TASK FORCE ON STRATEGIC UNCONVENTIONAL FUELS

America's Strategic Unconventional Fuels

Oil Shale • Tar Sands • Coal Derived Liquids • Heavy Oil • CO_2 Enhanced Recovery and Storage

Volume III – Resource and Technology Profiles

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IN RESPONSE TO SECTION 369 OF THE ENERGY POLICY ACT OF 2005 (P.L. 109-58)

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THE STRATEGIC UNCONVENTIONAL FUELS TASK FORCE

Honorable Samuel W. Bodman
Secretary of Energy
1000 Independence Ave SW
Washington, D.C. 20585

Dear Mr. Secretary:

The Task Force on Strategic Unconventional Fuels is pleased to submit its integrated strategy and program plan for *America's Strategic Unconventional Fuels*, as directed by Section 369(h)(5)(A) of the Energy Policy Act of 2005. This document builds on the report of *Initial Findings and Recommendations of the Task Force* that was completed in September 2006 and incorporates new recommendations resulting from the planning process and subsequent analyses.

This report is a product of a Task Force of eleven (11) members including the Secretaries of the Departments of Energy, Defense, and the Interior; the Governors of the States of Colorado, Kentucky, Mississippi, Utah, and Wyoming; and representatives of localities in those states that would be impacted by the development of the unconventional resources located therein. This report does not reflect agreement on all recommendations. However, the report lays out legitimate policy options which the Administration, Congress, States and local governments may consider. Nothing in this report reflects an official position of any member of the Task Force. The views and concerns of the Governors of the States of Colorado and Wyoming are articulated in prepared statements provided in an Appendix to Volume I of this report.

The Task Force concurs that the domestic and global fuels supply situation and outlook is urgent. Increasing global oil demand, declining reserve additions, and our increasing reliance on oil and product imports from unstable foreign sources require the Nation to take immediate action to catalyze a domestic unconventional fuels industry. Responsible development of America's oil shale, tar sands, heavy oil, coal, and oil resources amenable to recovery by carbon dioxide injection, to produce liquid fuels could reduce our dependence on imports and provide reliable and secure sources of strategically important liquid fuels. Aggressive development by private industry, and encouraged by government, could supply all of the Department of Defense's domestic fuels demand by 2016, and supply upwards of 7 million barrels per day of domestically produced liquid fuels to domestic markets by 2035. The Task Force has adopted that level as the objective for the Strategic Unconventional Fuels Program.

The Task Force has evaluated the extent and the potential contributions of each of these resources, and has developed a detailed plan for an integrated program to promote and accelerate their commercial development. In developing its recommendations and plan, the Task Force carefully considered and addressed the crosscutting issues, including environmental protection, water resources, socioeconomic impacts, markets, infrastructure, and carbon management, associated with concurrent development of unconventional fuels. The integrated program could achieve these goals in a sustainable and environmentally sound manner and mitigate against potential adverse impacts on affected states and communities.

This report presents development scenarios to be considered in establishing an unconventional fuels industry.

Respectfully submitted by:

TASK FORCE ON STRATEGIC UNCONVENTIONAL FUELS

CC: Distribution Attached

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Oil Shale Resource and Technology Profile

Oil Shale Working Group Analysis Prepared For The Strategic Unconventional Fuels Task Force

February 2007

1. OIL SHALE RESOURCE ACCESS

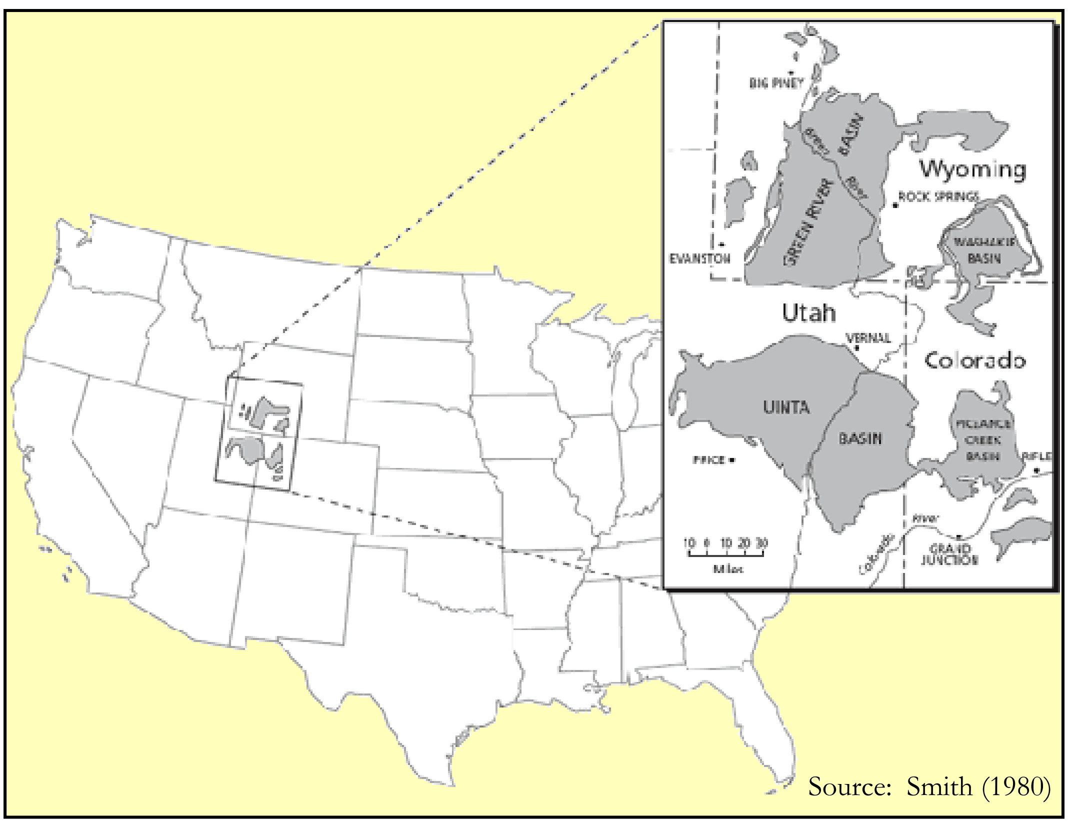
Oil shale is a hydrocarbon bearing rock that occurs in 27 countries around the world. Worldwide, the oil shale resource base is believed to contain about 2.6 trillion barrels, of which the vast majority (2 trillion barrels) is located in the United States.

The most concentrated U.S. oil shale deposits are located in Colorado, Utah, and Wyoming. Of the 1.2 trillion barrels contained in these three western states, the majority (80 percent) are located on Federal land managed by the Department of Interior (DOI). Access to the oil shale resources located on public lands is therefore a critical step in the future commercial development of this resource as discussed in this chapter.

SIZE

Large Areas of the United States contain oil shale deposits, but those in Colorado, Utah, and Wyoming contain the greatest promise for shale oil production in the immediate future (Figure III-1). The oil shale deposits in these three states occur beneath 25,000 square miles (16 million acres). These deposits contain approximately 1.2 trillion barrels of oil equivalent. Recovery of even a small fraction of this resource would represent a significant energy supply to supplement the Nation's oil supply for many decades.

Figure III- 1. Principal Reported Oil Shale Deposits of the United States



QUALITY AND GRADE

Oil shale resources of the United States have been extensively characterized. Yields greater than 25 gallons per ton (gal/ton) are generally viewed as the most economically attractive, and hence, the most favorable for initial development. Table III-1 from the U.S. Geological Survey[1] displays the richness of various oil shale deposits in three areas of the United States.

Table III- 1. U.S. Oil Shale Resource in Place (Billion Bbls)

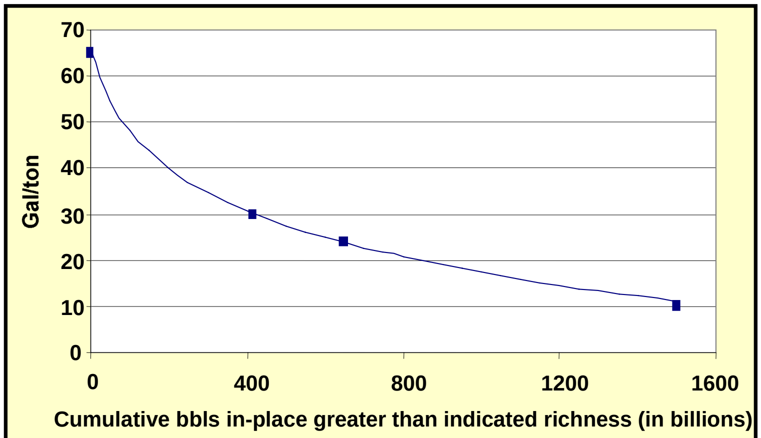
Deposits	**Richness (Gallons/ton)**		
Location	**5 - 10**	**10 - 25**	**25 - 100**
Colorado, Wyoming & Utah (Green River)	4,000	2,800	1,200
Central & Eastern States	2,000	1,000	NA
Alaska	Large	200	250
Total	**6,000+**	**4,000**	**2,000+**
Source: Duncan, and others (1965)			

The oil shale from each region of the U.S. has unique characteristics as summarized below.

WESTERN OIL SHALES

The most economically attractive deposits, containing in excess of 1.2 trillion barrels are found in the Green River Formation of Colorado (Piceance Creek Basin), Utah (Uinta Basin) and Wyoming (Green River and Washakie Basins). More than a quarter million assays have been conducted on the Green River oil shale. In the richest zone, known as the Mahogany Zone, oil yields vary from 10 to 50 gal/ton and, for a few feet in the Mahogany zone, up to about 65 gal/ton. According to Culbertson and Pittman[2], of the western resource, an estimated 418 billion barrels are in deposits that will yield at least 30 gal/ton in zones at least 100 feet thick. Donnell[3] estimates resources of 750 billion at 25 gal/ton in zones at least 10 feet thick (Figure III-2).

Figure III- 2. Cumulative Resource Greater than Indicated Richness



Source: Donnell (1964)

EASTERN OIL SHALES

Eastern oil shale deposits have been well characterized as to location, depth, and carbon content. The eastern shale is located among a number of states and is not as concentrated as the western shale. Additionally, eastern deposits have a different type of organic carbon than the western shale. As a result, conventional retorting of eastern shale yields less shale oil and a higher carbon residue as compared with the western shale. Because of these differences, industry interest in oil shale commercialization has focused on the rich, concentrated oil shale deposits of the western states.

In the future, Eastern shale has the potential to become an important addition to the nation's unconventional fuel supplies. The Kentucky Knobs region has resources of 16 billion barrels, at a minimum grade of 25 gal/ton. Near-surface mineable resources are estimated at 423 billion barrels[4]. Ninety-eight percent of these accessible deposits are in Kentucky, Ohio, Tennessee, and Indiana. With processing technology advances, for example the addition of hydrogen to the retorting process, potential oil yields could approach those of the western shale.

OTHER OIL SHALES

Numerous deposits of oil shale are found in the United States. The two most important deposits are the western and eastern areas described above. However, oil shale deposits also occur in Nevada, Montana, Alaska, Kansas, and elsewhere, but these are either too small, too low-grade, or have not yet been well explored to be considered for near-term development.

FACTORS CONSTRAINING WESTERN OIL SHALE DEVELOPMENT

The development of western oil shale will require access to public lands since 80 percent of the resource is located on Federal land managed by the Bureau of Land Management. The remaining resources are owned by states, individuals, private companies, and tribes. Privately owned lease holdings are concentrated near the southern margins of Colorado's Piceance Creek Basin where the oil shale outcrops to the surface. Oil leases on private lands have sufficient contiguous oil shale resources to support commercial-scale operations up to a maximum of 400 MBbl/d[5]. Mining and surface processing would limit the production from any one development to about 100 MBbl/d.

In contrast, public lands are concentrated near the center of the Piceance Creek Basin where the oil shale thickness increases from 200 feet at the basin margins to over 1,500 feet near the depositions center of the Basin. With increased thickness, there is a corresponding increase in the oil shale richness. Federally owned land could easily support a number of large projects with the ultimate production capacity of each lease of 100 to 300 MBbl/d.

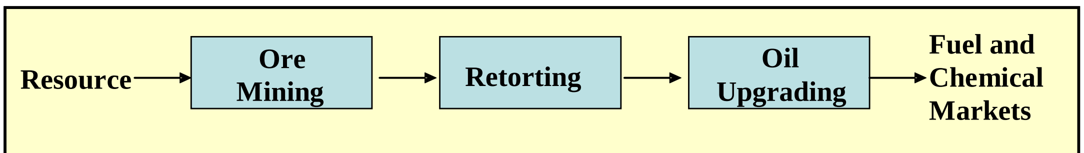
Because of the differences in thickness and quality, private developers will be reluctant to develop private lands first, so long as the possibility exists that the higher-grade resources on public lands will be available to potential competitors. Therefore, it is unlikely that large-scale commercial oil shale development will occur without the Federal government making public lands available for lease or exchange. Logical development patterns could be enhanced by trading Federal lands with states and/or private resource holders.

Conflicts between surface and subsurface uses may occur through priorities of resource management plans or through legislated priorities such as threatened and endangered species critical habitat, wilderness areas and the like. These potential conflicts will be addressed in the Department of Interior's process to develop an environmental impact statement for oil shale development on public lands.

2. TECHNOLOGY ADVANCEMENT AND DEMONSTRATION

Energy companies and petroleum researchers have, over the past 60 years, developed and tested a variety of technologies on a small scale for recovering shale oil from oil shale and processing it to produce fuels and byproducts. Both surface processing and in-situ technologies have been examined. Generally, surface processing consists of three major steps: (1) oil shale mining and ore preparation (2) pyrolysis of oil shale to produce kerogen oil, and (3) processing kerogen oil to produce refinery feedstock and high-value chemicals. This sequence is illustrated in Figure III-3.

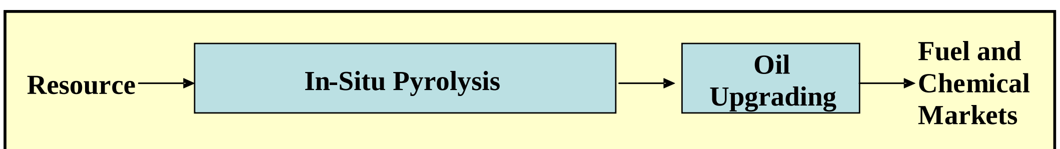
Figure III- 3. Conversion of Oil Shale to Products (Surface Process)



Source: DOE (2004, pg. 7)

For deeper, thicker deposits, not as amenable to surface- or deep-mining methods, the shale oil can be produced by in-situ technology. In-situ processes minimize or, in the case of true in-situ, eliminate the need for mining and surface pyrolysis by heating the resource in its natural depositional setting. This sequence is illustrated in Figure III-4[5]. Both process sequences are described in greater detail below and in Appendix A.

Figure III- 4. Conversion of Oil Shale to Products (True In-Situ Process)



Source: DOE (2004, pg. 8)

SURFACE MINING

Surface mining is likely to be used for those zones that are near the surface or that are situated with an overburden-to-pay ratio of less than about 1:1. Numerous opportunities exist for the surface mining of ore averaging better than 25 gallon/ton, with overburden-to-pay ratios of less than 1, especially in Utah.

UNDERGROUND MINING

Room and pillar mining is likely to be used for resources that outcrop along steep erosions. This method of mining was used successfully by government and by private industry to extract oil shale from along the southern boundary of the Piceance Creek Basin. Deeper and thicker ores near the center of the Basin will require vertical shaft mining, modified in-situ, or true in-situ recovery approaches that have not yet been proven at a commercial scale.

SURFACE RETORTING TECHNOLOGY

Once the shale has been mined, it must be heated to temperatures between 400 and 500 degrees centigrade to convert – or retort -- the kerogen to shale oil and combustible gases. Numerous approaches to surface retorting were tested at pilot and semi-works scales during the 1970s and 1980s.

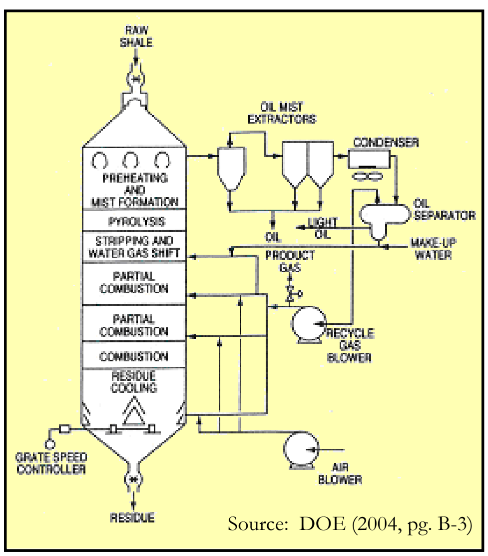
Two major types of surface retort facilities, vertical and horizontal, have offered significant promise, and are discussed below. Other variations are described in Appendix A.

Vertical Retorts

Vertical retorts have been used with increasing success and efficiency since the early days of oil shale operations. The Gas Combustion Retort (GCR), developed by the U.S. Bureau of Mines is one of the most successful vertical retorts (Figure III-5). GCR achieves high retorting and thermal efficiencies. One advantage of GCR is that it requires no cooling water, an important feature in semi-arid regions.

The Bureau designed and opened an oil shale mine, designed, constructed, and operated a vertical kiln technology, and successfully refined the shale oil produced. Upon the conclusion of the government research, the Anvil Point facility was leased to an industry consortium to further develop the Bureau's technology. This research resulted in an improved vertical gas combustion surface retorting technology now know as the Paraho Retorting Process. Experimental work continued through 1982. The largest Paraho retort constructed and successfully tested processed 300 tons/day (TPD) of oil shale.

Figure III- 5. Gas Combustion Retort



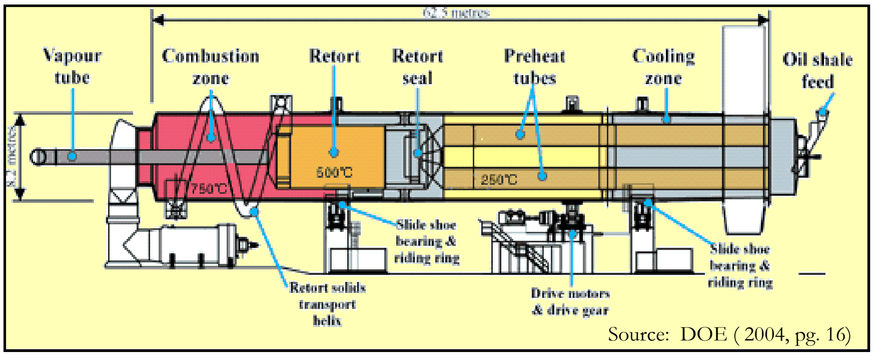
Source: DOE (2004, pg. B-3)

Horizontal Retorts

Horizontal retorts heat the shale through a horizontal kiln. The TOSCO II horizontal kiln uses ceramic balls to heat the oil shale. Field operations carried out in Colorado in the early 1970's used a shale feed rate of about 1,000 T/D. A consortium led by Exxon planned to use this retort in commercial development of an oil shale lease on public lands. However, commercial development was canceled during construction in 1982 in response to falling oil prices, continued escalation in the estimated cost of the facility, and high interest rates[6].

The Alberta Taciuk Processor (ATP) is more recent variation of the horizontal retort (Figure III-6). Initially designed for extracting bitumen from oil sands, the process was adapted for Australia using silica-based shale. Shale oil production of 3,700 Bbl/d have been reported[7]. In contrast to the silica-based material found in Australia, U.S. western oil shale has highly friable carbonate minerals that tend to disintegrate into small particles when agitated. These particles find their way into the shale oil and are difficult and costly to remove. This issue has raised questions about the ATP's viability for use in large scale commercial operations using carbonate-based western shale.

Figure III- 6. ATP Horizontal Rotary Kiln



Source: DOE (2004, pg. 16)

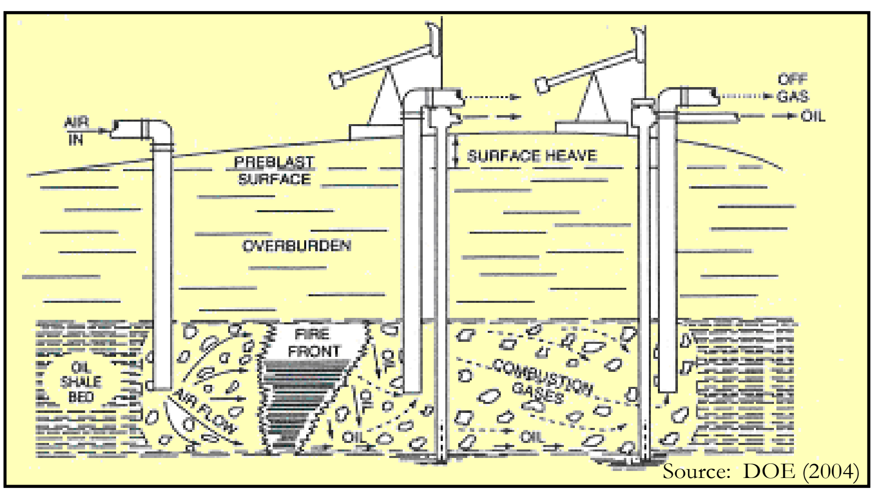
IN-SITU PROCESSING

In-situ processing involves heating the resource in-place, underground. Various approaches have been proposed and tested, including true in-situ and modified in-situ.

True in-situ processes

A true in-situ process involves 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. There are some difficulties in controlling the flame front that can leave some areas unheated and some oil and other byproducts of the heating process are not recovered. (Figure III-7)

Figure III- 7. Conventional True In-Situ Process

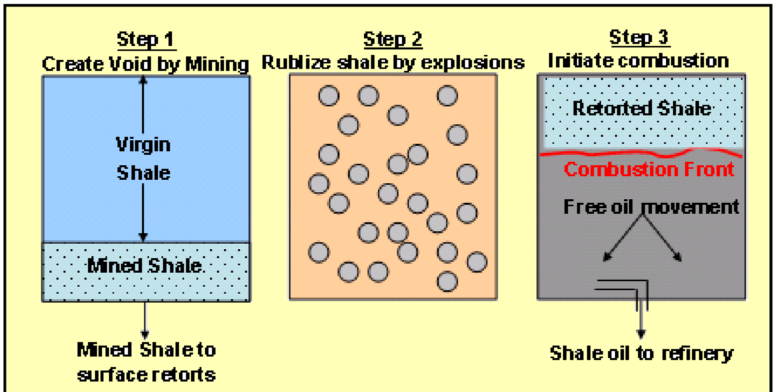


Source: DOE (2004)

Modified in-situ (MIS)

MIS involves mining below the target shale before heating. Once the shale is mined, the virgin shale is rubblized by explosions to create a void space of 20 to 25 percent. Combustion is started on the top of the rubblized shale and moves down the column. In advance of the combustion front, oil shale is raised to retorting temperature that converts the kerogen to shale oil and to gases. Both products are captured and returned to the surface. MIS processes can improve performance by heating more of the shale, improving the flow of gases and liquids through the rock, and increasing the volume and quality of the oil produced. Figure III-8 displays the modified in-situ process.

Figure III- 8. Modified In-Situ Process

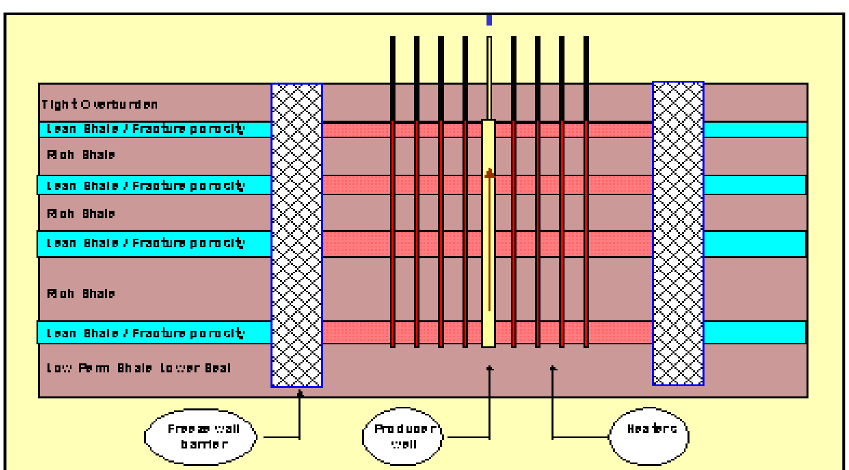


Source: INTEK, Inc. (2006)

In-Situ Conversion Process (ICP)

Shell Oil is researching a novel in-situ heating process that shows promise for recovering oil from rich, thick resources lying beneath several hundred to more than one-thousand feet of overburden. The process uses electric heaters, placed in closely spaced vertical wells, to heat the shale for 2 to 4 years. The slow heating creates micro-fractures in the rock to facilitate fluid flow to production wells (Figure III-9). Resulting oil and gases are moved to the surface by conventional recovery technologies.

Figure III- 9. Shell In-Situ Conversion Process Schematic



Source: Shell Oil Company (2003)

The ICP's slow heating is expected to improve product quality and recover shale oil at greater depths than other oil shale technologies. Additionally, the ICP process may reduce environmental impacts by eliminating subsurface combustion. An innovative "freeze wall" technology is being tested to isolate the production area from groundwater intrusion until oil shale heating, production, and post production flushing has been completed.

Shell is operating a modest field research effort in northwestern Colorado's Piceance Basin to test ICP's viability. The critical challenges facing the ICP technology include: development of reliable heater technology, improvements of down hole heater durability, and validation of the freeze wall technology for ground water protection.

Utilizing in-situ processing, there are locations that could yield in excess of one million barrels per acre and require, with minimum surface disturbance, fewer than 23 square miles to produce as much as 15 billion barrels of oil over a 40-year project lifetime.

DEVELOPMENT STATUS

The best existing technologies for producing U.S. oil shale have not yet been tested beyond the pilot scale. Demonstration of first-generation technologies will be required at a commercially-representative scale before significant private investment will lead to commercial production.

Major investments by industry and government have resulted in in-depth understanding of oil shale resources and the development and testing of a broad spectrum of surface retorting and in-situ technologies for converting oil shale to liquid fuels. The lessons learned and the technologies developed from these past efforts remain available and provide the technical basis needed to advance oil shale commercialization efforts.

Public Programs

Federally sponsored oil shale research dates back to World War II era concerns for oil supplies. Because of these concerns, Congress passed the Synthetic Liquid Fuels Act of 1944 which authorized the construction and operation of demonstration plants to produce synthetic liquid fuels from coal, oil shale, and agricultural products. Under this Act, and its extensions, the Bureau of Mines constructed, operated, and maintained the Anvil Points oil shale experimental station near Rifle, Colorado from 1944 to 1956.

The Bureau designed and opened an oil shale mine and developed the vertical gas combustion retort technology described in Section 2 of this report (see Figure 5). After a successful 12-year experimental program, the research facilities were placed on a standby status in 1956.

The government's facility was reactivated in 1964 under Public Law 87-796 that authorized the Secretary of Interior to enter into agreements to encourage further research on oil shale technologies at the Bureau's Anvil Point facility. The facility was leased to the Colorado School of Mines Research Foundation and six oil companies provided financial support. The experimental program was aimed at optimizing operating conditions. A total of 132 test runs were conducted in an effort to optimize process variables. The program was successfully complete in 1967 and the experimental information was used to improve the process design.

The improved process design was incorporated into what is now known as the Paraho Retorting Process. While similar in design to the government's vertical kiln, the Paraho retort features an improved shale feeding mechanism, improved gas distributors within the vertical retort, and an improved spent shale discharge system. In 1972, Paraho leased the government's Anvil Point facility to further develop its process.

From 1972 through 1982, Paraho, supported by a consortium of 17 oil companies, continued to improve the technology. The largest unit constructed and tested at the site was a semi-works unit having an internal diameter of 8.5 feet and a height of 75 feet. This unit was operated to process 300 tons/day of shale. Through 1976, the Paraho technology produced 34,000 barrels of shale oil. Of this, 10,000 barrels were refined at a local refinery into NATO gasoline, JP-4, JP-5/Jet A, and heavy fuel oil. These fuels were successfully tested in Navy vehicles and aircraft. From 1976 through 1982, Paraho continued to make technical improvements and produced 75,000 barrels of shale oil. This oil was refined into military fuels and successfully tested by the Air Force and in other military vehicles. The facility was placed in a standby condition in 1982.

Current Research and Project Development Efforts

The government first established an experimental facility at Anvil Points, CO in 1944. Sixty years later, oil shale from the mine is still being used to advance oil shale retorting technology. Research at the Anvil points and research by private industry on private lands have clearly shown that oil shale can be mined at commercial rates, crushed and sized before retorting, liquids recovered, shale oil refined in usable products, and products successfully used to fuel Air Force airplanes and Navy ship and land vehicles. The only step in this process not yet proven at commercial-scale is surface retorting.

Similarly, in-situ operations that involve heating the oil shale, moving produced shale oil and gases to a producing well, lifting them to the surface, and site reclamation have not yet been proven on a commercial scale.

To further research by private industry, the Department of the Interior Bureau of Land Management (BLM) initiated a Research, Development and Demonstration Leasing Program for Oil Shale. BLM received 19 lease applications and has selected five for lease negotiations Table III-2.

Table III- 2. Potential Industry Projects

Company	Project
Chevron	BLM R&D Lease to develop in-situ processes in Colorado
EGL Resources	BLM R&D Lease to develop in-situ processes in Colorado
Oil Shale Exploration	Plans for R&D of surface projects at the White River site in Utah
Oil Tech	Plans for R&D of surface projects at the White River site in Utah. Surface demonstration could be at commercially-representative scale of 10,000 Bbl/D by
Shell Oil	BLM R&D Lease to develop in-situ processes in Colorado. Potentially proceed to demonstration at commercially-representative scale by the end of the decade, with production beginning by 2016 and reaching 500,000 Bbl/D by 2022.
	Source: Bureau of Land Management (2006)

In addition to research leases, Congress recognized the need to move unconventional fuels toward commercialization and, in the Energy Policy Act of 2005, directed the:

- Department of Energy to assess the readiness and potential of existing oil shale technologies for demonstration and implementation at commercial scale,
- Department of the Interior to conduct a programmatic environmental impact statement (PEIS) for a commercial oil shale and tar sands leasing program and directed BLM to prepare regulations to facilitate commercial leasing, and
- Department of Energy to develop an integrated Commercial Strategic Fuels Development Program that focuses on oil shale and tar sands as well as heavy oil, enhanced oil recovery and coal liquids.

There is no commercial production of oil shale in the United States at this time. Higher oil prices and the expectation that public actions will be taken to overcome other major development impediments and uncertainties have stimulated oil shale interest and activity on the part of several major and independent energy and technology companies. Several private companies are currently conducting research and development efforts that could lead to field pilots, semi-works, or commercial-scale demonstration projects within a decade, and commercial scale operations soon thereafter.

Current mining and shale oil upgrading technologies are adequate to initiate an industry. However, retorting technologies still require demonstration at commercially-representative scale. As in other industries, including Alberta's tar sands, knowledge advances and technology improvements gained in first generation operations can be expected to significantly reduce costs and improve efficiencies of the next-generation operations.

Technology Hurdles

The retort technology presents the greatest level of uncertainty in terms of process efficiency, reliability and scalability. The final step before commercialization is the "commercial demonstration" and is sited at the location of the intended commercial facility. The demonstration represents the first full-scale module (10,000 to 20,000 ton/day) and is ultimately incorporated into the commercial facility. The unit is fully integrated with respect to material and heat flows, and process and environmental controls. The plant is generally run on a continuous basis for a number of months to gain operating experience and to identify any problems in the process design. Final design data is obtained on the unit. Detailed capital and operating cost data (+/- 5%) for the commercial facility are also obtained. Costs for such plants will be several hundred million dollars and require 3 to 4 years to build and operate.

The development pathway for oil shale technologies is clear and predictable, but the time scale required is long and costs are high.

POTENTIAL ACTIONS

Oil shale production is characterized by high capital investment, high operating costs, and long periods of time between expenditure of capital and the realization of production revenues and return on investment. For first-generation facilities there is substantial uncertainty about the magnitude of capital and operating costs because technologies are not yet proven at commercial scale. Revenues are uncertain because world crude oil prices are volatile and future market prices for shale oil and byproducts are unknown. These and other uncertainties pose investment risks that make oil shale investment less attractive than other potential uses of capital.

Government action and participation is warranted when needed to achieve urgent public goals, such as ensuring secure fuel supplies and ensuring economic vitality. The Federal government can help lower private investment risk by taking actions to reduce resource access, economic, technical, and regulatory uncertainties and by reducing the financial risks. The most effective of these actions include:

- Focus RD&D and technical assistance efforts on accelerating industry development of current and next generation technologies, helping industry resolve major technical issues, and evaluating and testing novel concepts that may hold potential for next-generation technologies.
- Consider co-funding facilities and personnel to develop and test oil shale mining and production technologies at pre-demonstration scale.
- Examine the feasibility of establishing research parks at or adjacent to existing western oil shale sites to enable RD&D and testing using shared infrastructure and to provide a source for mined shale for industry led RD&D efforts.
- Consider establishment of basin-specific environmental R&D efforts to assess environmental conditions and potential impacts and identify and advance environmental management practices and mitigation technologies that could facilitate unconventional fuels resource development.
- Provide cost-shared technical assistance to industry from DOE laboratories or other Federal facilities with directly relevant skills, expertise, and resources.
- Cost-share bench-scale and pilot testing for new next generation technologies.
- Cost-share demonstration projects of first generation and next generation technologies at commercially-representative scale.

3. DEVELOPMENT ECONOMICS AND INVESTMENT STIMULATION

Oil shale development is characterized by high capital investment and long periods of time between expenditure of capital and the realization of production revenues and return on investment. Revenues are uncertain because future market prices for shale oil and byproducts are unknown. Therefore, a key economic barrier to private development is the inability to predict when profitable operations will begin. The economic risk associated with this uncertain outcome is magnified by the unusually large capital exposure, measured in billions of dollars per project, required for development.

After initial commercial operations establish predictable cash flow forecasts, project development and expansions by private industry are expected to continue at a pace dictated by normal economic calculations. Such decisions will be based on the then well-defined costs of oil shale production compared with alternative investments.

The development economics issue is short-term. Once commercial operation is successfully demonstrated, capital and operating costs will fall as operations become more efficient and the industry matures and learns how best to economically develop the resource. If oil prices are maintained at only current levels, second and third generation technology will continue to improve, profitability will increase, and the relative economics of oil shale development will become more attractive. Over the longer-term, improving economic operations will attract the additional investment capital needed to expand operations just as it has for oil sands development in Canada.

This chapter discusses the costs of oil shale development, economic risk factors, economic incentives, the impact of development on public revenues (Federal, state, and local), and expected markets.

Three development cases are considered in the analysis. Of these, only the accelerated case has the potential to reach a production level of 2.5 million Bbl/d by 2030. The accelerated development schedule assumes:

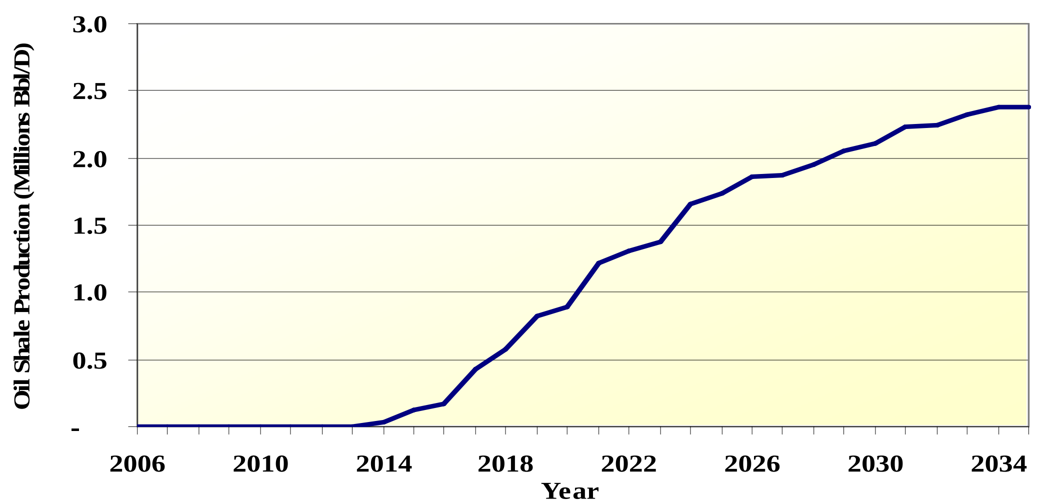
1. Oil prices will track the Energy Information Agency (EIA) low oil price case[8]. This EIA case assumes that oil prices reach a long-term equilibrium at about $35 per barrel,
2. A $5/Bbl production tax is applied to oil shale projects, and
3. High-risk demonstration projects are undertaken to reduce the technical risks associated with the development of a new industry.

Using these assumptions, demonstration projects begin to produce shale oil in 2010. Daily production is low initially (about 40,000 Bbl/d) as the new technology is tested. Process improvements learned from these initial operations are then incorporated into expansion of the demonstration facilities. Production begins to accelerate as these improvements are implemented and, by 2014, shale oil production reaches 250,000 Bbl/d.

Success of the initial demonstration projects encourages additional industry development. By 2020, shale oil production reaches 1 MMBbl/d, 2 MMBbl/d by 2025, and 2.4 MMBbl/d by 2030.

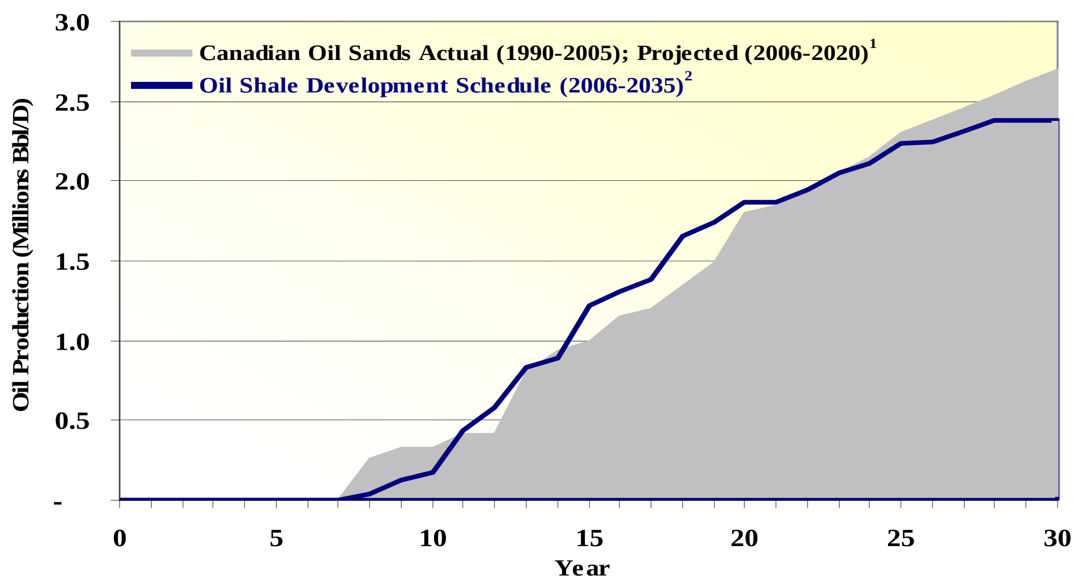
The accelerated production schedule used to estimate the economic impacts of oil shale development is given Figure III-10. The stair-step shale oil production pattern shown in this figure is similar to the development of the Canadian oil sands. Canadian oil sands production and the shale oil production schedule developed for this plan are plotted on a common time line in Figure III-11 beginning at year 0 and ending in year 30.

Figure III- 10. Potential Oil Shale Development Schedule



Source: Oil Shale Working Group (2006)

Figure III- 11. Canadian Oil Sands and U.S. Oil Shale Production Schedules



1) Canadian Oil Sands Production Source: Energy Information Administration, IEO (2006)
2) U.S. Oil Shale Development Schedule: Oil Shale Working Group (2006)

Development of Canada's oil sands and oil shale development in the United States have many common factors[9]; each offers a resource base that exceeds 1 trillion barrels and each has a similar average richness (25 gallon/ton). Oil shale will yield slightly more oil in terms of Bbl/ton processed (0.60 vs. 0.53) and a slightly higher quality of oil (38 vs. 34 degrees API).

Technology steps used to develop each resource are also similar: mining and ore preparation, extraction, coking and retorting, and upgrading[10]. Both crudes convert to high yields of liquid transportation fuels. The higher hydrogen content and closer proximity to markets of shale oil will yield a premium market value compared to West Texas Intermediate (WTI) grade conventional oil.

Canadian oil sands development was successfully undertaken as a cooperative effort between government and industry. The Comprehensive Report prepared by Canada's National Task Force on Oil Sands Strategies[11] was carefully considered in developing this oil shale plan. Common elements of the Alberta and Oil Shale Task Force Programs include providing access to resources, technology support, fiscal incentives, infrastructure support, regulatory streamlining, and environmental mitigation programs.

If both resources are developed according to plan, North America could be able to claim the largest oil reserves in the world. More importantly, the combined production that exceeds 5 million Bbl/d will serve as a critical bridge to the future, until other technologies can be developed.

COST ESTIMATES

Oil shale technologies must be demonstrated at commercial scale before definitive capital and operating costs of oil shale projects will be known. Cost estimates will vary according to the oil shale resource and the process selected. The components of capital cost for an oil shale project for mining and surface retorting:

- Mine development: surface or underground
- Retorting and upgrading facilities: design, manufacture, and construction of facilities
- Infrastructure: roads, pipelines, power, 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, and upgrading facilities.

First of a kind mining and surface retorting plants may be economic, providing a minimum 15% rate of return, at sustained average world oil prices between $44 and $54 per barrel. (Table III-3) In-situ processes may be economic at sustained average world oil prices above $30 per barrel.

Table III- 3. Estimated Costs and Minimum Economic Prices for Oil Shale Processes

Technology	Number of Tracts	Average Minimum Economic Price ($/Bbl)	Capital Costs (K$/SDB)	Operating Costs ($/Bbl)
Surface Mining	7	$44.24	$40 - $41	$12 - $13
Underground Mining	7	$54.00	$41 - $42	$16 - $17
Modified In-Situ	7	$65.21	$27 - $40	$18 - $26
True In-Situ	4	$37.75	$36 - $56	$19 - $20

Capital and operating costs can be expected to decrease over time with operating experience, improved understanding, design enhancements, and improved operating efficiencies, analogous to the experience of the Province of Alberta in developing its oil sands resources. Production costs in Alberta's oil sands have decreased by as much as 80 percent since the 1980s. Oil shale cost reductions of 40 to 50 percent could occur as lessons from first of kind facilities are applied[12].

ECONOMIC RISK FACTORS

Technology uncertainty is the largest single risk factor associated with oil shale development. This uncertainty remains even after 50 years of government and industry research to develop a commercially viable retorting technology.

Federally sponsored oil shale research dates to World War II when Congress authorized the construction and operation of demonstration plants to produce liquid fuels from oil shale. Under this authorization, the Bureau of Mines constructed, operated, and maintained the Anvil Points oil shale experimental station near Rifle, CO to further oil shale technologies.

The Bureau designed and opened an oil shale mine, designed, constructed, and operated a vertical kiln technology, and successfully refined the shale oil produced. Upon the conclusion of the government research, the Anvil Point facility was leased to an industry consortium to further develop the Bureau's technology. This research resulted in an improved vertical gas combustion surface retorting technology now known as the Paraho Retorting Process. The largest Paraho retort constructed and successfully tested processed 300 tons/day (TPD) of oil shale.

A commercial retort will need to process 30 to 60 times more oil shale than that (a commercial retort will use 10,000 TPD to 20,000 TPD of raw oil shale). Only one effort has ever been made in the U.S. to construct and operate this size commercial retort which failed due to technical issues[13]. This commercial development effort was the final test of a retorting technology developed by Union Oil Company of California (UNOCAL). The approach was invented in the 1940's and systematically moved toward commercial demonstration. By 1983, UNOCAL constructed the first full-scale commercial module designed to process 13,000 TPD of oil shale.

Supported with Federal loan and price guarantees, UNOCAL attempted to operate the plant over 40 times between 1983 and 1991. Each time, the plant was shut down for technical modifications. While in operation, UNOCAL produced 4.6 million barrels of shale oil. However, the facility achieved only about 25 percent of the commercial design rate. Overall, the UNOCAL retorting technology proved to be too difficult to scale to commercial operations. Experimental work was terminated in 1991, the plant decommissioned, and the site reclaimed.

Research at the Anvil Points Facility and on private lands has clearly shown that oil shale can be mined at commercial rates, crushed and sized before retorting, liquids recovered, shale oil refined into usable products, and products successfully used to fuel Air Force airplanes and Navy ship and land vehicles. The only step not yet proven at commercial-scale is surface retorting. Similarly, in-situ operations have not yet been proven at commercial-scale in the United States.

Both government and industry are aware of failures to achieve commercial operations. The government withdrew support from development in 1985 when Congress abolished the Synthetic Liquid Fuel Program. Industry withdrew its efforts to develop oil shale leases shortly thereafter.

Despite the termination of commercialization efforts in the 1980s, the numerous technologies developed for surface and in-situ production of shale oil in that era still hold significant promise.

Technology advances achieved since 1980, oil shale experience in other countries, and expectations for sustained higher oil prices all contribute to an improved outlook for oil shale development.

Even with an improved outlook, industry will be reluctant to move toward commercial oil shale development on the pace demanded to meet urgent energy requirements and public policy goals of reducing import dependence. The Task Force concludes that government research support is needed to achieve commercial shale oil production in a reasonable time period.

ECONOMIC INCENTIVES

A key economic barrier to oil shale development is the inability to predict when profitable operations will begin. The development of viable technologies (both surface and in-situ) will enable a better determination of development costs.

Income will depend on the price of oil that cannot be accurately predicted over the life of an oil shale project. The oil price collapse of the late 1980's helped to kill the initial efforts to develop oil shale on public lands under the Department of Interior's Prototype Oil Shale Leasing Program.

The economic risk of an oil price collapse would be largely eliminated if the government enters into a contract to purchase domestic shale oil at a guaranteed minimum price ($/Bbl). Both the DoD and the DOE (Strategic Petroleum Reserves) have ongoing oil procurement programs that could be employed to assure a stable future market. The DoD program purchases finished fuels to support military operations. The DOE purchases crude to be stored in the Strategic Petroleum Reserve. The Task Force recommends that government use its existing ongoing procurement programs and authorities to help assure a market for initial oil shale development. A price floor of about $40 per Bbl is assumed in the economic cases described below.

In addition to research and a price floor, the Task Force identified a production tax credit as one of several incentives that could have a significant effect on stimulating investment in oil shale development. Properly developed, this incentive could be revenue neutral to the government.

PRODUCTION POTENTIAL

Three cases were considered to evaluate the effect of economic incentives on shale oil production:

1. Base Case assumes a price floor of about $40/Bbl.
2. Measured Case assumes a price floor plus a $5/Bbl production tax credit.
3. Accelerated Case assumes a price floor, a production tax credit, and cost-shared demonstration projects undertaken to reduce the technical risks associated with the development of a new industry.

The Base Case production is estimated at 0.5 MMBbl/d by 2035, all from true in-situ projects (see Table III-4). This case will clearly not support a production goal of 2.5 MMBbl/d.

Measured Case production is estimated at 1.5 MMBbl/d by 2035 (see Table III-5). The production tax credit is effective at stimulating some shale oil production, but will not achieve 2.5 MMBbl/d.

Accelerated Case production (Table III-6) is estimated at 2.4 MMBbl/d by 2035. This is the only case that can achieve the production goal and it will require cost-shared demonstration projects.

Table III- 4. Potential Oil Shale Development Schedule – Base Case (Million BOE/d)

Project Type	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
TIS	-	-	-	-	-	-	-	-	-	0.05	0.05	0.05	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
TIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
TIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**0.05**	**0.05**	**0.05**	**0.30**	**0.30**	**0.50**	**0.50**	**0.50**	**0.50**	**0.50**	**0.50**	**0.50**	**0.50**	**0.50**	**0.50**	**0.50**	**0.50**	**0.50**	**0.50**	**0.50**	**0.50**

Table III- 5. Potential Oil Shale Development Schedule – Measured Case (Million BOE/d)

Project Type	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
TIS	-	-	-	-	-	-	-	-	-	0.05	0.05	0.05	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
S	-	-	-	-	-	-	-	-	-	-	-	-	0.01	0.02	0.03	0.05	0.06	0.06	0.08	0.08	0.08	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
TIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
TIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
TIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
TIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
TIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**0.05**	**0.05**	**0.05**	**0.31**	**0.32**	**0.53**	**0.55**	**0.86**	**0.86**	**0.88**	**1.18**	**1.18**	**1.21**	**1.51**	**1.51**	**1.51**	**1.51**	**1.51**	**1.51**	**1.51**	**1.51**

Table III- 6. Potential Oil Shale Development Schedule – Accelerated Case (Million BOE/d)

Project Type	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
S	-	-	-	-	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.03	0.03	0.06	0.06	0.06	0.06	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
S	-	-	-	-	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.03	0.03	0.06	0.06	0.06	0.06	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
TIS	-	-	-	-	0.01	0.01	0.01	0.01	0.10	0.10	0.10	0.10	0.10	0.20	0.20	0.20	0.20	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
TIS	-	-	-	-	0.01	0.01	0.01	0.01	0.10	0.10	0.10	0.10	0.10	0.20	0.20	0.20	0.20	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
TIS	-	-	-	-	-	-	-	-	-	0.05	0.05	0.05	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
U	-	-	-	-	-	-	-	-	-	-	-	-	0.03	0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
S	-	-	-	-	-	-	-	-	-	-	-	-	0.01	0.02	0.03	0.05	0.06	0.06	0.08	0.08	0.08	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
TIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
TIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
U	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
U	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.01	0.02	0.02	0.02	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.02	0.03	0.03	0.03	0.06	0.06	0.06	0.06	0.09	0.09	0.09	0.09	0.12	0.13
U	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05
MIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.01	0.01	0.01	0.01	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
TIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
MIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.01	0.01	0.01	0.01	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
TIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Total	**-**	**-**	**-**	**-**	**0.03**	**0.04**	**0.04**	**0.04**	**0.24**	**0.31**	**0.31**	**0.31**	**0.61**	**0.85**	**1.08**	**1.11**	**1.20**	**1.77**	**1.84**	**1.85**	**2.22**	**2.27**	**2.32**	**2.32**	**2.35**	**2.35**	**2.35**	**2.35**	**2.38**	**2.38**

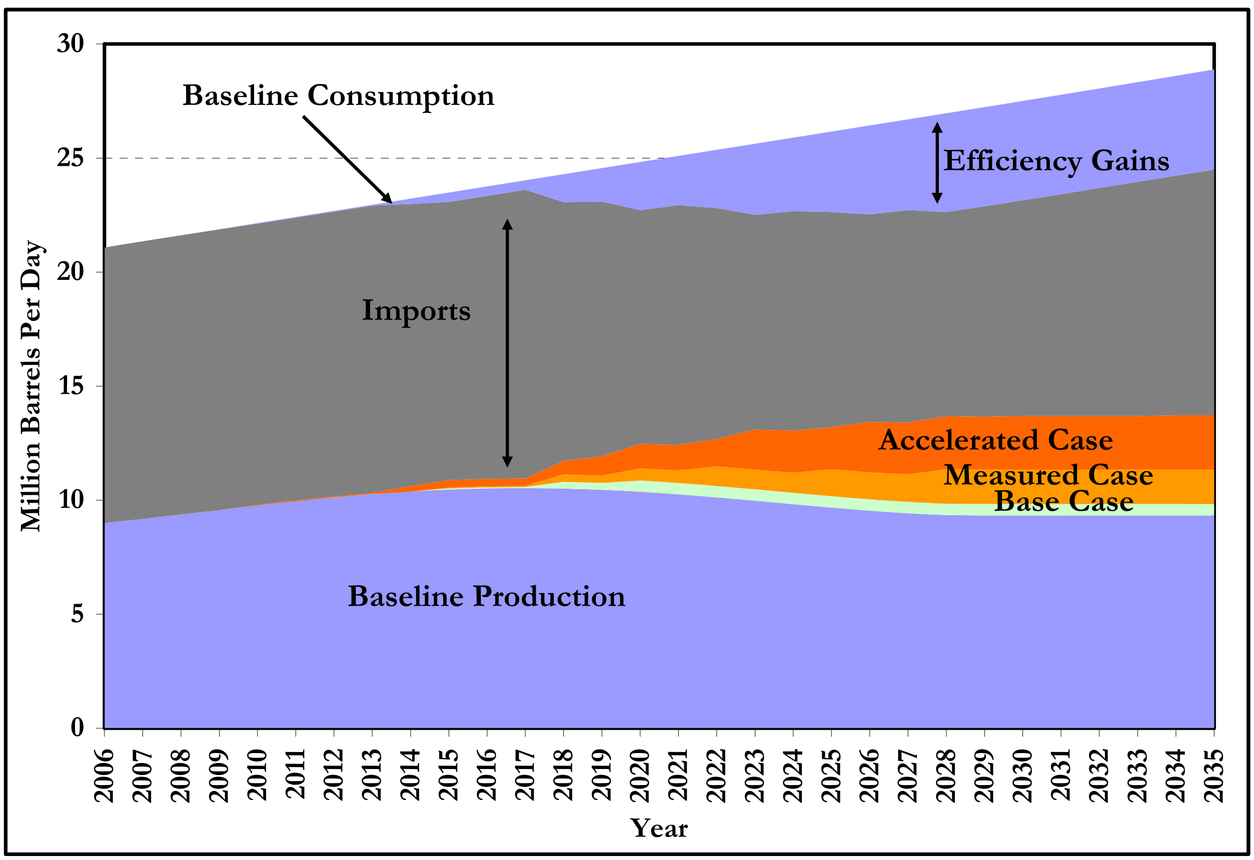
The Task Force recommends that the accelerated case be adopted to achieve the goal of producing 2.5 MMBbl/d of oil shale by 2035. The accelerated case assumes that a mix of projects will be used to achieve that goal, including projects that employ true in-situ, modified in-situ, surface mining/surface processing, and underground mining/surface processing technologies. While exact project locations are not known, existing land positions and past and current interests in leasing public lands suggest the following pattern of development:

- Private lands on the southern margins of the Piceance Basin in Colorado.
- Public lands near the center of the Piceance Basin in Colorado.
- Private and public lands in the Uinta Basin in Utah.

Each project is assumed to expand over time as the operator gains experience and moves to achieve economies of scale. Ultimate production from any single project ranges from 50,000 to over 200,000 Bbl/d.

The impact of the three alternative shale oil production cases is shown in Figure III-12. The Base Case has little impact in reducing the nation's continuing decline in domestic oil production. The Measured Case can help stabilize the nation's crude supplies. In contrast, the Accelerated Case will have a significant impact on increased domestic oil supply and on the need for foreign oil imports.

Figure III- 12. Production Potential for Oil Shale in the Base, Measured, and Accelerated Cases



INCREASED FEDERAL AND STATE REVENUES

The base, measured, and accelerated cases were analyzed to determine the relative costs and benefits of various ranges of government efforts to accelerate and promote oil shale development. All analyses are based on the National Strategic Unconventional Resource Model (NSURM)[14] developed specifically for the Task Force by the DOE Office of Petroleum Reserves. The results are not intended to be a forecast of what will occur; rather, they represent estimates of potential benefits and goals under the economic and technological assumptions of each case.

Direct Federal revenues generated in the base case by oil shale production would reach $0.9 billion per year by 2035. These revenues would more than double, reaching $2.63 billion per year by 2035 as a result of the industry and economic activity stimulated by the measured development case. In the accelerated case, Federal revenues would be more than tripled over the expected base case revenues, reaching $4.18 billion per year by the end of the 30 year period of analysis. (Figure III-13)

Direct state revenues generated in the base case would be $0.6 billion per year in 2035. These revenues would be more than doubled, exceeding $1.78 billion per year in 2035, as a result of the industry and economic activity stimulated by the measured development case. In the accelerated case, state revenues would be nearly tripled over the expected base case revenues, reaching $2.87 billion per year by the end of the 30 year period of analysis. (Figure III-14)

The total public sector revenues (sum of direct Federal and state revenues) from an oil shale industry would reach $1.51 billion per year by 2035 for the base case. The measured case will stimulate $4.41 billion per year. The accelerated case will increase this by $2.63 billion per year from the measured case, generating $7.04 billion per year by 2035. (Figure III-15)

Figure III- 13. Annual Direct Federal Revenues

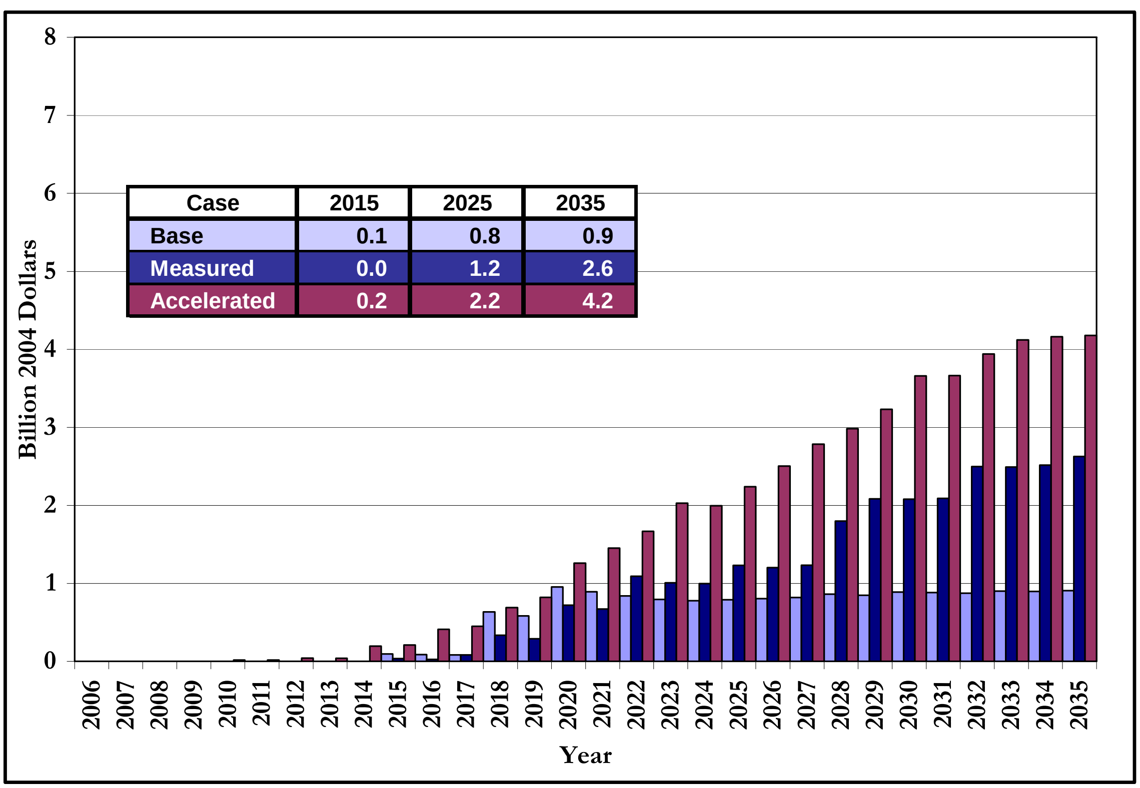


Figure III- 14. Annual Direct State Revenues

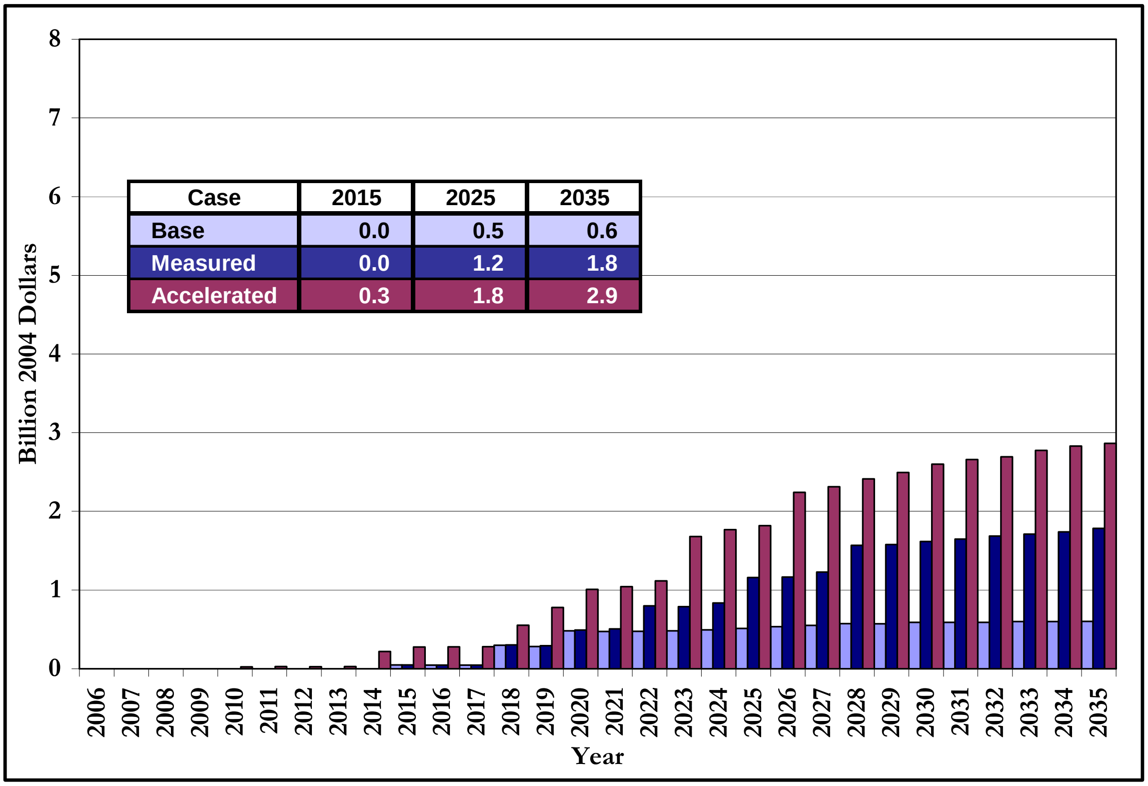
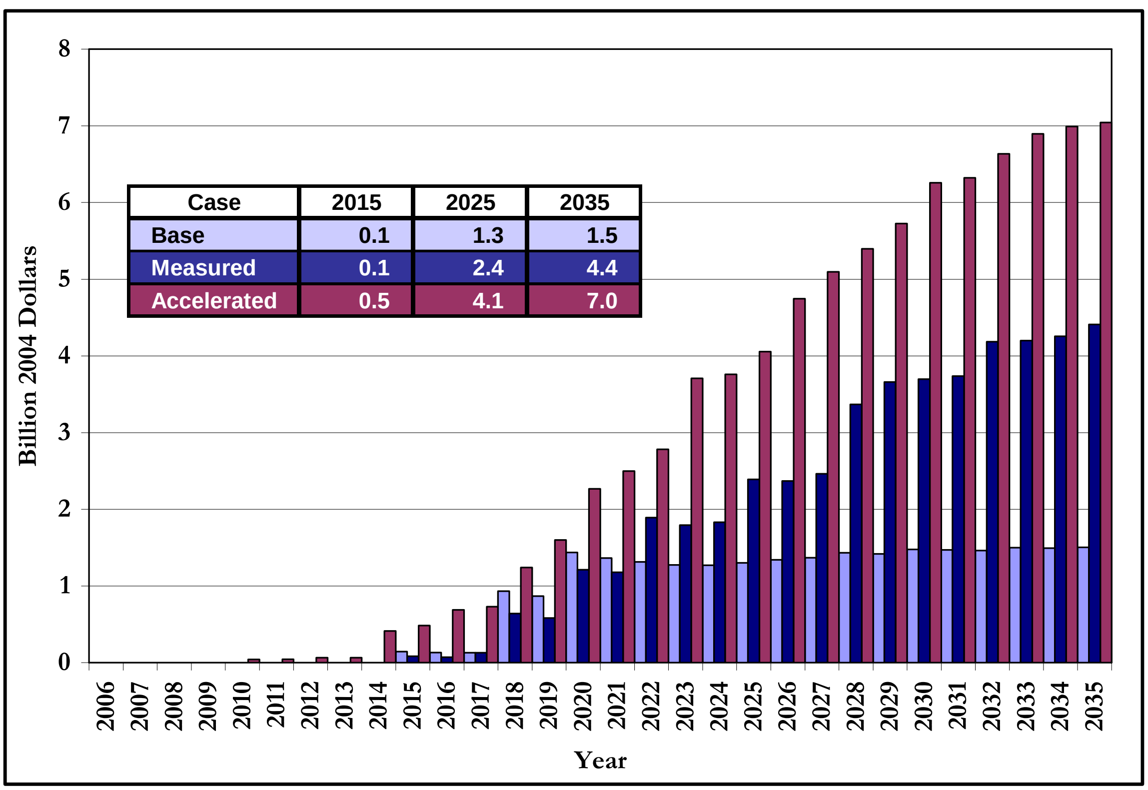


Figure III- 15. Annual Total Direct Public Sector Revenues



NATIONAL ECONOMIC BENEFITS

The development of an oil shale industry provides potential public benefits. 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:

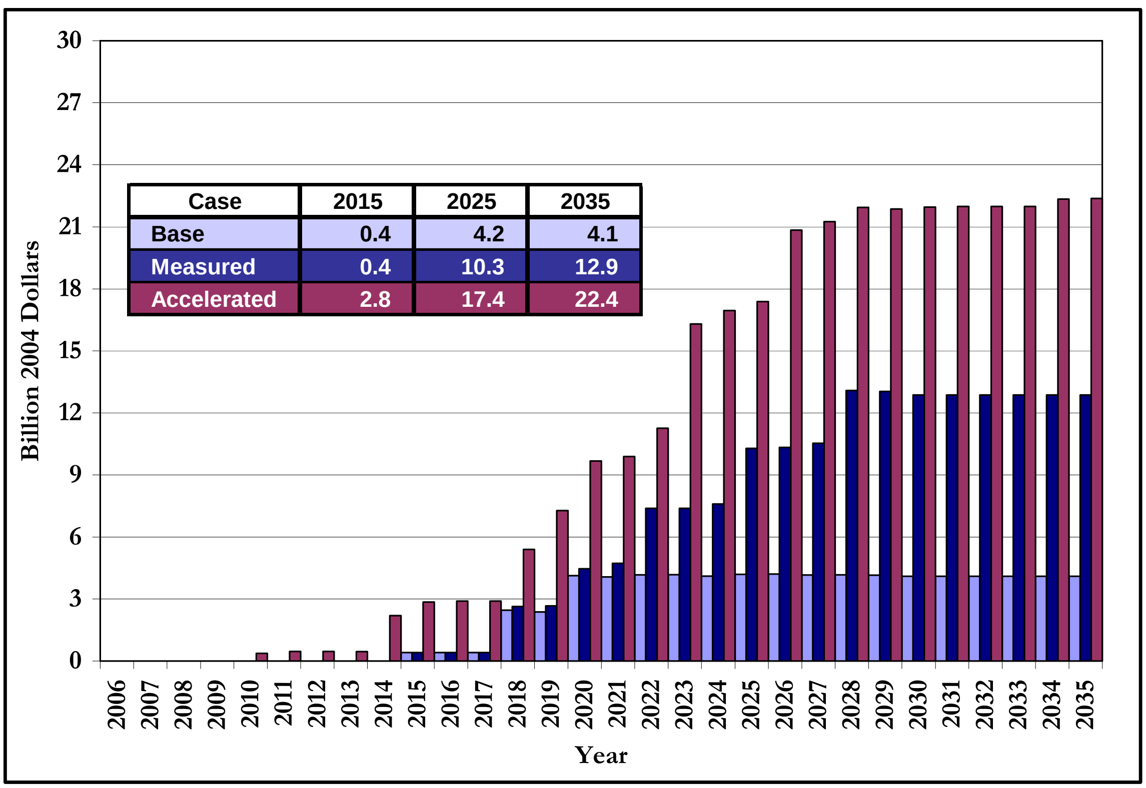
- direct Federal revenues (from Federal taxes and the Federal share of royalties),
- direct state/local revenues (from state and local taxes plus the state share of Federal royalties),
- contributions to gross domestic product (GDP), and
- value of avoided oil imports.

At a sustained annual production of about 2.5 million barrels of shale oil per year the cumulative value of these benefits over a 25 year period could exceed $500 billion.

Value of Imports Avoided

In the base case, it is estimated that domestic production of oil shale could reduce the cost of oil imports by $0.41 to $4.21 billion per year from industry inception to 2035. The measured case would increase these savings to between $0.41 and $13.09 billion per year. The accelerated case would save the United States $2.85 billion per year in 2015 and $22.37 billion per year by 2035 that would have otherwise been spent on imported oil. (Figure III-16)

Figure III- 16. Annual Value of Imports Avoided



Employment

Oil shale industry development will result in the addition of thousands of new, high-value, long-term jobs in the construction, manufacturing, mining, production, and refining sectors of the domestic economy. The NSURM model estimates direct petroleum sector employment, based on industry expenditures. The model also approximates the total number of jobs that will be created in the petroleum sector. Not all of the direct employment shown will be new jobs to the economy. Some will be filled by workers shifting from one industry sector to another. The jobs will not all be in the states where oil shale development sites are located. Other states that manufacture trucks, engines, steel, mining equipment, pumps, tubular goods, process controls, and other elements of the physical complex, as well as states where the projects are designed and managed or where fuel is refined into premium fuels and byproducts, will also share in the jobs creation.

Direct employment could range from 120 to 9,700 personnel in the base case. The measured case would directly employ about 1,880 people in 2015 and up to 26,000 in 2035. The accelerated case would stimulate the creation of 7,320 jobs in 2015 and almost 43,369 jobs in 2035. Figure III-17 displays the direct employment in the base, measured, and accelerated cases.

The total number of petroleum sector jobs (including indirect employment) ranges from 2,930 employees in 2015 to 20,830 in 2035 for the base case. The measured case increases these numbers to 4,320 jobs in 2015 and 59,810 personnel in 2035. The accelerated case will require an even more substantial employment base. In 2015, there will be a total of 16,840 jobs created and almost 99,750 by 2035. The total petroleum sector employment through 2035 is displayed in figure III-18.

Figure III- 17. Annual Direct Petroleum Sector Employment

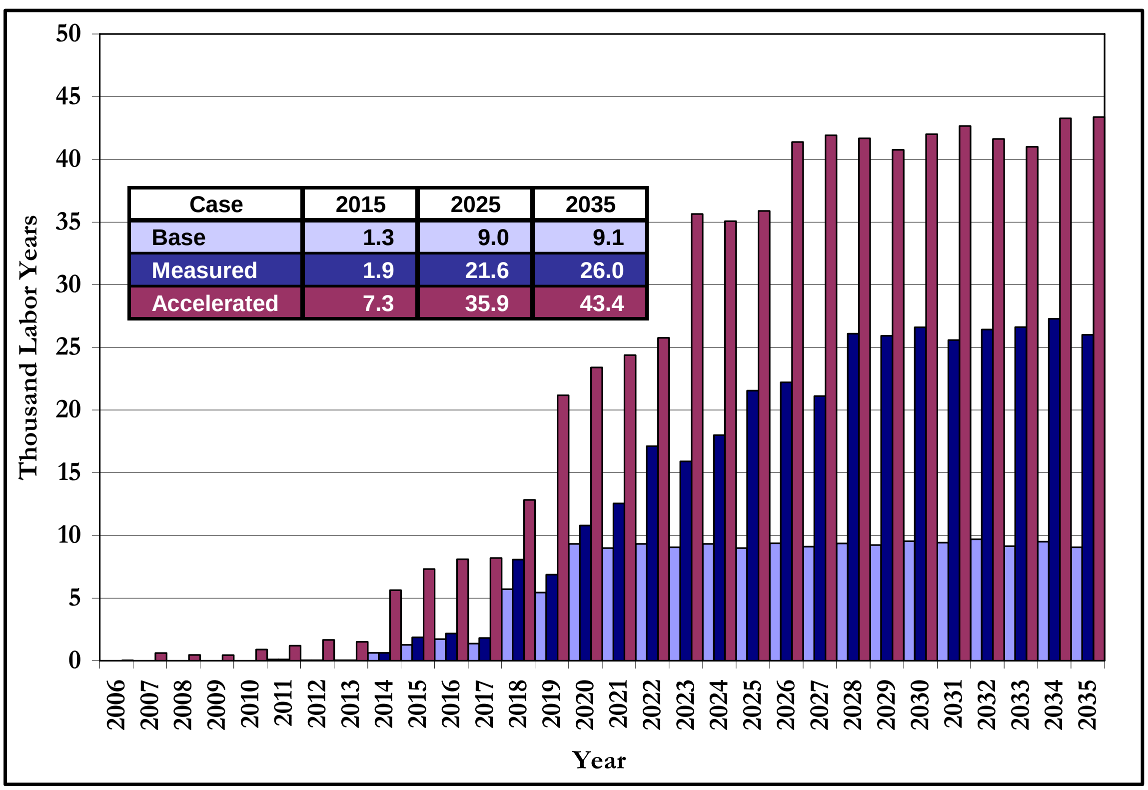
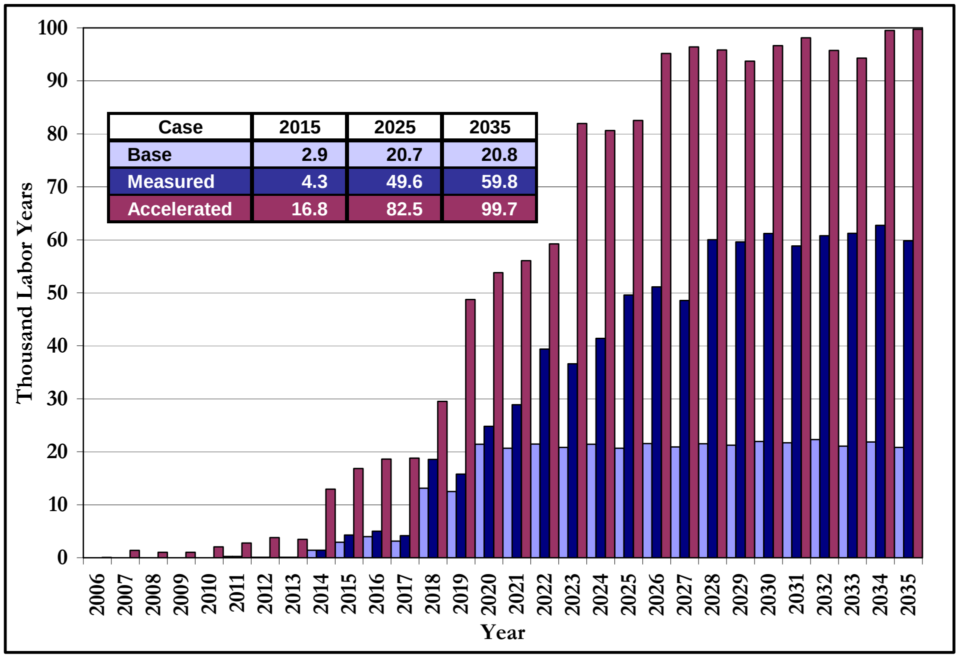


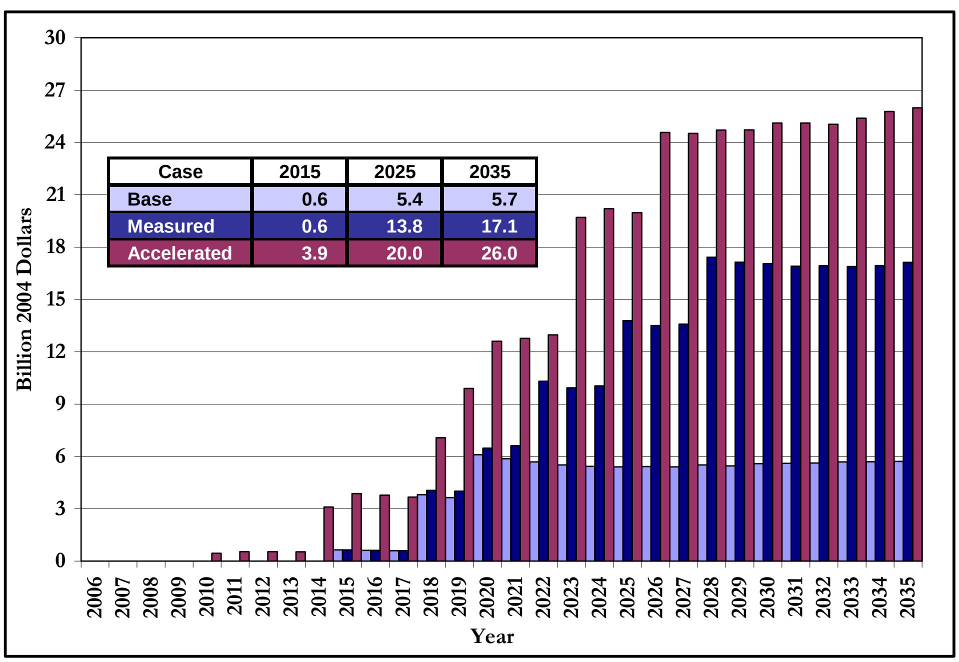
Figure III- 18. Annual Total Petroleum Sector Employment (Direct & Indirect)



Contribution to GDP

In the base case, annual direct contributions to GDP for the oil shale industry activity rises from $0.65 billion dollars per year in the early years, to $5.72 billion per year in 2035 (Figure III-19). With the addition of incentives, however, annual GDP contributions range from about $0.65 billion in the early years to about $17.13 billion per year by 2035 (measured case). The accelerated case would contribute $3.87 billion per year in 2015 and almost $26 billion per year by 2035.

Figure III- 19. Annual Direct Contribution to GDP



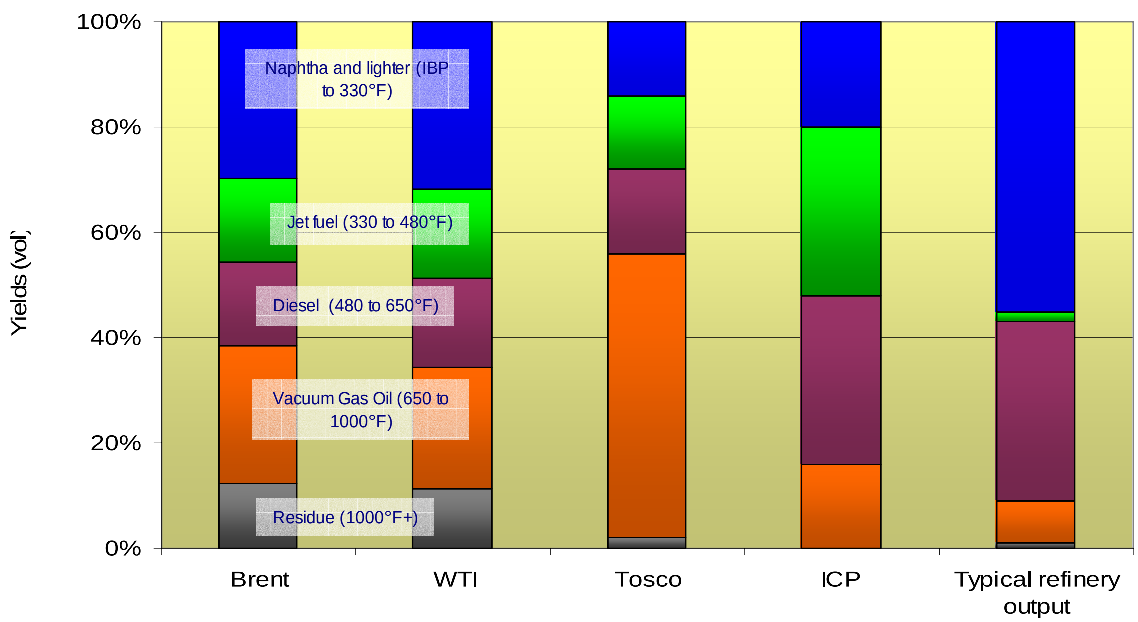
EXPECTED MARKETS

Shale oil is analogous to petroleum except for its high nitrogen and arsenic content. These are removed by upgrading which makes shale oil a premium quality refinery feedstock. Upgraded shale oil has almost no heavy residuals and is best suited to the production of diesel and jet fuels. However, the waxy nature of the feedstock allows the refiner to crack as deeply as desired to make either distillate fuels or motor gasoline.

Shale oil, whether produced from retorted oil shale at the surface or in situ, will require upgrading to meet current pipeline specifications. Upgraded shale oil will then be refined to produce finished fuels and chemicals. Traditional upgrading typically involves catalytic hydrogenation to remove heteroatoms (nitrogen, arsenic, sulfur, metals, and others). Upgraded shale oil, like Canadian syncrude from oil sands, will be free of distillation residue and will contain low concentrations of nitrogen and sulfur. These characteristics coupled with high hydrogen content add market value to the product. Thus, the upgraded shale oil will likely sell at a premium to West Texas Intermediate (WTI) crude (the industry benchmark).

Typical yield of products produced from shale oil are compared with Brent and West Texas Intermediate crudes in Figure III-20. This comparison shows that shale oil is a highly desirable feedstock for diesel and jet fuel production, or for producing a range of fuels including gasoline.

Figure III- 20. Typical Yields of Produced Shale Oil versus Crude Oil



In the Rocky Mountain, refineries have historically processed low-sulfur crude that has not required sophisticated coking and cracking units. These refineries will likely process the initial shale oil production, up to about 50,000 Bbl/d as discussed in Chapter 6 of this profile. Using these local refineries, the straight-run gasoline yield (the volume percent that distills below 450 ^{O}F) will vary from 5 to 45 percent, depending on the oil shale extraction process (see Table III-7).

In contrast, West Coast and Gulf Coast refineries have gradually adapted to processing heavier, higher sulfur crudes by adding coking and cracking units. Nationwide, the average barrel of oil yields about 47% gasoline, 23% diesel and heating oil, 10% jet fuel, 4% propane, 3% asphalt, and 18% other products[15].

Upgraded shale oil, whether from in situ or retorting processes, has no vacuum bottoms and its composition makes it an ideal feedstock for making diesel and jet fuel, or for cracking to obtain high gasoline yields. Cracking and hydrotreating or hydrocracking these shale oils can give gasoline yields of 60 percent.

Most California refineries have hydrocracking capabilities, making shale oil an excellent feedstock for producing gasoline in that state. Pipelines would need to be constructed from the shale oil producing area to supply California refineries. Further production expansions will likely require pipeline access to the refineries along the Gulf of Mexico. Products produced by these refineries are distributed throughout the United States by product pipelines, except to the West Coast.

Table III- 7. Composition and Properties of Selected U.S. Shale Oils (Source: DOE 2004, pg. 20)

	Gas Combustion Retorting Process	Tosco Retorting Process	Union Oil Retorting Process	Shell ICP Process
Gravity, API	19.8	21.2	18.6	38
Pour Point, °F	83.5	80	80	
Nitrogen (Dohrmann), wt. %	2.14 ±0.15	1.9	2(KJELDAHL)	1
Sulfur (X-ray F), wt. %	0.6999 ±0.025	0.9	0.9 (P BOMB)	0.5
Oxygen (neutron act.), wt. %	1.6	0.8	0.9	0.5
Carbon, wt. %	83.92	85.1	84.	85
Hydrogen, wt. %	11.36	11.6	12.0	13
Conradson carbon, wt.%	4.71	4.6	4.6	0.2
Bromine No.	33.2	49.5	Not available	
SBA wax, wt. %	8.1	Not available	6.9 (MEK)	
Viscosity, SSU.:				
100° F	270	106	210	
212° F	476	39	47	
Sediment, wt. %	0.042	Not available	0.043	
Ni, p.p.m	6.4	6	4	1
V,p.p.m.	6.0	3	1.5	1
Fe, p.p.m.	108.0	100	55	9
Flash (O.C.)°F	240		192 (COC)	
Molecular weight	328		306 (Calculated)	
Distillation				TBP/GC
450° at Vol. %	11.1	23	5	45
650° at Vol. %	36.1	44	30	84
5 Vol% at °F	378	200	390	226
10	438	275	465	271
20	529	410	565	329
30	607	500	640	385
40	678	620	710	428
50	743	700	775	471
60	805	775	830	516
70	865	850	980	570
80	935	920		624
90	1030			696
95	1099			756

Source: Cameron Engineers (1975), Shell (2003)

In summary, shale oil is an ideal feedstock for the production of diesel and jet fuels. Moreover, it can be cracked in today's refineries to make gasoline. Petrochemical plants can also use fractions to make waxes and other high-value specialty chemicals. Low concentrations of hydrocarbon residuals, sulfur, and contaminants in upgraded shale oil make it a refinery friendly feedstock that will command a premium over West Texas Intermediate crude. Initial shale oil production will be refined locally, and then pipelines and infrastructure will be required to move the shale oil west to

California and east and south to coastal refineries. On-time permitting and building of the pipeline infrastructure is the key element to moving produced shale oil to markets.

LIMITATIONS OF THE ANALYSIS

The analysis presented in this report has important limitations that should be considered before using its results. The results are primarily intended to provide a baseline calculation of the potential benefits of an oil shale industry, rather than a forecast of what is likely to happen over the next 25 to 35 years under current and assumed future economic conditions. These estimates, *although not a forecast*, provide a roadmap for the type and the level of benefits that could be targeted by the industry, and local, state, and the Federal governments through concerted and collaborative efforts.

The success of an oil shale industry depends very strongly on many factors including access to the resource, technology improvement through field demonstration at commercial scale, economic climate assurance, as well as environmental permit streamlining. The assumptions and limitations of the present analysis relative to these areas are discussed below:

- The analysis assumes that current technologies are successfully demonstrated to be viable at commercial scale over the next five to ten years. To the extent that this is not achieved, the development of the resource will be impeded.
- The analysis assumes that the environmental permitting process for the projects could be completed within three to five years. To the extent that the permitting process is not streamlined, and additional time is required, the timing of the production will be impacted.
- The analysis is based on the AEO 2006 oil price projection over the next 25 years. To the extent that the prevailing oil prices over this period are different from the AEO projections, the estimated benefits will be impacted.
- The economics are based on the use of average costing algorithms. Although developed from the best available data and explicitly adjusted for variations in energy costs, they do not reflect site-specific cost variations applicable to specific operators. To the extent that the average costs (used) understate or overstate the true project costs, the actual results will be impacted accordingly.
- The estimates of potential contribution to GDP, values of imports avoided, and employment do not take into account potential impacts to other sectors of the U.S. economy from altering trade patterns. It is possible that reduction in petroleum imports, depending on where the petroleum was coming from, could reduce the quantity being exported of some other good. It is likely, however, that such effects would be small.
- The analysis assumes that operators have access to capital to start and sustain the projects. The unconventional fuels projects are typically characterized as "capital intensive" and have longer payback period relative to oil and gas development projects. To the extent that capital is constrained, then the potential benefit estimated in this report is overestimated.

None of the above limitations invalidate the results in this analysis if they are viewed for what they are intended, which is an estimate of *upside potential*. Given the uncertainty of the size and combinations of the biases introduced by these limitations, it is assumed that the approach is valid, and the estimates are reasonable, for what they are intended.

4. ENVIRONMENTAL PROTECTION

POTENTIAL IMPACTS

Initial production of U.S. western oil shale will likely be focused in a relatively concentrated land area in parts of the states of Colorado, Utah, and Wyoming. The richest oil shale deposits are located in Colorado's Piceance Creek Basin and the Uinta Basin, Utah. Developing and operating industry-scale oil shale mining, production, and processing facilities could unfavorably impact the environment and some current uses, as discussed below.

Surface Impacts

Maximum cumulative land needed for a 1 million barrels per day industry is estimated to approach 80,000 acres[16]. Of this total, about 50,000 acres are needed for mine development, storage of overburden, storage of raw and processed shale, surface facilities, off-site land required for access roads, power and transmission facilities, water lines, and natural gas and oil pipelines. Up to 20,000 acres will be required for urban development. The remaining 10,000 acres will be needed for utility rights-of-way. Since the oil shale deposits occur beneath 16,000,000 acres, the surface area impacted by development is, therefore, only about 0.5% of the total land area of the oil shale region.

While the surface requirements are relatively small, oil shale processing will create local and regional environmental impacts. The major oil shale environmental issues are associated with air quality, spent shale disposal, water quality, in-situ recovery residuals, and impacts on the biology and ecology, each of which is discussed in the materials that follow.

Major Environmental Issues That Affect Oil Shale Development

- Air Quality
- Spent Shale Disposal
- Water Quality
- In-Situ Recovery Residuals
- Biology and Ecology

Air Quality

Most U.S. western oil shale source rock is a carbonate-based kerogen-bearing marlstone. Retorting involves heating the source rock, embedded with kerogen, to temperatures between 450 and 550 degrees centigrade. Heating carbonate rock to these temperatures generates not only shale oil, but also a slate of gases, some of which can be beneficially captured and re-used in plant operations or sold for conventional energy use.

The off-gases and stack gases of oil shale processes principally contain: Oxides of sulfur and nitrogen, carbon dioxide, particulate matter, water vapor, and hydrocarbons. Also, a potential exists for the release of other hazardous trace materials into the atmosphere. Commercially available stack gas cleanup technology could be used to limit emissions to within permitted quantities.

Regulated gases, such as sulfur oxides, will need to be captured and processed, or otherwise treated. The plant design requirements will need to be responsive both to the prevailing regulatory environment, and to possible future requirements for carbon dioxide (CO_2) capture and sequestration.

With significant conventional oil production in close proximity to the oil shale regions of Utah, Colorado, and Wyoming, potential beneficial use for significant quantities of CO_2 for improved oil recovery may exist. Opportunities may also exist to sequester CO_2 from oil shale operations in depleted oil and gas reservoirs, and in the coal deposits in the region. Sequestering in coal beds could lead to significant natural gas coal bed methane production.

Other produced gases, NO_x and SO_2, can most likely be controlled using commercially-proven technologies developed for petroleum refining and coal-fired power generation.

Prospective oil shale developers will need to employ appropriate control technologies to reduce potential air emissions which otherwise could result from construction and operation of surface facilities.

Spent Shale Disposal

In surface retorting operations, after mining and crushing, the raw oil shale will be conveyed to a processing unit called a retort where the oil shale is heated to a temperature of about 500 degrees centigrade. At this temperature, the solid organic material in oil shale is converted, by pyrolysis, to shale oil and gas. Spent shale, composed of carbonate materials and other minerals, is discharged from the retort and cooled. Depending on the location and the process, some spent shales can have contamination of heavy metals or toxic organic compounds that may require special handling, treatments, or disposal methods.

The volume of the spent shale will be 13 to 16 percent greater than its in-place volume[17]. This increased volume is caused by void spaces in the spent shale that are not present in the compacted shale before it is mined. Therefore, not all of the spent shale can be returned to the oil shale mine; surface disposal or alternative uses will be required to some extent in all cases applying surface retorts. Other uses of spent shale can include road bed material and aggregate for concrete production and building materials.

Water Quality

Controls are required to protect surface and ground waters from contamination by runoff from mining and retorting operations, from treatment facilities for products, other wastewaters, and particularly from retorted shale waste piles with respect to heavy metals in the leachate. Control will also be required for in-situ heating and combustion of oil shale.

Water is a by-product of oil shale retorting. Prior test data indicate water may be produced at a rate as high as 30-40 gallons-per-ton of shale retorted, but more typically, it will range from 2 - 5 gallons-per-ton depending on the retorting process employed. Produced water will contain a variety of organic and inorganic substances, but these foreign substances can be effectively removed with conventional technology. After treatment, excess produced water may be discharged or disposed of in evaporation panels.

Alternatively, such water can be minimally treated to remove odorous, volatile substances, and then used to wet spent shale during disposal operations. If this option were chosen, the water and any remaining mineral and organic substances would be physically trapped within the compacted spent shale disposal pile. This option could eliminate environmental hazards associated with disposal of incompletely treated water.

In-Situ Recovery Residuals

In-situ recovery technologies use one of two approaches, modified or true in-situ. Modified in-situ first creates a void space (with surface uplift), either through mining and blasting, or direct blasting followed by direct combustion of the rubblized shale. True in-situ recovers oil *without* first creating void spaces. The issues associated with surface mining, deep mining, and spent shale disposal do not apply to true in-situ processes. However, other subsurface impacts, including ground water contamination, are possible and must be controlled.

A true in-situ process has the potential to dramatically reduce waste disposal problems, runoff and other problems associated with mining, spent shale disposal, and surface reclamation. Since the vertical wells, or a combination of vertical and horizontal wells, of a true in-situ process are able to access thick sections of oil shale, the surface required for a given production rate may be smaller by a factor of as much as 10. There are locations of thick resources that could yield in excess of 1 million barrels per acre and require, with minimal surface disturbance, fewer than 23 square miles to produce 15 billion barrels of oil over a 40 year project lifetime.

In addition, since the hydrocarbon products can be higher API gravity than those produced by surface retorting technologies, further upgrading can be less costly. Upgrading could be done on-site, at local area refineries, or more distant refineries accessible by pipeline for either surface retorting or in-situ processes. A regional upgrader, charging a per barrel usage fee based on quality of incoming material, would be a beneficial option for upgrading liquids to pipeline quality liquids. This would allow efficient use of one or more shared-cost facilities, minimize footprint, and avoid unnecessary duplication of expensive hydrogen and sulfur recovery plants.

In conjunction with its in-situ conversion process (ICP) process currently being tested in Colorado, Shell Oil Company developed an environmental barrier system called a “freeze wall” to isolate the in-situ process from local groundwater. The freeze wall is created by freezing ground water occurring in natural fractures in the rock into a ring wall surrounding the area to be pyrolyzed. This barrier protects groundwater from contamination with products liberated from the kerogen while at the same time keeping water out of the area being heated.

Once pyrolysis is completed, the remaining rock within the freeze wall is flushed with water and steam to remove any remaining hydrocarbons and to recover heat from the spent reservoir. Heat from the produced steam can be used to provide process heat or generate additional electric power. Once the area has been sufficiently cleaned, the freeze wall can be allowed to melt and groundwater can flow through this area once more.

Biology and Ecology

Oil shale development will impact the biology and ecology of the area. The extent of impact will need to be evaluated and appropriate actions taken to mitigate the impact. Before any activity begins, investigations need to be conducted to determine existing field conditions. The primary objective is to provide adequate baseline information prior to mineral development activities that could cause destruction of habitat.

Plant and animal surveys provide information about the flora and fauna existing in the area that may be disturbed by subsequent program activities. The terrestrial ecosystems must be thoroughly evaluated, including vegetation, fauna, and flora climatology. A wildlife management plan for the area should be developed with Federal and state wildlife authorities to monitor and track wildlife dislocations. The primary concern is to maintain the habitat quality and keep population levels in balance.

Aquatic ecosystems should be characterized to aid in the development of procedures for minimizing damage to aquatic habitats. Seasonal variations of aquatic species and correlations between present water quality and existing aquatic species should be determined. Studies can also determine whether any rare or endangered species of fish exist in the streams.

Impact mitigation plans will need to be implemented based on detailed site-specific data and analyses of the data collected.

MITIGATION STRATEGIES

Environmental control technologies were developed for oil shale development through the early 1990's. Future development will build on that technology base and on advances that continue to be made and applied in similar mineral extraction (coal mining and reclamation) and processing (oil refining) industries. It is clear that any development must achieve the standards that have been developed over the years. Major regulations that will affect oil shale development are summarized below:

Major Regulations That Affect Oil Shale Development

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

National Environmental Policy Act (NEPA)

Each major project on public lands will need to comply with NEPA. The Bureau of Land Management, working with the relevant states, plans to develop a Programmatic Environmental Impact Statement (PEIS). Individual operators will then be expected to prepare a site-specific impact assessment.

Clean Air Act (CAA)

There have been major changes to the Clean Air Act since its inception in 1970. While the Federal government sets the standards for controlling air emissions, states have authority under their State Implementation Plans to implement these controls, including setting more strict standards. Every aspect of shale oil development - from mining and retorting to transportation - will need to comply with the Clean Air Act.

In 1990 revisions to the Clean Air Act, the list of "Hazardous Air Pollutants" (HAPs) or "air toxics" was expanded from seven to 189 Hazardous Air Pollutants, and authority was given to EPA to add additional substances to this list. Sources identified as emitters of these substances must use Maximum Available Control Technology (MACT) to control these emissions.

The second aspect of this set of regulations is whether the area in question is "in attainment" with respect to primary health standards. If it is not, additional restrictions on development will apply.

Ground-level ozone (smog) and particulate matter (PM-10) are included in this aspect of the Clean Air Act, and regulated in a similar fashion with attention to both region and specific project.

In 1997 the Clean Air Act was revised to tighten both the smog and particulate matter standards, and a program was developed for control of regional haze. As part of economic incentives, these amendments include provisions for "offsets" for improved control of certain emissions in new and expanded operations.

Under the 1990 revisions, there is a uniform permitting system for all requirements under the Clean Air Act. This is similar to the permitting under the Clean Water Act (National Pollution Discharge Elimination System (NPDES) permits.

Resource Conservation and Recovery Act (RCRA)

The regulatory provisions of this law are quite complex with respect to waste management. Applicable requirements will cover any part of the process producing waste (solid or hazardous), handling of all wastes, storage, handling process water, etc. The regulations are well established. The compliance program is handled by the states with oversight by EPA regional offices.

Tailings management for RCRA substances will be potentially benefited by continuing research in process technology and in waste management.

Clean Water Act (CWA)

Requirements under the Clean Water Act, first passed in 1972, are well established. The basic permitting system under this law is NPDES. The Clean Water Act jurisdiction is over surface waters, and does not include groundwater, which is under the purview of RCRA. Over the past decade this program has evolved into a holistic approach to watershed management, and away from the project-by-project control strategy.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)

This law was passed in 1980, and was not yet implemented by the time the last oil shale development phase ended. Aspects of this law most germane to new projects are reporting new releases. Operators are required to develop emergency response plans in accordance with regulations. These requirements are well understood, but plans must be developed and approved for each project.

Emergency Planning and Community Right-to-Know Act (EPCRA) (also known as SARA Title III)

This legislation was not in existence during the last development phase for shale oil. Requirements under this law include coordinated emergency planning by private industry, state and local governments, and Federal agencies. Other requirements include annual filings of emissions of listed substances.

Although this is a new requirement, it has been implemented throughout the country and operators are now familiar with how to coordinate the planning efforts, and governmental agencies, including local governments, are also familiar with the requirements. An educational process will likely be required. The annual reporting of releases was a major hurdle during implementation of this law, but has now settled into established procedures and formulas.

Pollution Prevention Act

The Pollution Prevention Act of 1990 focused industry, government, and public attention on reducing the amount of pollution through cost-effective changes in production, operation, and raw materials use. The law established the policy that source reduction is fundamentally more desirable than waste management or pollution control. Operators are required to file an annual toxic chemical release form and include a toxic chemical source reduction and recycling report for the proceeding calendar year. The reporting requirements are linked to the Toxic Release Inventory (TRI) required under EPCRA.

Toxic Substances Control Act (TSCA)

Under TSCA, operator's must file a pre-manufacture notice identifying substances to be produced. Toxicological testing may be required of the operators, and if so, can take several years. Much coordinated work was done in defining the products of shale oil retorting in the early 1980s. Nevertheless, because of changes in technology, the process will at least have to be reviewed by both operators and the EPA.

Endangered Species Act

Consideration will be given to protected plants and animals in the Environmental Impact Statement, but additional information regarding protective measures will be required for permitting. Much of this species information has now been digitized using geographic information systems, and maps are available through state and private non-governmental organizations.

Occupational Health and Safety Regulations

The hazards and risks to human health and worker safety associated with oil shale production are similar to those that exist and are controlled in other mining, oil production, chemical processing, and refining industries.

Oil shale operations will be subject to occupational health and safety regulations of both the Occupational Safety and Health Administration (OSHA) and the Mine Safety and Health Administration (MSHA) depending on the process involved. MSHA will have jurisdiction over mining operations under regulations for metal and nonmetal mines, both surface and underground. OSHA regulations will cover all other operations involved. Both sets of regulations involve reporting, worker training, and hazard communication.

Since oil shale was first seriously considered in the United States in the 1970s, most of these environments have been characterized in terms of required industrial hygiene and safety analyses.

Operators are expected to carry out operations in a manner that is compliant with applicable regulations and consistent with modern industrial hygiene practices.

CARBON MANAGEMENT STRATEGY

U.S. western oil shale is a carbonate rock matrix imbedded with organic sedimentary kerogen which, when heated, will liberate not only shale oil but also carbon dioxide that may need to be captured and processed, or otherwise sequestered.

Amine absorption is the current world-wide standard for CO_2 capture. The technology is widely applied to remove CO_2 from produced natural gas and, in limited cases, to remove CO_2 from flue gas. The base technology is not owned and is considered general technical knowledge. However, many firms have advanced amine absorber technology and will make this technology available commercially with a proprietary license addition.

Application of amine technology to flue gas will significantly increase the amount of energy needed by 24% to 40%. Additional equipment is needed, and this will increase capital cost. Overall capture cost according to the Intergovernmental Panel on Climate Change[18] is estimated to be $29 to $51 per metric ton of CO_2. A report written by the Energy Information Agency[19] estimates the cost at $10 to $60 per metric ton of CO_2 captured.

The DOE has mounted an aggressive program to improve the efficiency of capture and to reduce capture costs[20]. The goal of these efforts, by 2012, is to develop two new capture technologies that each result in less than a 10% increase in the cost of energy services. This new technology, if successful, would be available for application to a growing oil shale industry.

Once captured, CO_2 can be used for a wide variety of applications that have value. For example, the use of CO_2 for food processing, for many industrial processes, and for injection into oil and/or gas bearing formations to increase the production of oil and gas while, at the same time, sequestering the injected gas. Detailed geologic and engineering analyses are required to define the most cost-effective method of CO_2 sequestration.

One key demonstration underway since 2000 provides a carbon capture and storage model that may be part of the oil shale carbon management strategy. In this model, CO_2 from the Great Plains coal gasification Plant located in North Dakota is being transported by a 330-km dedicated pipeline to the Weyburn oil field located in Saskatchewan, Canada. Following extensive study, the International Energy Agency[21] concluded that the CO_2 injected into the field will remain securely stored underground for at least 5, 000 years. Over the life of the project, the Weyburn field is expected to store 14 million tons of CO_2 and produce 130 million barrels of incremental oil. Capture of the CO_2 from the stack is not used because the gasification plant uses oxygen to produce a stream of CO_2. This gas stream has purity greater than 90% and is transported directly to the Weybum field for injection.

Carbon capture and sequestration has become an important technical focus of international interest. Technical advances coupled with site-specific geologic and energy studies will guide the development of project-specific carbon management strategies.

5. REGULATORY AND PERMITTING ISSUES

Oil shale plants will be required to obtain dozens of permits and approvals, involving all levels of government. In 1977, an oil shale developer reported that it took two and a half years just to identify all of the requirements. Today, while environmental laws have matured and permitting processes have improved, delays remain a major risk for large mining and industrial projects. To reduce these risks, a cooperative effort of local, state, and Federal entities is planned as a new initiative to streamline the permitting process.

Issues associated with permitting and regulating oil shale leases on public lands include the lease size, lease limitations, fragmented ownership, and protests and litigation. In addition, the DOI has developed and is implementing new oil shale leasing initiatives.

LEASE SIZE LIMITATIONS

The Mineral Leasing Act of 1920 limited the size of individual oil shale leases to 5,120 acres (8 square miles). The effect of this restriction is to create a de facto preference for thick zones in the centers of the basins, which could be suitable for in-situ processes. However, many rich, but thinner near-surface zones, particularly in Utah, and possibly in Wyoming, may not be viable under this restriction. Congress, in Section 369 of the Energy Policy Act of 2005, increased the size of an individual lease from 5,120 to 5,760 acres. Leased tracts will be governed by regulations to be developed by BLM which may consider the amount of recoverable resource as a guide for tract size.

SINGLE LEASE LIMITATION

The Mineral Lease Act of 1920 limited individual lessees to one lease. This was even more restrictive than the limitation on acreage. Congress, in Section 369 of the Energy Policy Act of 2005, increased the number of leases a single entity may hold to 50,000 acres in any one state. A requirement for reasonable, but effective due diligence on lease acquisition may be imposed by BLM regulation.

FRAGMENTED OWNERSHIP

The oil shale resource ownership is fragmented between Federal, state, tribal and private lands. This fragmentation will, in all but a few exceptions, prevent a lessee or owner from developing resources without combining a land position from multiple owners. Limitations imposed by fragmented ownership are particularly acute for state lands in Utah and Wyoming where isolated school sections are scattered throughout the resource locations. Blocking up oil shale holdings into logical development units under single ownership would be beneficial to all parties. While provisions exist in the Federal Land Policy Management Act and Federal Land Exchange Acts, there is no directive at the Federal level to consolidate holdings in logical units.

Congress addressed this issue in Section 369 of the Energy Policy Act of 2005 and directed the DOI to consider the use of land exchanges where appropriate and feasible to consolidate land ownership and mineral interests. Further, the Secretary is directed to give priority to land exchanges on public lands containing deposits of oil shale or tar sands within the Green River, Piceance Creek, Uintah, and Washakie geologic basins. The Secretary is further directed to consider the geology of the respective basin in determining the optimum size of the lands to be consolidated. Land exchanges undertaken to respond to Congressional directives must be implemented in accordance with section 206 of the Federal Land Policy and Management Act of 1976 (43 U.S.C 1716).

PROTESTS AND LITIGATION

Protests of government leases are delaying Federal oil and gas development in Utah, Wyoming, and Colorado and can be expected to do so with oil shale leases as well. For example, "In Colorado, 80 percent of the [oil and gas] leases are protested," said IPAMS Executive Director Marc W. Smith. "That's just the front end. There are more opportunities for protest before the first well is drilled." [22]

BLM director Kathleen Clark confirmed the Colorado figure and said the situation is even worse in Utah, where all of BLM's 2004 oil and gas leases are under protest. "When we go to lease, the level of protests is 640 percent of what it was in the previous administration. Last year, we had over 300 requests for State Director reviews - a provision that wasn't even used 4 years ago. The protests are coming from people and groups who want to treat multiple-use lands as wilderness."

Some of these protests arise over insufficient information in the lease application. Others appear to be obstructionist in nature. Agency permit review may also be delayed due to lack of adequate human resources to promptly process the applications.

OIL SHALE LEASING PLANS

The DOI BLM has developed and is implementing leasing programs for oil shale on Federal lands, including provisions for RD&D and commercial scale development. To support this effort, the Federal oil shale task force should:

- Coordinate with BLM and Utah, Colorado, and Wyoming to mitigate identified impediments.
- Evaluate oil shale resources and prepare recommendations for their logical development.
- Develop information needed to support legislative and regulatory solutions to impediments.

Lease Block Optimization

In response to Congressional directives, BLM should analyze resource characteristics and ownership patterns to determine optimal lease block configurations. Leased areas should be sufficient in size to support projects operating at full commercial scale for durations of at least 30 years. Work with private and tribal landowners to define lease blocks that meet commercial requirements and enable the efficient development of the resource.

Land Exchanges

In response to Congressional directives, BLM should exchange Federal lands for state or private lands, as may be appropriate, to achieve efficient resource leasing and development. Exchanges pursuant to this Act should be conducted in accordance with the Federal Land Policy Management Act of 1976 and Federal Land Exchange Facilitation Act of 1988.

Expedited Permitting

Congress should mandate compliance with Executive Order No. 13211 (42 U.S.C. 13201 note) and impose deadlines for consideration of permit applications.

6. INFRASTRUCTURE

Oil shale development, initially in the western states of Colorado, Wyoming, and Utah, requires infrastructure to support industry development and operation, to supply process inputs, and to upgrade and transport manufactured fuels and other products to defense and civilian markets.

The Federal government must understand project requirements and infrastructure gaps and facilitate infrastructure development to meet the requirements.

MARKETS

Products produced from oil shale differ from conventional petroleum. In general, upgraded shale oil will be free of distillation residue and will contain low concentrations of nitrogen and sulfur. Both characteristics add market value to the product.

However, current refineries, particularly Gulf Coast refineries, are highly integrated, complex refineries designed to accept higher concentrations of distillation residue and sulfur. In fact such refineries count on purchasing such crude oils at a lower price to optimally utilize the unit capacities built into those refineries. In the Rocky Mountain West, where sweet (low sulfur) crudes have been the historic norm, and where increasing amounts of oil sand synthetic crude oil from Canada are being run, refineries are simpler in design and matching unit capacities with shale oil will be easier.

Western refining capacity (Utah, Colorado, Wyoming, and New Mexico) is about 527 thousand barrels per day (Bbl/d) as shown in Table III-8 Increases in the demand for oil have been met by Canadian imports that, in 2004, averaged 252 MBbl/d[23]. About one-half of the oil demand is supplied locally and the other half is imported from Canada. Shale oil will need to compete with Canadian syncrude on a price and quality basis.

Utah and Wyoming refineries can probably absorb first shale oil production, up to about 50 MBbl/d. However, growth of the oil shale industry will soon outstrip existing regional pipeline and refining capacity. For distribution to broader markets, both to the east and to the west, additional infrastructure will be required.

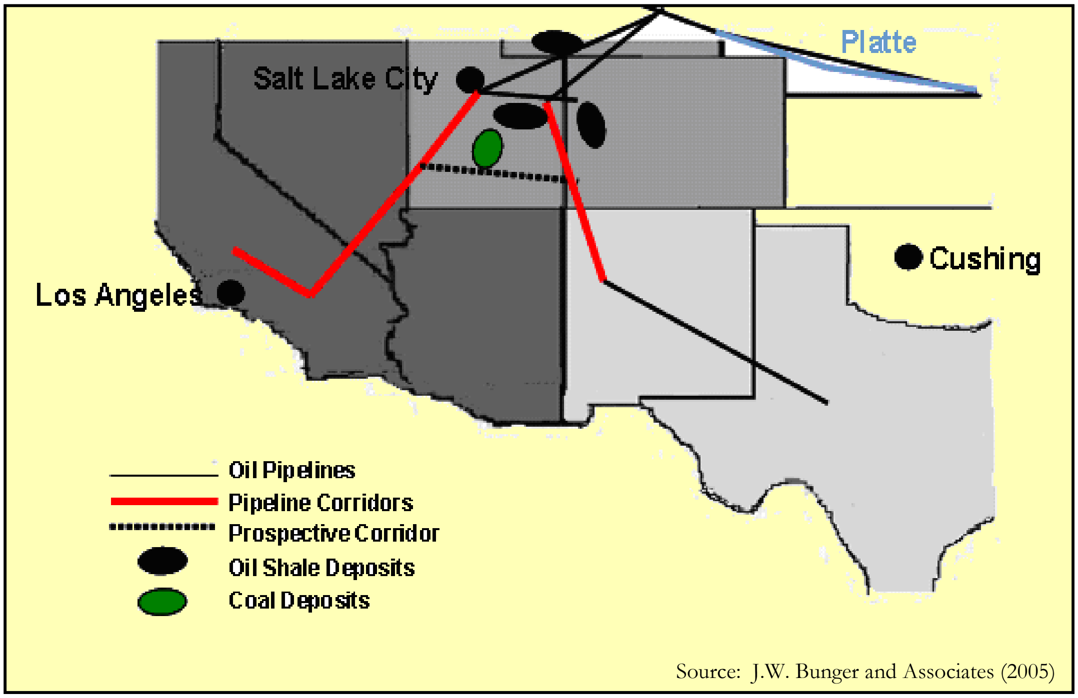
Table III- 8. Western Refining Capacities (Barrels/Day)

Utah	**167,000**
Colorado	**94,000**
Wyoming	**153,000**
New Mexico	**113,000**
Total	**527,000**
	Source: EIA (2006)

PIPELINES

Pipeline corridors connect oil shale country south to New Mexico, west to Salt Lake City and northeast to the mid-continent area. Construction of a new pipeline in a potential corridor along I-70 to the Kern River gas pipeline corridor is possible in order to serve the California markets (Figure 21[24]). A key issue will be permitting of pipeline additions and expansions.

Figure III- 21. Oil Shale Infrastructure



Source: J.W. Bunger and Associates (2005)

In addition to pipelines, a wide range of other infrastructure requirements are needed to support a growing oil shale industry, including natural gas, electricity, and water.

NATURAL GAS

Natural gas may be required for process heat and for upgrading shale oil to pipeline quality. Natural gas is indigenous to the region and produced in ample quantity. Technologies that require the least amount of imported energy are most desirable.

ELECTRICITY

Some technologies may require additional electric power generation capacity. Natural gas or coal-burning facilities may need to be constructed and/or existing facilities expanded.

WATER

There is limited availability of water to support industry and associated economic activity. Use will be prioritized according to water rights and applicable law. Because energy development can compete in the marketplace for water, the main issue will be how to manage any economic dislocations caused by this competition for a scarce resource.

An overlying issue will be the question of the availability of adequate water supplies to support a commercial-scale oil shale industry – especially in light of increasing demand for water in the west, with particular concerns in the Colorado River Basin.

The Colorado River Basin drainage supplies much of the water from western Wyoming to southern California. That region has experienced and continues to experience significant population and economic growth. The result has been a dramatic increase in demands on Colorado River water, with all Colorado River Compact states now insisting on exercising their rights to the volumes established by the compacts. In recent years, the lack of "normal" precipitation and resulting stream flows has brought into question whether the Colorado can reliably supply the needs of the region.

Water rights are real property that can be bought and sold with older or more senior rights generally having greater value. Most of the early water rights were filed for agricultural irrigation or domestic use. In the early 1900's, individuals and corporations began to file for water rights to support mineral operations, including oil shale. Water was not then perceived to be much of an issue. However, during the 1950s and 1960s, as interest in oil shale increased and larger plants were being planned, the companies and government agencies recognized the need for secure water supplies for oil shale operations.

Participating companies aggressively filed for water rights on the major streams and began planning water storage reservoirs to impound water. Some companies also began purchasing senior water rights from ranchers. Interest in groundwater increased, and some water wells were drilled to secure subsurface water rights. Most companies with private oil shale holdings have, at a minimum, now secured conditional water rights and have plans in place to develop and store sufficient water for their future operations. Nearby communities, in most cases, have water supplies to support some growth but will likely look to the companies to augment those supplies as part of the project approval process to minimize socioeconomic impact.

During the 1970's and 1980's, the heightened interest in western oil shale drew much attention to water availability. The Federal government evaluated the availability of water supplies needed to support the leases offered under the prototype oil shale leasing program. At that time, it was determined that water was available to support the prototype lease development and an expansion of that initial development. However, water may still be a limiting factor in the ultimate size of the industry.

KEY RESOURCE AVAILABILITY

Past detailed analyses of raw materials and heavy equipment needed to support a 2 million Bbl/d oil shale industry[25] have shown no major issues. For example, steel demand was calculated to be less than 1% of the Nation's steel production, expenditures for heavy construction represented only 1.2% of the Nation's total expenditures, and heavy construction labor was 1.2% of the Nation's heavy construction labor pool. Raw materials, equipment, and labor for an expanding oil shale industry were therefore not expected to represent a major constraint on development. Planning for long-lead items will continue to be required by industry to effectively expand this industry.

Development will create both temporary and permanent employment. Construction of the plants and urban communities create temporary employment in the sense that the job terminates with the completion of construction. Many of the temporary positions may be transitioned to permanent long-term employment is associated with the plant operations and supporting services. Actual labor requirements will depend on the mix of technologies chosen by industry to develop the resource and the timing of the development. However, as many as 100,000 direct and indirect new jobs could be created by the construction and operation of a 2 MMBbl/d shale oil industry.

Major construction for oil sands development in Canada may be nearing a development peak in the 2010 to 2020 period. This is the same time frame when operations in the U.S. will begin to need a large labor pool for commercial oil shale development. Skilled labor needed for oil shale development may therefore be transferable from similar operations in Canada. The status of both oil sands and oil shale development will need to be assessed over time and labor support plans developed.

7. SOCIO-ECONOMIC PLANNING AND IMPACT MITIGATION

The vast majority of socio-economic impacts will result from the influx of workforce and permanent population growth. The total populations of the states of Colorado (~5M), Utah (~2.3M) and Wyoming (~0.5M) represent less than 3% of the U.S. population. At present no more than about 100,000 residents are distributed in the immediate three-state oil shale region. As a result, even the first development stages will have a major impact on local communities through an influx of people.

COMMUNITY OBJECTIVES

Local communities' primary concern is for oil shale development to occur in an orderly fashion. This requirement entails effective planning and communication and the availability of financial resources to support these processes. Relatively small amounts will be required in the initial phases, increasing as community infrastructure needs to be built. A common problem for the impacted areas is that the financial needs invariably precede the project tax and royalty revenues.

Large financial benefits will flow from these developments, locally, regionally and nationally, but the timing of the revenues will not coincide with that of the costs. The question is how to bridge this timing gap in a way that results in an equitable risk/benefit relationship for both the public and private sectors. Local communities should not be expected to take upfront financial risks for developments over which they have little control.

Local communities are also concerned about being overwhelmed with an influx of people seeking jobs that have yet to materialize; so keeping expectations at a realistic level is important. This can only happen with realistic development projections, joint public/private growth planning, and effective communicating of results to the public at large.

Communities have indicated several objectives they seek to achieve in assessing the potential and desirability of developing a domestic oil shale industry in rural Colorado, Utah, and Wyoming:

- Secure revenues for planning, impact assessment, and communication with state and Federal agencies to anticipate development impacts and implement advanced plans for mitigation.
- Establish policy and promote legislation that minimizes potential economic risks to states and communities associated with industry failure or energy price volatility.
- Secure funding for timely development of necessary community infrastructure.
- Anticipate and provide for best available solutions for community health, education, environmental, economic, and quality of life concerns.
- Coordinate with industry relative to needs and support of direct work force, families, and population growth associated with project development.

Orderly and efficient development will require alignment of interests of many stakeholders. These developments will be long-term in nature and economic and community growth activities must engender the support of local populations. Community needs should be met, insofar as possible, through a consensus of private and public interests at large. Initial discussions with key constituencies, thus far, have yielded significant and valuable insights that can inform Federal planning efforts.

COMMUNITY PLANNING ACTIVITIES

Several organizations already exist in the oil shale development region to assist in community and socio-economic planning.

Utah

Regional counties and cities have planning and zoning boards that will form a nucleus for socio-economic planning.

Uintah County has a public land board as well as a full time support staff and a contracted expert to advise them on issues involving all aspects of public lands.

The Uintah Basin Association of Governments also provides staff and assistance for economic development and planning.

The School of Business and Economic Research at the University of Utah maintains state socio-economic models (REMI model) and statistics.

Colorado

Colorado has established the Associated Governments of Northwest Colorado and the Department of Local Affairs for joint review, economic modeling, and assessment activities.

CLUB 20 is a coalition of individuals, businesses, tribes, and local governments in Colorado's 22 western counties, organized for the purpose of speaking with a single unified voice on issues of mutual concern.

In prior times a joint state/local/industry CITF (Cumulative Impacts Task Force) was established to develop computer models and assess socio-economic impacts.

Establishing a tri-state task force for these purposes may be worth considering. As program planning progresses, it may be advisable to establish additional groups and forums to better enable stakeholder engagement.

Funding Community Planning and Infrastructure Development

Oil shale is located in a very sparsely settled area on the western slope of the Rocky Mountains. The shale deposits are bounded in Colorado by the small towns of Rangely, Meeker, Rifle, and Grand Valley. Glenwood Springs, a larger resort community, is approximately 75 road miles east of the Parachute Creek area; Grand Junction, the area's major trade and services center, is approximately 110 road miles west of the center of potential development. Vernal, Utah is just north of the major Utah oil shale resources.

Rapid growth will greatly expand the demand for municipal and human services, such as police and fire protection, medical services, sanitary facilities, educational services, and transportation. For most of the smaller communities, annual operating costs are about equal to annual revenue. Therefore, capital improvement expenditures are largely financed by municipal bond issues that are constrained by statutory bonding limits tied to property values. For these reasons, it is difficult for small communities to raise capital funds needed to support rapid growth in a timely manner.

Under the 1973 Prototype Oil Shale Leasing Program, Colorado dedicated a part of its lease bonus payments to a fund aimed at community infrastructure. Distributions from the fund from 1975 through 1979 totaled $29.6 million for specific projects including Rangely streets and drainage, Meeker streets and drainage, and Rifle municipal water.

One Federal revenue stream that directly relates to oil shale development is Mineral Lease Funds collected by the Minerals Management Service (under the Mineral Leasing Act of 1920) for production of oil, gas, minerals, and other resources on Federal land. Fifty percent of these funds are distributed to the state of origin, 40 percent goes to the Federal Land and Water Conservation Fund, and 10 percent goes to the Federal General fund. Because the U.S. public at large will reap extraordinary benefits from oil shale development, it may be appropriate that Mineral Lease Funds be used as a type of 'investment bank' to provide funds for costs associated with extraordinary growth. Revenues from a growing industry should be more than adequate to pay back these loans in a reasonable period of time.

APPENDIX A - OIL SHALE TECHNOLOGIES (adapted from DOI[4])

This appendix reviews the major technologies that were developed for oil shale mining, retorting, and upgrading between 1960 and 1991. Much of the information in this appendix is excerpted from external sources[26,27]. More recent technology advances that can contribute to improved performance and cost-efficiencies are discussed in the body of this report.

There are two basic retorting approaches. With conventional surface processes, the shale is brought to the heat source, namely the retort. With in-situ processes, the heat source is placed within the oil shale itself. Conventional surface retorts require the mining of the oil shale by surface or deep mining methods: the transporting of the shale to the retort facility, the retorting and recovering of the shale oil, and finally the disposing of the "spent" shale. In-situ retorting involves the application of heat to the kerogen while it is still embedded in its natural geological formation, and then the recovery of the fluid kerogen by conventional means. Examples of in-situ approaches include modified and true in-situ processes, as described below.

MINING

With the exception of the "true in-situ" process to be described below, oil shale must be mined before it can be converted to shale oil. Depending on the depth and other characteristics of the target oil shale deposits, either surface mining or underground mining methods may be used.

Surface Mining – Due to less complexity, fewer safety issues, and lower costs, open-pit surface mining is the preferred method whenever the depth of the target resource is favorable to access through overburden removal. In general, open-pit mining is viable for resources where the over burden is less than 150 feet in thickness and where the ratio of overburden thickness to deposit thickness is less than one - to - one. Removing the ore may require blasting if the resource rock is consolidated. In other cases, exposed shale seams can be bulldozed. The physical properties of the ore, the volume of operations, and project economics determine the choice of method and operation.

Underground Mining – When overburden is too great, underground mining processes are required. Underground mining necessitates a vertical, horizontal or directional access to the kerogen-bearing formation. Consequently, a strong "roof" formation must exist to prevent collapse or cave-ins, ventilation must be provided, and emergency egress must also be planned.

Room and pillar mining has been the preferred underground mining option in the Green River formations. Advanced technologies have already been developed, tested, and demonstrated, safely and successfully, by Cleveland-Cliffs, Mobil, Exxon, Chevron, Phillips and Unocal. Technology currently allows for cuts up to 27 meters in height to be made in the Green River formation, where ore-bearing zones can be hundreds of meters thick. Mechanical "continuous miners" have been selectively tested in this environment, as well.

Depending on the ore size limitations of various retorting processes, mined oil shale may need to be crushed using gyratory, jaw, cone or roller crushers, all of which have been successfully used in oil shale mining operations.

For limited uses, including electric power generation, oil shale can be burned directly, without further processing to liquid form. This has been the norm in Estonia where raw oil shale is burned as power plant boiler fuel. The high calcium carbonate content of some oil shale ores provides an effective matrix for oil shale use in fluidized bed combustion technologies. Atmospheric- and pressurized-fluidized bed technologies have been developed and used in the United States since the 1970s to burn medium and high-sulfur coals in power plant applications and minimize sulfur dioxide and other atmospheric emissions. Another direct use of oil shale is for road paving. Road paving applications range from simple compaction on the roadbed to mixtures with water or hydrocarbon solvents and asphalt pitch.

CONVERTING ORE TO SHALE OIL

Unlike the bitumen derived from tar sand, the kerogen in oil shale is a solid that does not melt and is insoluble. To create other fuels, the kerogen must be converted from a solid to a liquid state. In general, releasing organic material from oil shale and converting it into a liquid form requires heating the shale to some 500 degrees C – in the absence of oxygen - to achieve a pyrolysis which converts the kerogen to a condensable vapor which, when cooled, becomes liquid shale oil. This process is called "retorting."

Depending on the efficiency of the process, a portion of the kerogen may not be vaporized but deposited as "coke" on the remaining shale, or converted to other hydrocarbon gases. In some processes, residual carbon and hydrocarbon gases may be captured and combusted to provide process heat. For the purposes of producing shale oil, the optimal process is one that minimizes the thermodynamic reactions that form coke and hydrocarbon gases and maximizes the production of shale oil.

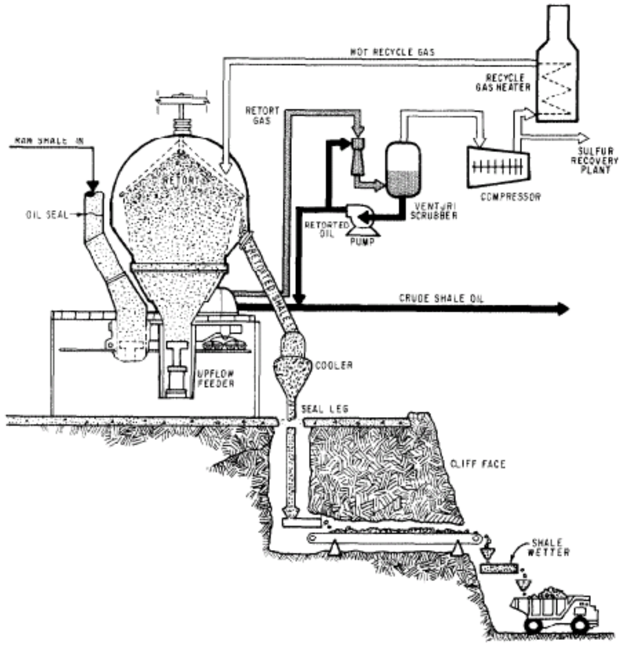
Maximum oil production requires pyrolysis at the lowest possible temperature (about 480 degrees centigrade) to avoid unnecessary cracking of hydrocarbon molecules, which reduces oil yields.

Conventional Oil Shale Retorts - Examples of conventional retorts include "TOSCO II" and "Union B", Petrosix gas combustion, Paraho, Lurgi-Ruhrgas and Kiviter, as well as the new Alberta Taciuk Process ("ATP") now being demonstrated in Australia.

Of the projects and processes used in the U.S., Union B was the longest lived, produced the most shale oil (4.6 million barrels between 1980 and 1991), and received the most significant technological evaluation. Worldwide, the Petrosix retorts in Brazil and Kiviter Retorts in Estonia have produced tens of millions of barrels over their lifetimes.

Union B – The retort developed by Union Oil Company of California (UNOCAL) consists of a vertical refractory-lined vessel (***Figure A-1***). It operates on a downward gas flow principle, and the shale is moved upward by a unique charging mechanism usually referred to as a "rock pump." Heat is supplied by combustion of the organic matter remaining on the retorted oil shale and is transferred to the [raw] oil shale by direct gas-to-solids exchange. The oil is condensed on the cool incoming shale and flows over it to an outlet at the bottom of the retort. The process does not require cooling water.

Figure A- 1. Union B Retort



The retort was initially developed in the 1940's and moved systematically toward commercial operations. Two research sized pilot plants were followed by a 350 TPD retort in 1954. The technology was successfully scaled to 1,200 TPD by 1974. The next logical step was the construction and operation of a commercial retort that would process about 13,000 TPD of oil shale.

Construction of the 13,000 TPD retort was completed in 1983. From 1983 through 1986, UNOCAL attempted to operate the plant over 40 times. However, sustained operations could not be achieved. The retort could only be operated for up to two weeks before it had to be shut down for modifications. Even during the short operating periods, the unit could only be operated at 43% of the design rate.

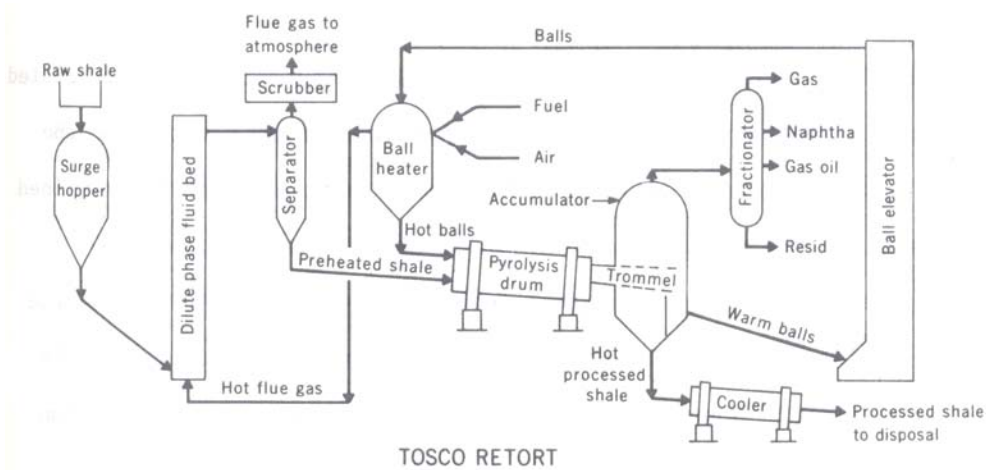
Technical review of the UNOCAL operations by the General Accounting Office[28] showed the spent-shale cooling and removal system to be the major technical problem. The retort was designed to accept raw shale at the bottom of the vertical kiln and move upward using a rock-pump mechanism. The retorted shale exited the top of the retort at 920 degree F and was to be cooled before it was hauled to a disposal site. UNOCAL was not able to evenly cool the retorted shale.

UNOCAL continued to make process improvements and began to sell shale oil in December 1986. From 1986 through 1991, UNOCAL produced and sold 4.6 million barrels of shale oil. Production over this five year period averaged 2,500 BPD; about 25 percent of the design rate.

Overall, the under-feed retorting technology proved to be too difficult to scale to commercial operations. Experiment work was terminated in 1991. The plant was decommissioned and the site reclaimed.

TOSCO II – Colony Development Operation, comprised of Arco, Sohio, the Oil Shale Company (TOSCO), and the Cleveland Cliffs Iron Company operated projects from the mid 1960s to 1972 using the TOSCO II retort (***Figure A-2***). This process employed a rotary type kiln utilizing ceramic balls heated in external equipment to accomplish retorting. Shale reduced to one-half inch size or smaller is preheated and pneumatically conveyed through a vertical pipe by flue gases from the ballheating furnace. The preheated shale then enters the rotary retorting kiln with the heated pellets where it is brought to retorting temperature of 900 degrees F (500 degrees C) by conductive and radiant heat exchange with the balls. Passage of the kiln discharge over a trommel screen permits recovery of the balls from the spent shale for reheating and recycling. The spent materials are then routed to disposal. Excellent oil recoveries and shale volumes were achieved.

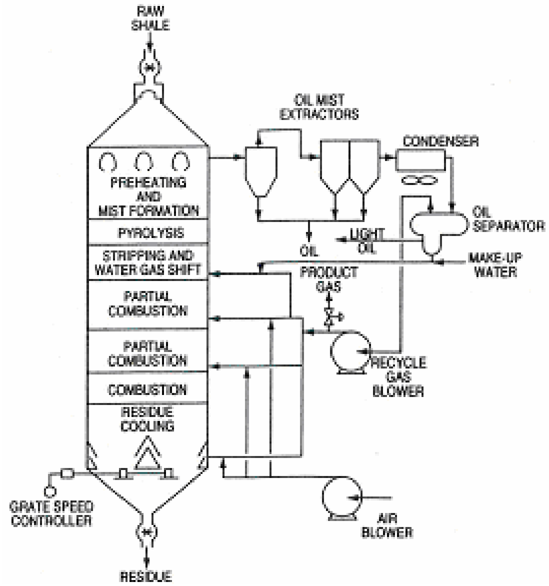
Figure A- 2. TOSCO Retort



Ceramic balls transfer heat to the shale. No combustion takes place in retort.

Gas Combustion Retort – Vertical-shaft retorts can be traced back to Scottish oil shale retorts that evolved from coal gasification technologies. "When U.S. Bureau of Mines engineers set out to develop a high-efficiency, high throughput oil shale retort specifically for the Green River Formation shale, they elected to develop a vertical shaft Gas Combustion Retort (GCR) that would burn the incondensable gases of the retorting process as fuel." Of the numerous technologies studied in the Bureau of Mines program, the gas combustion retort [then] gave the most promising results (***Figure A-3***). This retort is a vertical, refractory-lined vessel through which crushed shale moves downward by gravity. Recycled gases enter the bottom of the retort and are heated by the hot retorted shale as they pass upward through the vessel. Air is injected into the retort at a point approximately one-third of the way up from the bottom and is mixed with the rising hot re-cycle gases. Combustion of the gases and some residual carbon from the spent shale heats the raw shale immediately above the combustion zone to retorting temperature. Oil vapors and gases are cooled by the incoming shale and leave the top of the retort as a mist. The novel manner in which retorting, combustion, heat exchange and product recovery are carried out gives high retorting and thermal efficiencies. The process does not require cooling water, an important feature because of the semi-arid regions in which the oil shale targets occur.

Figure A- 3. Gas Combustion Retort

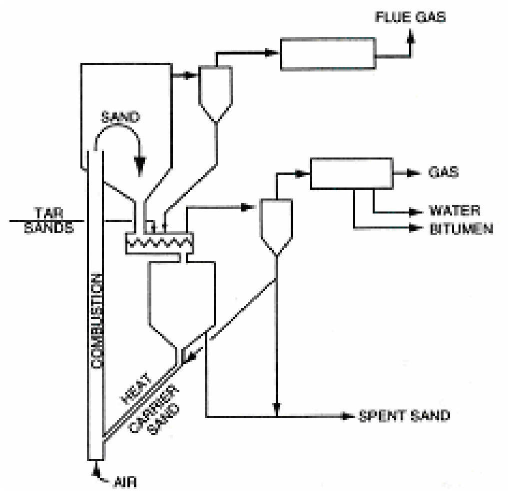


Paraho – The Paraho retorting process is typical of vertical-shaft retorts in which crushed shale with the fines removed descends through the retort under the influence of gravity. Zones for each step in processing the shale are maintained by managing gas flow in the retort. The retort can be operated 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. The Paraho facility was reactivated by a private company in 2005 to gather additional experimental data needed to support future development decisions.

Petrosix Vertical-Shaft Retort – The largest surface oil shale pyrolysis reactor currently operating is the Petrosix 11-m vertical shaft Gas Combustion Retort (GCR) used in Brazil's Oil shale development program. It was designed by the engineers who designed and built the Bureau of Mines GCR and the Paraho GCR.

Lurgi-Ruhrgas – The Lurgi-Ruhrgas technology developed in Germany (***Figure A-4***) features a lift pipe in which residual carbon is burned off spent hot solid feedstock to provide process heat. Burned feedstock is carried to the retort for solid-to-solid heat transfer to the raw feedstock. It has been successfully tested for processing Green River Oil Shale.

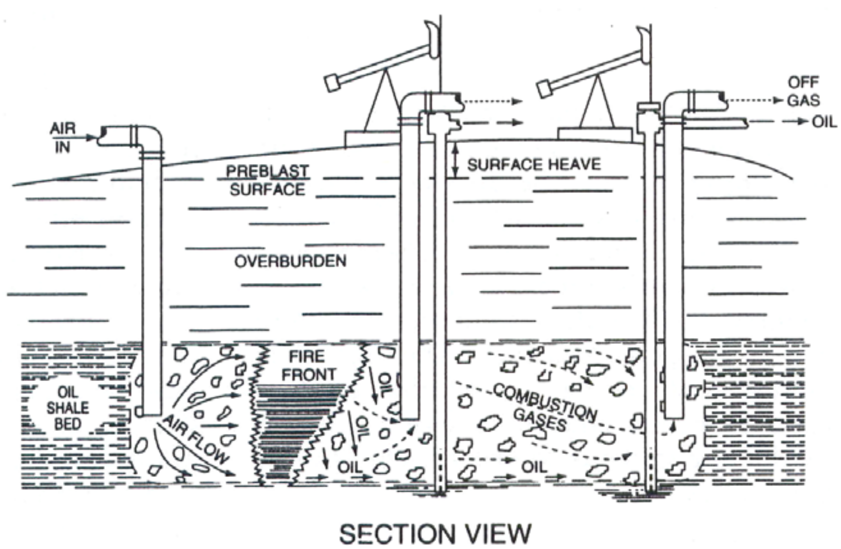
Figure A- 4. Lurgi-Ruhrgas Retort



In-Situ Retorting Processes – In-situ processes can be technically feasible where permeability of the rock exists or can be created through fracturing. "True in-situ" processes do not involve mining the shale. The target deposit is fractured, air is injected, the deposit is ignited to heat the formation, and resulting shale oil is moved through the natural or man-made fractures to production wells that transport it to the surface.

In true in-situ processes, difficulties in controlling the flame front and the flow of pyrolized oil can limit the ultimate oil recovery, leaving portions of the deposit unheated and portions of the pyrolized oil unrecovered. An example is shown in ***Figure A-5***.

Figure A- 5. Geokinetics Horizontal Modified In-Situ Retort



Modified in-situ processes attempt to improve performance by exposing more of the target deposit to the heat source and by improving the flow of gases and liquid fluids through the rock formation, and increasing the volumes and quality of the oil produced. Modified in-situ involves mining beneath the target oil shale deposit prior to heating. It also requires drilling and fracturing the target deposit above the mined area to create void space of 20 to 25 percent. This void space is needed to allow heated air, produced gases, and pyrolized shale oil to flow toward production wells. The shale is heated by igniting the top of the target deposit. Condensed shale oil that is pyrolized ahead of the flame is recovered from beneath the heated zone and pumped to the surface.

The Occidental vertical modified in-situ process was developed specifically for the deep, thick shale beds of the Green River Formation. About 20 percent of the shale in the retort area is mined; the balance is then carefully blasted using the mined out volume to permit expansion and uniform distribution of void space throughout the retort. A combustion zone is started at the top of the retort and moved down through the shale rubble by management of combustion air and recycled gases. Full-scale retorts would contain 350,000 cubic meters of shale rubble.

APPENDIX B

- 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 vender 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 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 contribute 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.
- Table 1, presented above, summarizes the model results for the four known extraction technologies. The average minimum economic cost shown in the table below represents the average of the breakeven prices for a given technology across the 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.

Tar Sands Resource and Technology Profile

Tar Sands Working Group Analysis
Prepared For The
Strategic Unconventional Fuels Task Force

February 2007

1. RESOURCE ACCESS

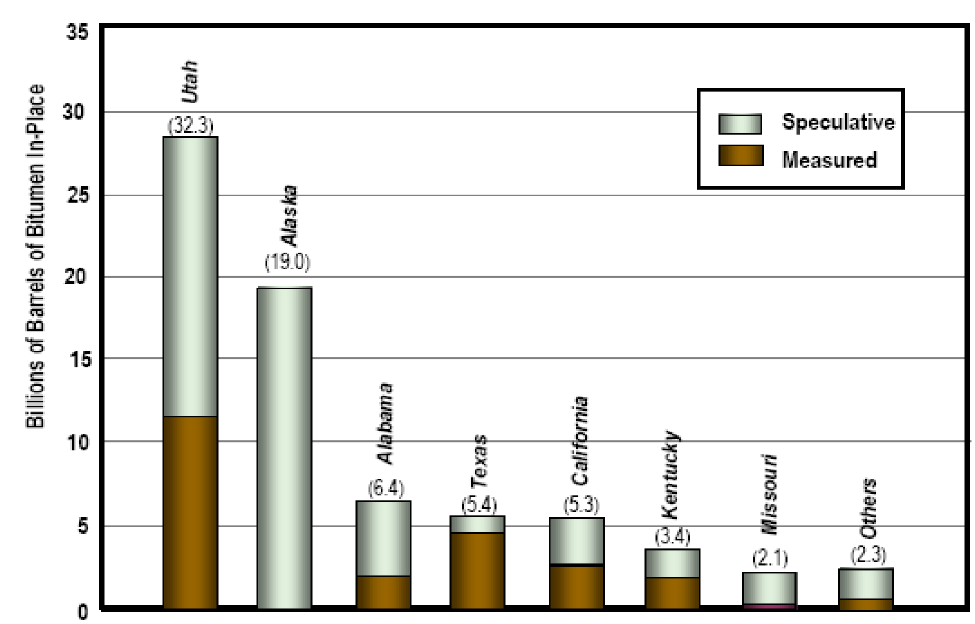
Tar sands (referred to in Canada as oil sands) are a combination of clay, sand, water, and bitumen; a heavy, black, asphalt-like hydrocarbon. (Figure III-22) Tar sands can be mined and processed to extract the oil-rich bitumen, which is then upgraded and refined into synthetic crude oil. Unlike oil, the bitumen in tar sands cannot be pumped from the ground in its natural state; instead tar sand deposits are mined, usually using open pit techniques, or produced in-situ by underground heating or other processes.

Figure III- 22. Tar Sands

SIZE

The U.S. tar sands resource in place is estimated to be 60 to 80 billion barrels of oil. The resource is substantial, but far smaller than Alberta's oil sands or U.S. oil shale resources (Figure III-23). About 11 billion barrels of U.S. tar sands resources may ultimately be recoverable[29].

Figure III-23. U.S. Tar Sands Resources



Source: DOE/FE/NETL (1991).

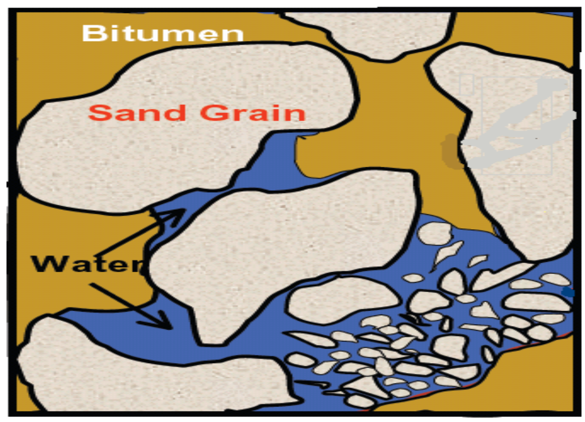
The rate of resource development and the potential volume of production are somewhat dependent on future oil prices. It also depends on industry access to resources on state and Federal lands and the availability of infrastructure for resource development and product upgrading. With current price projections, the near term incremental U.S. tar sands production potential to 2025 will probably not exceed 250,000 Bbl/d.

However, should very high oil prices persist, a greater portion of the resource will become economic, and leaner and more fragmented resources may become economically producible.

QUALITY AND GRADE

U.S. tar sands differ somewhat in quality and configuration from Canadian tar sands. U.S. tar sands are generally leaner in grade, less uniform in quality, and have higher sulfur content. U.S. tar sands are typically found in layered sandstone and are often consolidated, or cemented. Figure III-24 displays the composition of tar sands typical of the Canadian resource. Unlike U.S. sands, Canadian tar sands are less consolidated mixed with sand and water. While Canadian tar sands are water wetted, U.S. tar sands are more typically hydrocarbon wetted. New extraction technology approaches may be required.

Figure III-24. Composition of Typical Alberta Oil Sands



LOCATION AND AVAILABILITY

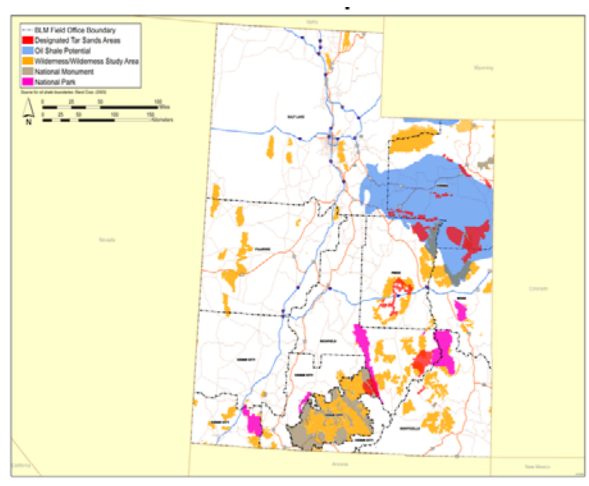
U.S. largest measured tar sands deposits are found in Utah. The rest is found in deposits in Alabama, Texas, California, Kentucky, and other states.

Utah has between 19 and 32 billion barrels of tar sands, about one-third of the domestic resource. Utah's tar sands resource is concentrated in the eastern portion of the state, predominantly on public land.

Approximately 19 billion barrels of speculative resources are thought to exist in Alaska.

Utah Resources: Figure III-25 displays the location of tar sands deposits in Utah.

Figure III- 25. Oil Shale and Tar Sands Deposits in Utah (Source: U.S. BLM)



The known (measured) and potential additional (inferred) resource for each of the major Utah deposits are displayed in Table III-9 and discussed below. The four largest Utah deposits are:

- ***Sunnyside*:** The Sunnyside deposit contains enough recoverable resource to support a 100,000 Bbl/d operation. Thermal or solvent treatment may be required as the ore is consolidated.
- ***Tar Sand Triangle (TST):*** The bitumen is characterized by high sulfur content, similar to Alberta oil sands but, unlike the Uinta Basin deposits described above, which are low in sulfur. TST is located near Canyon Lands National Park, and development is likely to meet with challenges. There appears to be interest in this deposit for in-situ recovery. The product could be transported by truck and rail in bitumen or diluted bitumen state.
- ***PR Spring:*** This sizeable resource is close to the surface, but is fragmented by erosion and multiple beds. It is in a primitive area, which may slow development. A few rich zones could each support modest size operations on the order of 25 to 50 MBbl/d.
- ***Asphalt Ridge*:** Asphalt Ridge was characterized by SOHIO as holding about 1 billion barrels of recoverable oil with the potential to support a 50 MBbl/d facility. Since then, growth of the community of Vernal has encumbered some of the resource. Two rich locations could produce significant yields of bitumen but in more modest quantities than contemplated by SOHIO. Alberta technology could be adapted for use in the unconsolidated sands of the rich zones.

Table III- 9. Major Tar Sands Deposits in Utah

Deposit	Known Resource (MMBbl)	Additional Potential (MMBbl)
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)		

Tar sands found in Alaska, Alabama, Texas, California, and Kentucky are relatively deeper and thinner, so less economic to develop.

CONSTRAINING FACTORS

Most of the Utah tar sands resource is located on public lands, some of which is state owned and some of which is Federally owned and managed. Some significant tar sand deposits on Federal lands overlay oil and gas deposits and were included with gas and oil in "combined hydrocarbon leases".[30]

The Energy Policy Act of 2005 directed the Bureau of Land Management (BLM) to evaluate the environmental, social, and economic impacts of a new commercial leasing program for oil shale and tar sands in the western states, as part of a programmatic environmental impact statement (PEIS). The results of this evaluation will influence future actions to provide access to the tar sands resource. A commercial leasing program could be in place as early as 2007.

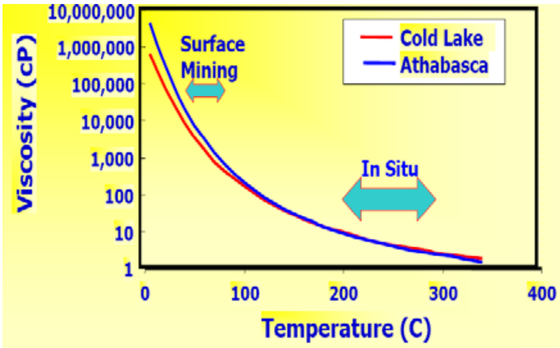
Significant portions of major U.S. tar sands deposits are located in or adjacent to national or state parks, wilderness areas, or pristine environments that may constrain development or restrict development to specific approaches or technology processes.

2. TECHNOLOGY ADVANCEMENT AND DEMONSTRATION

Technology for producing and processing tar sands has come a long way since tar sands were first mined in the 1960's. Methods for mining have greatly improved and strides have also been made in the extraction process. Extracting the bitumen from the sand is energy intensive, however new methods are being developed to decrease the amount of energy required.

The technology to be used for producing oil sands varies with the nature of the resource and its depositional setting. Shallower, colder resources are more viscous, but more easily accessible by surface mining. Deeper, warmer resources are less viscous, but may still require heating to make them producible by pumping technologies. This can be done by cyclic steam injection or other in-situ heating methods described below. The relationship between the viscosity of the resource and its temperature is displayed in Figure III-26.

Figure III- 26. Relationship between Viscosity and Temperature



MINING AND EXTRACTION

Mining: Tar sands deposits near the surface can be recovered by open pit mining techniques (Figure III-27). New methods introduced in the 1990s considerably improved the efficiency of tar sands mining, reducing the cost. These systems use large hydraulic and electrically powered shovels to dig up tar sands and load them into enormous trucks that can carry up to 320 tons of tar sands per load.

Figure III- 27. Open-Pit Tar Sands Mining

Extraction: Once the tar sands have been mined, the bitumen must be extracted from the sand. The two key processes used to extract bitumen are: hot water extraction and cold water extraction.

- **Hot Water Extraction** – With this process, hot water is added to the sand and the slurry is agitated, causing the bitumen to float to the top of vessel, where it is skimmed off. The bitumen is later upgraded into synthetic crude oil. About two tons of tar sands yield one barrel of oil. Roughly 75% of the bitumen is recovered.
- **Cold Water Extraction** –This process does not use heat to catalyze the process, but relies on agitation to separate of the bitumen from the sand.

IN-SITU PRODUCTION

In-situ production methods are used on bitumen deposits buried too deep for mining to be economical. These techniques include steam and solvent injection, and in-situ combustion. Steam injection has been the favored method.

- **Cyclic Steam Stimulation:** As shown in Figure III-28, steam is injected into the reservoir to warm the bitumen and lower its viscosity. The less viscous bitumen can be pumped, with water, to the surface. This process works well but ultimately recovers 17% of the original oil in place.
- ***Steam Assisted Gravity Drainage*** – works with paired horizontal wells, steam is injected in the upper well and oil is extracted through the lower well. This process has a 60-70% recovery rate of original oil in place.(Figure III-29) The high recovery rate makes this technology very desirable; however, technical challenges still remain. Low initial oil rates, artificial lifting and horizontal well operation challenges must be overcome.

Figure III-28. Cyclic Steam Injection Process

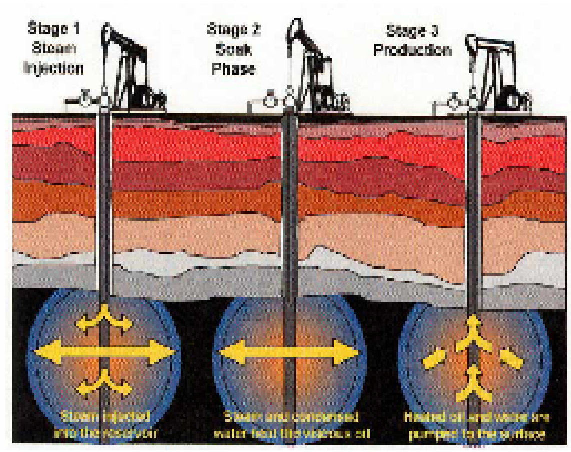
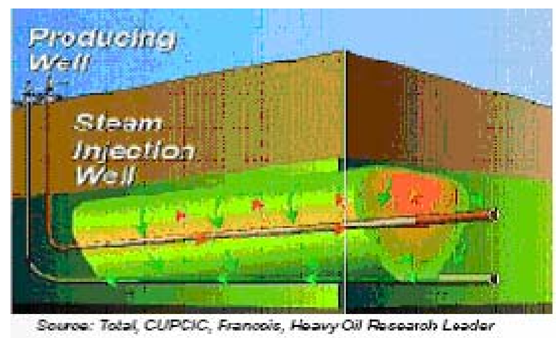


Figure III-29. Steam Assisted Gravity Drainage



NOVEL TECHNOLOGIES

In addition to thermal processes, the following technologies are being explored:

- **Vapor Extraction** can be used with vertical or horizontal wells. Vaporized solvents are injected to create a vapor-chamber through which oil flows by gravity drainage. The process may have lower energy costs and allow in-situ upgrading. Vapor extraction has not yet been field tested or demonstrated at commercial scale and is not proven.
- **Cold Production** - Where sand content is high, Cold Heavy Oil Production with Sand (CHOPS) technology may apply. Low recovery rates require significant drilling to sustain cold production volumes, but the absence of thermal energy requirements to reduce viscosity can make the approach more economic than thermal processes.

DEVELOPMENT STATUS

With the exception of about 2,700 Bbl/d produced in-situ from four California fields (2003), oil is not currently produced from tar sands in commercial quantity in the United States.

Canada's Alberta Oil Sands: Canada has a large-scale commercial tar sands industry with demonstrated technology, allowing a portion to be booked as proved reserves. They produce more than 1 MMBbl/d and output is expanding rapidly.

United States: Recently, prices for crude oil may make U.S. tar-sands commercially attractive. Government and industry are evaluating the potential of U.S. tar sands. However, there is no current commercial development or production of U.S. tar sands. The Energy Policy Act of 2005 directed the BLM to conduct a programmatic environmental impact statement (EIS) on tar sand lands, and make these lands available for leasing by 2007.

Because U.S. tar sands are different in quality and composition from Alberta tar sands, modifications to technologies proved in Alberta may be necessary to cost-effectively produce synthetic oil from U.S. resources. Development and demonstration of technology applicable to U.S. tar sands may be necessary at the pre-commercial or pilot stage before the potential can be fully evaluated.

The 2005 Energy Policy Act directive to the BLM to initiate a Leasing Program for Development of Oil Shale and Tar Sands was a significant step in commercialization program efforts. It also directed the Department of Energy to update its assessment of U.S. unconventional oil resources.

There are no known U.S. tar sands R&D, demonstration, or commercial scale projects that have been announced in the United States. However, several projects are being considered. Private parties have recently acquired significant tar sands resources in the Asphalt Ridge deposit.

Oil companies have done much to improve horizontal drilling technologies that could be used for in situ production of bitumen material. However, the consolidated nature of the sands and the fragmented deposits will require more knowledge of the reservoir for in situ operations.

Separation of the bitumen from the consolidated sands require different crushing and sizing mechanisms than are used in Canada. Bitumen samples from U.S. tar sands have mostly been near surface, grab samples. Other samples may not have had proper storage before testing leading to heavily oxidized samples in both cases. This tar sand material may be different enough in character from commercial production that improper designs could be proposed for recovery of the bitumen.

A water allocation plan and plans to ensure sufficient water for development is a serious concern. Technologies for treating water for reuse should be evaluated to ensure that most water is recycled.

POTENTIAL ACTIONS

Section 29 of the Federal tax regulations provides an, "Alternative Fuel Production Credit" which allows producers to take a $3 ($8.19 in 2006 dollars) credit per barrel of oil equivalent produced.

- Qualified facilities must be *in service* before Jan. 1993 or after June 1998 and before Jan. 2010.
- The credit is only available if the price of crude is less than $23.50 per barrel ($64.19 in 2006$).
- If the price is between $23.50 and $29.50 ($64.19-$80.58 2006$), the credit's proportionately less.
- If the price of a barrel of crude oil is greater than $29.50 ($80.58 in 2006$), there is no credit.

States and localities may also have tax credits for producers of tar sands. First of a kind commercial units need credit or price guarantees regardless of the price of petroleum. Government should model after Canada with a phased-out price or credit structure based on production after partnering with industry for first of a kind units. The oil and gas program of DOE has partnered with several universities and national laboratories to hone seismic measurements of reservoirs. The government should use this expertise to partner with pilot in situ projects to allow more measured reservoir parameters for production of oil from these tar sands.

3. DEVELOPMENT ECONOMICS AND INVESTMENT STIMULATION

COST ESTIMATES

U.S. tar sands development economics are expected to be similar to or higher than those experienced for Alberta tar sands development. Costs may be higher initially as technologies are adapted to address the variances in characteristics of U.S. tar sands resources. Requirements for underground mining would also increase costs.

Tar sands projects require large capital investments. Capital costs are dependent on the production technology that is chosen. Mining is more capital intensive than alternative in-situ processes. Table III-10 reflects the capital costs estimated for various tar sands processes in Canada.

Table III- 10. 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. (Converted to 2006 $USD)	

The operating costs for tar sands production will vary with the process. Table III-11 reflects the 2003 operating costs experienced in Canada in 2003 for various types of production and processing plants and technologies. Costs do not include upgrading required before sale to a refinery.

Table III- 11. Estimated Operating and Total Supply Costs of Tar Sands by Recovery Type (2006 U.S. $ / Bbl)

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
Source: National Energy Board of Canada, An Energy Market Assessment, 2004. (Converted to 2006 $USD)			

ECONOMIC RISK FACTORS

The oil price can make or break the tar sands production industry. Historical prices of $20 per barrel would not effectively support the industry. Today the price of a barrel of crude oil is hovering above $60. The EIA predicts that crude prices will range from $48 to $56 over the next 20 years.

However, historical price cycles have taught the industry that high oil prices do not usually last for long. There are huge price risks for a tar sands industry if the bottom falls out on crude prices. To reduce risk, there are incentives that the government can put into play.

As always, there is significant additional capital and operating costs for first commercial plants. This is also true of tar sands plants in the U.S. even though significant information exists from the Canadian experience to shorten the process and provide a firm groundwork on which to build.

Tar sands development is also constrained by market risks. These include the ability of existing refiners in target markets to absorb additional quantities of synthetic crude.

4. ENVIRONMENTAL PROTECTION

POTENTIAL IMPACTS

The major environmental issues that challenge tar sands production and processing include surface disturbance, air emissions, and impacts in regional water supplies.

Emissions - Production and processing of bitumen and syncrude produces a slate of gases that includes carbon dioxide, sulfur dioxide, and nitrous oxides. Technology is available to control and reduce emissions. Scrubbers installed on coking units, for example, can reduce emission of sulfur compounds by 60 percent.[31]

Land Disturbance – The area of land disturbed depends on whether the operation involves mining or an in-situ process. A surface mining operation on the scale of 50 MBbl/d would require 10,000 acres of land. This land can later be reclaimed with cleanup and rejuvenation efforts. At Syncrude Canada, nearly 22 percent of the land that was disturbed in 2004 was reclaimed[32].

Regional Water Impacts – Depending on the process, a large volume of water may be needed as an input in the extraction and processing of bitumen. In 2004, Syncrude Canada required 30.6 million cubic meters for its operation; 88% of which was recycled in the plant. The rest was treated and discharged. The release of treated water can affect the regional water quality and supply. The experience in Canada has been positive so far. The Regional Aquatic Monitoring Program evaluates any changes in water quality in the regional water system surrounding Syncrude's operations. In their 2003 report, they indicated that water quality downstream of the tar sands operations was consistent with previous years.[33]

MITIGATION STRATEGIES

The following Federal laws would likely apply to U.S. tar sands 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 Act, and the Endangered Species Act. In addition to Federal regulations, state and local standards and permitting processes must also be adhered to.

Significant portions of major U.S. tar sands deposits are located in or adjacent to national or state parks, wilderness areas, or pristine environments that may constrain development or restrict development to specific approaches or technology processes.

CARBON MANAGEMENT STRATEGY

CO_2 is not regulated in the U.S. However, public concerns about its role as a warming agent have led to increasing attention to processes that produce this gas. Production of bitumen and upgrading to syncrude produces CO_2. CO_2 capture is energy intensive and costly in terms of capital and operating costs. Commercial amine scrubbing technology is available; however, costs for capture of the CO_2 are highly dependent upon concentration of the CO_2 in the flue gases. Therefore, if CO_2 capture is a goal, it is best to consider that in the overall design of the plant.

5. INFRASTRUCTURE

Development of a tar sands industry in Utah would require infrastructure development to support tar sands mining, upgrading, and transportation.

Individual projects would require infrastructure including roads and power supply. Roads would have to be built to haul heavy equipment and materials as well as the mined tar sands or produced bitumen or synthetic crude oil produced.

Because initial volumes would be relatively low, it is expected that most of the produced liquids would be hauled by rail or truck rather than pipeline from the project site to the up-grader and from the up-grader to the refinery.

6. SOCIO-ECONOMIC PLANNING AND IMPACT MITIGATION

The development of a commercial tar sands industry in the U.S. would have limited **social and economic impacts** on local communities.

Mine development, construction, and operation of tar sands plants at the scale presently anticipated would have minimal impacts on regional population and demand for community services.

Additional effort is required to determine the employment requirements for projects developing U.S. tar sands resources.

Up-front assessment of the impact on local and regional communities is essential to anticipate their requirements. Communities will need funds to develop the infrastructure that is necessary to support a tar sands operation and associated population growth.

Production of tar sands in the U.S. is unlikely to exceed 250,000 barrels per day by 2025. A *hypothetical* measured development timeline, assuming government actions to provide access incentives, might take the following path to attain that level of production[34]:

- **Asphalt Ridge:** A first generation facility of 10 MBbl/d could be built by 2010 and expanded to 20 MBbl/d by 2013. Product will be asphalt and possibly byproducts.
- **Sunnyside:** A first generation facility of 50 MBbl/d could be built by 2014 producing syncrude, potentially expanding to 100 MBbl/d by 2018.
- **PR Spring:** Initial production of 25 MBbl/d could be initiated by 2015 for syncrude using retort technologies. An additional 50 MBbl/d plant using surface processing could be initiated by 2018.
- **Tar Sand Triangle:** A 20 MBbl/d plant could be constructed by 2015, expanding to full production of 80 MBbl/d by 2021.

Coal-Derived Liquids Resource and Technology Profile

CTL Working Group Analysis
Prepared For The
Strategic Unconventional Fuels Task Force

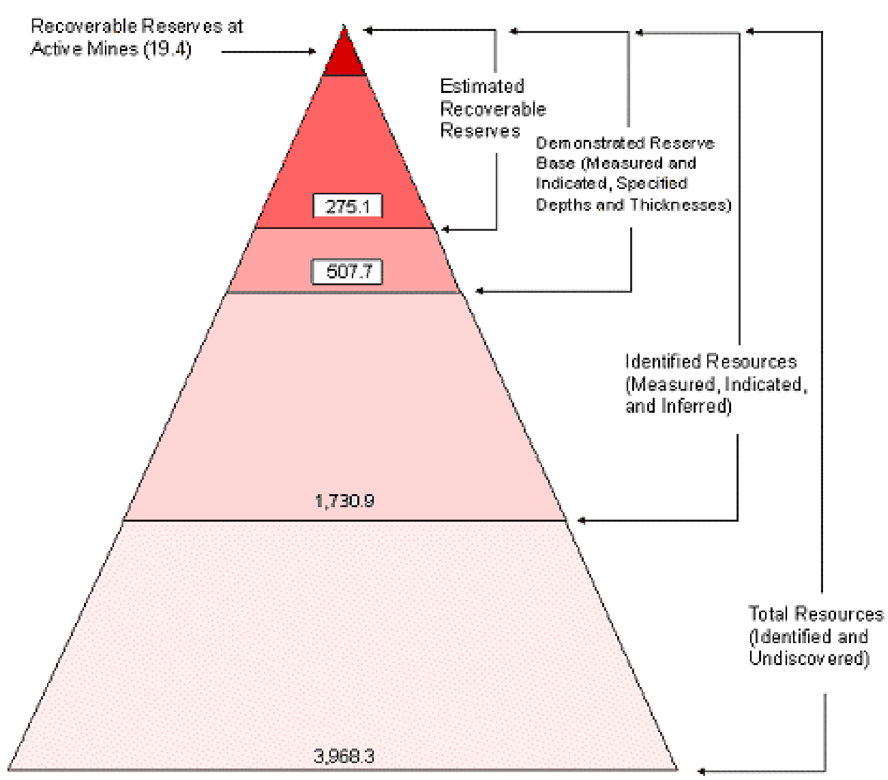
February 2007

1. RESOURCE ACCESS

Coal is the most abundant fossil fuel resource in the U.S. Recoverable coal reserves are estimated (as of January 1, 2005) at 267 billion tons. As coal mining technology improves and additional geological information becomes available, this reserve estimate will grow, since it is based on current mining methods and the *measured* and *indicated* reserves within a *total* U.S. coal resource base estimated at nearly 4 trillion tons (Figure III-30).[35]

Based on current annual production of nearly 1.1 billion short tons, the U.S. has an approximate 250-year coal supply.[36,37] However, this estimate needs to be placed within the context of the projected use of domestic coal in the U.S. and how coal reserves and resources are defined and quantified. To the first point, the EIA projects a steady rise in coal consumption to 1.78 billion short tons by 2030 in its reference economic growth case. The increase is largely due to the need for new coal-fired power generating capacity, projected to increase at 1.5% per year through 2030. To the second point, the EIA estimates the "demonstrated coal reserve base" (DRB) at 508 billion short tons, which would provide an ample cushion to counter any additional increase required for Coal to Liquids (CTL) production. The DRB extends the estimated recoverable reserves to include "resources that meet specified minimum physical and chemical criteria related to current mining and production practices."

Figure III-30. Delineation of U.S. Coal Resources and Reserves



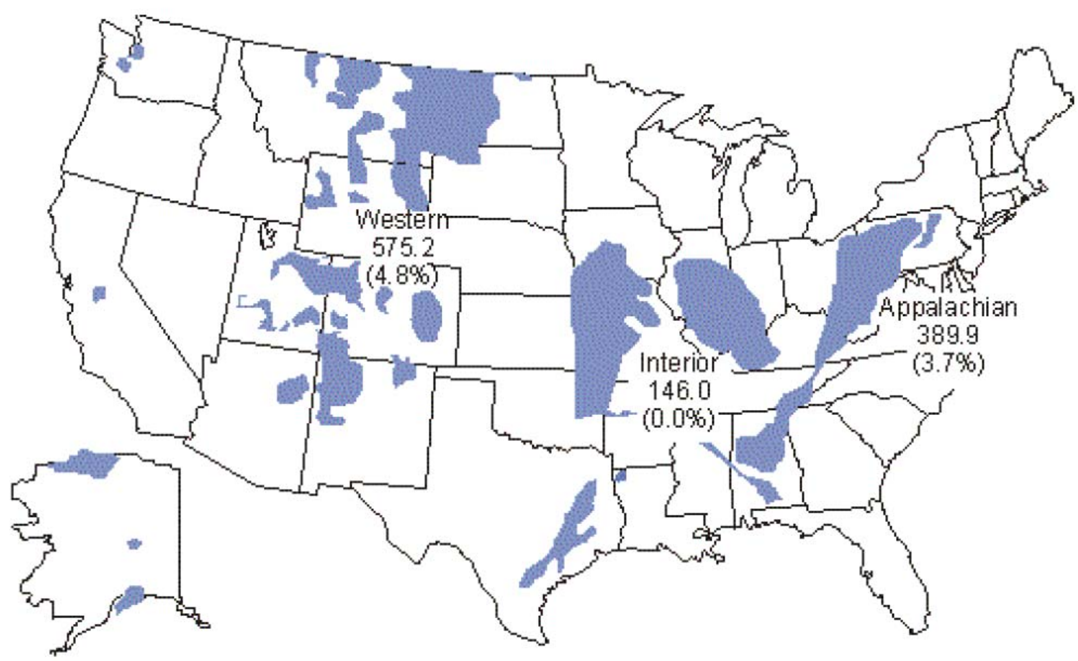
Demonstrated U.S. reserves of bituminous, sub-bituminous, and lignite are 271 billion tons, 185 billion tons, and 44 billion tons, respectively. The coal resources in the U.S., therefore, appear fully able to support strategically significant levels of liquids production from coal. For example, an industry ultimately producing clean coal fuels equivalent of 4 million barrels per day (MMBPD) would consume roughly 700 million tons of coal per year, depending on the coal quality. A century of liquids production at this level would consume about a quarter of the currently estimated recoverable coal reserves. This should be more than enough time to allow the transition to non-fossil sources of transportation fuels.

COAL PRODUCTION

Coal resources are broadly distributed throughout the U.S., with coal mines operating in 26 states. Recoverable reserves are located in 33 states, of which the 15 states hold about 96% of the nation's total.[38] Figure III-31 shows that about half of the coal is produced in the West, including Alaska, and the other half from the Interior and Appalachian regions.

While recent coal production of 1.11 billion tons has been close to all-time highs, over the past 20 years there has been a shift in production from the Midwest and the Appalachian region to the Western region, in particular, to the Powder River Basin in Wyoming and Montana. This geographic shift reflects greater reliance on large surface mining operations, due to the geological characteristics of Western coal deposits and technical advances that have lowered the costs of surface excavation of coal. For new energy plants located east of the Mississippi, the lower cost of western coal may be balanced by the economic advantages in the Interior and Appalachian regions of the U.S. that have an extensive number of mines and interconnected transportation infrastructure.

Figure III-31. Map of Coal Distribution in the U.S. (Current Production in Millions of Short Tons per Year in 2004 and Percent Increase in Production over Prior Year)



U.S. coal reserves are categorized by rank, which relates to its age and thermal energy content. The 3 major coal ranks are bituminous, sub-bituminous and lignite in descending order of thermal energy content. These coals also cover a wide variation in sulfur, moisture and mineral matter content. Anthracite, the highest ranked coal, is not included in this analysis because it represents only 3% of the nation's estimated recoverable coal reserves. Although a niche market may develop for anthracite - fueled CTL plants, such as the planned WMPI project in northeast Pennsylvania, anthracite coal is not likely to be significant for fueling new power generating and CTL plants.

Nearly all coal produced in the U.S. is used domestically for electric power production.[39] More than one-half the electricity generated in the U.S. comes from coal-fired power plants. Over the next few decades, coal's major role in power production will likely continue, if not increase in magnitude. For example, between 2004 and 2030, the EIA forecasts in its AEO2006 reference case that total electricity generation will grow from 4.0 to 5.9 trillion kilowatt-hours, with coal's share of nationwide power generation growing from 50 percent to 57 percent.

COAL QUALITY

Coal is a complex substance, with composition and characteristics varying greatly among the various deposits in the U.S. For CTL production, the key variable is rank, but even within the same rank, ash content and the consequent variation in properties of the ash as it is transformed during heating can be decisive in process design.

Table III-12 shows coal ranks, their differing characteristics and the specific state from which the coal was sampled and analyzed. When evaluating sites for CTL plants, the intended coal resource(s) for the plants will require different coal processing requirements to accommodate each plant's technology configurations and ensure equivalent product quality required by the consumer.

Table III- 12. Regional Coal Characteristics (As-Received Basis)

Region	Reserves, Billion Short Tons	Btu/lb, HHV	Mineral Matter, %	Sulfur, %	Moisture, %
Bituminous Coal Appalachian (West Va.)[a]	19.30[g]	13,404	9.1	2.15	1.7
Bituminous Coal Midwest (Illinois)[b]	38.20	11,000	14.3	4.45	8.0
Sub-bituminous West (Wyoming)[c]	21.80	8,426	6.3	0.45	28.0
Sub-bituminous (Alaska)[d]	2.50	7,800	9.0	0.20	27.0
Lignite Southwest (Texas)[e]	9.95	7,900	9.0	0.59	30.0
Lignite North Dakota[f]	6.90	7,800	8.2	0.69	27.0

[a] Argonne National Laboratory Premium Coal Sample Bank (Pittsburgh #8), http://www.anl.gov/PCS/
[b] NETL, "Quality Guidelines for Energy System Studies", 2-24-04 (Illinois #6)
[c] NETL, "Quality Guidelines for Energy System Studies", 2-24-04 (Wyodak)
[d] Usibelli Coal Co. web site, http://www.usibelli.com/specs.html
[e] Wilcox seam, from SNG paper.
[f] Benson, S.A. Mitigation of Air toxics from Lignite Generation Facilities, Energy & Environmental Research, 1995
[g]. West Virginia reserves only.

FACTORS CONSTRAINING COAL-DERIVED LIQUID DEVELOPMENT

Significant deployment of CTL facilities would require the use of large quantities of coal, meaning a significant expansion of the U.S. coal mining industry. For example, an 80,000 BPD CTL plant would use approximately 15 million tons of coal per year. For a 2.6 MMBPD CTL industry, this would result in about a 35% increase in demand for coal. Coupled with the same projected increase for coal due to electricity demand in 2025, it is clear that mining capacity expansion is a critical issue.

If the CTL plants are not sited near the mines, then coal transportation would also become an important issue. The current infrastructure of railroads and railcars used to transport coal and other goods is inadequate to handle this projected increase in demand for coal. Additional barge capacity, particularly in the Midwest and eastern sections of the U.S., may also be required to meet additional coal demand. Significant investments to upgrade and improve the current rail transportation system would be required since rail lines are already congested. Additionally, new roads would be required to accommodate increased private, coal and service vehicles for these CTL plants.

Coal is dispersed regionally throughout the U.S. Significant progress has been made in coal mining, both in its productivity and safety, but more needs to be done. New mines would have to open, not only for new fuel uses, but for current and increased electric power generation as well. Analysis of public policy, mine siting, and permitting and safety issues would lead to recommendations that can address key infrastructure barriers and the extent to which an acceleration of mining research would be needed to improve efficiency and safety while reducing environmental impacts.

2. TECHNOLOGY ADVANCEMENT AND DEMONSTRATION

Coal can be converted into liquid fuels using two types of technology: direct and indirect liquefaction.

DIRECT LIQUEFACTION

Direct liquefaction converts coal at high temperature and pressure in the presence of hydrogen and catalyst to hydrocarbon liquids. This process underwent a new phase of development beginning in the 1970s in a worldwide effort to find a cost competitive means to provide syncrude for further refining to transportation fuels. At the outset, several process concepts were pursued in the U.S., United Kingdom and Japan, each based on a different combination of catalyst, temperature, and hydrogen pressure. Over time, accumulating experience guided an evolution toward a common approach of multi-stage liquefaction based on the use of dispersed catalysts in the first stage followed by supported catalysts in upgrading stages. These technologies were demonstrated in several laboratory and pilot plants and shown to reliably produce a valuable product more easily refined than many crude oils.

The main effort in research and development was always focused on the reduction of the cost of production in order to make the process economically competitive with crude oil. Finding the means to reduce the capital cost of the plant was the prime objective. By the 1990s, the low price of crude oil was a challenge that could not be overcome. In addition to cost, another problem arose in the form of more stringent U.S. environmental limitations on the content of aromatic compounds and sulfur in motor fuels. Fuels generated by direct liquefaction are rich in high octane aromatics. In recent times, this turned to a shortcoming that made the process a poor fit to the specifications for fuels sold in the domestic marketplace. By the 1990s, interest in direct liquefaction in the U.S. all but disappeared.

Countries such as the People's Republic of China (PRC) and India – with large coal reserves and insufficient domestic petroleum to meet their transportation fuel demands – are potential candidates for using CTL technologies to provide fuels to supplement conventional petroleum. Although largely dormant in the U.S., direct liquefaction is being actively pursued in the PRC. The Shenhua project now under construction in Inner Mongolia is intended to bring a full scale commercial unit into production in 2007 to convert 7,000 tons/day of low sulfur sub-bituminous coal into 20,000 barrels per day (BPD) of diesel fuel and gasoline. This single train of reactors uses technology licensed from Headwaters Inc. and is based on development work sponsored by DOE.[40] Exploitation of this technology can serve U.S. interests because any additional production of fuels from alternative resources reduces the overall world demand for petroleum and benefits all consumers by easing pressure on crude oil prices.

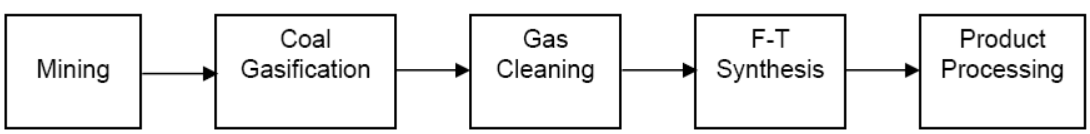
In order for direct liquefaction to have more than a token benefit, the initial Shenhua project must be successful and more units commissioned. In this context, it is important to note that parallel efforts are under way in the PRC to erect commercial-scale indirect coal liquefaction plants. Presumably, these plants have lower technical risks because the designs are derived from Sasol technology that has already been proven at full commercial scale. On the other hand, the direct coal liquefaction project, while supported by a 6 ton/day pilot plant constructed in Shanghai, has no precedent on a larger scale. The more than 1000-fold scale-up from pilot plant to commercial unit is an ambitious objective that carries more than the typical amount of risk. These plants will also incorporate technologies specific to Chinese coals and environmental regulations, which will likely differ from those associated with any plant sited in the United States.

The U.S. market will eventually determine the appropriateness of direct liquefaction technology. If the technology is successful in the PRC, it will garner increased global interest, perhaps in combination with indirect liquefaction in a hybrid configuration. In this scenario, the low-value residue from the direct liquefaction process would be gasified to provide a low cost source for synthesis gas production, rather than incurring a cost penalty for disposal. The recent National Coal Council (NCC) report suggested that this might be a good time to revisit the direct liquefaction pathway, particularly if the scale-up in the PRC is successful. The NCC report suggests the possibility of hybrid direct and indirect plants.

INDIRECT LIQUEFACTION

In the indirect liquefaction process, coal is first gasified with oxygen and steam to produce a synthesis gas consisting of carbon monoxide and hydrogen. This gas is cleaned of all impurities and the clean synthesis gas is sent to F-T reactors where most of the clean synthesis gas is converted into liquid hydrocarbon fuels. The liquid products from indirect liquefaction are zero sulfur, essentially zero aromatic hydrocarbons that require minimal additional refining to produce ultra clean diesel or jet fuels. Carbon dioxide is produced mainly during the water gas shift and F-T synthesis reaction and therefore can be readily captured in that area of the plant for subsequent storage. The unconverted synthesis gas can either be recycled back to the F-T reactors to maximize liquid fuels or combusted in a gas turbine combined-cycle power plant to generate electric power.[41] Thus, indirect coal liquefaction plants can be configured to produce liquid fuels only or a combination of liquid fuels and electric power. The latter plants are termed co-production or poly-generation plants. Figure III-32 schematically illustrates the five key operations associated with producing liquid fuels from coal via indirect liquefaction.

Figure III-32: Key Indirect Liquefaction Process Steps



In light of EIA forecasts for continued growth in power and transportation fuel demand, co-production or poly-generation plants that produce F-T fuels and generate electric power would be an attractive option for future deployment of clean coal technologies. Detailed examples of liquid fuels only and polygeneration CTL configurations are shown in Appendix A. If hydrogen is the required product in the future, polygeneration plants could readily be converted to power and hydrogen facilities by bypassing the F-T unit and sending the synthesis gas to a shift reactor and a hydrogen separation device to produce pure hydrogen.

Sasol in South Africa has been using liquefaction technology since the 1950s to produce liquid fuels from coal. In the early 1980s, Sasol built two large, indirect coal liquefaction facilities (Sasol II and

III), which currently produce about 150,000 BPD of transportation fuels. In the 1990s, Sasol incorporated Lurgi fixed-bed coal gasification technology and Sasol Advanced Synthesis (SAS) high temperature F-T reactors. Worldwide, however, no commercial CTL plant has been built that combines and integrates advanced coal gasification with advanced F-T synthesis technologies. This is because of the significant risks related to building such a first-of-a-kind plant, including uncertainties in performance, capital and production costs, and environmental performance. Additionally, the volatility of world oil prices further amplifies the risks associated with building first-of-a-kind plants.

DEVELOPMENT STATUS

Current Research and Project Development Efforts

CTL technology is considered commercial. This section provides summary tables of announced projects in the United States and internationally. Table III-13 below provides a list of announced projects under consideration in the United States.

Table III- 13. Coal to Liquids Plants under Consideration in the United States

State	Developers	Coal Type	Capacity (bpd)
AZ	Hopi Tribe, Headwaters	Bituminous	10,000 – 50,000
MT	State of Montana, Bull Mountain Land Company, DKRW Energy	Sub-bituminous	22,000
MT	State of Montana	Sub-bituminous/lignite	10,000 – 150,000
ND	GRE, NACC, Falkirk, Headwaters	Lignite	10,000 – 50,000
OH	Rentech, Baard Energy	Bituminous	2 plants, 35,000 each
WY	DKRW Energy	Bituminous	33,000
WY	Rentech	Sub-bituminous	10,000 – 50,000
IL	Rentech*	Bituminous	2,000
IL	American Clean Coal Fuels	Bituminous	25,000
PA	WMPI	Anthracite	5,000
WV	Mingo County	Bituminous	10,000
MS	Rentech	Coal/petcoke	10,000
AK	State of Alaska, AIDEA, Chinese Petroleum Corp. of Taiwan	Sub-bituminous	80,000
LA	Synfuel Inc.	Lignite	Not available

Table III-14 is a list of coal to liquids (CTL) pilot plants in the United States.

Table III- 14. CTL Pilot Plants in the United States

Location	Owner	Capacity
Colorado	Rentech	10-15 barrels per day
New Jersey	Headwaters Incorporated	Up to 30 barrels per day
Oklahoma	ConocoPhillips	300-400 barrels per day
Oklahoma	Syntroleum	70 barrels per day

Table III-15 provides a list of international CTL plants and projects under development.

Table III- 15. International CTL Plants and Projects

Country	Owner/Developer	Capacity (barrels/day)	Status
South Africa	Sasol	150,000	Operating
China	Shenhua	20,000 (initially)	Under Construction
China	Lu'an Group	~3,000 to 4,000	Under Construction
China	Yankuang	40,000 (initially) 180,000 (planned)	Under Construction
China	Sasol JV (2 studies)	80,000 (each plant)	Planned
China	Shell/Shenhua	70,000 – 80,000	Planned
China	Headwaters/UK Race Investment	Two 700-bpd demo plants	Planned
Indonesia	Pertamina/Accelon	~76,000	Under Construction
Australia	Anglo American/Shell	60,000	Planned
Philippines	Headwaters	50,000	Planned
New Zealand	L&M Group	50,000	Planned

Technology Hurdles

The integration of advanced coal gasification technologies and advanced F-T synthesis technologies that have been developed over the past twenty years has not been attempted. This poses significant technical risks that may be considered unacceptable by potential process developers and investors. Additionally, CTL facilities may be polygeneration plants, producing liquid fuels and generating power, thereby combining elements of both the power and petroleum industries. This further complicates the issue of which industry would take the lead in developing such facilities, in addition to understanding the complexities of two very different commercial markets.

POTENTIAL ACTIONS

As noted, CTL Technology is commercial and significant progress has been made in advancing current technologies that have been developed but not yet demonstrated for large first-of-a-kind, pioneer CTL plants. However, there is still significant opportunity for continued research and development. Additional advances could further reduce the cost of producing ultra-clean liquid transportation fuels from coal, possibly by 25% or more through novel pathways and incorporation of new technologies being developed in existing programs, including: coal gasification, synthesis gas cleanup, carbon capture and storage, and hydrogen (production of high hydrogen-content liquid carriers).

Computational science is a rapidly expanding area of research that offers the potential to shortcut development time by providing the theoretical basis for subsequent R&D activities. It provides the opportunity to quickly explore novel "out-of-the-box" processing strategies to guide and accelerate experimental research. The computational work would likely focus on critical chemical and physical aspects of converting coal to premium fuels: the fundamentals of catalyst activity/selectivity; separation of small catalyst particles from the liquid product; impact of the fuel on engine performance and durability; optimum system integration to achieve high process efficiency, minimal pollutant emissions and CO_2 capture; and computational frameworks to enable virtual demonstration of the entire fuel life cycle. These findings could be experimentally verified by laboratory research and modeling, followed by larger-scale bench and pilot-scale testing.

Systems engineering is an important activity needed to evaluate the technical and economic feasibility of: novel processes resulting from computational research; advanced integrated gasification and F-T processing concepts and clean-up technology; advanced reactor types to improve the process efficiency when utilizing specific regional coals; novel in-situ reactions/processing; and modeling of the gas-solid-liquid physics of the F-T reactor to help achieve the highest throughput and liquid product quality. Life cycle analyses would also be performed on a "mine-to-wheels" basis to pinpoint those parts of the overall system impacting health, environment, and safety.

3. DEVELOPMENT ECONOMICS AND INVESTMENT STIMULATION

COST ESTIMATES

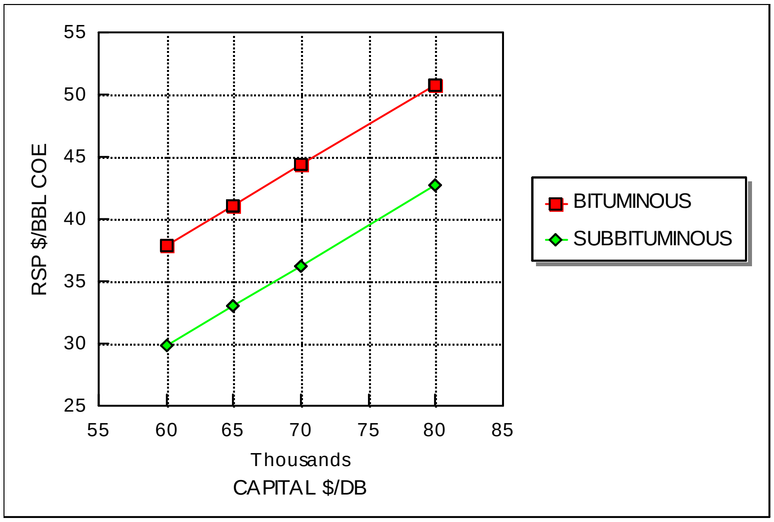
Because no grassroots CTL plants have been built since the early 1980s, it is difficult to accurately estimate the costs of liquid fuels produced from new facilities. The Sasol plants came in on budget with a capital cost of about $6 billion. This would equate to approximately $40,000 per daily barrel at a production rate of 150,000 BPD. However, it is not possible to meaningfully compare this data with a new CTL plant built in the U.S.. The Sasol plants produce a substantial amount of chemical byproducts, and in many years, revenue from these byproducts has exceeded the revenue from the fuels. Inflation and fluctuating currency exchange rates also complicate comparison; the Sasol plants were built in the early 1980s, so the capital cost of $40,000 per daily barrel in 1980 dollars would be approximately double in 2005 dollars.

To estimate the potential costs for new CTL plants in the U.S., one must resort to conceptual plant simulation analyses. In 1993, Bechtel undertook a conceptual baseline design study of a nominal 50,000 BPD bituminous coal-based F-T plant for the U.S. Department of Energy (DOE). In 1993 dollars, Bechtel estimated the capital cost to be $59,500 per daily barrel.[42] Adjusting for inflation to 2004 dollars, this capital cost estimate becomes about $80,000 per daily barrel. If this cost represents a first-of-a-kind (FOAK) facility, then it can be assumed that, through learning by design, building of pioneer plants, and targeted research to develop advanced technology, this capital cost could be reduced. A rough estimate is that the capital costs of a 50,000 barrel per day plant will be between $3.5 and $4.5 billion.[43] Overall, smaller, first-of-a-kind (FOAK) CTL plants with fuel production in 10,000 to 20,000 BPD range are unlikely to be profitable unless the price of low-sulfur, light crude oil is at least $40 to $55 per barrel depending on the coal used[44]. The recent Southern States Energy Board CTL cost when compared on an equivalent basis suggests that the cost envelope may be a few dollars higher.[45] This price range takes into account the wide range of costs for delivered coal and the band of uncertainty associated with preliminary cost analyses. As noted, FOAK pioneer plants will likely be built with a lower output and thus have higher per barrel capital cost requirements. On the other hand, subsequent, 50,000 BPD plants will benefit from learning-by-doing, and it is not unreasonable to anticipate production costs eventually dropping to below $40 per barrel.[46]

Figure 4 plots the estimated economics of CTL plants for bituminous and sub-bituminous coals[47]. The lines show the variation of the required selling price (RSP) of diesel fuel produced from CTL plants using bituminous and sub-bituminous coal as a function of the capital costs. A capital cost range of $60,000 to $80,000 per daily barrel was chosen based on prior conceptual study results for a modern CTL plant. Referring to Figure III-33, if the capital cost of a first-of-a-kind CTL plant is $80,000 per daily barrel, the RSP of the diesel fuel on a crude oil equivalent basis would be $51 per barrel and $43 per barrel for bituminous and sub-bituminous coals, respectively (this is equivalent $46 per barrel and $40 per barrel for bituminous and sub-bituminous coals if we utilize the crack spread assumed in the Southern States Energy Report). Clearly, more detailed design studies must be initiated to more accurately define costs for site-specific locations and particular coals.

The diesel fraction, representing 70 to 80% of the CTL product slate, would have a cetane number greater than 70, which improves combustion efficiency. Because of the high quality of these liquids, minimal additional refining is needed to produce ultra-clean diesel and jet fuels. Naphtha, representing the other 20 to 30%, makes an excellent cracker feed for olefins production or other chemicals and may be a valuable fuel for advanced engines. Also, it could serve as an excellent material for reforming to produce hydrogen.

Figure III-33: Economic Summary for CTL Plants



Assumptions:

1. Bituminous coal is priced at $30 per ton; sub-bituminous at $10 per ton
2. The capital charge factor is 12 percent. (Capital charge is the percent of capital cost that must be recovered each year)
3. The capacity factor of the plants is assumed to be 90 percent. This factor refers to the actual production over a specified time period divided by plant design production.
4. F-T diesel has a differential value that is $9 per barrel over crude oil based on the historical differential value between WTI and CARB diesel for the last three years.
5. The RSP is given in terms of the dollars per barrel on a crude oil equivalent basis.

ECONOMIC RISK FACTORS

World oil price volatility poses a significant market risk to the deployment of CTL facilities. For example, as recently as the late 1990s, prices were in the $10 to $20 per barrel range, but are now about $60 per barrel after reaching $76.31 for West Texas Intermediate, as of August 8, 2006. Market forces could produce another oil price drop if demand slows or new supplies are brought on-stream. Further, the cartel of oil exporting countries can influence world prices by agreeing to artificially expand or limit production to discourage the deployment of CTL and other alternative fuels. This latter barrier could be mitigated by providing a combination of financial incentives discussed in the following section.

Combined with the volatility of world oil markets, the uncertainty and magnitude surrounding the capital cost of CTL plants compounds the market risk. The actual costs of building a CTL plant are unknown, since no detailed engineering designs of commercial-scale, first-of-a-kind plants have been produced recently in the U.S. A rough estimate is that the capital costs of a 50,000 BPD plant will be between $3.5 and $4.5 billion plant at $60,000 to $80,000 per daily barrel. The investment risk for such a large sum is considerable, particularly given the volatility of world oil prices and the technical risks associated with integration of technologies in these first-of-a-kind plants.

ECONOMIC INCENTIVES

To facilitate deployment of early pioneer CTL plants, some form of incentive package would be required to address the economic uncertainties and technical risks associated with constructing and operating first-of-a-kind plants. Section 1307 of EPACT 2005 (Public Law 109-058) amended Sections 48A and 48B of the Internal Revenue Code to include incentives that reduce the risk of coal gasification projects. While the focus of the Sections 48A and 48B incentives are related to integrated gasification combined-cycle (IGCC) technology, advanced coal-based generation, and industrial gasification, these incentives are also available for co-production facilities that would produce both electric power and liquid fuels from coal. The United States Department of Energy and the National Energy and Technology Laboratory (NETL) are currently providing technical support to the Secretary of Treasury regarding implementation of the Sections 48A and 48B incentives. It is possible that one or two pioneer CTL plants could benefit from these current incentives.

Recently, several Congressional bills have been introduced (HR 5653 and Senate 3325) that, if enacted, would provide significant incentives for Fischer-Tropsch plants of 10,000 to 20,000 BPD production capacity or more – with incentives capped at 20,000 BPD. These bills cover the potential for additional loan guarantees, tax credits for capital expenditures, and treating capital expenditures as expenses and excise tax reductions.

Co-Fund Site Specific Design Studies

Private sector companies and the federal government (DOE) have conducted research and development since the early 1980s to improve F-T technology. Advanced coal gasification and F-T conversion technologies have been developed to reduce product cost, but have not been demonstrated in an integrated system at sufficient size to confirm the potential economics and production efficiencies. Significant risk will remain until plants integrating the technologies are designed, built, and operated. Design studies would provide private sector partners and the federal government and state governments with solid information on economic viability and technical risk. Industry would use this experience to develop the confidence needed by capital markets to secure financing and the government would use the information to guide research and provide an incentive framework targeted at facilitating the deployment of CTL plants. The following is a potential scenario that could be considered for implementing the design studies:

Assume up to five plant design studies are conducted on coals that represent the key coal types found in the U.S. This strategy would preclude any bias toward a specific region and also create designs for liquid fuels plants that utilize coals having diverse characteristics (e.g., ash, sulfur, moisture, heating value, and metals). The designs would then provide the basis for industry and government (federal and state) decision-making on detailed design of three to five baseline pioneer plants (10,000 to 20,000 BPD) projected to begin production in 2012 to 2015. Governmental entities would seek upfront funding for these designs with significant cost sharing by industry to encourage only serious and capable industrial participants and stakeholders. The governments would evaluate the need for additional up-front funding for engineering design activity including permitting for specific locations (to better define cost and risk) to foster the construction of these pioneer plants. It is anticipated that there would be no direct federal government funding beyond that identified for designs.

Analyze Incentive Packages Directed at Promoting Early Commercial Experience

There is significant technical and financial risk associated with first-of-a-kind, pioneer CTL plants. Various financial incentives could reduce this risk and meet the aggressive goal of having up to five regional coal-to-liquid plants in operation during the 2012 to 2015 timeframe. To define the optimal package of incentives that reduce technical and financial risk and spur industry interest while minimizing the cost to the federal government (DOE and DOD) and perhaps interested state governments could jointly sponsor a study of incentives that achieve these goals. This study would review historical experiences with earlier incentives-based programs as well as examine existing incentives from EPACT 2005, and Section 11113 of the surface transportation act (SAFETEA-LU), which amends the IRS code for the Volumetric Excise Tax Credit for Alternative Fuels, providing a $0.50 per gallon credit for F-T liquids produced from coal (terminating on September 30, 2009). Additionally, new incentives – such as loan guarantees, investment tax credits, price floor and ceilings, product off-take agreements, and other innovative mechanisms – would be evaluated for applicability to these first plants. The study would also investigate regional incentive packages. Upon completion, the results of the incentives analysis would be reported to the federal Administration, Congress and the state participants.

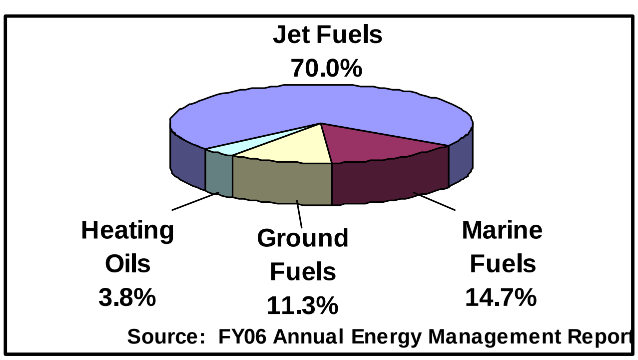
EXPECTED MARKETS

Several end-use markets have the potential to act as early entry points for CTL fuels because these markets have the ability to realize the specific benefits of CTL fuel characteristics. Additionally, these points of entry can build public familiarity with CTL fuels and, longer-term, lead to introduction into the private sector vehicle fleet. The early entry markets are the Department of Defense (DOD) use in military applications, commercial fleets such as the Clean Cities Program, and the home heating oil market (Northeast Home Heating Oil reserve).

Military Applications

The Department of Defense is promoting the production and utilization of high-value fuels from domestic coal and oil shale resources. DOD's yearly fuel requirements total about 300,000 BPD, 70% of which is for jet fuels as seen in Figure III-34.

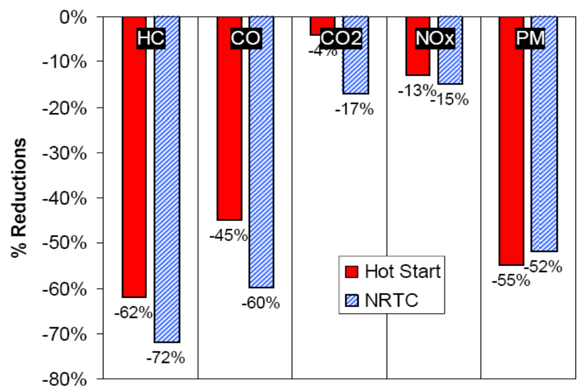
Figure III-34: Department of Defense Fuel Requirements[48]



DOD studies have shown that F-T fuel can reduce particulate emissions by as much as 78% and 96% for cruising and idling jet operating modes, respectively.[49] For several years, DOD has conducted successful joint laboratory tests with DOE on F-T fuel for jet aircraft. In addition to the environmental benefits, F-T fuels have a high degree of thermal stability, which provides enhanced system performance for military aircraft. Based on these results, DOD is ready to initiate a comprehensive F-T fuel testing and certification program. The activities associated with this new effort will initially require several barrels per day of fuel to fully characterize the fuel and much larger quantities later for long-term tests in full-scale military engines.

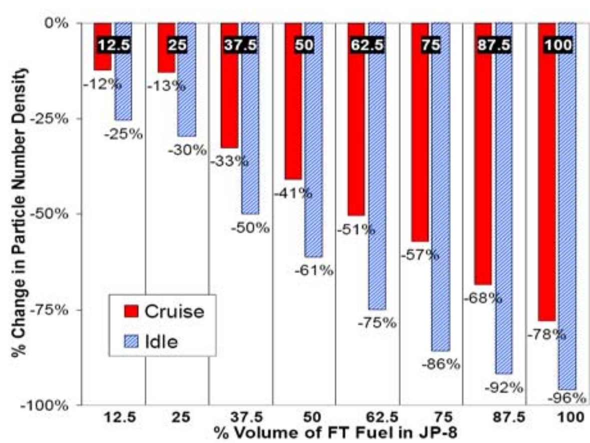
Daily military land and sea fuel use amounts to 35,000 BPD and 46,000 BPD, respectively, closely mimicking vehicle, marine engine and boiler applications found in the public sector. The Army conducted testing at Southwest Research Institute on a GM 6.5 liter diesel engine to compare F-T fuel to EPA certified low sulfur diesel fuel. The F-T fuel produced lower emissions of unburned hydrocarbons, carbon monoxide, carbon dioxide, NO_x and particulates. Also, since the fuel had inherent zero sulfur, all SO_x emissions were eliminated. (Figure III-35)

Figure III-35: Army Test of F-T Fuel Compared to Low Sulfur Diesel[50]



The Air Force conducted tests of F-T fuel with blends of petroleum-derived JP-8 fuel in a small helicopter engine. As the percentage of F-T increased in each blend, particulate emissions were reduced proportionately. With 100% F-T, emissions were reduced by 78% and 96% for engine cruise and idle modes, respectively. (Figure III-36)

Figure III-36: F-T and F-T/Petroleum Fuel Blends Burned in a T-63 Helicopter Engine[51]



It is likely that the DOD's F-T certification program for military air, land and sea platforms will identify blends of F-T with conventional diesel fuel as the nearest-term application to introduce the fuel into military fleets. As significant quantities are produced, the blends could provide a source for testing in counterpart engines in the commercial sector.

Commercial Fleets (Clean Cities)

DOE's Clean Cities Program is designed to advance the economic, environmental, and energy security of the U.S. by supporting local decisions to adopt practices that contribute to reduced petroleum consumption in the transportation sector. Today, Clean Cities' stakeholders are currently displacing 15,600 BPD of gasoline equivalent, with a goal to displace 10 times that amount by 2020. Achieving this goal is the equivalent of or taking one supertanker off the high seas every eight days.

Coal-derived liquids, which are on DOE's list of acceptable fuels for use in the Clean Cities Program, could help achieve this goal with concurrent emissions reductions associated with using premium F-T diesel fuel. Table III-16 shows how F-T diesel fuel yielded significant emission reductions when it was substituted for a high-quality California diesel fuel in a 10.3-liter engine.[52]

Table III- 16. Percent Reduction of Emissions When F-T Diesel Fuel was substituted for High-Quality CA Diesel Fuel in a 10.3 Liter Engine

Emission	% Reduction
NOx	12
Particulates	24
Carbon Monoxide	18
Hydrocarbons	40

Home Heating Oil (Northeast Home Heating Oil Reserve)

The market demand for home heating oil in the U.S. is approximately 200,000 BPD. Of the 7.7 million households in the U.S. that use heating oil to heat their homes, 5.3 million households (69%) reside in the Northeast region of the country – making this area especially vulnerable to fuel oil disruptions. On July 10, 2000, the Administration directed, and the Department of Energy subsequently established, a heating oil reserve in the Northeast capable of assuring home heating oil supply for the Northeast states during times of very low inventories and significant threats to immediate supply. The current structure of the Heating Oil Reserve provides the capability of delivering 2 million barrels of heating oil, an amount sufficient to provide protection for 10 days against supply disruption.

Home heating oil is not subject to transportation fuel sulfur limits. The sulfur level ranges between 2,000 and 2,500 ppm sulfur, compared to current diesel fuel limits of 500 ppm that will be legislatively lowered to 15 ppm as of September 2006. Replacing conventional heating oil with low sulfur fuel (such as that produced in the F-T process) would provide local and regional environmental benefits and result in less boiler and furnace maintenance due to reduced iron sulfate buildup on the heat exchangers.[53]

Future Markets

If the benefits of using coal-derived F-T fuel are demonstrated by the military and public sector vehicle fleets, and development of CTL technology proceeds, it is anticipated that the F-T market would expand to personal vehicles and possibly the commercial jet fuel market. The EIA projects a steady increase in fuel economy resulting from more sales of hybrid and diesel-powered vehicles, which bodes well for a future F-T diesel fuel market. Further, incorporation of CO_2 capture and storage at CTL production facilities should result in no greater life cycle greenhouse gas emissions than those accompanying the production and use of conventional petroleum-derived gasoline.

In addition, Sasol has reported that for the past seven years, aircraft flying from Johannesburg International Airport have used a semi-synthetic blend of 50% jet fuel from coal produced at a Sasol Ltd. coal-to-liquids refinery, and 50% derived from traditional crude oil refining. Sasol has clearly demonstrated that synthetic jet fuel can be produced from coal; it has been proven in commercial use. Sasol hopes to win final approval this year for use of 100% synthetic fuel, also derived from coal. Coal derived Fischer-Tropsch could be a substantial market in the mid-term. For example, interest has been shown by airlines such as JetBlue for Fischer-Tropsch jet fuel and other alternate fuels.[54]

4. ENVIRONMENTAL PROTECTION

CTL plants would use advanced clean coal gasification technology to produce transportation fuels and/or electric power. Pollutant emissions will be minimal because coal-derived sulfur will be removed and converted into elemental sulfur. Nitrogen oxides will be minimized using low-NOx burners in the turbines and selective catalytic reduction (SCR) in the flue gas stream, and mercury will be removed, perhaps by some combination of pre- and post-combustion processes. Water use will be minimized by using air coolers where possible, and solids emissions will consist of non-leachable slag from the gasification process. Because of the sensitivity of the F-T catalyst to poisons, all contaminants must be removed to near-zero levels (ppb levels) and this ensures that overall plant emissions would be close to zero.

At present, no requirements exist in the U.S. to manage carbon emissions from fossil fuel sources. However, should carbon management be required, carbon dioxide produced during the conversion process could be captured for subsequent storage in deep saline aquifers or sold for use in enhanced oil recovery (EOR) operations. A study done in 2004 for production of substitute natural gas (SNG) from coal assumed that the value of CO_2 for EOR was $12/ton[55], which would significantly improve the economics of a CTL plant.

With carbon capture and storage, it is expected that CTL plant emissions and the emissions from utilization of CTL products would be comparable to those associated with the production and consumption of petroleum-based fuels. If sequestration of carbon dioxide is required, an additional $4 per barrel for the price of low-sulfur, light crude oil would be required for profitable operation. It has been estimated that a CTL plant with no carbon capture would release about 0.78 tons of carbon dioxide per barrel of product in comparison to a current refinery emitting about 0.1 tons of carbon dioxide per barrel of product. When carbon sequestration is employed for both facilities (92% captured and stored at the CTL plant and 40% at the refinery), the carbon dioxide emissions are equivalent.[56]

EVIRONMENTAL BENEFITS

Clean fuel products from the CTL F-T process could enable the use of more efficient engine and emission control technologies to reduce the release of criteria pollutants into the atmosphere. Coal-derived fuels would meet or exceed all current fuel specifications and could be used in blends with petroleum-based fuels or as a stand-alone fuel. With respect to criteria pollutant emissions, the CTL plant itself would be comparable to and probably better than a modern, state-of-the-art coal gasification plant since all contaminants must be removed to very low levels to protect the F-T catalyst. The plants, by virtue of the technology, also produce a concentrated stream of CO_2 that provides an inherent capability to efficiently capture this greenhouse gas.

ENVIRONMENTAL BARRIERS

As a carbon-rich fossil fuel, coal releases large quantities of carbon dioxide when converted into fuels and power. For a typical bituminous coal, approximately 670 pounds of carbon (or 2,450 pounds of carbon dioxide) would be emitted for every barrel of FT liquids produced. This compares to about 250 pounds of carbon (or 900 pounds of carbon dioxide) emitted for every barrel of petroleum fuels produced. If concerns over global climate change continue, CTL plants would have to capture and permanently store the carbon dioxide produced during the conversion process. Concerns over criteria pollutant emissions and toxics like mercury should be minimal because CTL plants would incorporate technologies comparable to modern, state-of-the-art gasification plants and the removal of these pollutant precursors can be readily accomplished within the plant process operations.

Water use in CTL plants is also an issue, particularly in geographical areas of low rainfall and/or limited water resources. However, use of air cooling in place of water cooling can substantially reduce water requirements to less than one barrel of water per barrel of F-T product. Generation of large quantities of coal-derived mineral waste also should not be an issue since this waste product is a non-leachable slag suitable for sale as aggregate.

More production from existing mines and the opening of new coal mines will be required to accommodate a CTL industry and increased electricity demand. These facilities will require land for construction and support operations such as roads, railroads and storage facilities that create changes in land use, alter topography, and impact ecological systems. Mitigation and reclamation strategies would need to be implemented to offset some of these changes to land and ecological resources. Currently, there are very strict reclamation regulations in place and they are being further enhanced to encourage a reforestation initiative to better restore the land, while concurrently improving water quality and providing a source for carbon sequestration.

Even if the environmental risks are addressed, there is a very good possibility of public reluctance to accept the need for new facilities, particularly these coal-based plants. Measures would need to be taken to involve the general public and other state, local, and non-governmental entities to assure them that these plants could effectively protect human health and safety and the environment.

However, CTL plants would be expected to have very low environmental criteria pollutants. They would also be designed to accommodate carbon capture and pressurization for subsequent sequestration in saline aquifers or oil reservoirs for enhanced oil recovery (EOR). Therefore, these plants could remove a good deal of uncertainty associated with possible new environmental regulations. Early plants which would sell or demonstrate CO_2 use for EOR would be encouraged

Site-specific early design studies would provide the ability to obtain information on environmental baselines for the plants. These plants would be ready for CO_2 separation and capture and the information obtained would define resource requirements. Site-specific information would also address where the resources, such as coal and water, are coming from, how they are delivered and how waste products are to be reused or disposed. Additionally, current R&D activities co-sponsored by DOE and industry are being pursued to improve CO_2 separation and capture and define CO_2 storage sinks.

CARBON MANAGEMENT STRATEGY

Amine absorption is the current world-wide standard for CO_2 capture. The technology is widely applied to remove CO_2 from produced natural gas and, in limited cases, to remove CO_2 from flue gas. The base technology is not owned and is considered general technical knowledge. However, many firms have advanced amine absorber technology and will make this technology available commercially with a proprietary license addition.

Application of amine technology to flue gas will significantly increase the amount of energy needed by 24% to 40%. Additional equipment is needed, and this will increase capital cost. Overall capture cost according to the Intergovernmental Panel on Climate Change[57] estimated to be $29 to $51 per metric ton of CO_2. A report written by the Energy Information Agency[58] estimates the cost at $10 to $60 per metric ton of CO_2 captured.

The DOE Office of Clean Coal has mounted an aggressive program to improve the efficiency of capture and to reduce capture costs.[59] The goal of these efforts, by 2012, is to develop two new capture technologies that each result in less than a 10% increase in the cost of energy services. This new technology, if successful, would be available for application to a growing CTL as well as oil shale industry.

Once captured, CO_2 can be used for a wide variety of applications that have value. For example, the use of CO_2 for food processing, for many industrial processes, and for injection into oil and/or gas bearing formations to increase the production of oil and gas while, at the same time, sequestering the injected gas. Detailed geologic and engineering analyses are required to define the most cost-effective method of CO_2 sequestration.

One key demonstration underway since 2000 provides a carbon capture and storage model that may be part of the carbon management strategy. In this model, CO_2 from the Great Plains Coal Gasification Plant located in North Dakota is being transported by a 330-km dedicated pipeline to the Weyburn oil field located in Saskatchewan, Canada. Following extensive study, the International Energy Agency[60] concluded that the CO_2 injected into the field will remain securely stored underground for at least 5, 000 years. Over the life of the project, the Weyburn field is expected to store 14 million tons of CO_2 and produce 130 million barrels of incremental oil. Capture of the CO_2 from the stack is not used because the gasification plant uses oxygen to produce a stream of CO_2. This gas stream has purity greater than 90% and is transported directly to the Weyburn field for injection.

Carbon capture and sequestration has become an important technical focus of international interest. Technical advances coupled with site-specific geologic and energy studies will guide the development of project-specific carbon management strategies for liquid fuels production.

The USAF has expressed a strong desire to have greater focus, research, and development for the reuse or reforming of CO_2. This emphasis on the complete use of all products from the F-T process creates greater value-added in the production of synthetic fuels and reduces environmental issues associated with storage.

5. REGULATORY AND PERMITTING ISSUES

PERMITTING PROCESS[61]

A broad scope of environmental issues may be present in siting a new facility or expanding the capacity of an existing one pursuant to the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act, the National Environmental Policy Act and other federal, state and local laws. Substantial "up front" work is also required regarding site and design factors prior to the submission of an application for a new refinery, chemical or fuel plants such as CTL facilities. Depending on the complexity of the new plant and the siting, the permitting process can take between one and two years after a complete application is filed. Those seeking to construct CTL plants may also revise their applications after they have been submitted. In addition, administrative appeals during the permitting process and judicial review can add substantially to the time required for final approval.

As mentioned earlier, under current federal environmental law and regulations, state and local authorities consider and approve most of the environmental permits that are required for CTL plants. States may also impose separate or additional requirements that can be more stringent than those required for compliance with federal law and regulations. In addition, state and local decision-making with respect to refineries and other large industrial and commercial facilities can frequently involve land use and other local issues, such as conditional use permits, local fire, building and plumbing codes, as well as connections to sewer systems and construction approvals.

Legislative/Regulatory Considerations in Developing Coal Resources

Coal production in the United States is currently 1.1 billion tons per year. The industry is well developed and regulatory requirements for mines are in place. The following discussion is from the National Coal Council report:

"The advent of the environmental movement in the United States in the early 1970's brought with it laws to clean up and protect our air (Clean Air Act) and water resources (Federal Water Pollution Control act). Within the next decade, additional laws were enacted that addressed hazardous wastes and fish and wildlife production. In 1977, coal mining activities were significantly regulated through the Surface Mining Control and Reclamation act of 1977 (P.L. 95-87).

The federal Surface Mining Control and reclamation Act (SMCRA) establishes a "nationwide program to protect society and the environment from the adverse effects of surface coal mining operations and surface impacts of underground coal mining operations and to promote the reclamation of mined areas left without adequate reclamation."

SMCRA addresses virtually every environmental and land use issue associated with coal mining and established standards mad protocol for coal operations. The federal regulations needed to implement SMCRA were developed by the newly formed office of Surface Mining. OMS's regulations were more comprehensive than the statute, and they established new levels of both design and performance standards for coal mining operations. In establishing requirements for designating lands as unsuitable for coal mining and standards for addressing surface subsidence from *underground coal mining operations. The federal program also set up a mechanism to collect a fee to reclaim the unreclamed sites from past coal mining activities.*

States with coal reserves that wanted to regulate their coal industry developed their own laws and regulations. The state programs had to be compatible with their federal counterparts. The state had the primary authority to regulate the coal industry with its boarders, albeit with federal oversight from OSM.

A provision in SMCRA (Section 522) allowed any interested person to petition the state regulatory authority to designate a coal-bearing property as unsuitable for coal mining. If the regulatory authority found that mining would cause a significant and/or unfavorable impact to environmental resources or historic structure or that successful reclamation would not be feasible, the land could be declared off-limits to mining. There was no provision for compensation. This "designation of land as unsuitable for coal mining" affected thousands of acres of coal throughout the coal-bearing regions of the country in the late 1980s and early 1990s.

Permit issued under SMCRA comply with all other applicable federal and state laws and regulations. Consequently, water discharges associated with coal mining operations are required to be permitted under the federal or state program governed by the Clean Water Act. These permits set specific effluent standards that discharge must meet. Mining companies comply with these regulations.

Both SMCRA and the clean Water Act contain language that either directly or indirectly addresses the need to protect the water flow in perennial streams. SMCRA establishes buffer zones for surface coal mining operations that require setback distances to be maintained. Underground mines, particularly those utilizing long-wall mining systems, sometimes leave coal, in place under certain conditions to avoid the restricting stream flow. Large blocks of coal are left in place as the long-wall system stops, is disassembled, reset as a new location, and restarted in order to protect streams.

Another provision of the Clean Water Act pertains to the dredge and fill permits issued by the Army Corps of Engineers. These permits allow for spoil, basically soil and rock, to be placed in valleys containing streams. There permits to create "valley fills" are essential to conduct a form of surface mining known as mountaintop mining. Over the past decade, this form of mining, which is conducted in central Appalachia (portions of Kentucky, Virginia, and West Virginia) has come under increasing scrutiny as the mining operations have increased in size and number. SMCRA allows for mountaintop mining operations. The Corp of Engineers has established an extensive permitting process that allows placement of spoil material from the mountaintop mining operations into stream channels. The same permitting process for valley fills is also used for coal refuse disposal in Appalachia.

The impact of any mining operations on habitats containing threatened and endangered species (plant or animal) is also covered in SMCRA. U.S. Fish and Wildlife Service and comparable state agencies review permit applications. If mining activities are likely to cause significant impact on these organisms, mining plans are revised to avoid impacts to these habitats, Where the risk to the endangered species is deemed to great, the mining will not be allowed.

Another provision of the SMCRA- based regulation deals with the potential of post-mining discharge. These are discharge from the mine (primarily underground mines) that occur after the mine is closed and the mine workings flood with groundwater. OSM has developed a policy, which has been adopted by most states, that prohibits permits from being issued for any new mine likely to have a post-mining leakage. Currently permitted mines with post mining discharge were grandfathered under the policy and those mines are addressing the long-term funding for treating their discharges. Coal seams are likely t develop post-mining discharges after mining are evaluated. If they cannot be mined without pos-mining discharges, they cannot be mined."[62]

MITIGATION STRATEGIES

Major regulations that will affect CTL development are summarized below:

Clean Air Act (CAA)

There have been major changes to the Clean Air Act since its inception in 1970. While the Federal government sets the standards for controlling air emissions, states have authority under their State Implementation Plans to implement these controls, including setting more strict standards. Every aspect of will need to comply with the Clean Air Act.

In 1990 revisions to the Clean Air Act, the list of "Hazardous Air Pollutants" (HAPs) or "air toxics" was expanded from seven to 189 Hazardous Air Pollutants, and authority was given to EPA to add additional substances to this list. Sources identified as emitters of these substances must use Maximum Available Control Technology (MACT) to control these emissions.

The second aspect of this set of regulations is whether the area in question is "in attainment" with respect to primary health standards. If it is not, additional restrictions on development will apply.

Ground-level ozone (smog) and particulate matter (PM-10) are included in this aspect of the Clean Air Act, and regulated in a similar fashion with attention to both region and specific project.

In 1997 the Clean Air Act was revised to tighten both the smog and particulate matter standards, and a program was developed for control of regional haze. As part of economic incentives, these amendments include provisions for "offsets" for improved control of certain emissions in new and expanded operations.

Under the 1990 revisions, there is a uniform permitting system for all requirements under the Clean Air Act. This is similar to the permitting under the Clean Water Act (National Pollution Discharge Elimination System (NPDES) permits.

Resource Conservation and Recovery Act (RCRA)

The regulatory provisions of this law are quite complex with respect to waste management. Applicable requirements will cover any part of the process producing waste (solid or hazardous), handling of all wastes, storage, handling process water, etc. The regulations are well established. The compliance program is handled by the states with oversight by EPA regional offices.

Tailings management for RCRA substances will be potentially benefited by continuing research in process technology and in waste management.

Clean Water Act (CWA)

Requirements under the Clean Water Act, first passed in 1972, are well established. The basic permitting system under this law is NPDES. The Clean Water Act jurisdiction is over surface waters, and does not include groundwater, which is under the purview of RCRA. Over the past decade this program has evolved into a holistic approach to watershed management, and away from the project-by-project control strategy.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)

This law was passed in 1980. Aspects of this law most germane to new projects are reporting new releases. Operators are required to develop emergency response plans in accordance with regulations. These requirements are well understood, but plans must be developed and approved for each project.

Emergency Planning and Community Right-to-Know Act (EPCRA) (also known as SARA Title III)

Requirements under this law include coordinated emergency planning by private industry, state and local governments, and federal agencies. Other requirements include annual filings of emissions of listed substances.

Although this is a new requirement, it has been implemented throughout the country and operators are now familiar with how to coordinate the planning efforts, and governmental agencies, including local governments, are also familiar with the requirements. An educational process will likely be required. The annual reporting of releases was a major hurdle during implementation of this law, but has now settled into established procedures and formulas.

Pollution Prevention Act

The Pollution Prevention Act of 1990 focused industry, government, and public attention on reducing the amount of pollution through cost-effective changes in production, operation, and raw materials use. The law established the policy that source reduction is fundamentally more desirable than waste management or pollution control. Operators are required to file an annual toxic chemical release form and include a toxic chemical source reduction and recycling report for the proceeding calendar year. The reporting requirements are linked to the Toxic Release Inventory (TRI) required under EPCRA.

Toxic Substances Control Act (TSCA)

Under TSCA, operators must file a pre-manufacture notice identifying substances to be produced. Toxicological testing may be required of the operators, and if so, can take several years. Much coordinated work was done in defining the products of shale oil retorting in the early 1980s. Nevertheless, because of changes in technology, the process will at least have to be reviewed by both operators and the EPA.

Endangered Species Act

Consideration will be given to protected plants and animals in the Environmental Impact Statement, but additional information regarding protective measures will be required for permitting. Much of this species information has now been digitized using geographic information systems, and maps are available through state and private non-governmental organizations.

Occupational Health and Safety Regulations

The hazards and risks to human health and worker safety associated with CTL production are similar to those that exist and are controlled in other mining, oil production, chemical processing, and refining industries.

CTL operations will be subject to occupational health and safety regulations of both the Occupational Safety and Health Administration (OSHA) and the Mine Safety and Health Administration (MSHA) depending on the process involved. MSHA will have jurisdiction over mining operations under regulations for metal and nonmetal mines, both surface and underground. OSHA regulations will cover all other operations involved. Both sets of regulations involve reporting, worker training, and hazard communication.

NATIONAL COAL COUNCIL RECOMMENDATIONS

The recent National Coal Council provided a series of recommendation related to permitting and regulation of coal mining and power and fuel production including:

- Reduce permitting delays and regulatory uncertainty by expediting permitting with a joint (federal and state) process, including Advanced Clean Coal power plants; using, where appropriate, federal sites, including Base Realignment And Closure (BRAC) sites; exempting initial CTL and CTG plants from New Source Review (NSR) and National Ambient Air Quality Standards (NAAQS) offset requirements; and where it has not been done, implementing the recommendations proposed by The National Coal Council in the 2004 report *Opportunities to Expedite the Construction of New Coal-Based Power Plants.*
- Provide incentives for upgrading the transportation infrastructure by providing federal tax incentives to support taxpayers who invest in railroad infrastructure capacity; and urging Congress to appropriate funds for the upgrade of the inland waterway system, including barge access.
- Ensure that all existing, identified U.S. economically recoverable reserves remain a part of the resource base by: seeking balance between precautionary protectionist policies and energy security; supporting active enforcement of existing laws, including the Clean Water Act, the Endangered Species Act, the Surface Mining Control and Reclamation Act, and the Wilderness Act; actively involving the DOE in addressing energy security in any policymaking that would "sterilize" significant coal reserves; and opposing overlapping and additional regulation that needlessly reduces access to the United States' most abundant energy resource-coal. Recent examples would be the last-minute inclusion of the Kaiparowits Plateau in the Grand Staircase-Escalante National Monument designation and the Forest Service's recently extended Roadless Forest Protection to July 16, 2007.
- Continue to support the provisions of the Mine Safety and Health Act by ensuring a progressive approach to the important issue of enhancing mine safety and working to provide enhanced funding for mine safety research by the National Institute for Occupational Safety and Health (NIOSH).
- Conduct a thorough and updated survey of U.S. coal reserves.[63]

6. INFRASTRUCTURE

Coal-Derived Liquids development requires infrastructure to support industry development and operation, to supply process inputs, and to upgrade and transport manufactured fuels and other products to defense and civilian markets.

The federal government, state governments and effected localities must understand project requirements and infrastructure gaps and facilitate infrastructure development to meet the requirements.

COAL EXPANSION[64]

The National Coal Council has conducted an in-depth survey of existing data and finds that the mining industry and U.S. transportation infrastructure can be expanded to accommodate growth in coal production by over 1,300 million tons per year by 2025. Coal production at a significantly increased level can be conducted in a safe and environmentally friendly manner, meeting public concern over both mine safety and environmental impacts.

The National Coal Council finds that it is in the national interest to create a new energy manufacturing industry by doubling coal production to meet the future energy needs of the American people. Public support for such an effort will be widespread once a full understanding of the nation's energy situation is attained in the context of the importance of stable energy supply and prices to the quality of life in America. In addition, significant coal reserves can be found in over 25 states, and extensive coal mining, refining, gasification and electricity production at enhanced levels can be distributed across these states. The transportation infrastructure, of course, must be strengthened and supplemented. But the benefits will be widely dispersed—lower energy prices, millions of jobs in thousands of communities, and improved national security and economic well-being for all Americans.

WATER

Water use in CTL plants is an issue, particularly in geographical areas of low rainfall and/or limited water resources. However, use of air cooling in place of water cooling can substantially reduce water requirements to less than one barrel of water per barrel of F-T product. Generation of large quantities of coal-derived mineral waste also should not be an issue since this waste product is a non-leachable slag suitable for sale as aggregate.

EMPLOYMENT

Limited historical information is available on the employment benefits of CTL production. However, recent activities such as the Waste Management Processors, Inc. (WMPI) 5,000 BPD co-production facility planned for construction in eastern Pennsylvania will provide useful information that can be used for estimating purposes.[65] Coupling this information with extensive data by the Energy Information Administration (EIA) on United States mining statistics and employment, one can make a rough estimate of the employment benefits of producing 2.6 MMBPD of liquid fuels from coal. It is assumed that there would be no reduction in domestic refining employment since the production of CTL fuels would balance the expected increase in refined product demand that would otherwise be satisfied by imported refined products.

The U.S. produced 1.1 billion short tons of coal in 2004 and had just below 74,000 employees in the coal mining industry.[66] This equates to about 15,000 short tons of coal produced per employee. Assuming 2.6 MMBPD of liquid fuels from coal are produced at some year beyond 2025, and a short ton of coal yields between 2.0 and 2.5 barrels of liquid fuels, this would lead to the creation of about 20,000 new jobs in the coal mining industry. These estimates are based on the need for an additional 1 million tons per day of domestic coal production, or about 350 million additional tons per year.

To achieve the overall 2.6 MMBPD goal for CTL fuels capacity, at least 25 new plants would be required, which results in about 120,000 new construction-related jobs. Once the plants are in operation, approximately 35,000 permanent jobs (direct employment) related to plant operations would be created.

In addition to direct employment in new mining and plant operations for a 2.6 MMBPD liquid fuels from coal industry, indirect employment increases will occur. These indirect increases can be attributed to the need for equipment, materials, supplies, and services for mining and plant operations; the opportunities for other sectors of the economy to grow as workers spend their income; and the generation of taxes that support additional employment. A rough estimate of indirect employment can be obtained by multiplying the number of direct jobs by a factor between two and three. The combined total of new mining and plant operation jobs, excluding construction, is approximately 55,000. Using the lower factor of two, the number of new indirect jobs would be about 110,000.

KEY READINESS OF EQUIPMENT, TRAINED PEOPLE AND RESOURCE AVAILABILITY

If multiple CTL plants are built concurrently worldwide in combination with the deployment of other options, competition for critical process equipment and engineering and labor skills would emerge. There is contemporary evidence that this bottleneck is being encountered today in Qatar, where it is proposed to construct several GTL plants simultaneously. Tight contractor markets and higher raw material costs are also increasing capital costs. The lack of critical equipment and skilled personnel could hinder the growth and development of a CTL industry. The U.S. may find that an evolving CTL industry would be competing for raw steel, fabrication capacity, and limited process engineering design skills.

The U.S. has limited infrastructure to build CTL plant components, particularly the high-pressure gasifier and reaction vessels. This lack of production capacity could lead to bottlenecks that impact how fast these plants can be ramped up. The issue of readiness and its effect on ramp-up of CTL plants has been included in the projection of production capability in Appendix A. In addition, there is an opportunity to increase enrollment of scientists and engineers to address skilled labor requirements. Finally, to help meet global energy requirements, international cooperation could be fostered among friendly nations to build plants in their own country or others and provide components for those plants.

7. SOCIO-ECONOMIC PLANNING AND IMPACT MITIGATION

The CTL plants will likely be located near coal-producing regions to minimize transportation and other logistical costs. A wide swath of rural America from Appalachia through the Midwest, Great Plains and Rocky Mountains will directly benefit from the jobs and economic stimulus these plants will generate. Many communities in these regions have not shared the benefits of the high-tech boom of the 1990s. Instead, many have suffered from plant closings by companies that could not compete with cheap manufactured imports from Asia. The construction of CTL plants will revive these communities and help restore the social fabric frayed by years of falling employment, declining income and rising emigration. There will be community impacts however.[67]

The impacts of CTL plants on local and regional communities will likely be very similar to the impacts generated during the construction and operation of conventional coal-fired power stations. For example, Southern Illinois University estimated in an economic analysis study that the 1,500-megawatt Prairie State electric generating facility in Washington County, Illinois, would inject more than $2.8 billion into the state economy, generate more than $200 million in new tax revenues for state and local governments, create more than 1,800 construction jobs per year during the building of the mine and plant, and create 450 permanent mine and power plant jobs.

These gains are realized as the direct expenditures to build and operate these plants stimulate the demand for good and services in other sectors of the economy. For example, the construction of coal energy manufacturing plants would increase the demand for steel, concrete and other building materials. There would be subsequent rounds of spending, known as indirect impacts, as these sectors draw on their suppliers. Finally, there are induced impacts from the consumption spending by households from higher income levels generated by the direct and indirect economic impacts. For example, workers at CTL plants would purchase local services, such as dining, entertainment and health care, which generate income in these sectors.

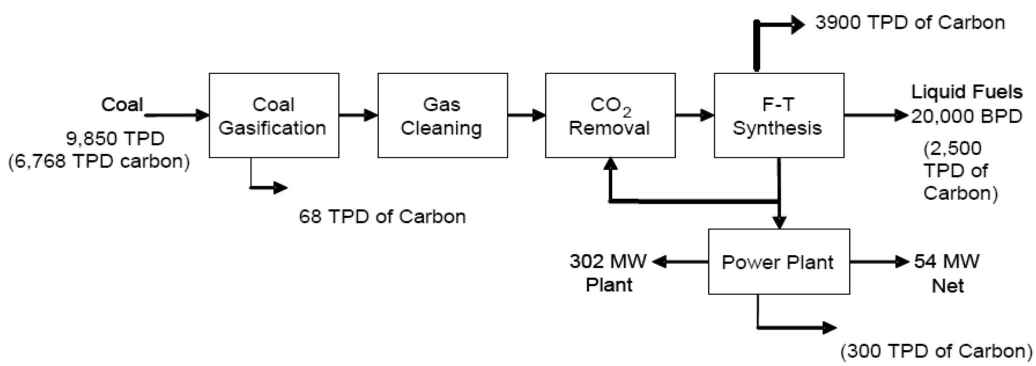
The very aggressive vision for coal described in this study would create over 200 CTL plants scattered from Pennsylvania to Wyoming, each roughly the size of a 1500 MW power plant. Most of these plants will be in rural areas with relatively high unemployment and limited resources for schools and other public services. With the income generated from CTL plants, these communities can restore these services and improve the quality of life not only for employees at the plants but also for their neighbors and families.

There will be issues however, rapid growth in a relatively small, concentrated area, will greatly expand the demand for municipal and human services, such as police and fire protection, medical services, sanitary facilities, educational services, and transportation. For most of the smaller communities, annual operating costs are about equal to annual revenue. Therefore, capital improvement expenditures are largely financed by municipal bond issues that are constrained by statutory bonding limits tied to property values. For these reasons, it is difficult for small communities to raise capital funds needed to support rapid growth in a timely manner. These communities are also resource-constrained to fund the detailed analysis, planning and initial preparedness activities that must precede industry development.

APPENDIX A - CTL CONCEPTUAL PLANT & COMMERCIAL DEVELOPMENT

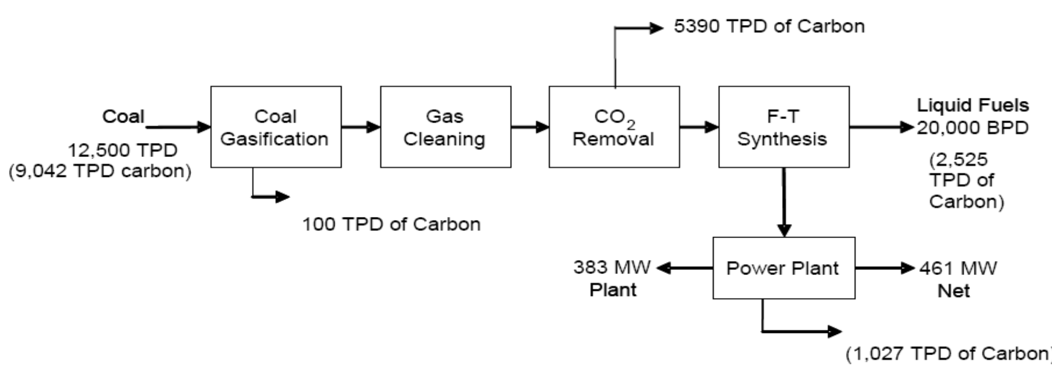
Figure A-1 shows a block flow schematic of a CTL plant that is designed to produce liquid fuels only. This plant is configured to capture 90% of the carbon that would otherwise be released into the atmosphere within the plant boundary. About 9400 tons per day (TPD) of bituminous coal is gasified to produce about 20,000 BPD of liquid fuels (naphtha and diesel). The power plant on site generates all of the power needed to run the plant and the surplus power (54 MW) is exported. The figure also shows the carbon balance around the plant. Of the 6768 TPD of carbon fed to the plant 3,900 TPD is captured, 2,500 TPD is contained in the liquid fuels, and 300 TPD is emitted.

Figure A - 1. Liquid Fuels Only CTL Plant



An example of a polygeneration plant is shown in Figure A-2. This plant is designed to produce about 20,000 BPD of F-T fuels and 460 MW of net power from 12,500 TPD of bituminous coal. Overall plant higher heating value efficiency is estimated to be 47%. The feed coal contains 9,042 tons per day of carbon. Of this carbon, 2,525 TPD is contained in the F-T hydrocarbon fuels, 5,390 TPD is captured, and the remaining 1,127 TPD is emitted into the atmosphere.

Figure A - 2. Polygeneration CTL Plant

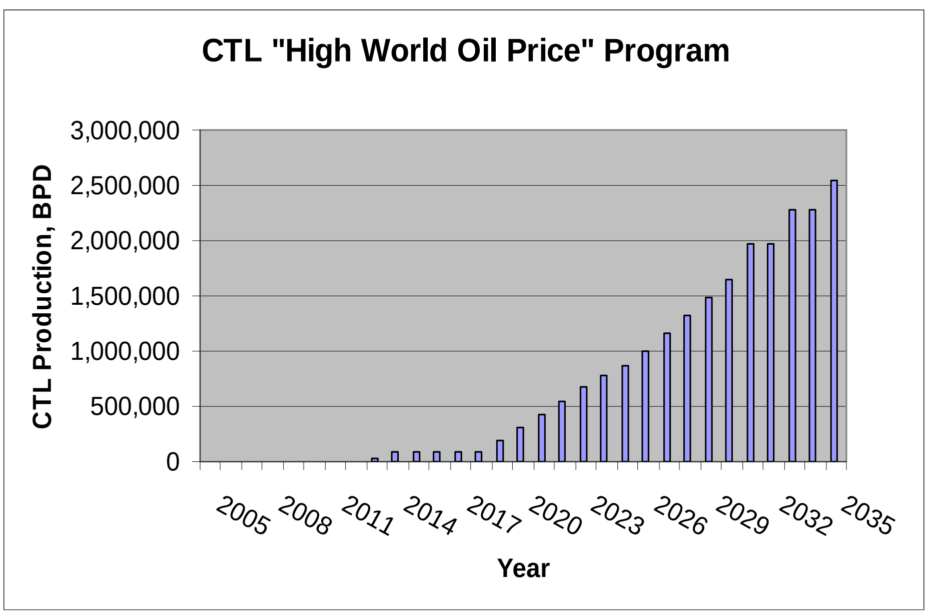


CTL Proposed Ramp-up Discussion

Several organizations have proposed potential Coal to Liquid (CTL) ramp-ups based on their analyses which have been recently published in several major study reports (National Coal Council, Southern States Energy Board). In addition, the DOE Energy Information Agency (EIA) has included the domestic production of liquids produced from coal in their reference and high world oil cases. The EIA CTL projection for the reference case is 230,000 BPD in 2020 at $45 per barrel* and 760,000 BPD in 2030 at $50 per barrel. For the high world oil case, CTL production is projected to be 290,000 BPD in 2020 at $80 per barrel and 1,690,000 BPD in 2030 at $90 per barrel. These cases are based on the NEMS model. The CTL writing group has used two bench marks for preparation of potential CTL ramp-ups. Both are considered to be accelerated and not "business as usual" approaches for the introduction of CTL fuels. The more conservative of the two accelerated CTL production ramp-ups is based on the EIA Annual Energy Outlook 2006 High World Oil Projection Case. This scenario was prepared by LTI based on the AEO case which assumes that High World Oil price alone will cause the introduction and ramp-up of CTL. This projected ramp-up, as shown in Figure 10, is based on the assumed building of the WMPI 5,000 BPD first plant (selected in the DOE's Clean Coal Power Initiative) or one of similar scale, followed by five commercial pioneer plants of 10,000 – 20,000 BPD using a variety of United States coals (Bituminous, sub-bituminous and lignite). In the working group approach, these first plants will have some form of government incentive to facilitate the eventual deployment of regional coal plants of 50,000 – 80,000 BPD that would not require government support.

* All prices per barrel are in $2004

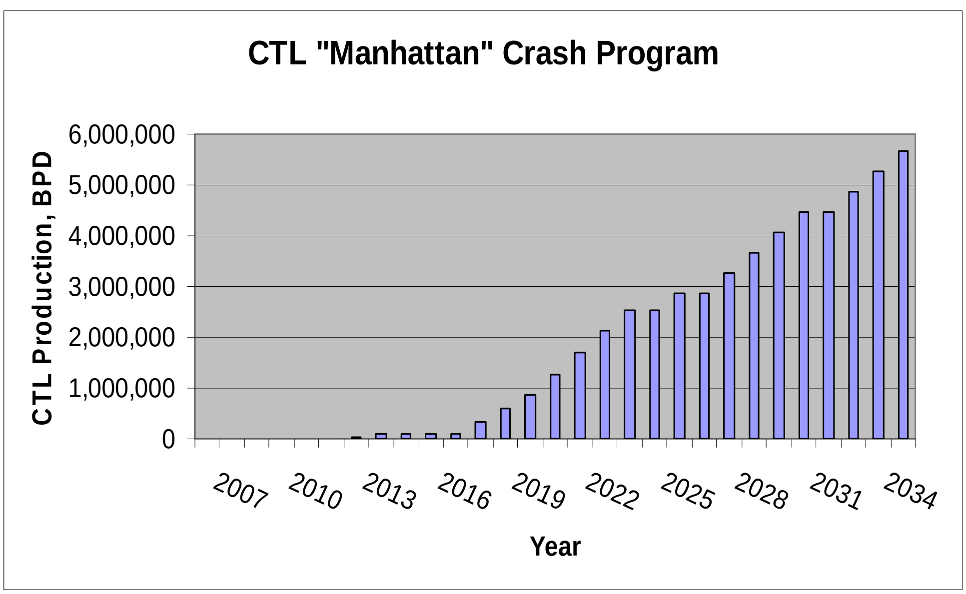
Figure A - 3. CTL Ramp-up based on AEO "High World Oil Price" Scenario



The second ramp-up is based on the recent National Coal Council (NCC) study prepared for the Secretary of Energy in which projection was made for the continued use of coal in an environmentally acceptable manner - including increases in electric production, production of coal based liquid fuels for transportation, production of substitute natural gas and hydrogen. The specific NCC recommendation was for the United States to achieve a production of 2.6 Million BPD of CTL by 2025 (about 10% of 2025 United States petroleum usage). This would require 475 million ton per year of additional coal use. The projection was used by the CTL working as a bench mark for its ramp-up. The NCC projection, although lower than that projected in the recent Southern States Energy Board – is considered to be a "Manhattan" type crash program that would require not only high world oil prices as identified in the AEO analysis but also significant government incentives as suggested in both the National Coal Council and Southern States Energy Board studies for a series of plants beyond the pioneer plants. The National Coal Council specific key points and recommendations for this Manhattan type ramp-up of CTL production is included in the Appendix to this Action Plan.

The proposed actions in the CTL chapter (CTL Action Plan) are considered the beginning of the process that would need further actions to possibly achieve this aggressive level of CTL production. This projected ramp-up is shown in Figure 11. As with the previous AEO high world oil price projection, it is based on the assumed building of the WMPI first plant (Clean Coal Power Initiative) or one of similar scale, five commercial pioneer plants of 10,000 – 20,000 BPD using a variety of United States Coal (bituminous, sub-bituminous, and lignite) followed by regional coal plants ranging from 50,000 BPD to eventually 80,000 BPD. In this study the number of plants being initiated during each year (starting in 2014 after the construction and initial operation of the pioneer plants) is assumed to be 5 which is an aggressive approach created by an actual or impending lack of capability to supply the U.S. transportation fuel demand. There is a built-in assumption that readiness issues can be handled. This assumption is being reviewed by an Office of Fossil Energy study. It is assumed that the CTL plants would be regionally dispersed among the major U.S. coal seams – Appalachian, Interior including North Dakota and Texas lignite and western sub-bituminous with each major coal region having one third of the plants.

Figure A - 4. CTL Ramp-up based on National Coal Council Scenario



APPENDIX B – FISCHER-TROPSCH PROCESS-adapted from "the fischer-tropsch process: 1950-2000[68]"

PREPERATION OF SYNGAS

In an F-T complex, the production of purified syngas typically accounts for 60–70% or more of the capital and running costs of the total plant. Since the cost of syngas is high it is important that the maximum amount is converted in the downstream F-T reactors. This requires that the composition of the syngas matches the overall usage ratio of the reactions. For cobalt-based FT catalysts the dominant reaction is the F-T reaction itself, typically

$CO + 2.15H_2 \rightarrow$ hydrocarbons + H_2O.

That is, the H_2/CO usage ratio is about 2.15. When iron-based catalysts are used, however, the water-gas shift (WGS) reaction also readily occurs

$CO + H_2O \rightarrow CO_2 + H_2$

and so this changes the overall usage ratio. For the low-temperature F-T (LTFT) process the H_2/CO usage ratio is typically about 1.7. At higher temperatures the WGS is rapid and goes to equilibrium and this allows CO_2 also to be converted to F-T products, via the reverse WGS followed by the F-T reaction. Thus if the syngas has a ratio of $H_2/(2CO + 3CO_2)$ equal to about 1.05 all of the H_2, CO and CO_2 can in principle be converted to F-T products.

Currently in all three Sasol plants, the primary source of syngas is from the gasification of coal in Lurgi dry-ash gasifiers. Where the coal enters the gasifier the temperature is only about 600 ˚C and hence there is a coproduction of aromatic tars, oils and naphthas and phenols as well as ammonia, all of which have to be separated and worked up into saleable products. In the gasification zone of the gasifiers the temperature is about 1200 ˚C and hence under the operating pressure of about 3MPa a considerable amount of methane is also produced. After purification, i.e. removal of excess CO_2 and all of the H_2S and organic sulphur compounds, the syngas contains about 11% methane. The H_2/CO ratio is about 1.8 and so is suitable as feed gas to the wax producing LTFT reactors. In the case of the high-temperature F-T (HTFT) synthesis producing gasoline and light olefins the methane contained in the purified Lurgi syngas together with the methane produced in the F-T reactor is catalytically reformed in autothermal reactors. The reformed gas together with the Lurgi gas has a $H_2/(2CO + 3CO_2)$ ratio close to the desired value of 1.05 and so is suitable as feed to the HTFT reactors. The complexity of the syngas production from coal accounts for the higher production cost relative to syngas from methane.

The Mossgas plant is based on methane which is catalytically reformed in two stages, primary tubular reactors followed by secondary autothermal reactors. The tail-gas from the F-T reactors, containing unconverted syngas, CH_4 and CO_2 is recycled to the autothermal reformers. The recycling of CO_2 ensures the attainment of the required $H2/(2CO+3CO_2)$ ratio for the HTFT reactors.

In the Shell plant the primary source of syngas is from the non-catalytic partial oxidation of CH_4 at high pressure and at about 1400 °C. The CH_4 slip is only about 1%. The H_2/CO ratio is about 1.7 and this is below the 2.15 required for the cobalt-based catalyst used in the F-T section. The ratio is raised by adding the H_2 rich gas produced by catalytic stream reforming the tail-gas of the F-T reactors (after knock-out of the water and heavier F-T hydrocarbons).

In the proposed Exxon AGC-21 process which has been demonstrated in a 8000 t per year unit, syngas is prepared by catalytic reforming in a fluidized bed unit. Since the rate of heat exchange is much higher, the differential pressure lower and the gas through-put higher in fluidized bed reactors compared to fixed bed reactors the cost of producing syngas from methane should be significantly lower.

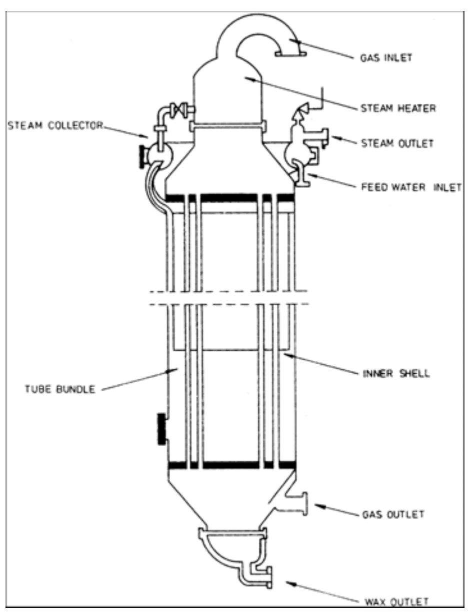
In the proposed Syntroleum process methane is reformed at low pressure in air blown reactors and this eliminates the need for an oxygen plant. F-T synthesis is also carried out at low pressure. The viability of these processes needs to be demonstrated on a larger scale.

FT REACTOR OPTIONS AND DEVELOPMENT

Currently there are two F-T operating modes. The high-temperature (300–350 °C) process with iron-based catalysts is used for the production of gasoline and linear low molecular mass olefins. The low-temperature (200–240 °C) process with either iron or cobalt catalysts is used for the production of high molecular mass linear waxes.

Since the F-T reactions are highly exothermic it is important to rapidly remove the heat of reaction from the catalyst particles in order to avoid overheating of the catalyst which would otherwise result in an increased rate of deactivation due to sintering and fouling and also in the undesirable high production of methane. High rates of heat exchange are achieved by forcing the syngas at high linear velocities through long narrow tubes packed with catalyst particles to achieve turbulent flow, or better, by operating in fluidized catalyst bed reactor. Fig. B-1 depicts a multi-tubular reactor and Fig. B-2 shows three types of fluidized bed reactors.

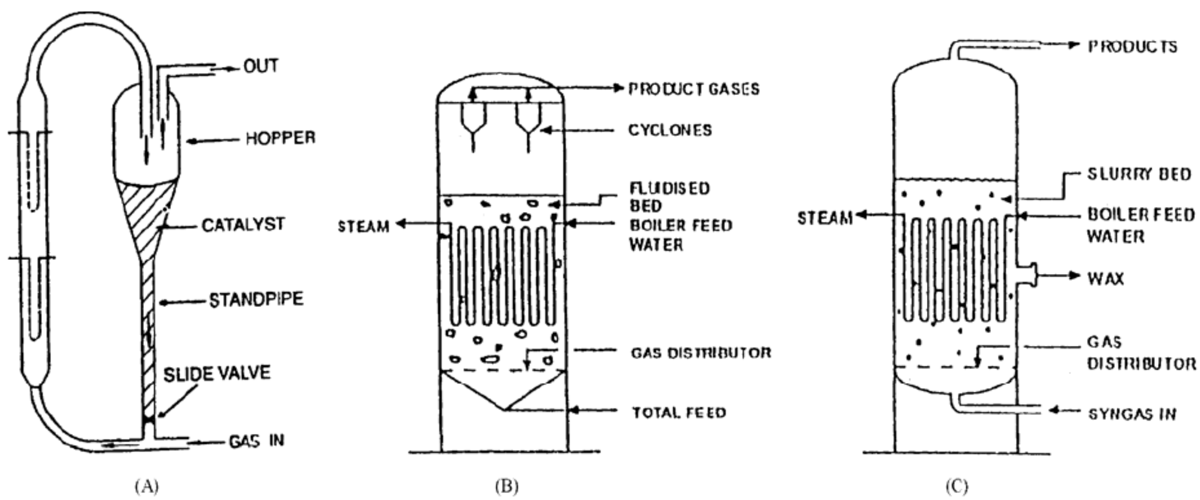
Figure B- 1. Multitubular fixed bed F-T reactor



High-temperature operation

The commercial F-T reactors in the Brownsville, TX, plant, which only operated for a brief period in the mid 1950s, were of the fixed fluidized bed (FFB) type (Fig. B-2B). The reactors operated at about 2MPa and 300 ◦C, i.e. they were HTFT reactors. For the first Sasol plant at Sasolburg the Kellogg-designed circulating fluidized beds (CFBs) (Fig. B-2A) were chosen. These reactors operated at about 2MPa and 340 ◦C. After making some process and catalyst improvements these reactors operated very well for many years. The improved reactors were named Synthol reactors. For the two new Sasol plants constructed about 25 years later at Secunda the same type of reactors were installed but with improved heat exchangers and the capacity per reactor was increased three-fold (wider diameter and higher operating pressure). The same larger type of CFB reactors, with further improved heat exchangers, were installed in the Mossgas F-T complex. It should be noted that in CFB reactors there are two phases of fluidized catalyst. Catalyst moves down the standpipe in dense phase while it is transported up the "reaction" zone (left-hand side of Fig. B-2A) in lean phase. To avoid the feedgas going up the standpipe the differential pressure over the standpipe must always exceed that over the reaction zone. At the high operating temperature carbon is deposited on the iron-based catalysts and this lowers the bulk density of the catalyst and thus the differential pressure over the standpipe. It is therefore not possible to raise the catalyst loading in the reaction section in order to compensate for the normal decline of catalyst activity with time-on-stream.

Figure B- 2. Fluidized bed F-T reactors: (A) CFB reactor; (B) ebulating or FFB reactor; (C) slurry phase bubbling bed reactor. Types (A) and (B) are two phase systems (gas and solid catalyst), while type (C) has three phases present, gas passing through a liquid containing catalyst.



Although the original commercial HTFT reactors at Sasolburg were CFB units, the Sasol R&D department's HTFT pilot plants used to develop improved catalysts and to study various process variables were FFB units. Under apparently similar process conditions the pilot plant units appeared to outperform the commercial units and so in the late 1970s it was decided to investigate the feasibility of commercial sized FFB units. Because rumor had it that the commercial units at the Brownsville, TX, plant had experienced fluidization problems, an exhaustive study of the fluidization behavior of the Sasol HTFT catalyst was undertaken using large Plexiglas units. In 1984 a 1m i.d. FFB demonstration reactor, designed by Badger, was brought on-line at the Sasolburg plant. In 1989 a 5m i.d., 22m high commercial unit came on stream and it met all expectations. From

1995 to 1999 the 16 second generation CFB reactors at Secunda were replaced by eight FFB reactors, four of 8m i.d. with capacities of 470×103 t per year each and four of 10.7m i.d. each with a capacity of 850×103 t per year. These reactors were named Sasol Advanced Synthol (SAS). It is of interest to note that about 35 years after the shut down of the Brownsville, TX, F-T plant which used FFB reactors improved versions of the same type of reactor are operating at Sasol.

The main advantages of FFB over CFB reactors are as follows:

- The construction cost is 40% lower. For the same capacity the FFB reactor is much smaller overall.
- Because of the wider reaction section more cooling coils can be installed increasing its capacity. (More fresh gas can be fed by either increasing the volumetric flow or by increasing operating pressure. Pressures up to 4MPa are feasible.
- At any moment all of the catalyst charge participates in the reaction, whereas in the CFB only a portion of it does.
- For the reasons previously discussed the lowering of the bulk density by carbon deposition is of less significance in the FFB and thus a lower rate of on-line catalyst removal and replacement with fresh catalyst is required to maintain high conversions. This lowers the overall catalyst consumption.
- Because the iron carbide catalyst is very abrasive and the gas/catalyst linear velocities in the narrower sections of the CFB reactors is very high these sections are ceramic lined and regular maintenance is essential. This problem is absent in the lower linear velocities FFB reactors and this allows longer on-stream times between maintenance inspections.

Low-temperature operation

Under the operating conditions used the large amount of wax produced is in the liquid phase in the FT reactors and so three phases are present, liquid, solid (catalyst) and gas. In top-fed multitubular reactors (Fig. 12) the wax produced trickles down and out of the catalyst bed. In slurry reactors (Fig. 13C) the wax produced accumulates inside the reactors and so the net wax produced needs to be continuously removed from the reactor.

For the Sasolburg F-T plant which came on stream in 1955 five multitubular ARGE reactors (designed by Lurgi and Ruhrchemie) were installed for wax productions. These reactors are currently still in operation. Each reactor contained 2050 tubes, 5 cm i.d. and 12m long. They operate at 2.7MPa and 230 °C. The production capacity of each is about 21 × 103 t per year. Based on Sasol R&D pilot plant studies an additional high capacity reactor operating at 4.5MPa was installed in 1987.

In the Shell Bintuli plant which came on stream in 1993 there are four large multitubular reactors each with a capacity of about 125 × 103 t per year. There are probably about 10 000 tubes per reactor. As cobalt-based catalysts are used, which are much more reactive than the iron-based catalysts used in the Sasolburg reactors, the tube diameters of the Shell reactors are narrower in order to cope with the higher rate of reaction heat released.

The use of slurry bed reactors for F-T synthesis was studied by several investigators in the 1950s, e.g. Kölbel developed and operated a 1.5m i.d. unit. In the late 1970s Sasol R&D compared the performance of fixed and slurry bed systems in their 5 cm i.d. pilot plants and found the conversions and selectivities to be similar. Further development was delayed because a reliable system was required to separate the net liquid wax produced from the fine friable precipitated iron-based catalyst used. In 1990 an efficient filtration device was tested in a 1m i.d. demonstration slurry bed reactor. In 1993 a 5m i.d. commercial unit was commissioned and has been in operation ever since. Its capacity is about 100 × 103 t per year which equals that of the combined production of the original five ARGE reactors. Note again that only about 40 years after Kölbel's pioneering work did the first commercial slurry reactor come on-line. Using a cobalt-based catalyst Exxon successfully operated a 1.2m i.d. slurry bed reactor for wax production. The unit's capacity was 8.5 × 103 t per year.

The advantages of slurry over multi-tubular reactors are as follows:

- The cost of a reactor train is only 25% of that of a multi-tubular system.
- The differential pressure over the reactor is about four times lower which results in lower gas compression costs.
- The lower catalyst loading translates to four-fold lower catalyst consumption per tonne of product.
- The slurry bed is more isothermal and so can operate at a higher average temperature resulting in higher conversions.
- On-line removal/addition of catalyst allows longer reactor runs.

The disadvantage of a fluidized system is that should any catalyst poison such has H_2S enter the reactor all of the catalyst is deactivated, whereas in a fixed bed reactor all the H_2S is adsorbed by the top layers of catalyst, leaving the balance of the bed essentially unscathed.

FT CATALYSTS, PREPERATION AND ACTIVITY DECLINE

Only the metals Fe, Ni, Co and Ru have the required F-T activity for commercial application. On a relative basis taking the price of scrap iron as 1.0 the approximate cost of Ni is 250, of Co is 1000 and of Ru is 50 000. Under practical operating conditions Ni produces too much CH_4. Besides the very high price of Ru the available amount is insufficient for large scale application. This leaves only Fe and Co as viable catalysts.

Iron-based catalysts used for wax production (LTFT process) are currently prepared by precipitation techniques, promoted with Cu and K_2O and bound with SiO_2. The iron content is high; typically the composition is 5 g K2O, 5 g Cu and 25 g SiO_2 per 100 g Fe. Prior to F-T application the catalysts are usually partially pre-reduced with either H_2 or mixtures of H_2 and CO. The iron catalysts used in the high-temperature application is prepared by fusing magnetite together with the required chemical (usually K_2O) and structural promoters such as Al_2O_3 or MgO. The catalyst is pre-reduced with H_2 at about 400 °C.

Cobalt-based catalysts are only used in the LTFT process as at the higher temperatures excess CH_4 is produced. Because of the high price of Co it is desirable to minimize the amount used but to maximize the available surface area of the metal. To achieve this, the Co is dispersed on high area stable supports such as Al_2O_3, SiO_2 or TiO_2. Typically the cobalt metal loadings vary from 10 to 30 g per 100 g of support. The catalysts are also usually promoted with a small amount of noble metal, e.g. Pt, Ru, Re which is claimed to enhance the reduction process and also keep the Co metal surface "clean" during F-T. It has been found that there is a clear correlation between activity and Co metal area irrespective of the nature of the support, i.e. the support has no chemical effect on the turn over frequency of Co sites.

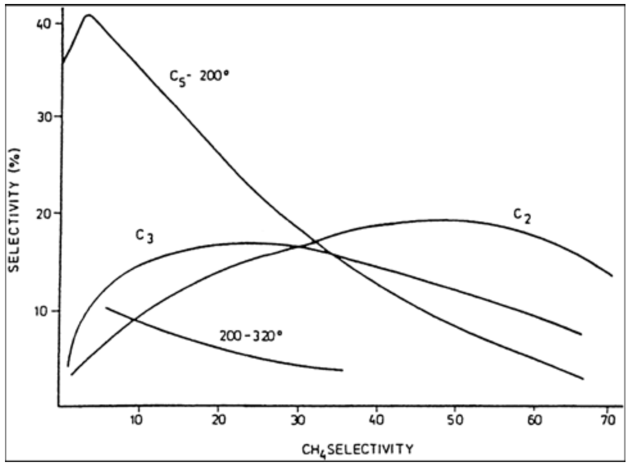
In order to minimize reactor down-time and catalyst consumption it is vital that the F-T catalysts maintain high activity for long times. Both Co and Fe catalysts are permanently poisoned by sulfur compounds and thus the sulfur content of the syngas should be kept below about 0.02 mg/m3 (STP). The exact detail of the chemical steps occurring during F-T remains a contentious topic but because the carbon–oxygen bond in CO has to be broken during the process it is very probable that both carbon species such as elemental C, CHx , etc. and oxygenated species such as O, OH, H_2O, etc. are chemisorbed on the surface of the metal catalyst. The former represent "carbided" metal sites and the latter "oxidized" metal sites. The process of course involves rapid cycling, i.e. at any instant a particular surface metal atom could be in the oxidized, carbided or reduced state. This chemical cycling should enhance sintering and so loss of active surface area. The metal in the oxidized state can also chemically interact with the support forming inert aluminates, silicates, etc. The smaller the supported metal particles, i.e. the higher the proportion of exposed surface metal atoms, the higher the likelihood of these processes occurring. This could mean that a very highly dispersed metal may well have a high initial F-T activity but could rapidly decline with time-on-stream. For similar reasons high H_2O/H_2 ratios within the reactor should not exceed some critical value. High conversions can nevertheless be achieved by recycling a portion of the tail-gas after water and heavy product knock-out. This is common practice in F-T operations.

For iron-based catalysts bulk phase oxidation occurs in addition to the above factors. At high temperatures aromatics are formed which lead to fouling of the surface by aromatic coke. Large amounts of elemental carbon is also formed which results in catalyst break up and subsequent physical loss of the low density carbide and alkali rich fines from the fluidized bed reactors. The deposition rate of elemental carbon increases with the alkali promoter content of the catalysts and correlates with the value of $pCO/p2H_2$ at the reactor entrance. The latter factor means that if the syngas pressure is increased then despite the higher F-T production rate the rate of carbon deposition is lower.

F-T SELECTIVITY

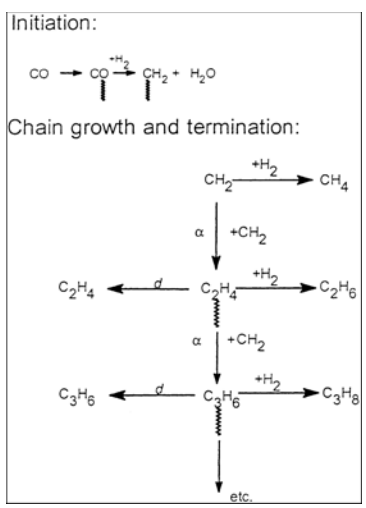
Irrespective of operating conditions the F-T synthesis always produces a wide range of olefins, paraffins and oxygenated products (alcohols, aldehydes, acids and ketones). The variables that influence the spread of the products are temperature, feed gas composition, pressure, catalyst type and promoters. There is, however, always a fixed interrelation between the individual products irrespective of what variables were altered. Fig. B-3 illustrates the relationship between the CH4 selectivity and that of some selected hydrocarbon cuts. The explanation of these interrelationships lies in the stepwise growth process occurring on the catalyst surface. Fig. B-4 illustrates the concept of the process. The CH_2 units, formed by the hydrogenation of CO are taken as the "monomers" in a stepwise oligomerization process. At each stage of growth the adsorbed hydrocarbon species has the option of desorbing or being hydrogenated to form the primary F-T products or of adding another monomer to continue the chain growth. If it is assumed that the probability of chain growth (*a*) is independent of the chain length then it is a simple matter to calculate the product distribution for various values of *a*. The agreement between the calculated and observed results, with the exception of the C1 and C2 products, is good and this supports the concept of a stepwise growth process.

Figure B- 3. The relation between selectivity of the CH4 and that of various hydrocarbon cuts (on a carbon atom basis) for the HTFT process.



It must be stressed that it is not proposed that Fig. A-8 represents the actual F-T mechanism. Various detailed mechanisms have been proposed over the last 50 years and this matter still remains controversial. Some of the questions that arise are: does the chemisorbed CO molecule first dissociate into C and O atoms and the C is then hydrogenated to CH_2 monomers; or is CO hydrogenated to "CHO" or "HCOH" species which insert into the growing chain; or does CO insert directly and is then subsequently hydrogenated. Since large amounts of alcohols and aldehydes are formed in the F-T synthesis and appear to be primary products insertion of some form of oxygenated species is required to account for these products. The linear olefins, which also are formed in large amounts, must be primary products as at the partial pressures of hydrogen present in the reactors virtually all olefins should, according to thermodynamics, be hydrogenated to paraffins. The viability of the F-T process depends on three key factors, the life, the activity and the product selectivity of the catalyst. The question is asked whether detailed knowledge of the chemical reaction sequences occurring will in fact result in improvements in these three key factors. Better catalyst formulations and synthesis process conditions are more likely to result in improvements.

Figure B- 4. F-T stepwise growth process. Note that no specific chemical mechanism is implied in the sequence presented.



Effect of temperature

For all F-T catalysts an increase in operating temperature results in a shift in selectivity towards lower carbon number products and to more hydrogenated products. The degree of branching increases and the amount of secondary products formed such as ketones and aromatics also increases as the temperature is raised. These shifts are in line with thermodynamic expectations and the relative stability of the products. As Co is a more active hydrogenating catalyst the products in general are more hydrogenated and also the CH_4 selectivity rises more rapidly with increasing temperature than it does with Fe catalysts.

Effect of chemical and structural promoters

For iron-based catalysts the "basicity" of the surface is of vital importance. The probability of chain growth increases with alkali promotion in the order Li, Na, K and Rb. Because of the high price of Rb potassium salts are used in practice. The basicity of the catalyst does not only depend on the amount of K added but also on the anion used as well as on the presence and amount of oxides such as SiO_2, Al_2O_3, etc. with which the alkali can chemically react to form less basic compounds. These oxides may either be impurities present or deliberately added as supports, binders or spacers. In general cobalt-based catalysts are much less influenced by the presence of chemical or structural promoters. While it has been found by various investigators that the addition of low levels of noble metals such as Ru, Re or Pt enhance the F-T activity of the Co catalysts it is not clear if the selectivities are influenced.

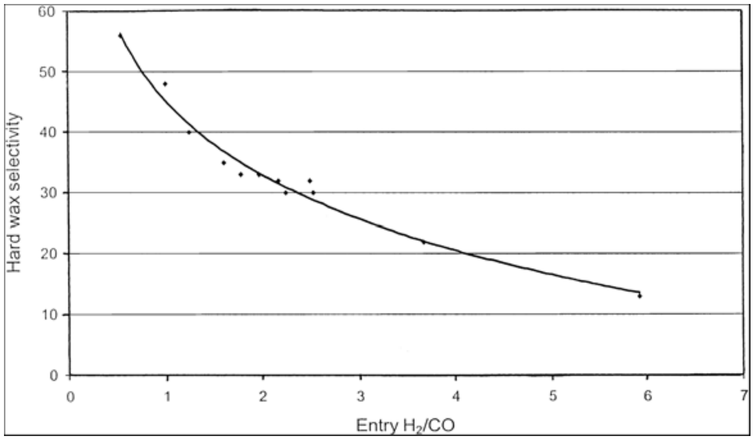
Feed-gas composition and pressure

Taking the scheme shown in Fig. 15 as a guide it can be argued that the lower the partial pressure of CO the lower the surface coverage by the CH_2 species, the lower the probability of chain growth and the higher the probability of desorption of the *n*(CH_2) species. The higher the H_2 partial pressure the more likely the termination of the surface species to paraffins. Thus, one could expect that as the H_2/CO ratio increases the selectivity would shift to lighter and more saturated hydrocarbons. This could, however, be an oversimplification as the presence of CO_2 and of H_2O could complicate matters. For example, since the chemisorption of CO is much stronger than that of H_2 the presence of CO_2 and H_2O could have a greater negative effect on H_2 than on CO chemisorption. Thus, the selectivity may possibly correlate better with a more complex ratio such as

$$\frac{p_{H_2}^{a}}{xp_{CO}^{b} + yp_{CO_2}^{c} + zp_{H_2O}^{d}}$$

Commercial FT reactors operate at high gas linear velocities and so there is likely to be a high degree of plug flow through the units. This means that the composition and partial pressures change along the length of the reactor and so possibly the F-T selectivities as well. For both design and control purposes it should be useful to establish a relatively simple relationship between the total feed gas composition (that of the sum of the fresh feed and recycle flows) and the overall product selectivity. To this end 5 cm i.d. pilot plant studies were carried out using various pressures, gas compositions and recycle ratios with standard commercial iron catalysts at fixed temperatures. Typical results for the low-temperature fixed bed process are shown in Fig. B-5. As high wax production is the key objective of LTFT the hard wax selectivity was used as the indicator of selectivity. In the runs the total pressures, the partial pressures of CO_2 and the H_2/CO ratios were varied over wide ranges. As can be seen from Fig. B-6 the simple H_2/CO ratio adequately reflects the wax selectivity.

Figure B- 5. The selectivity of hard wax (BP > 500oC) as a function of the H2/CO ratio at the entrance for the fixed bed LTFT process using precipitated iron catalyst.



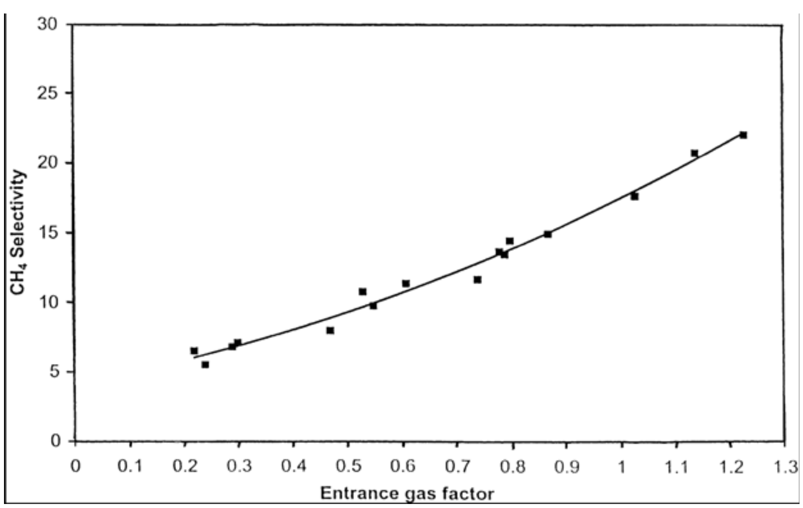
A similar series of experiments was carried out for the HTFT fluidized process. Since there is a good correlation between CH_4 selectivity and that of all of the other products in the HTFT process (see Fig. 13) the CH_4 selectivity is used here to reflect the overall selectivity. There is no correlation with the simple H2/CO ratio. The factor

$$\frac{p_{H_2}^{0.25}}{p_{CO} + 0.7\, p_{CO_2}}$$

at the reactor entrance appears to correlate well (see Fig. B-6). Note that, unlike the LTFT case, changes in the total and in the CO_2 partial pressures were found to influence the selectivity and this is accounted for in the above factor. As an alternative approach the average partial pressures in the reactor were used for correlation and then it was found that the factor also correlated.

$$\frac{p_{H_2}^{a}}{x p_{CO}^{b} + y p_{CO_2}^{c} + z p_{H_2O}^{d}}$$

Figure B- 6. The selectivity of CH4 as a function of the entrance gas factor at the reactor entrance for the HTFT process with iron catalysts.



In recent years there has been a lot of work done on cobalt-based catalysts but detailed results of pilot and demonstration plant tests have not been published. From the pre-war fixed bed studies in Germany and in later laboratory scale studies the F-T wax selectivity correlated with the H_2/CO ratio of the gas as is the case for iron catalysts in the same temperature range, namely 200–240 °C. With regard to the effect of total pressure, however, cobalt catalysts behaved differently in that as the pressure was increased the wax selectivity increased.

KINETICS OF THE F-T REACTION

For the purpose of comparing the F-T kinetics of iron-based as against cobalt-based catalysts the following two kinetic equations are used:

for iron,

$$r = \frac{m p_{H_2} p_{CO}}{p_{CO} + a p_{H_2O}}$$

for cobalt,

$$r = \frac{k p_{H_2} p_{CO}}{(1 + b p_{CO})^2}$$

The equation for iron was based on extensive studies carried out with the commercially used iron catalysts in the fixed and fluidized pilot plant units at Sasol R&D. Thus, total pressures varied from 0.8 to 7.6MPa and the effects of varying individually the partial pressures of H_2, CO, CO_2 and H_2O were investigated. Residence times were varied by using different catalyst charges and thus the reaction profiles through the reactors were determined. Some of the key findings were as follows:

- The partial pressure of H_2O had a strong negative effect, whereas that of CO2 had no influence on the F-T rate.
- The rate increased with hydrogen pressure and at low conversion levels the rate was solely dependent on pH_2.
- The percent conversion remained constant when the total pressure was increased while keeping all other variables constant, such as feed-gas composition, residence time, etc.

The equation also described the reaction profiles in the commercial F-T reactors. It is of interest to note that the equation based on all the above investigations turned out to be the same as that published about 25 years earlier.

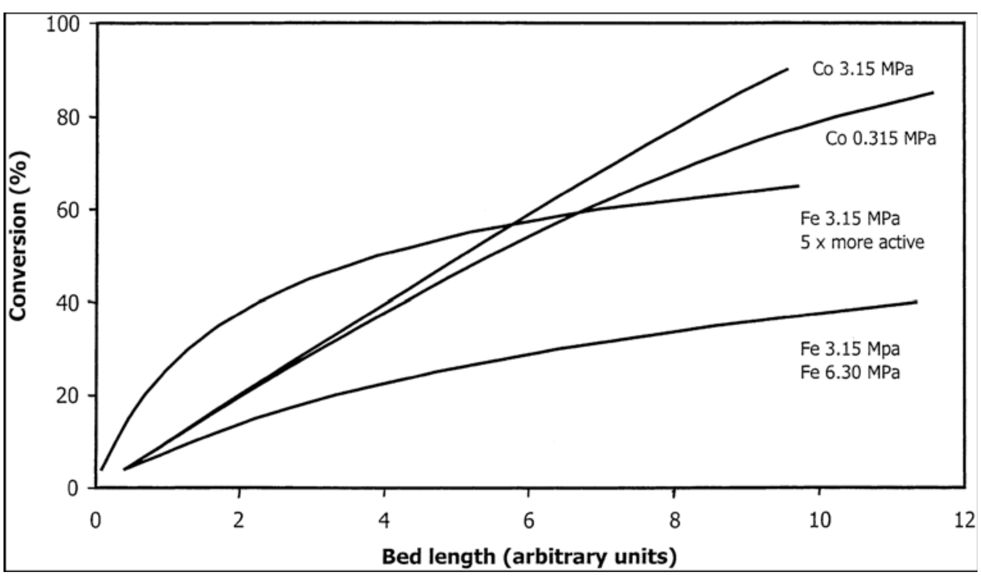
For cobalt catalysts no kinetic information appears to have been published for the industrial fixed bed reactors of the Shell plant or for the demonstration slurry bed units operated by Exxon and Sasol but laboratory investigations have confirmed that the Satterfield equation is satisfactory. The most significant difference between the iron and cobalt equations is the absence of a water vapor pressure term in the latter equation. Chemically it is well known that iron is oxidized at much lower H_2O/H_2 ratios than is cobalt metal and so it can be argued that under F-T conditions a much larger fraction of the exposed iron surface will be occupied by oxygen atoms/ions at any instant resulting in a loss of actives F-T sites as the conversion, i.e. the H_2O/H_2 ratio, increases along the reactor length. This gives cobalt a big activity advantage over iron catalysts.

The percent conversion profiles for various cases were calculated for the LTFT process using the two presented equations. The results are shown in Fig. 18. For this particular set of calculations the constants *m* and *k* were deliberately chosen so that at 3.15MPa a conversion of 4% was achieved at the same catalyst bed length, i.e. the "initial" activities of the Fe and Co catalysts were the same. The H_2/CO ratios of the feed-gases were taken as equal to the respective usage ratios of the two catalysts. Once through operation is assumed (i.e. no tail-gas is recycled). The calculations show that the cobalt catalyst is superior in that much higher conversions per pass can be achieved. If the iron catalyst was made to have an "intrinsic", i.e. initial, activity five times higher than that of the cobalt catalyst the iron catalyst would be superior up to about 50% conversion but beyond this level it would again drop well below that of cobalt.

The calculations indicate that high conversions can be achieved with cobalt catalysts in single stage reactors without the need to recycle part of the tail-gas or to run two stages with water knock-out between stages. For iron-based catalysts high conversions, e.g. 90%, can be achieved but this requires two stage operation together with gas recycling and this increases both capital and running costs. It should, however, be borne in mind that because of the high price of cobalt, the metal needs to be highly dispersed, i.e. very small Co crystals will be present on the oxide support. As discussed in previously these very small Co particles could deactivate at high H_2O/H_2 ratios, i.e. high conversions. To avoid this it may nevertheless be advisable to operate with two stages with water knock-out between, or alternatively, to recycle a portion of the tail-gas after water knock out.

As observed in practice, the calculations (Fig. B-7) also show that for iron-based catalyst the conversion profile does not change with an increase in total pressure if the residence time and other variables are constant. Thus, doubling the pressure and the gas feed rate results in doubling the reactor's production rate. The calculations indicate similar results can be expected for cobalt catalyst. Thus operating at low pressures as proposed by Syntroleum, may well give high percent conversions but the actual production rates will be low and so either more or much larger reactors will be required.

Figure B- 7. The calculated conversion profiles for LTFT operation with cobalt- and iron-based catalysts.



VERSATILITY OF THE FT PROCESS

The FT reaction inevitably produces a wide range of products but by applying various downstream work-up processes the yields of the desired products can be markedly increased.

Gasoline: For maximum gasoline production the best option is using the high capacity FFB reactors at about 340 °C with iron catalyst. This produces about 40% straight run gasoline. Twenty percent of the F-T product is propene and butene. These can be oligomerized to gasoline and because the oligomers are highly branched it has a high octane value. The straight run gasoline, however, has a low octane value because of its high linearity and low aromatic content. The C5/C6 cut needs to be hydrogenated and isomerized and the C7–C10 cut needs severe platinum reforming to increase the octane value of these two cuts. Di-isopropyl ether can be produced from propene and water and this will further boost the octane number of the gasoline pool. The overall complexity of gasoline production, however, make it less attractive than the diesel fuel option.

Diesel fuel: The very factors that count against the production of high quality gasoline, namely high linearity and low aromatic content are very positive factors for producing high cetane diesel fuel. The recommended process option is the use of the high capacity slurry bed reactors with cobalt catalysts and operated to maximize wax production. The straight run diesel selectivity is about 20% and after hydrotreatment its cetane number is about 75. The heavier than diesel products accounts for about 45–50% of the total and mild hydrocracking produces a large proportion of high quality diesel, virtually free of aromatics. The final diesel pool has a cetane number of about 70. As the market normally requires a cetane number of 45 the FT diesel can either be used in areas where there are very tight constraints on diesel quality or it can be used as blending stock to upgrade lower quality diesel fuel. The naphtha produced would need severe reforming to convert it to high octane gasoline. Preferably it could be steam cracked as it would produce a high yield of ethylene.

The mild hydrocracking of wax was investigated at the Sasol R&D division during the 1970s. The product heavier than diesel was recycled to extinction. The overall yields were about 80% diesel, 15% naphtha and 5% C1–C4 gas. When the decision to construct the third Sasol plant was made the wax hydrocracking proposal was rejected because at that time making gasoline was the more economic option and the straight duplication of the second plant resulted in huge savings in time and capital. Also at that stage, the FT slurry reactors had not yet been developed. About 20 years later the same concept of wax hydrocracking was implemented at the Shell Bintulu plant where multi-tubular F-T reactors are used and currently Sasol/Chevron are designing a slurry F-T plant with wax hydrocracking in Nigeria. A similar plant at Qatar is in the pipeline.

Chemicals: The high-temperature fluidized bed F-T reactors with iron catalyst are ideal for the production of large amounts of linear _-olefins. As petrochemicals they sell at much higher prices than fuels. The olefin content of the C3, C5–C12 and C13–C18 cuts are typically 85, 70 and 60%, respectively. Ethylene goes to the production of polyethylene, polyvinylchloride, etc. and propylene to polypropylene, acrylonitrile, etc. The extracted and purified C5–C8 linear olefins are used as comonomers in polyethylene production. The longer chain olefins can be converted to linear alcohols by hydroformylation. The only required purification of the narrow feed cuts is the removal of the acids. The hydroformylation was investigated at the Sasol R&D laboratories in the early 1990s. The alcohols are used in the production of biodegradable detergents. Their selling prices are about six times higher than that of fuel. The LTFT processes produce predominantly longer chain linear paraffins. After mild hydrotreatment to convert olefins and oxygenates to paraffins the linear oils and various grades of linear waxes are sold at high prices.

Heavy Oil Resource and Technology Profile

Heavy Oil Working Group Analysis
Prepared For The
Strategic Unconventional Fuels Task Force

February 2007

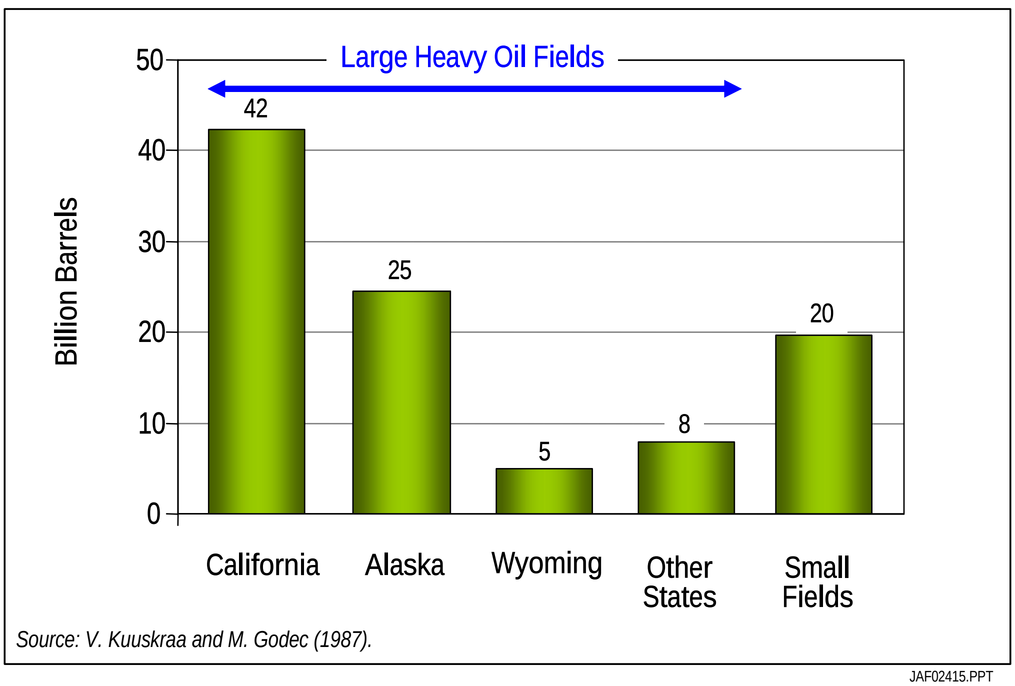
1. RESOURCE ACCESS

"Heavy oil" is an asphaltic, dense, viscous type of crude oil that has an API gravity between 10° and 20° (920 to 1,000 kilograms per cubic meter). Generally, this 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.

The domestic heavy oil resource is large, on the order of 100 billion barrels[69] of original oil in-place (OOIP). This resource is concentrated in 248 large, heavy oil reservoirs, holding 80 billion barrels of OOIP. While the resource is primarily located in California (42 billion barrels), Alaska (25 billion barrels), and Wyoming (5 billion barrels), numerous other states, such as Arkansas, Louisiana, Mississippi and Texas, also contain significant volumes of heavy oil (Figure III-37).

There is a need to update the data on domestic heavy oil. The primary published national study on domestic heavy oil (and one still used by Congress and others) dates back to 1987,[70] which built upon earlier work by Meyer and Schenk[71]. Since these studies were published, much has been learned about the heavy oil resource base and heavy oil extraction technology. An up-to-date study of heavy oil could provide valuable insights on formulating policies, initiatives, and technology for more efficiently developing this large domestic resource.

Figure III-37. Size and Distribution of the U.S. Heavy Oil Resource

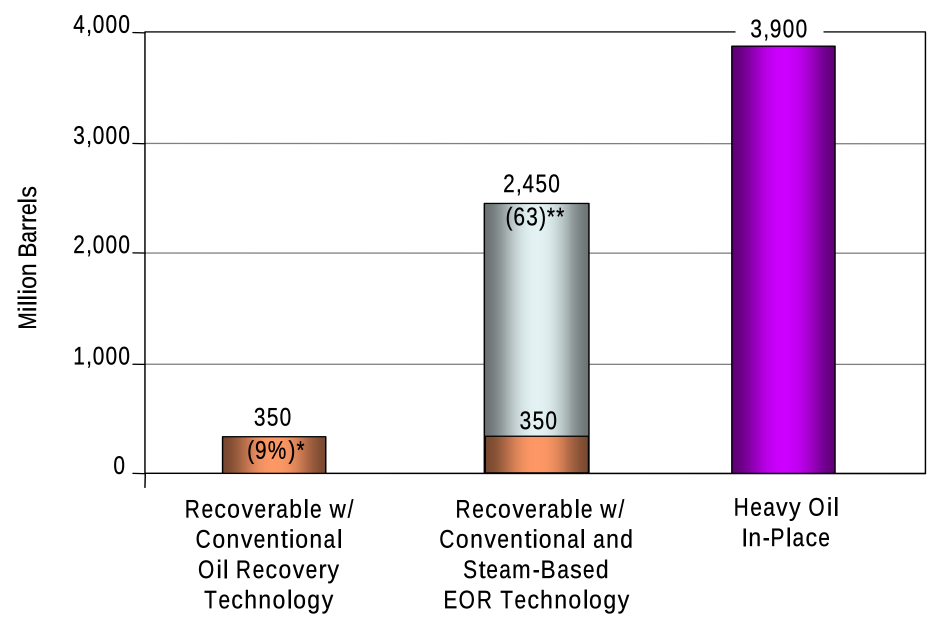


2. TECHNOLOGY ADVANCEMENT AND DEMONSTRATION

Widespread use of steam injection and, to a lesser extent, in-situ combustion and cyclic steam injection (technologies that enable this viscous heavy oil to flow more readily and thus to be recovered efficiently) have enabled industry to economically produce a significant portion of the heavy oil resource in shallow (less than 3,000 feet of depth) reservoirs, particularly in California. These technologies have generally been applied to large fields, since thermal EOR applied to smaller fields often has lower profit margins due to the greater capital expense per barrel of incremental oil recovered.

Moreover, modest advances in heavy oil recovery technology, particularly applied to steam-based thermal EOR, provide an example of how higher recovery efficiencies can be achieved in older shallow heavy oil fields. For example, application of steam injection has enabled the giant Kern River shallow heavy oil field, with 3.9 billion barrels of OOIP, to produce and prove nearly 2.5 billion barrels of domestic heavy oil. This is far in excess of the 0.35 billion barrels that was judged to be recoverable with conventional primary and secondary recovery methods, Figure III-38. This example demonstrates that with efficient thermal EOR technology, nearly two-thirds (63%) of the resource in-place may become recoverable from favorable shallow heavy oil fields, much more than the 9% recoverable with primary/secondary recovery technology alone.

Figure III-38. Oil Recovery from the Shallow, Geologically Favorable Kern River Heavy Oil Field, California



*(9%) Recovery Efficiency with Conventional Technology
** (63%) Recovery Efficiency with Enhanced Heavy Oil Recovery Technology
Source: Advanced Resources International EOR Database (2005).

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Federal Enhanced Oil Recovery Technology Programs

Initial work by Federal government in enhanced oil recovery (EOR) was a part of field demonstration projects started by the U.S. Bureau of Mines in 1974, which was taken over by DOE in 1978. Six of these initial demonstration projects were thermal/heavy oil projects. With the exception of steam flooding, the early demonstration of EOR techniques was largely uneconomic, with some incremental oil recovery.

The basic lesson learned from these programs was that oil and gas reservoirs, with few exceptions, were much more complicated than previously believed. Effective deployment of EOR recovery technology was determined to depend on a thorough geologic characterization of the reservoir. The best recovery technology deployed into a poorly understood reservoir was determined to be ineffective, or if by chance it was effective, the success would be difficult to repeat.

In the mid-1980s, DOE initiated the Reservoir Life Extension Field Demonstration program, which evolved into the Reservoir Class Program in the early 1990s. This program built upon these lessons, with a strategy predicated on reservoir characterization and play definition, and is generally regarded as one of DOE's most successful programs.

According to an assessment of the National Research Council,[72] the EOR/Field Demonstration programs successfully demonstrated thermal, gas, chemical, and microbial techniques and developed screening models and databases that stimulated production of nearly 1.5 billion barrels of oil equivalent over the period from 1996 to 2005, and provided $625 million in cost savings to oil producers and nearly $2.2 billion in incremental federal and state revenues.

The goal of the current EOR program is to "develop technologies to more efficiently recover petroleum from known reservoirs not producible by current technology, reduce the rate of well abandonment, and improve reservoir modeling and process prediction techniques."[73]

In February 2006, DOE launched a new effort through a solicitation to fund research of up to $3 million per project for field-testing and validating integrated enhanced recovery/sequestration technologies.[74] Projects may last 2–5 years and require a 50 percent cost share by the recipient. The projects will be managed through FE's National Energy Technology Laboratory (NETL).

Demonstration of Current Heavy Oil Technologies

Data from the California Department of Conservation shows that the production of heavy oil in California using thermal EOR, waterflooding and primary depletion, while significant at nearly 474,000 barrels per day, has been declining, Table III-17. Of this, about 286,000 barrels per day is produced from thermal EOR processes.[75] Nationwide, thermal EOR production is also declining, with approximately 302,000 barrels per day being produced from 55 thermal EOR projects in 2006, a decline from nearly 346,000 barrels per day in 2004.[76]

In contrast, oil production from in-situ combustion process is on the increase in the U.S., with several new projects in Montana and North and South Dakota, and production has increased at the Bellevue combustion project in Louisiana.

Table III- 17. Heavy Oil Production in California (January of each year)

Year	Heavy Oil (20^o API Gravity and Below)		
	Number of Producing Wells	Production (Bbl/day)	% of State Production
1994	29,873	627,405	67.9
1995	29,113	644,726	67.6
1996	29,693	664,981	69.9
1997	30,524	656,415	71.9
1998	31,641	659,300	70.1
1999	30,467	618,680	71.8
2000	30,372	581,453	70.2
2001	30,754	551,125	68.9
2002	30,636	521,357	65.6
2003	30,727	510,137	65.8
2004	30,183	473,602	64.4

Source: California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, *2004 Annual Report of the State Oil and Gas Supervisor*, 2005

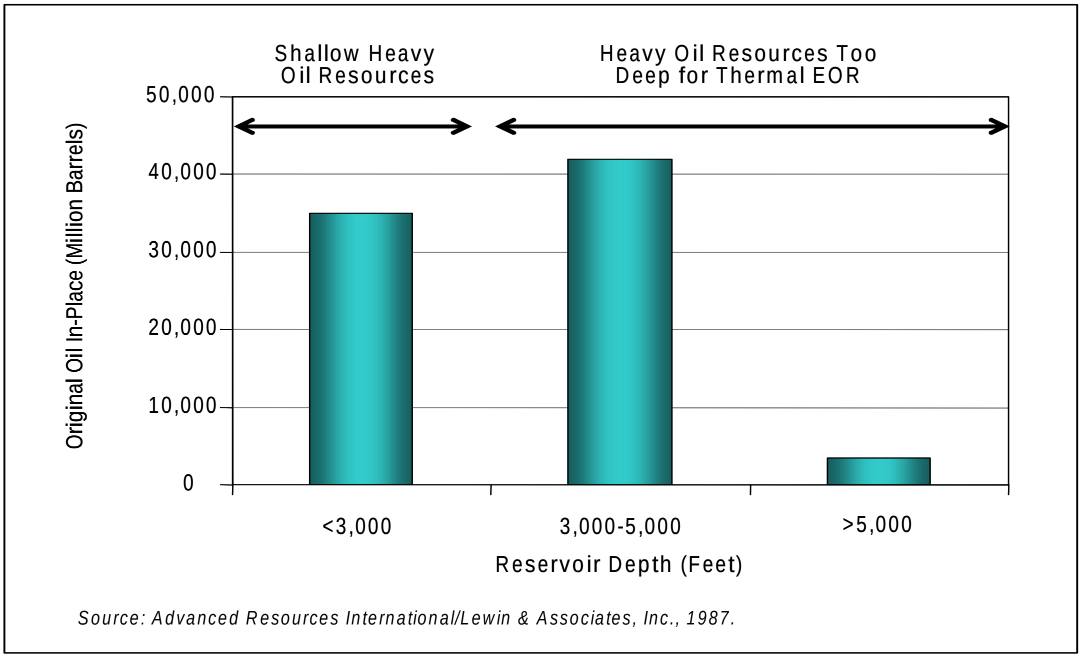
In addition, a number of new thermal EOR projects have started up or are in the planning stages in Canada, many of which are planning to apply the steam-assisted gravity drainage (SAGD) recovery process to oil sands operations, which could be directly transferable to some U.S. heavy oil prospects. These include PetroCanada's Firebag project, Encana's Christina Lake project, Canadian Natural Resources Primrose and Wolf Lake projects, and Japan Canada Oil Sands Hangingstone pilot. Other large projects are planned by OPTI Canada and Nexan (Long Lake), ConocoPhillips (Surmount), and Imperial, who plans further expansion at its Cold Lake operations.[77]

Thermal EOR technologies have also been demonstrated to be profitable in field scale applications for over 30 years in shallow heavy oil reservoirs. Traditional thermal EOR technologies include steam flood, cyclic steam stimulation, and in-situ combustion.

However, a significant portion of the domestic resource is in reservoirs that are too deep for efficient application of traditional thermal EOR technology. For example, of the 80 billion barrels of OOIP in the 248 large domestic heavy oil reservoirs, about 45 billion barrels of OOIP are in reservoirs that are too deep for efficiently using today's steam-based EOR technology. The distribution of the heavy oil resource by depth is shown in Figure III-39. Because of depth limits in applying today's thermal EOR technology, a significant volume of the heavy oil resource remains "stranded".

The application of heavy oil recovery technologies has not been sufficiently demonstrated in deeper and more geologically challenging settings. Further advances in heavy oil recovery technology will be required to efficiently and economically recover this large volume of deep "stranded" heavy oil. This could involve the use of horizontal wells, low cost immiscible CO2, and advanced thermal EOR technology.

Figure III-39. Distribution of Domestic Heavy Oil Resources by Depth



Moreover, new heavy oil recovery technologies are evolving to improve their efficiency and expanded their applicability, including thermal EOR technologies like SAGD, as well as non-thermal methods such as cold flow with sand production, a cyclic solvent process, and the VAPEX process. While these technologies are primarily being demonstrated for application to the Canadian oil sands resources, their applicability to U.S. heavy oil resources should be investigated.

Finally, and perhaps most importantly, particular emphasis needs to be placed on evaluating technologies that could help recover more of the underdeveloped heavy oil resource in Alaska. Further advances in heavy oil recovery technology, adapted to the special geological, reservoir, environmental, and operational situations in Alaska, will be essential for increasing oil recovery from Alaska's large heavy oil endowment. Advanced oil recovery technologies, such as miscibility enhanced CO2-EOR and CO2-philic mobility control agents, will be essential for recovering more from the largely undeveloped 25 billion barrel heavy oil resource in Alaska, in the Schrader Bluff, West Sak and other formations, without disturbing the permafrost.

Initial steps are being taken to produce a portion of the in-place oil resource from two large heavy oil reservoirs on the Alaska North Slope. The Schrader Bluff Formation in the Milne Point Unit has experienced a steady growth in heavy oil production, reaching 19,000 barrels per day in 2003, from a few thousand barrels per day in the 1990s. It is now producing about 15,000 barrels per day. The West Sak Formation in the Kuparuk River Unit, after years of experimentation and delay, produced 16,500 barrels of heavy oil per day in April 2006. The Unit operator has submitted plans to the Department of Natural Resources, Alaska to conduct an aggressive program of horizontal well drilling and water injection to increase West Sak heavy oil production to 45,000 barrels per day by 2007.

Several steps could be taken to overcome the barriers currently facing the development of domestic heavy oil resources. Ideally, these would be in the form of a series of "basin-opening" strategies, consisting of the set of basin-specific, combined state and federal actions necessary for yielding the full potential for the heavy oil development in each U.S. basin. These basin-specific actions would uniquely reflect the reservoir conditions of each basin, the needs of pre-commercial R&D and field activities, and the required advances in technology applicable to each basin.

While unique to each basin, each "basin-opening" initiative would have several common elements, targeting barriers currently inhibiting the full development of the resource, as follows:

- Reduce current geological, technical, and economic risks through an aggressive program of research and field tests. Optimizing the performance of current CO2-EOR and heavy recovery practices and expanding their application will help lower the geological, technical, and economic risks involved with these technologies. This was the pathway used by the DOE and the Gas Research Institute to reduce geologic and technical risks which helped commercialize domestic unconventional gas, which now accounts for over one-third of domestic natural gas production. State-Federal partnerships devoted to technology transfer would help address the barriers that currently inhibit the application of heavy oil and CO2-EOR technologies. Also, engaging in collaborative Canadian/U.S. efforts such as sharing technology and conducting jointly-funded field R&D could help facilitate application of the best technologies appropriate for U.S. heavy oil and oil sands resources.

- Promote significant advances in technology, particularly technology that increases oil recovery efficiency and lower costs. This would involve testing new concepts such as gravity-stable CO_2 flooding and horizontal wells in our many geologically challenging oil reservoirs for CO2-EOR prospects, and SAGD and other technologies in heavy oil reservoirs. Transfer of this technology, primarily targeted to the independent producers who are now the backbone of our fledgling domestic industry, is critical. Moreover, demonstrating an integrated "zero emissions" steam, hydrogen and electricity generation system, which provides "EOR-Ready" CO2 from the residue products from heavy oil (and oil sand) upgrading and refining, would provide an efficient, synergistic approach toward future oil recovery.

- Provide "risk-mitigation" incentives to protect against sharp drops in oil prices for those producers willing to try new technologies. At the Federal level, recent modifications proposed for the Section 43 EOR tax credits could help accomplish this, as could royalty relief for resources underlying Federal lands. At the state level, severance tax relief could also help provide risk mitigation incentives, though many states already provide severance tax relief for new EOR projects.

- Promote policies and incentives to accelerate the availability of "EOR ready CO_2." A portfolio of performance-based incentives could be initiated, including: royalty relief, federal tax credits, reduced state severance taxes, and credits for capturing and productively using industrial emissions of CO_2 to accelerate the recovery and use of CO_2 generated from industrial sources. Previous analyses have shown that an incentive package equal to $5 per barrel for incremental oil produced by would be revenue neutral, from an overall public expenditures view, where each barrel of incremental domestic oil provides this much or more to our various public treasuries.[78]

This "basin-opening" initiative reflects a new model of public-private partnerships and incentives. It would help "kick-start" activity and would attract capital to this promising, but still costly oil recovery alternative. A similar model of public-private partnerships and incentives helped launch the joint CO_2-EOR and CO_2 storage project in the Weyburn oil field in Saskatchewan. EnCana expects to recover an additional 130 million barrels of "stranded" oil while injecting two million tons of CO_2 emissions from the Dakota Gasification Company in Beulah, North Dakota, making this Canada's largest CO_2 sequestration project.

3. DEVELOPMENT ECONOMICS AND INVESTMENT STIMULATION

COST ESTIMATES

The primary cost components of a typical heavy oil development project will depend on the recovery technology employed. For thermal EOR projects, these costs are similar to CO_2-EOR project costs, and include the following:

- Well drilling and completion costs for new production and steam injection wells. Often new wells are drilled to provide a tighter well spacing pattern or to replace older, unusable wells.
- Lease equipment for new producing wells. The newly drilled wells are equipped with water handling and disposal facilities, electricity supply, down hole pumps, and other lease equipment
- Lease equipment for new injection wells. The new injections wells need to include water and steam injections systems, a header, water and steam gathering lines, and electricity.
- Conversion or reworking of existing wells for steam injection. The conversion of existing oil production wells to steam injection wells requires replacing the tubing string and adding distribution lines and headers. The reworking of existing wells requires pulling and replacing the tubing string and pumping equipment.
- Steam generation and injection costs. The costs of steam injection include the costs of the steam generators, surface production and vapor recovery lines, and associated equipment.
- Annual operations and maintenance (O&M) costs. These include the costs for lifting the produced crude, for operating the wells, and for maintaining the lease.
- Fuel costs. The largest single cost component for thermal heavy oil projects is the cost of fuel used to general steam, generally natural gas.
- Heavy oil upgrading costs. Some costs may need to be incurred to upgrade the more viscous, more costly heavy oil produced to allow it to be input into existing crude oil pipelines.
- General and Administrative costs. These are typical general and administrative costs (e.g., insurance, accounting, etc.) entailed in operating a heavy oil project.

The costs also can vary considerably from field to field, but some general algorithms can be developed. For example, though somewhat out of date, representative costs algorithms are provided in the 1987 IOGCC/Lewin and Associates' report. [79]

ECONOMIC RISK FACTORS

Because of the high capital costs associated with commercial development of fossil fuels using heavy oil recovery technologies, fiscal incentives can help reduce the risk and improve the attractiveness of investments in developing these fuels. While the upfront capital costs may not be as high for EOR projects as for most other unconventional fuel resources, a critical issue remains the costs associated with generating the steam required for these operations. High and volatile natural gas prices, combined with high and volatile prices for the produced oil, can make investment in new EOR projects more risky, perhaps, than more traditional recovery processes, or than other investment opportunities overseas. Encouraging producers (primarily independent producers, which are responsible for most oil production in the U.S. today) to apply EOR technologies, particularly in settings where it has not previously been applied, may be critical to its wide-scale application. To partially address this barrier, many states already have fiscal incentives in place to encourage the application of EOR technology.

Further investigation and assessment of potential fiscal and other incentives at the federal level to encourage investment in heavy oil recovery projects is warranted.

4. ENVIRONMENTAL PROTECTION

POTENTIAL IMPACTS

Environmental concerns exist with the development of heavy oil. Since most of the resource potential exists in already producing fields, many of the environmental concerns related to oil and gas development and production have already been addressed within the existing regulatory oversight framework for these fields.

In the development of heavy oil resources, the primary concern is potential air emissions, particularly that associated with generating the steam used in most thermal EOR operations. Nearly all existing thermal EOR operations have converted their steam generation facilities from burning lease crude to burning natural gas, to reduce the emissions associated with this process.

Technologies for heavy oil recovery require significant amounts of water to generate steam.

5. REGULATORY AND PERMITTING ISSUES

Heavy oil development in areas with an established history will be overseen by regulatory bodies with a long history of oversight for domestic operations. However, areas that have not experienced much oil development could face comparable challenges to other unconventional sources of liquid fuels.

6. INFRASTRUCTURE

Thermal EOR technologies to produce heavy oil will generally be applied in traditional producing areas; therefore most of the required crude oil infrastructure already exists in the area, but may be underutilized due to declining production. Thermal development often allows for the more efficient utilization of existing oil production and transportation infrastructure, minimizing impacts.

The large-scale development of heavy oil resources may require some investment in infrastructure enhancements and modifications to handle and process the more viscous, lower quality heavy oil that is produced. This may require the use of diluents added to the heavy oil to improve its ability to flow into the oil pipeline distribution network, and perhaps the need for upgrading facilities to process the heavy oil if it is to be shipped to refineries not equipped to handle the lower quality crude.

7. SOCIO-ECONOMIC PLANNING AND IMPACT MITIGATION

Heavy oil development opportunities exist throughout the U.S., but the largest accumulations of untapped potential are in California, Alaska, and Wyoming. The scope and timing of development for heavy oil will depend on a number of factors, including: (1) future prices for crude oil and other energy sources, particularly natural gas, (2) the pace of new investment and cash flow from ongoing operations that can be "plowed back" into new development, (3) assumptions concerning the pace of field demonstration of "state-of-the-art" technologies and the pace of development and demonstration of "next generation" technologies. The pace of development will also depend on the extent to which any fiscal incentives are provided to stimulate the development of these resources.

Unconventional fuels development can have both significant benefits and significant impacts on affected communities, and significant up-front funding for impacts assessment and infrastructure planning, as well as access to resources to develop services, infrastructure, and facilities will be required to support industry and population growth associated with the development of these resources. In addition, a need exists to establish mechanisms to shield impacted communities from the financial risks associated with potential energy price declines.

In case of the development of heavy oil resources such concerns are quite different. Again, since the resource potential identified to date exists primarily in already producing basins or regions (which is mostly the case for heavy oil development), many of the socioeconomic and community infrastructure concerns relate to sustaining or increasing production in areas otherwise experiencing, or that are likely to experience, a decline in production without these new development. If production declines in these traditional producing areas, it will significantly impact the local economy, and reduce the government revenue basis that helps support community infrastructure and services. In other words, CO2-EOR and/or heavy oil resource development prevents substantial economic impacts that could occur to local populations and economies should production decline, by sustaining or perhaps even increasing oil production in the area.

Given concerns about future energy price volatility, and recognizing the experiences endured by "emerging" energy resources when faced with declining and volatile prices in the past, the establishment of an integrated local and regional infrastructure plan for unconventional fuels development that will support efficient development, realize synergies, and reduce duplicative investments may be required. Again, because CO2-EOR and heavy oil recovery technologies will generally be applied in traditional producing areas, most of the required crude oil infrastructure already exists in the area, but may be underutilized due to declining production. This development often allows for the more efficient utilization of existing oil production and transportation infrastructure, minimizing impacts.

On the other hand, large-scale development of resources amenable to CO2-EOR technologies will require substantial investment in infrastructure to bring CO2 to these fields. In this regard, the issues for CO2-EOR are comparable to those for other unconventional fuels resources, but again, generally not at the same scale. In addition, the large-scale development of heavy oil resources may require some investment in infrastructure enhancements and modifications to handle and process the more viscous, lower quality heavy oil that is produced.

CO_2-EOR Resource and Technology Profile

CO_2-EOR Working Group Analysis Prepared For The Strategic Unconventional Fuels Task Force

February 2007

1. RESOURCE ACCESS

Congressional budget language for Fiscal Years 2004 and 2005 directed that the Department of Energy (DOE) Oil Program conduct "basin-oriented" assessments to "examine new steps to accelerate adoption of CO_2-EOR [carbon dioxide enhanced oil recovery]." In addition, budget language for Fiscal Year 2006 continued this direction and added emphasis on "productively using industrial sources of CO_2." In response, DOE requested that Advanced Resources International undertake an assessment of the status of CO_2-EOR and examine how this technology could augment domestic oil supplies and encourage the productive use of industrial CO_2.

Similarly, the Energy Policy Act of 2005 (Section 369 (p)), or EPAct, directed that the Secretary of Energy update the 1987 technical and economic assessment of domestic heavy oil resources that was prepared by the Interstate Oil and Gas Compact Commission. [80] It further directs that this update "include all of North America and cover all unconventional oil, including heavy oil, tar sands (oil sands), and oil shale. In response to the Congressional budget language three sets of CO_2-EOR assessments were conducted, as follows.

Ten Basin Studies. The first set of studies assessed the CO_2-EOR potential in ten U.S. basins/areas. The primary objective of these assessments was to describe the "size of the prize" for CO_2-EOR technology in specific areas of the country. A secondary objective was to identify and characterize the set of policies and economic conditions that would facilitate productive use of industrial CO_2 to facilitate the production of domestic resources using CO_2-EOR. These studies, published by the DOE/Office of Fossil Energy (FE) in February 2006, conclude that today's oil recovery practices leave behind a large resource of "stranded oil" – amounting to 390 billion barrels in the regions studied (Figure III-40). Such stranded oil represents a substantial target for EOR technology. Of this, the reports show that the ten regions have a technically recoverable potential of almost 89 billion barrels using the "state-of-the-art" CO_2-EOR technologies (Table III-18).[81]

Figure III-40. Large Volumes of Domestic Oil Remain "Stranded" After Primary/Secondary Oil Recovery

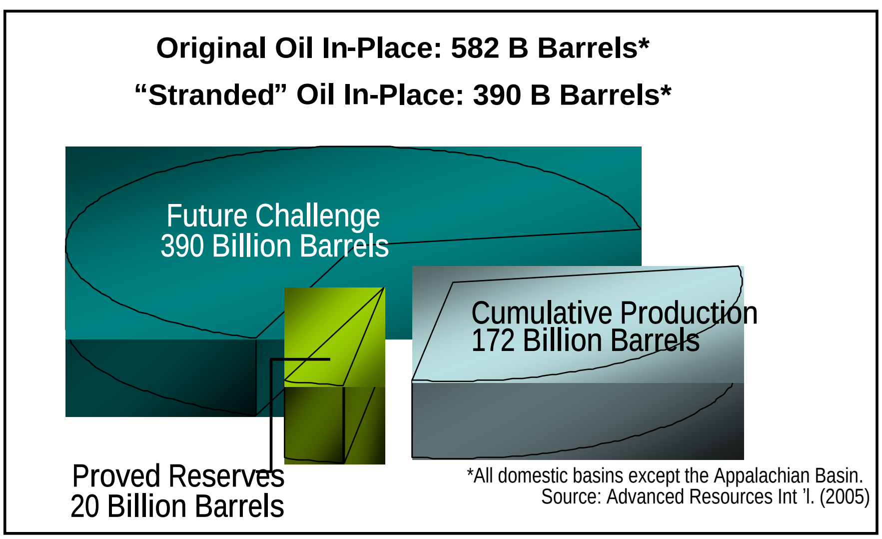


Table III- 18. Technically Recoverable Oil Resources ("State-of-the-Art" CO_2-EOR; Ten Basins/Areas)

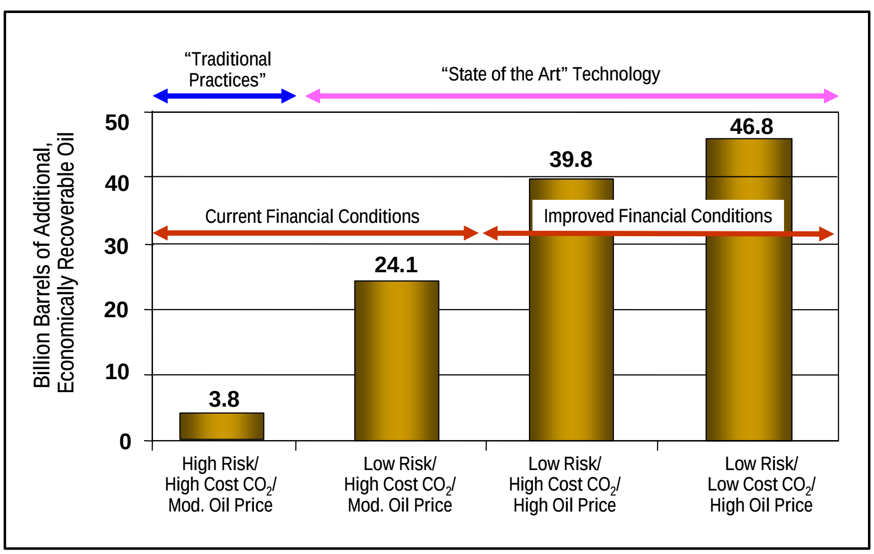
Basin/Area	DATABASE (Large Reservoirs)			ALL RESERVOIRS (Ten Basins/Areas)		
	# of Reservoirs	% of Resource	# Favorable For CO_2-EOR	OOIP* (Billion Barrels	ROIP** (Billion Barrels)	Technically Recoverable (Billion Barrels)
1. Alaska	34	97%	32	67.3	45	12.4
2. California	172	90%	88	83.3	57.3	5.2
3. Gulf Coast	239	60%	158	44.4	27.5	6.9
4. Mid-Continent	222	59%	97	89.6	65.6	11.8
5. North Central	154	61%	72	17.8	11.5	1.5
6. Permian	207	74%	182	95.4	61.7	20.8
7. Rockies	162	68%	92	33.6	22.6	4.2
8. Texas, East/Central	199	65%	161	109	73.6	17.3
9. Williston	93	72%	54	13.2	9.4	2.7
10. Louisiana Offshore	99	80%	99	28.1	15.7	5.9
Total	**1,581**		**1,035**	**581.7**	**390**	**88.7**

*Original Oil in Place, in all reservoirs in basin/area; ** Remaining Oil in Place, in all reservoirs in basin/area.
Source: Advanced Resources Int'l, 2005.

The reports conclude that from 4 to 47 billion Bbls of the 89 billion Bbls of technically recoverable oil could be economically recovered with CO_2-EOR technology. This range depends on factors such as future oil prices, the level of technology applied to the CO_2-EOR projects, the risk profile acceptable for these projects, and the cost of CO_2 supplies to projects in each region. Specifically:

- Under "traditionally practiced" CO_2-EOR technology only a modest portion, almost 4 billion Bbls, is expected to be economic to develop and produce.[82]
- With "state-of-the-art" CO_2-EOR technology (larger volumes of CO_2, modified injection designs) plus lower technical/economic risks, from 24 to 40 billion Bbls could become viable.[83]
- Ensuring the availability of affordable, lower cost ("EOR-Ready") CO_2 supplies would increase the economically viable resource to 47 billion barrels.[84] Figure III-41 summarizes these results.

Figure III-41. Economically Recoverable Resources for Alternative CO_2-EOR Scenarios



Game Changer Technologies. Another DOE/FE study also published in February 2006 examined how potential "next generation" CO_2-EOR technology could increase the "size of the prize," and further support productive use of industrial CO_2. The study reviews the performance and technical limitations of past CO_2-EOR floods, both successful and unsuccessful, sets forth theoretically and scientifically possible advances in technology for CO_2-EOR, and examines, using reservoir simulation, how much these "next generation" CO_2-EOR technologies would improve oil recovery efficiency of existing oil reservoirs (as well as expand their CO_2 storage capacities).

While the scientifically possible "next generation" technologies set forth in the report have yet to be fully developed or demonstrated in field-level applications, the report demonstrates that the wide-scale implementation of such "next generation" CO_2-EOR technology advances have the potential to increase domestic oil recovery efficiency from about one-third to over 60 percent of the original oil in place (OOIP), doubling the technically recoverable resources in the six domestic oil basins/areas studied to date (Table III-19).[85]

Table III- 19. Technically Recoverable Oil Resource from "State-of-the-Art" and "Next Generation" CO_2-EOR Technology (First Six Basins/Areas Assessed, Billions Barrels)

Basins/Areas	ALL RESERVOIRS		"STATE-OF-THE-ART"	"NEXT GENERATION"
	OOIP*	ROIP**	Technically Recoverable	Additional Technically Recoverable
California	83.3	57.3	5.2	8.1
Gulf Coast	60.8	36.4	10.1	8.9
Oklahoma	60.3	45.1	9	11.1
Illinois	9.4	5.8	0.7	0.9
Alaska	67.3	45	12.4	11.4
Louisiana Offshore (Shelf)	28.1	15.7	5.9	-
Total	**309.2**	**205.3**	**43.3**	**40.4**

*Original Oil In-Place, in all reservoirs in basin/area; ** Remaining Oil in Place, in all reservoirs in basin/area.
Source: Advanced Resources International, 2005.

Residual Oil Zone (ROZ). This set of reports, also published in February 2006, addressed the question of is there a larger than traditionally viewed domestic oil resource base that is applicable to CO_2-EOR. Five reports introduce one of the most exciting new, unconventional oil resources that can be added to our domestic oil resource base. This is stranded (or residual) oil in the transition zone (TZ) below the traditional oil-water contact that exists in many domestic oil reservoirs. This resource in the ROZ has not previously been included in any official domestic oil resource estimates or databases. Typically, the "producing oil-water contact" for a reservoir is set at the first occurrence of free water. A significant zone of residual oil can exist below this "producing oil-water contact" due to capillary effects, hydrodynamics, and basin tilt. Reservoir simulation shows that, with proper design, CO_2-EOR can technically (and economically) recover a significant portion of this oil resource.

Work was undertaken in three U.S. oil basins – the Permian, Williston and Big Horn -- to more rigorously define the size and potential of this new resource and to determine how much may be recoverable using CO_2-EOR techniques.[86] A report on the Big Horn Basin report identifies 13 fields and 4.4 billion barrels of oil in-place in the ROZ, with 1.1 billion barrels technically recoverable. A

Williston Basin report identifies 20 fields and 6.8 billion barrels of oil in-place in the ROZ, with 3.3 billion barrels technically recoverable. Finally, the largest ROZ resource potential was identified in the Permian Basin of West Texas and Eastern New Mexico. This basin has 56 oil fields (in 5 oil plays) and 30.7 billion barrels of oil in–place in the ROZ, with 11.9 billion barrels technically recoverable (Table III-20).

Table III- 20. Recoverable Oil Resource form the Residual Oil Zone in Selected Basins

Basins	No. of Fields	TZ/ROZ OIP (Billion Barrels)	Technically Recoverable TZ/ROZ (Billion Barrels)
Big Horn	13	4.4	1.1
Permian	56	30.7	11.9
Williston	20	6.8	3.3
Others	-	-	-
Total	**89**	**41.9**	**16.3**

In summary, this set of assessments concludes that a large volume of oil - - nearly 400 billion barrels - - remains unrecoverable ("stranded") in already discovered domestic oil fields. This is because traditional oil recovery technology recovers only about one-third of the OOIP. The application of both thermal and CO_2-EOR technologies can recover a substantial portion of this "stranded oil". Moreover, EOR technology - - advances that are scientifically possible but not yet fully developed - - could further improve efficiencies and add oil supply. The studies also concluded that additional domestic oil resources - - resources not currently included in any national totals - - exist in residual oil zones that could also be recoverable with EOR technology.

Converting this technically recoverable resource into increased annual domestic oil production would substantially contribute to national energy goals to reduce dependence on imported oil. Moreover, using industrial CO_2 as the injection fluid for CO_2-EOR would result in significant geologic sequestration of CO_2, reducing atmospheric greenhouse gas (GHG) concentrations, and contributing to national goals for reducing the carbon intensity of the U.S. economy.

As described elsewhere in this report, CO_2-EOR recovery technologies will generally be applied in traditional producing areas, where most of the required crude oil infrastructure and production facilities already exists in the area, but may be underutilized due to declining production. This development will often allow for the more efficient utilization of existing oil production and transportation infrastructure, minimizing impacts. New facilities will often be sized to utilize existing or refurbished infrastructure, to the extent possible.

Given the large and diverse distribution of this resource potential, there appear to be no major technical constraints to providing the necessary facility enhancements, which can be tailored to the size, location, and development status of the particular resource setting.

2. TECHNOLOGY ADVANCEMENT AND DEMONSTRATION

As traditionally practiced, CO_2-EOR technology will raise overall domestic oil recovery efficiency by only a few percent. This is because: (1) CO_2-EOR is applied in only a few of U.S. domestic oil basins, primarily the Permian Basin; (2) the traditional form of this technology is economic in a relatively small group of geologically favorable oil reservoirs; and, (3) traditionally practiced CO_2-EOR designs provide only a modest (on the order of 10%) incremental recovery of the OOIP in a reservoir.

However, the widespread application of 'state-of-the-art" CO_2-EOR technologies could greatly improve these recovery efficiencies, especially to basins where it has not been traditionally applied. In fact, fully two-thirds of the oil in-place could be feasible to produce from an expanded group of domestic oil reservoirs. Moreover, the integrated application of a suite of "next generation" technologies could result in even higher oil recovery efficiencies. A series of "next generation" CO_2-EOR technologies could double the oil recovery efficiency from geologically favorable oil reservoirs and raise overall domestic oil recovery efficiency to over 60%. In addition, "next generation" technology could extend the miscible CO_2-EOR technology to a broader range of domestic oil reservoirs. For example, integrated application of three "next generation" CO_2-EOR technologies (i.e., high volume injection of CO_2, innovative process and well designs, and effective mobility control) could enable up to 80% of the OOIP to become recoverable (including 34%, on average, from primary and secondary recovery).

The incremental surface footprint for nearly all future CO_2-EOR applications and most heavy oil development applications is relatively small, since new CO_2-EOR and heavy oil development projects will overwhelmingly take place in traditional producing fields and basins.

The environmental considerations and issues associated with CO_2-EOR and heavy oil projects are discussed elsewhere in this report.

Initial work by Federal government in EOR was a part of field demonstration projects started by the U.S. Bureau of Mines in 1974, which was taken over by DOE in 1978. Twelve of these initial demonstration projects involved chemical floods, five involved CO_2 injection, and six were thermal/heavy oil projects. With the exception of steam flooding, the early demonstration of EOR techniques was largely uneconomic, with some incremental oil recovery.

The basic lesson learned from these programs was that oil and gas reservoirs, with few exceptions, were much more complicated that previously believed. Effective deployment of EOR recovery technology was determined to depend on a thorough geologic characterization of the reservoir. The best recovery technology deployed into a poorly understood reservoir was determined to be ineffective, or if by chance it was effective, the success would be difficult to repeat.

In the mid-1980s, DOE initiated the Reservoir Life Extension Field Demonstration program, which evolved into the Reservoir Class Program in the early 1990s. This program built upon these lessons, with a strategy predicated on reservoir characterization and play definition, and is generally regarded as one of DOE's most successful programs.

According to an assessment of the National Research Council,[87] the EOR/Field Demonstration programs successfully demonstrated thermal, gas, chemical, and microbial techniques and developed screening models and databases that stimulated production of nearly 1.5 billion barrels of oil equivalent over the period from 1996 to 2005, and provided $625 million in cost savings to oil producers and nearly $$2.2 billion in incremental Federal and state revenues.

The goal of the current EOR program is to "develop technologies to more efficiently recover petroleum from known reservoirs not producible by current technology, reduce the rate of well abandonments, and improve reservoir modeling and process prediction techniques."[88] DOE-funded R&D is currently being pursued in the areas of horizontal wells for improved reservoir contact, 4-dimensional seismic to monitor the behavior of CO_2 fluids, automated field monitoring systems for detecting problems, and injecting larger volumes of CO_2.[89]

In February 2006, DOE launched a new effort through a solicitation to fund research of up to $3 million per project for field-testing and validating integrated enhanced recovery/sequestration technologies.[90] Projects may last 2–5 years and require a 50 percent cost share by the recipient. The projects will be managed through FE's National Energy Technology Laboratory (NETL).

CO_2-EOR technologies have been demonstrated to be profitable in commercial scale applications for nearly 30 years. Currently, 82 CO_2-EOR projects (Figure III-42) provide 237,000 barrels per day of production in the United States (Figure III-43). Ten years ago, production from CO_2-EOR was only about 170,000 barrels per day, growing nearly 40% in the decade. In just the last five years, a number of new players have entered the CO_2-EOR business:

- OxyPermian purchased Altura, while adding new CO_2-EOR projects in West Texas.
- KinderMorgan, the primary supplier of CO_2 to the Permian Basin in West Texas, has purchased several oil fields in the basin amenable to CO_2-EOR.
- Denbury is developing a number of fields -- primarily utilizing CO_2 from its Jackson Dome natural CO_2 source field, supplemented with some CO_2 obtained from industrial sources, for new EOR projects in Mississippi and Louisiana.
- Anadarko is expanding its use of CO_2 from the LaBarge gas processing plant in Wyoming for several CO_2-EOR projects in the Rockies.

Figure III-42. Distribution of CO_2-EOR Projects and Sources of Anthropogenic CO_2 in the United States

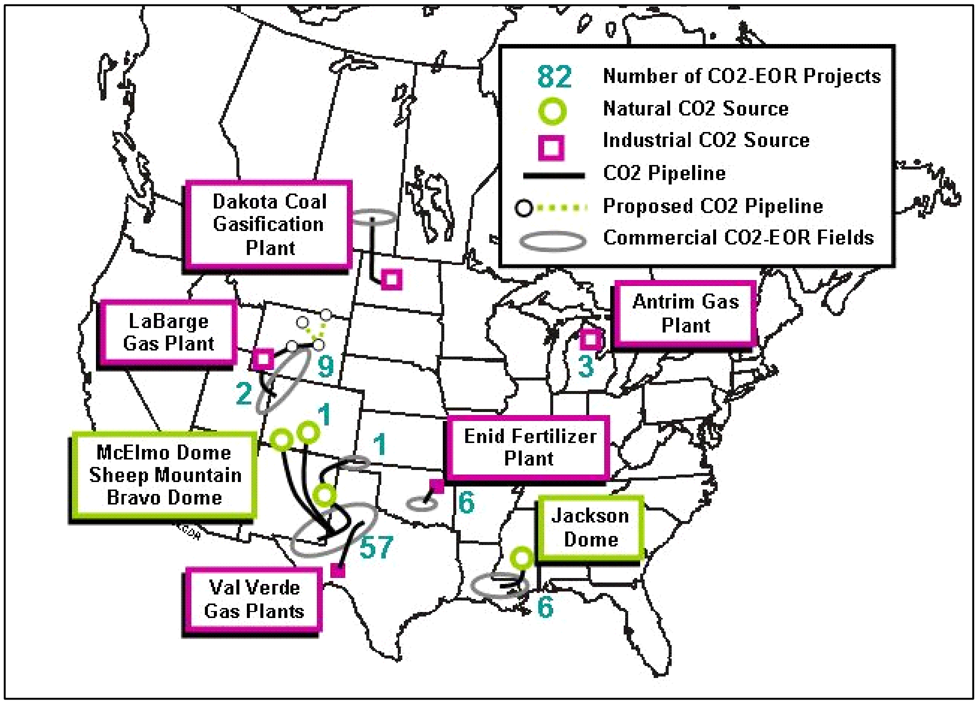
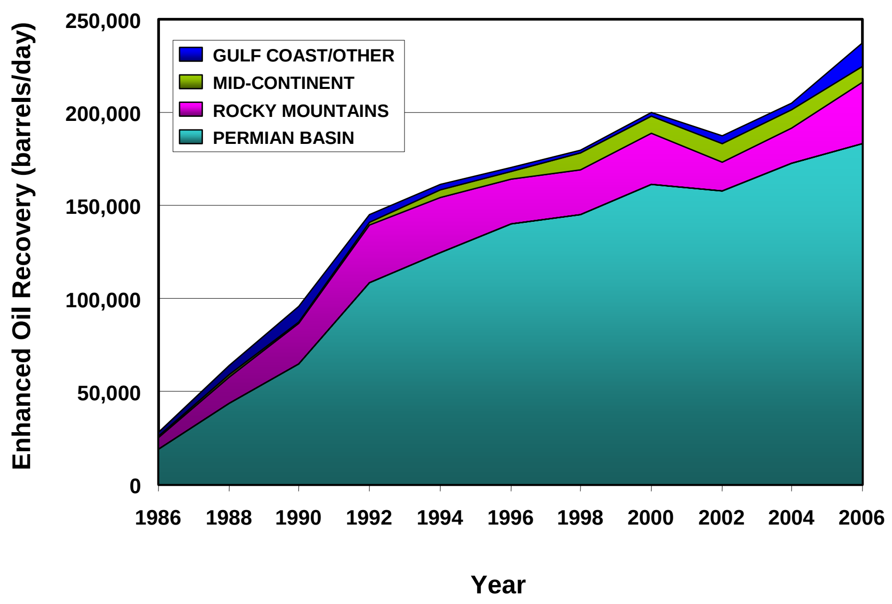


Figure III-43. Historical Production from CO_2-EOR Processes in the United States



Moritis, Guntis, "CO2 injection gains momentum" Oil and Gas Journal, April 17, 2006

In addition, production continues to increase in Encana's Weyburn CO_2 flood in Canada, producing 6,500 barrels per day of incremental oil. This project buys its CO_2 from the Dakota Gasification Synfuels plant in Beulah, North Dakota. Apache Canada has also stated CO_2 injection in the Midale field, also using CO_2 from this synfuels facility.

Despite the growing level of domestic CO_2-EOR activity, significant barriers nonetheless exist that currently inhibit expanded and accelerated application of CO_2-EOR technology These barriers include: (1) market risks and uncertainties in technology performance that deter private investments, especially in areas where CO_2-EOR technology has not yet been commercially proven, as CO_2-EOR represents a costly and front-end loaded investment opportunity; (2) low oil recovery due to inherent limitations in traditional technology, particularly in geologically challenging oil fields, where the higher oil recovery efficiencies obtainable with "state-of-the-art" technologies are yet to be demonstrated; and (3) lack of available, affordable ("EOR-ready") CO_2 supplies, even though large volumes of industrial CO_2 emissions exist.

As such, understanding the mutually beneficial link between CO_2 -EOR and new industrial sources of CO_2, particularly CO_2 from production of synthetic and other unconventional fuels, is critical to the successful development of all unconventional fuel resources.

Significant improvements to the effectiveness of thermal EOR technologies can also be achieved by improving the knowledge base on reservoir displacement mechanisms, and by developing new techniques for in situ characterization of fluid and reservoir characteristics. Work is also required in the development of improved reservoir simulators that incorporate techniques for coupling geomechanics and fluid flow with the accurate representation of phase equilibria and thermal and mass transfer effects. In addition, recent advances in drilling and production from unconsolidated sands can facilitate the application of heavy oil recovery strategies not possible a decade ago.

Moreover, new heavy oil recovery technologies are evolving to improve their efficiency and expanded their applicability, including thermal EOR technologies like SAGD, as well as non-thermal methods such as cold flow with sand production, a cyclic solvent process, and the VAPEX process. While these technologies are primarily being demonstrated for application to the Canadian oil sands resources, their applicability to U.S. heavy oil resources should be investigated.

Finally, and perhaps most importantly, particular emphasis needs to be placed on evaluating technologies that could help recover more of the underdeveloped heavy oil resource in Alaska. Further advances in heavy oil recovery technology, adapted to the special geological, reservoir, environmental, and operational situations in Alaska, will be essential for increasing oil recovery from Alaska's large heavy oil endowment. Advanced oil recovery technologies, such as miscibility enhanced CO_2-EOR and CO_2-philic mobility control agents, will be essential for recovering more from the largely undeveloped 25 billion barrel heavy oil resource in Alaska, in the Schrader Bluff, West Sak and other formations, without disturbing the permafrost.

Initial steps are being taken to produce a portion of the in-place oil resource from two large heavy oil reservoirs on the Alaska North Slope. The Schrader Bluff Formation in the Milne Point Unit has experienced a steady growth in heavy oil production, reaching 19,000 barrels per day in 2003, from a few thousand barrels per day in the 1990s. It is now producing about 15,000 barrels per day. The West Sak Formation in the Kuparuk River Unit, after years of experimentation and delay, produced 16,500 barrels of heavy oil per day in April 2006. The Unit operator has submitted plans to the Department of Natural Resources, Alaska to conduct an aggressive program of horizontal well drilling and water injection to increase West Sak heavy oil production to 45,000 barrels per day by 2007.

Several steps could be taken to overcome the barriers currently facing the development of domestic heavy oil resources and resources amendable to CO_2-EOR. Ideally, these would be in the form of a series of "basin-opening" strategies, consisting of the set of basin-specific, combined state and Federal actions necessary for yielding the full potential for the application of CO_2-EOR and/or heavy oil development in each U.S. basin. These basin-specific actions would uniquely reflect the reservoir conditions of each basin, the opportunities for accessing CO_2 supplies (for CO_2-EOR projects), the needs of pre-commercial R&D and field activities, and the required advances in technology applicable to each basin.

While unique to each basin, each "basin-opening" initiative would have several common elements, targeting barriers currently inhibiting the full development of the resource, as follows:

- **Reduce current geological, technical, and economic risks through an aggressive program of research and field tests**. Optimizing the performance of current CO_2-EOR and heavy recovery practices and expanding their application will help lower the geological, technical, and economic risks involved with these technologies. This was the pathway used by the DOE and the Gas Research Institute to reduce geologic and technical risks which helped commercialize domestic unconventional gas, which now accounts for over one-third of domestic natural gas production. State-Federal partnerships devoted to technology transfer would help address the barriers that currently inhibit the application of heavy oil and CO_2-EOR technologies. Also, engaging in collaborative Canadian/U.S. efforts such as sharing technology and conducting jointly-funded field R&D could help facilitate application of the best technologies appropriate for U.S. heavy oil and oil sands resources.

- **Promote significant advances in technology, particularly technology that increases oil recovery efficiency and lower costs**. This would involve testing new concepts such as gravity-stable CO_2 flooding and horizontal wells in our many geologically challenging oil reservoirs for CO_2-EOR prospects, and SAGD and other technologies in heavy oil reservoirs. Transfer of this technology, primarily targeted to the independent producers who are now the backbone of our fledgling domestic industry, is critical. Moreover, demonstrating an integrated "zero emissions" steam, hydrogen and electricity generation system, which provides "EOR-Ready" CO_2 from the residue products from heavy oil (and oil sand) upgrading and refining, would provide an efficient, synergistic approach toward future oil recovery.

- **Provide "risk-mitigation" incentives to protect against sharp drops in oil prices for those producers willing to try new technologies**. At the Federal level, recent modifications proposed for the Section 43 EOR tax credits could help accomplish this, as could royalty relief for resources underlying Federal lands. At the state level, severance tax relief could also help provide risk mitigation incentives, though many states already provide severance tax relief for new EOR projects.

- **Promote policies and incentives to accelerate the availability of "EOR ready CO_2."** A portfolio of performance-based incentives could be initiated, including: royalty relief, Federal tax credits, reduced state severance taxes, and credits for capturing and productively using industrial emissions of CO_2 to accelerate the recovery and use of CO_2 generated from industrial sources. Previous analyses have shown that an incentive package equal to $5 per barrel for incremental oil produced by would be revenue neutral, from an overall public expenditures view, where each barrel of incremental domestic oil provides this much or more to our various public treasuries.[91]

This "basin-opening" initiative reflects a new model of public-private partnerships and incentives. It would help "kick-start" activity and would attract capital to this promising, but still costly oil recovery alternative. A similar model of public-private partnerships and incentives helped launch the joint CO_2-EOR and CO_2 storage project in the Weyburn oil field in Saskatchewan. EnCana expects to recover an additional 130 million barrels of "stranded" oil while injecting two million tons of CO_2 emissions from the Dakota Gasification Company in Beulah, North Dakota, making this Canada's largest CO_2 sequestration project.

3. DEVELOPMENT ECONOMICS AND INVESTMENT STIMULATION

COST ESTIMATES

The primary cost components of a typical CO_2-EOR project include the following:

- Well drilling and completion costs for new production and injection wells. Often new wells are drilled to provide a tighter well spacing pattern or to replace older, unusable wells.
- Lease equipment for new producing wells. The newly drilled wells are equipped with water handling and disposal facilities, electricity supply, down hole pumps, and other lease equipment
- Lease equipment for new injection wells. The new injections wells need to include water and CO_2 injections systems, a header, water and CO_2 gathering lines, and electricity.
- Conversion or reworking of existing wells for CO_2-EOR. The conversion of existing oil production wells to CO_2 injection wells requires replacing the tubing string and adding distribution lines and headers. The reworking of existing wells requires pulling and replacing the tubing string and pumping equipment.
- CO_2 purchase and injection costs. The CO_2 purchase costs are related to the oil price. For established areas with existing CO_2 pipelines, the CO_2 costs typically average 3% of the long-term oil price (e.g., 3% * $25/B equals $0.75/Mcf). For new areas, the CO_2 costs typically average 4% to 5% of the long-term oil price.
- CO_2 recycle plant and distribution pipeline costs. A CO_2 recycle plant plus a CO_2 pipeline distribution system (from the CO_2 trunkline to the oil field) are required and installed at the start of the project.
- Annual operations and maintenance (O&M) costs. These include the costs for lifting the produced crude, for operating the wells, and for maintaining the lease.
- CO_2 recycle costs. These include the costs of separating the produced oil from the produced water and CO_2 and the costs of power for reinjecting the produced CO_2.
- General and Administrative costs. These are typical general and administrative costs (e.g., insurance, accounting, etc.) entailed in operating a CO_2-EOR project.

While these costs can vary widely from field to field, some general algorithms can be developed. These costs are described in detail in the Appendices to the basin studies described above.[92]

ECONOMIC RISK FACTORS

Because of the high capital costs associated with commercial development of fossil fuels using CO_2-EOR and heavy oil recovery technologies, fiscal incentives can help reduce the risk and improve the attractiveness of investments in developing these fuels. While the upfront capital costs may not be as high for EOR projects as for most other unconventional fuel resources, a critical issue remains the costs associated with supplying the CO_2 or generating the steam required for these operations. High and volatile natural gas prices and high potential costs for CO_2, combined with high and volatile prices for the produced oil, can make investment in new EOR projects more risky, perhaps, than more traditional recovery processes, or than other investment opportunities overseas. Encouraging producers (primarily independent producers, which are responsible for most oil production in the U.S. today) to apply EOR technologies, particularly in settings where it has not previously been applied, may be critical to its wide-scale application. To partially address this barrier, many states already have fiscal incentives in place to encourage the application of EOR technology.

Further investigation and assessment of potential fiscal and other incentives at the Federal level to encourage investment in heavy oil recovery and CO_2-EOR projects and the development and delivery of "EOR-ready" CO_2 supplies to CO_2-EOR projects is warranted.

ECONOMIC INCENTIVES

Many states already have fiscal incentives in place to encourage CO_2-EOR technology application. In addition, EPAct contained provisions that authorized Federal royalty relief to encourage application of CO_2-EOR on Federal lands (Section 354), Federal loan guarantees for projects that "avoid, reduce, or sequester … anthropogenic emissions of greenhouse gases (Title XVII), and directed DOE to establish a grant program for CO_2-EOR demonstrations in the Williston Basin and Cook Inlet (Section 354(c)).

Moreover, one of the major constraints to expanded use of CO_2-EOR is lack of CO_2 supplies[93]. A recent report published by the National Coal Council[94] contains a comprehensive characterization of the potential for coal-to-liquids (CTL) technologies (among other approaches to increase use of domestic coal resources) to help increase domestic production of liquid fuels. The report describes a series of potential actions that could be pursued to help facilitate the application of this technology. Importantly, the report recognizes that CTL plants will emit significant volumes of CO_2, on the order of 0.6 to 0.8 metric tons of CO_2 per barrel of coal liquids produced, and recommends a series of incentives to encourage the development of CO_2-EOR projects to provide a value-added market for this CO_2. (Similarly, large emissions of CO_2 will also be a characteristic of oil shale and tar sands technologies.)

For example, based on the information from industry experts and data provided in the DOE/FE "basin studies", a 25,000 barrel per day CTL plant could provide enough CO_2 supply to support 75,000 to 100,000 barrels per day of domestic oil production using CO_2-EOR – a ratio of 3 barrels of CO_2-EOR production for every barrel of liquids production from CTL technology. As such, a valuable, synergistic linkage exists between CTL and CO_2-EOR, with each benefiting from and each contributing to the success of the other, working jointly to increase domestic oil supplies. Several experts (D. Hawkins; C.L. Miller) recently (April 24th, 2006) told the Senate Energy and Natural Resources Committee that this CO_2 could be sold for use in CO_2-EOR operations, providing both a valuable revenue stream as well as a carbon management option for CTL plant operators.[95]

EXPECTED MARKETS

A close and mutually beneficial relationship could and should exist between CO_2-EOR and other potential alternative sources of liquid fuels, including coal liquids, heavy oil, oil shale, and oils sands. The development of all of these resources has a large "CO_2 footprint," but the CO_2 from these developments could be used to help further CO_2-EOR.

4. ENVIRONMENTAL PROTECTION

POTENTIAL IMPACTS

Resource Access

Significant portions of the nation's unconventional fuels resources are located on public lands that are currently restricted from leasing and development, and that reasonable and reliable access to these resources will be required to enable and stimulate investment. While some potential resources amenable to CO_2-EOR technologies underlie public lands, the vast majority does not, and all of the potential identified in the DOE reports referenced above exist in already producing fields, implying that leases for these fields have already been granted. Consequently, constraints associated with access to Federal lands are not a significant issue with regards to exploiting the potential for CO_2-EOR in the United States.

Environmental Impacts

Concerns about potential environmental impacts could hinder the development of most domestic unconventional fuel resources, and could cause major delays in permitting and development.

Environmental concerns also exist with the development of resources amenable to CO_2-EOR and heavy oil development, but these concerns are quite different. Again, since the most of the resource potential exists in already producing fields, many of the environmental concerns related to oil and gas development and production have already been addressed within the existing regulatory oversight framework for these fields.

Many unconventional resources require water in significant quantities for growing local communities supporting resource development, for resource recovery processes, and for disposal and reclamation purposes. Technologies for heavy oil recovery also require significant amounts of water to generate steam, and CO_2-EOR projects require significant amounts of water in order to pursue a 'water-alternating-gas," or WAG, injection processes. However, much this water will come from the oil formation itself, as it is produced with the oil.

CARBON MANAGEMENT STRATEGY

Environmental Benefits from CO_2 Injection and Subsequent Storage. A critically important aspect of developing potential resources amenable to CO_2-EOR technology is that this can provide a significant market for "EOR-Ready" CO_2, particularly from new industrial sources, which could include sources associated with unconventional fuels projects such as shale oil, oil sands, and coal-to-liquids projects. In addition, the refining and gas processing sectors of the oil and gas industry produce large volumes of CO_2 emissions, contributing to the carbon intensity of the domestic economy. These sources can provide a significant, cost-effective method for reducing large volumes of CO_2 that would otherwise be emitted to the atmosphere, and minimize the impact of these emission on potential global warming. The size of the potential market is about 380 Tcf, equal to 20 billion metric tons of CO_2, Table III-21.

Table III- 21. CO_2-EOR Projects Sequestering U.S. Anthropogenic CO_2

Basin/Area	Technically Recoverable (Billion Barrels)	Purchased CO_2 (Tcf)
1. Alaska	12.4	51.4
2. California	5.2	23.9
3. Gulf Coast	6.9	33.3
4. Mid-Continent	11.8	36.3
5. Illinois/Michigan	1.5	5.7
6. Permian	20.8	95.1
7. Rockies	4.2	27.5
8. Texas, East/Central	17.3	62
9. Williston	2.7	10.8
10. Louisiana Offshore (Shelf)	5.9	31
Total	**88.7**	**377.1***

*Equal to 20 billion metric tons.
Source: Advanced Resources Int'l, 2006.

Future oil prices and the cost of "EOR-ready" CO_2 will determine how much of this large market may be economically captured. Natural sources of CO_2 currently provide about 2 Bcf per day to CO_2-EOR operations, which will only meet a portion -- 40 to 50 Tcf -- of this market demand for CO_2. Therefore, industrial sources of CO_2, which currently only provide about 0.5 Bcf per day (Table III-22), will need to be expanded dramatically to meet the remainder of the market requirements that will be necessary to satisfy the potential demand for CO_2 in CO_2-EOR projects. For example, as much as 2.2 Bcf per day could be provided just from refineries located in the states containing the 10 basins/areas that were the subject of the DOE studies referenced above. This includes CO_2 emissions from hydrogen plants, FCC units, and refinery process heaters.[96]

Table III- 22. CO_2-EOR Projects Sequestering U.S. Anthropogenic CO_2

State/ Province	Plant Type	CO_2 Supply		EOR Fields	Operator
		MMcfd	MMT/Yr		
Texas	Gas Processing	110	2.3	Sharon Ridge, Sacroc, Others	ExxonMobil, KinderMorgan
Colorado	Gas Processing	60	1.3	Rangely	Chevron
Wyoming	Gas Processing	180	3.8	Patrick Draw, Lost Solider, Wertz, Others	Anadarko
Michigan	Gas Processing	2	0.1	Dover	Core Energy
Oklahoma	Fertilizer	35	0.7	Purdy, Sho-Vel-Tum	Anadarko, Chaparral
North Dakota	Coal Gasification	145	3.1	Weyburn (Canada)	EnCana, Apache
TOTAL		**532**	**11.3**		

Source: Advanced Resources International, 2004

Looked at from another perspective, if incremental domestic oil production could increase 2 to 3 million barrels per day (730 to 1,095 million barrels per year) from using CO_2-EOR, this would require on the order of 0.5 to 0.75 million metric tons (MMT) of CO_2 per day, or 180 to 270 MMT of CO_2 per year, the equivalent to removing 30 to 50 million cars from U.S. highways.[97]

The potential ultimate theoretical capacity offered by domestic oil reservoirs for "storing" CO_2 associated with CO_2-EOR prospects is estimated at 870 Tcf (51 billion tons) of CO_2, while facilitating the recovery of roughly 200 billion barrels of domestic oil.[98] Advanced CO_2-EOR technologies and market-based inducements to sequester CO_2 could appreciably increase the storage potential of CO_2-EOR to 100 to 200 billion tons of CO_2, while further increasing domestic oil supply. Theoretically, this CO_2 storage potential could accommodate **all** of the industrial CO_2 emissions for the years 2012-2050, if captured and stored, to reach "CO_2 emissions stabilization" at year 2001 levels.

5. REGULATORY AND PERMITTING ISSUES

Some environmental concerns are associated with the potential large scale injection, and subsequent storage, of CO_2. As described above, regulation of CO_2 injection well is established in U.S., and existing oil and gas and/or environmental agencies are already in place in oil and gas producing states that should be able to efficiently oversee and approve industry activities. In Texas, for example, there are over 52,000 permitted injection wells, with over 10,000 permitted to inject CO_2, and 8,000 injecting CO_2 exclusively. These oil fields into which the CO_2 is injected are known natural geologic traps, and more is known geologically about such producing oil and gas fields than any other geologic CO_2 storage option under consideration.

However, regulatory considerations will differ depending on whether CO_2 is being injected into a geologic formation for purposes of CO_2-EOR, or whether it is being injected for purposes of permanent sequestration after CO_2-EOR operations are completed. There are several fundamental considerations that must be addressed when addressing CO_2 sequestration risks that are unique to this process and are not necessarily transferable from the traditional regulatory analogues. In particular, the key issue related to long term storage will be the extent to which it can be guaranteed that the CO_2 will remain "permanently" sequestered, and how this "permanence" will be defined. Target storage reservoirs must be configured for anticipated storage for thousands of years.

Several other critical issues related to government organizational structure that oversees storage activities will need to be addressed. These issues include: (1) who will be responsible for the ultimate recording keeping and oversight of these activities, what information should be recorded and maintained, and how this responsibility will be established to ensure longevity; (2) how will issues of potential liability be addressed, given the unprecedented time frame characteristic of CO_2 sequestration; (3) how should property rights and ownership issues be addressed in this context; and (4) how will oversight and enforcement responsibilities be established.

Another consideration relates to the large scale of operations that would be associated with a large-scale CO_2-EOR industry. This consideration will be the ability of various regulatory agencies to deal with the scale anticipated if CO_2-EOR becomes a wide-spread process. Hundreds of projects would need to be permitted and regulated, corresponding to thousands of wells injecting CO_2. This would require numbers of regulatory personnel way in excess of that currently in place, even in states already responsible for permitting and regulating large numbers of oil and gas operations.

Efforts are currently well underway to address regulatory concerns about permanent CO_2 storage, including efforts by the International Energy Agency (IEA), the European Union, the U.S. Environmental Protection Agency (EPA), and the Interstate Oil and Gas Compact Commission (IOGCC) (an organization of state governors from oil and gas producing states in the U.S.) to develop regulatory guidelines for CO_2 storage. Also, a number of additional efforts at "real-world" applications can provide information and help guide processes to address this issue, including:

- Regulatory experiences and requirements associated with CO_2-EOR projects in Canada (in the province of Saskatchewan) such the Weyburn project

- Experiences and issues raised associated with processes for obtaining experimental CO_2 injection well permits being sought as part of the DOE's Regional Sequestration Partnerships[99] Phase II demonstration projects
- Ongoing activities by industry to develop industry best practices for CO_2 injection and storage/sequestration, such as activities underway by the American Petroleum Institute (API), the International Petroleum Industry Environmental Conservation Association (IPIECA), the Ground Water Protection Council (GWPC), and the CO_2 Capture Project (CCP).

6. INFRASTRUCTURE

As described elsewhere, because CO_2-EOR and thermal EOR technologies will generally be applied in traditional producing areas, most of the required crude oil infrastructure already exists in the area, but may be underutilized due to declining production. Thermal and CO_2-EOR development often allows for the more efficient utilization of existing oil production and transportation infrastructure, minimizing impacts.

On the other hand, large-scale development of resources amenable to CO_2-EOR technologies will require substantial investment in infrastructure to bring CO_2 to these fields. In this regard, the issues for CO_2-EOR are comparable to those for other unconventional fuels resources, but again, generally not at the same scale.

In addition, the large-scale development of heavy oil resources may require some investment in infrastructure enhancements and modifications to handle and process the more viscous, lower quality heavy oil that is produced. This may require the use of diluents added to the heavy oil to improve its ability to flow into the oil pipeline distribution network, and perhaps the need for upgrading facilities to process the heavy oil if it is to be shipped to refineries not equipped to handle the lower quality crude.

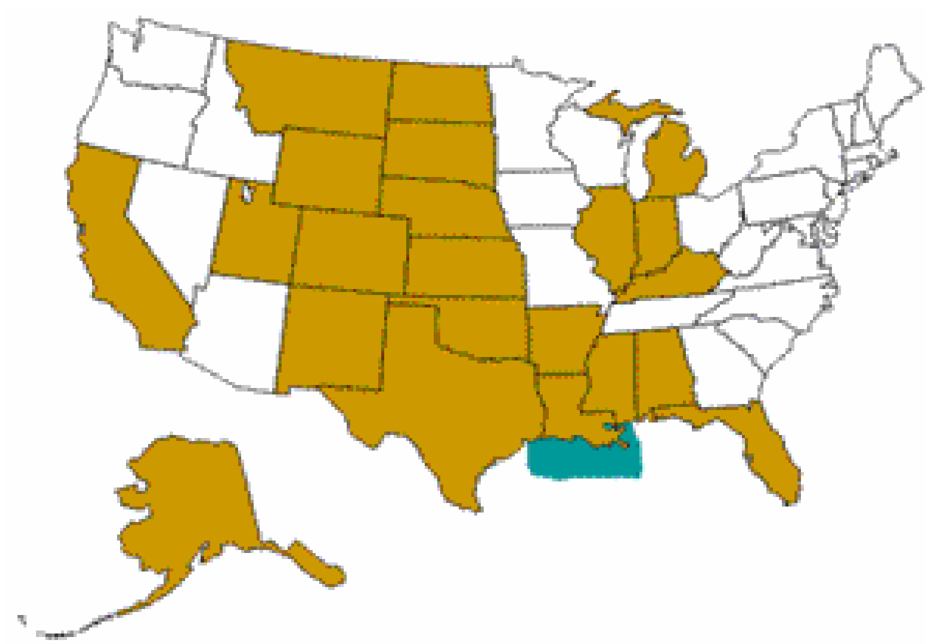
As described above, technologies for heavy oil recovery require significant amounts of water to generate steam, and CO_2-EOR projects also require significant amounts of water in order to pursue a 'water-alternating-gas," or WAG, injection process, though much of this water can comes from the oil formation itself, as it is produced with the oil. For such projects, water management plans comparable to traditional oil development and production operations will be required.

The requirements for and availability of key resources will depend on the scope and pace of development for CO_2-EOR and heavy oil resources, as described in item 22 below. The development of these resources will require the same level and expertise, in general, as that associated with any oil and gas development and production operations.

7. SOCIO-ECONOMIC PLANNING AND IMPACT MITIGATION

CO_2-EOR development opportunities exist throughout the U.S., with basins in all of the states shaded in Figure III-44 showing some CO_2-EOR potential. In addition to the Permian Basin of West Texas and Eastern New Mexico, substantial ongoing activity is taking place in Mississippi and Louisiana and in Wyoming, along with Saskatchewan in Canada. Several projects are also in the planning stages in California.

Figure III-44. U.S Basins/Regions Assessed to have Future Potential for CO_2-EOR



The scope and timing of development for CO_2-EOR and heavy oil will depend on a number of factors, including: (1) future prices for crude oil and other energy sources, particularly natural gas, (2) the pace of new investment and cash flow from ongoing CO_2-EOR and other production operations that can be "plowed back" into new development, (3) assumptions concerning the pace of field demonstration of "state-of-the-art" technologies and the pace of development and demonstration of "next generation" technologies, (4) assumptions about the cost and availability of "EOR Ready" CO_2. The pace of development will also depend on the extent to which any fiscal incentives are provided to stimulate the development of these resources.

Unconventional fuels development can have both significant benefits and significant impacts on affected communities, and significant up-front funding for impacts assessment and infrastructure planning, as well as access to resources to develop services, infrastructure, and facilities will be required to support industry and population growth associated with the development of these resources. In addition, a need exists to establish mechanisms to shield impacted communities from the financial risks associated with potential energy price declines.

In case of the development of resources amenable to CO_2-EOR, such concerns are quite different. Again, since the resource potential identified to date exists in primarily in already producing fields (in the case of CO_2-EOR) and/or already producing basins or regions (which is mostly the case for heavy oil development), many of the socioeconomic and community infrastructure concerns relate to sustaining or increasing production in areas otherwise experiencing, or that are likely to experience, a decline in production without these new development. If production declines in these traditional producing areas, it will significantly impact the local economy, and reduce the government revenue basis that helps support community infrastructure and services. In other words, CO_2-EOR and/or heavy oil resource development prevents substantial economic impacts that could occur to local populations and economies should production decline, by sustaining or perhaps even increasing oil production in the area.

Given concerns about future energy price volatility, and recognizing the experiences endured by "emerging" energy resources when faced with declining and volatile prices in the past, the establishment of an integrated local and regional infrastructure plan for unconventional fuels development that will support efficient development, realize synergies, and reduce duplicative investments may be required. Again, because CO_2-EOR and heavy oil recovery technologies will generally be applied in traditional producing areas, most of the required crude oil infrastructure already exists in the area, but may be underutilized due to declining production. This development often allows for the more efficient utilization of existing oil production and transportation infrastructure, minimizing impacts.

On the other hand, large-scale development of resources amenable to CO_2-EOR technologies will require substantial investment in infrastructure to bring CO_2 to these fields. In this regard, the issues for CO_2-EOR are comparable to those for other unconventional fuels resources, but again, generally not at the same scale. In addition, the large-scale development of heavy oil resources may require some investment in infrastructure enhancements and modifications to handle and process the more viscous, lower quality heavy oil that is produced.

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83 Assumes an oil price of $30 -$40 /barrel, a CO2 cost of $1.20 -$2.00/Mcf ($20-$40/ton), a ROR hurdle rate of 15% (before tax), and 1.0 hydrocarbon pore volume of CO2 injected
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