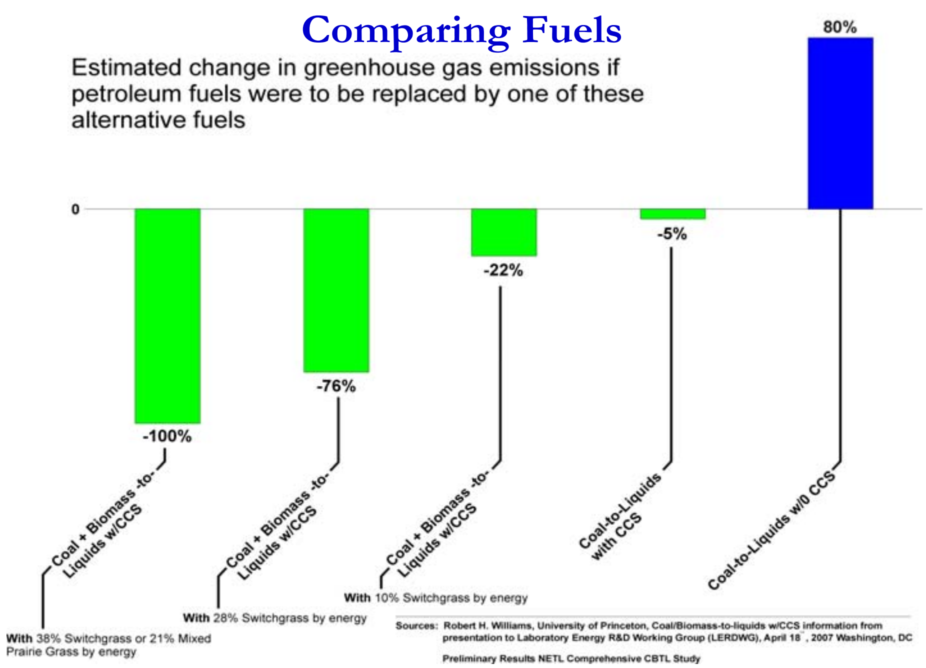
- The Massachusetts Institute of Technology in 2007 identified the major issues relating to sequestration as:
  - Sufficient capacity for storage;
  - Understanding of storage mechanisms;
  - Establishing a process to certify injection sites;
  - Monitoring and verification of the movement of subsurface CO_2;
  - Probability of and risks associated with leakage.
- MIT concluded that "there do not appear to be unresolvable open technical issues underlying these questions" and that "the hurdles to answering these technical questions well appear manageable and surmountable."[6]
- Sequestration issues also include legal questions relating to (a) ownership of pore space, (b) transfers of ownership and liability, (c) competition between mineral rights and storage rights, carbon dioxide reduction credit allocation, and (d) territorial and constitutional jurisdiction.[7]

Carbon Dioxide Emissions Technology

- The Fischer-Tropsch process utilized in production of coal-to-liquids (CTL) and in co-production of electricity and transportation fuels, hydrogen, or chemicals via Integrated

Gasification Combined Cycle (IGCC) requires separation of CO_2 from the synthesis gas, and consequently produces a concentrated stream of carbon dioxide at low cost that may be sequestered or utilized.

- Shale oil, heavy oil, and oil from tar sands will likely be centralized in large manufacturing facilities in which concentrated streams of carbon dioxide can be captured for beneficial use or sequestration.
- Because production of transportation fuels from all types of unconventional energy resources will either employ or produce large amounts of electricity, development of generation technologies for efficiently capturing carbon dioxide is a major consideration in development of unconventional fuels industries, as well for the national energy mix in general.
- Government and industry partnerships are developing a wide range of technologies for reducing CO_2 emissions by increasing the efficiency of electricity generation that range from near-immediate CO_2 emissions reductions of 7 - 8 percent from power plants that operate at supercritical temperatures and pressures to near-term (7 – 10 years) reductions of 20 - 30 percent by ultra supercritical power plants and longer-term (10 years or more) near total reductions from IGCC and sequestration.[8]
- Government and industry are developing a wide range of technologies for reducing CO_2 emissions in coal gasification and production of transport-tion fuels from coal. The chart below shows that production of liquid transportation fuels from coal utilizing processes that sequester CO_2 can result in no more, and possibly less, CO_2 emissions as conventional petroleum fuel. The addition of biomass to the coal in the gasification stage of CTL production along with carbon capture and sequestration can dramatically reduce the amount of CO_2 emissions.



Sources: Robert H. Williams, University of Princeton, Coal/Biomass-to-Liquids w/CCS information from presentation to Laboratory Energy R&D Working Group (LERDWG), April 18, 2007 Washington, DC
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8 National Coal Council. Technologies to Reduce or Capture and Store Carbon Dioxide Emissions: A Report to the Secretary of Energy. 2007.

Appendix 2 – Western Energy Corridor Initiative

Summary Approach

NPOSR /National Labs

Western Energy Corridor Initiative

The proposed study is to assess the impacts of oil shale development in the context of all other development in Colorado, Utah, and Wyoming. The study is to consist of three distinct phases.

Phase I – Comprehensive Baseline Assessment: To enable accurate and quantitative evaluations of environmental and economic impacts, predevelopment or baseline conditions must be established. Baseline information will include various data encompassing energy and other natural resources, air quality, water quality and quantity, technology, policy, economics, population dynamics, regulations, etc.

Phase II – Develop Analytical Tools: Assessing cumulative impacts will require the application of sophisticated modeling tools to characterize processes and activities at multiple scales and to consider the complex interdependencies of multiple alternative development scenarios involving diverse energy resources. This will require the identification of useful models that already exist, modifying existing models as appropriate, and developing new models.

Phase III – Integrated Impact Assessment of Development Scenarios: The models identified/developed in Phase II will be utilized to determine integrated impacts under a variety of development scenarios, as needed for regional decision-making by local, state, and federal governments.