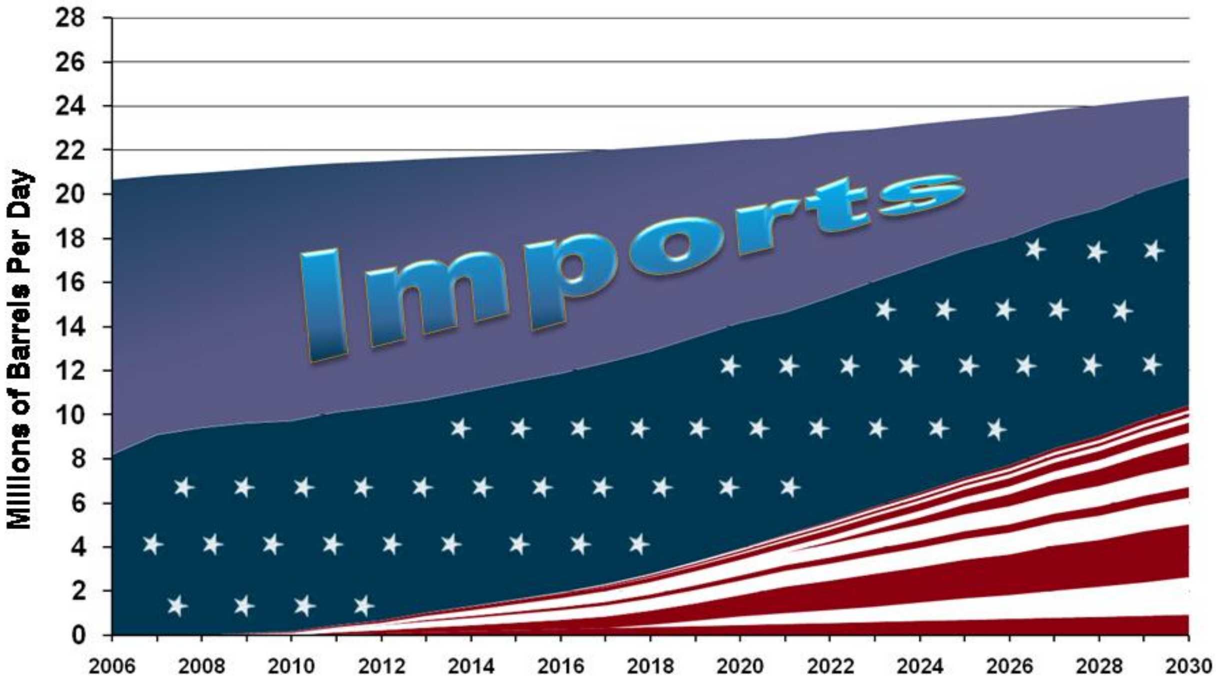
Attaining Energy Security in Liquid Fuels Through Diverse U.S. Energy Alternatives



DOE/NETL-2007/1278

August 1, 2007

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I. Executive Summary

The U.S. energy strategy debate is typically presented as an either/or choice—the pursuit of energy independence versus maintaining our current interdependence with the global energy market. The following analysis posits the existence of a third option that would enable the United States to achieve a much higher level of energy self-sufficiency without total market withdrawal. This middle ground is referred to as "advantageous interdependence."

Advantageous interdependence retains a meaningful but modest import component in the Nation's energy mix, based on competitive pricing with domestic energy supply alternatives. As a result, U.S. strategy for energy security would include more credible, achievable targets than those required by energy independence. Concurrently, achieving advantageous interdependence would restore balance and elasticity to world energy markets, exert downward pressure on oil prices, and curtail our 30-year susceptibility to external market and political forces, goals that cannot be achieved through continuing and deepening traditional interdependence.

This analysis focuses on U.S. liquid fuel demand, which currently represents our Nation's greatest energy vulnerability. It is based on the Energy Information Administration's (EIA) *Annual Energy Outlook 2007* (*AEO'07*) "High (Oil) Price Case." It also presents a unique vision of the U.S. energy supply that includes an array of domestic energy alternatives rarely considered cumulatively in today's forecasts:

- Coal-to-liquids (CTL)
- Oil shale
- Enhanced oil recovery (EOR)
- Methane hydrates
- U.S. oil sands
- Biomass gasification
- Cellulosic ethanol
- Plug-in hybrid vehicles (electricity from coal with carbon capture, solar, wind, and nuclear)
- Hydrogen fuel cell vehicles
- Reduction of energy demand from vehicle fuel efficiency standards

Roughly, 99 percent of the U.S. endowment of solid, liquid, and gaseous fuels requires technical advances and/or further exploration to be economically recoverable (see figure 1a). However, the estimated sum of these resources totals approximately 51 trillion barrels of oil equivalent—43 times greater than the current estimate of the world's proved oil reserves. If only 2–3 percent can be recovered economically, the United States will secure additional energy reserves equal to the current estimate of the entire world's proved oil reserves. This supply would endure for more than 180 years at the current rate of U.S. oil consumption (.025x51trillion/7bnb/yr).

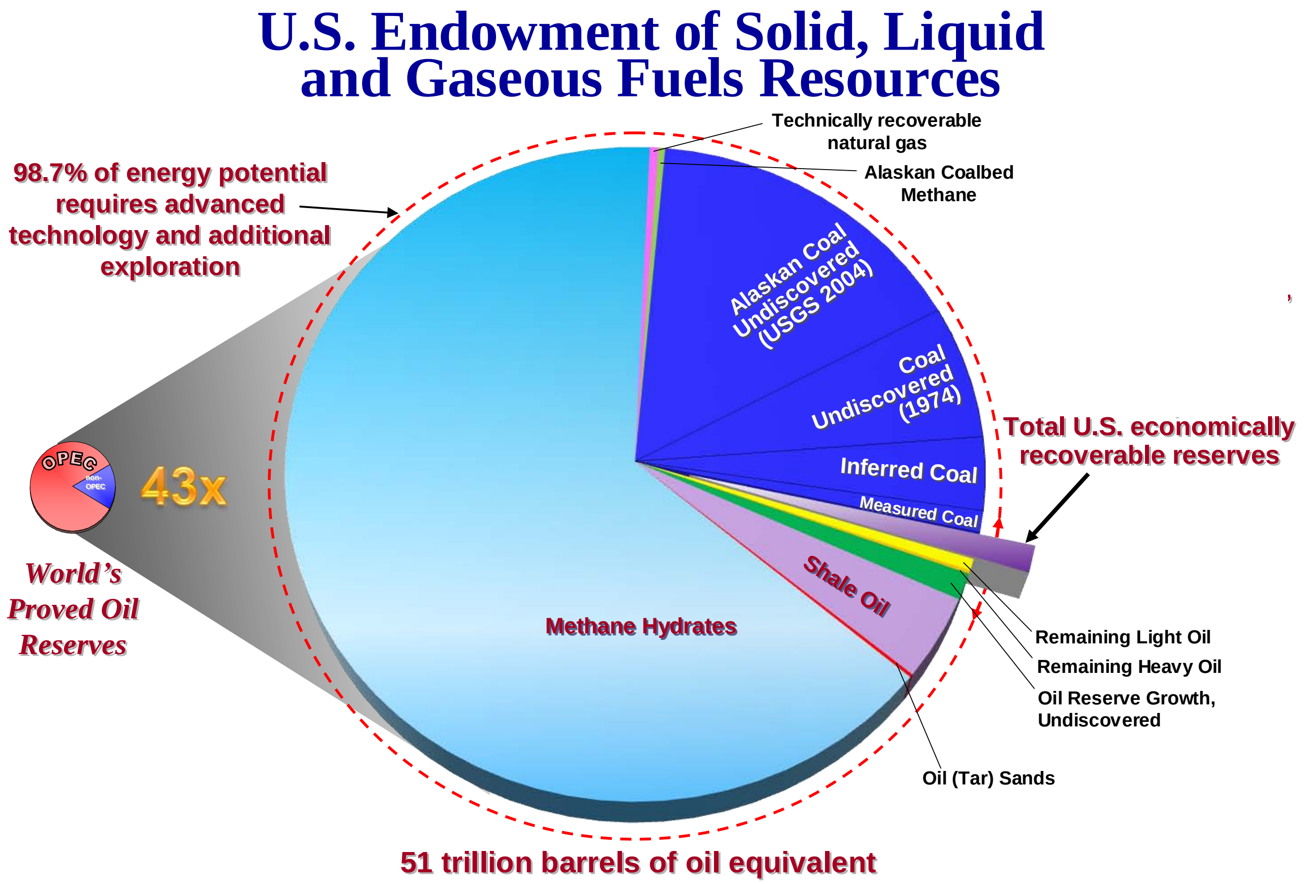

Figure 1a

The level of U.S. self-sufficiency necessary to achieve advantageous interdependence in liquid fuels is undetermined and will vary with time and world market conditions. For the purpose of this analysis, however, an illustrative level of 15 percent liquid fuel imports by 2030, based on pre-1973 import levels and the Administration's plan to double the Nation's strategic petroleum reserve, represents an achievable and meaningful target (see figure 2a).

To achieve this approximate level of imports, the United States must develop 8–12 million barrels per day (MMbd) of incremental domestic liquid fuel alternatives. For reference, 8 MMbd would be comparable to the added oil production from the North Sea, Prudhoe Bay, and Cantarell fields in the mid-1980s that supported a significant moderation in world oil prices at that time. Similarly, successful development of domestic alternatives would exert competitive price pressure on oil imports.

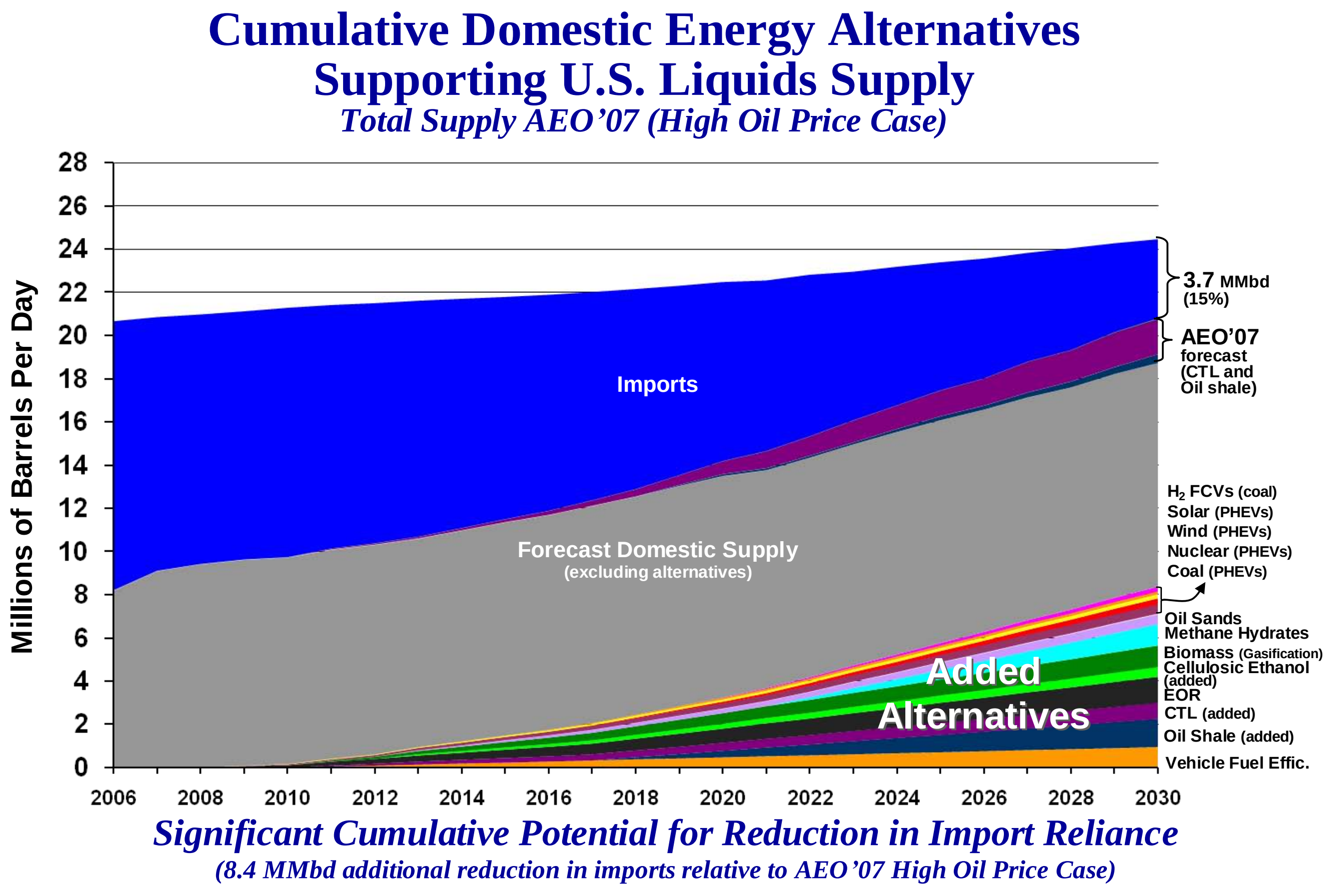

Figure 2a

In general, the estimates presented in this report are technically possible, and the overall displacement of imports is achievable with adequate attention to the development of alternative technologies. Technical obstacles exist in some cases but reflect the kind of challenges that U.S. ingenuity has repeatedly met in the past. The scale and timing of each alternative's contribution are felt to be reasonable with respect to industry expectations and conservative with respect to industry forecasts. Additionally, the world energy market appears to be entering a period of sustained tight supplies and high prices that will support and justify the time, cost, and effort required to bring these technologies to fruition.

A primary responsibility in any forward-looking domestic energy-development activity will be to ensure that, as part of the overall technical solution, levels of greenhouse gas (GHG) emissions, as well as other environmental impacts, remain within bounds deemed acceptable by society. Although some alternatives, such as CTL and oil shale, have higher GHG emissions per unit of product fuel than a normal oil refinery, several new energy alternatives considered in the analysis have the potential to significantly reduce GHG emissions associated with U.S. liquid fuel use. Prospects for associated GHG mitigation are addressed in separate, ongoing NETL studies.

This analysis does not make specific recommendations for policy in support of any domestic energy alternatives or make budget recommendations for the research and development necessary to develop their associated technologies. Instead, it is anticipated that the vision for potential U.S. energy-security benefits fostered by such alternatives will promote future consideration of these matters by responsible parties.

The United States has a long history of developing technologies to achieve economic and national security goals. Considering the level of domestic alternative energy resources available, the probability of reestablishing our Nation's energy security appears high, if these resources are given appropriate attention. To insulate but not isolate itself from the uncertainties of the world energy market, the United States should consider a domestic energy strategy that remains interdependent with the global energy community to the extent that such interdependency remains "advantageous."

Summary, Chapter II, "Considering the U.S. Energy Situation, Resources, and Alternatives"

Oil price assumptions play a critical role in forecasting energy supply and demand. A net decline in real oil price by 2030, per the *AEO'07* "Reference Case," appears neither likely nor representative of today's energy security concerns, especially in view of recent oil price trends, difficulties foreseen in adequately increasing spare oil-production capacity, persistent geopolitical tensions within key energy exporting regions, worldwide trends toward increased energy resource nationalization, and reduced confidence in the future discovery of large oil fields.

This analysis relies on the AEO'07 "High (Oil) Price Case," which indicates the effect of price in addressing energy security and more closely reflects a world grappling with energy security concerns.

The analysis considers the potential contribution from a broad variety of domestic energy alternatives, including fossil and non-fossil sources, in mitigating U.S. liquid fuel import dependence. Numerous analyses of U.S. energy alternatives over the last several years advocate the increased use of U.S. resources to resolve the Nation's energy needs. However, proposed alternatives are usually confined to the proponents' specific areas of interest. Narrowly focused energy solutions leave the United States vulnerable, with no meaningful near-term alternatives. In addition to the heightened risk of failure, such limited efforts delay the development of a wide range of potentially important domestic energy alternatives.

Summary, Chapter III, "Contribution of Diverse U.S. Energy Alternatives"

In the "High (Oil) Price Case," with 2030 oil price reaching roughly $100 per barrel in 2005 dollars, EIA projects that nearly 50 percent of the Nation's liquid fuel energy supplies will continue to be met by imports. Given present geopolitics, concern must be raised about the ability of the United States to reliably and sustainably meet rising energy demands based on such a high level of imports.

The EIA is constrained in the AEO to forecasting alternatives that are currently technically or economically viable. Thus, AEO omits such potential domestic alternatives as methane hydrates and U.S. oil sands and projects negligible energy contributions from EOR tied to CO2 sequestration. These resources, however, promise to create a new long-term energy security paradigm for the United States, even if only one or two begin to contribute economically in meeting U.S. liquid fuel demand. Simultaneously pursuing multiple energy alternatives allows less aggressive production targets for individual alternatives while still achieving a significant overall reduction in imports.

Summary, Chapter IV, "Achieving Advantageous Interdependence"

The historic energy interdependence of the United States has resulted in declining energy security as characterized by increased imports and steadily increasing energy prices over the last eight years. It has discouraged development of unconventional energy alternatives, and it presupposes a perpetual U.S. military presence in the Persian Gulf, which helps confer market power to producing nations. A bid for energy independence, on the other hand, would necessitate the total displacement of global imports with U.S. alternatives—a difficult and unnecessary achievement.

Advantageous interdependence is the middle ground between historic interdependence and independence. Advantageous interdependence maintains a small but meaningful level of energy imports to maintain long-standing open energy markets and ensure healthy competition among energy resources Although any import reliance could conceivably leave the United States vulnerable to import curtailments in the mid-term, two key distinctions lead to a U.S. position of advantageous interdependence for energy supply: 1) the extent to which energy-producing nations can exercise leverage over the United States and other consuming nations will have been greatly reduced, and 2) failure of producing nations to act as reliable suppliers under such altered circumstances would eventually prove economically harmful.

The strategy of developing energy technologies that convert the large potential of U.S. alternative energy resources into useable reserves will have an enormous impact on the Nation's competitive participation in world energy markets.

Summary, Chapter V, "Conclusion"

To the extent conventional oil production capacity margins increase in response to the development of non-conventional energy alternatives, competition within the world oil market would improve enormously. In this situation, the influence of alternative energy programs would be evident in stable or reduced energy prices.

Establishing the technical and economical feasibility of major U.S. alternative energy resources can serve as a valuable insurance policy for the Nation against the geologic and geopolitical uncertainties of meeting future energy demands. If consideration is given to the potential offered by a diverse set of domestic energy options, a window of opportunity will open for developing alternative technologies with less risk than traditionally envisioned. With minor success, the U.S. endowment of energy resources can be converted into significant levels of reserves that will sustain the economic growth and well-being of the United States for generations to come.

II. Considering the U.S. Energy Situation, Resources, and Alternatives

This analysis focuses on the energy security benefits associated with pursuing domestic energy alternatives that could collectively support liquid fuel requirements, clearly the most vulnerable U.S. energy segment according to current and forecasted import levels. In developing this report, other recent industry analyses of energy security alternatives have been referenced and compared. The current report, however, reflects the cumulative contributions from a more diverse set of domestic energy alternatives, including the consideration of two key domestic energy resources that are discounted (or totally omitted) in most other reports due to their current production technology status: methane hydrates and U.S. oil sands. Other significant U.S. resources involving CTL and oil shale are often scaled down in their estimated production contribution due to immature or inadequate experience with related production technologies. Discounting the potential contributions from such significant energy resources, particularly over long periods of time, ignores the demonstrated, historic capability of the United States to develop technologies that have proven critical in sustaining national security and economic well being.

A. *Scenarios, Supporting Data, and Assumptions*

Several unique aspects of this analysis set it apart from similar analyses:

1. Reliance on the "High (Oil) Price Case" in the *AEO'07*, which projects a lower level of oil demand and imports by 2030 than in the "Reference Case," due to demand destruction, conservation, and more efficient use;

2. Anticipation, within a reasonable time frame, of successful commercialization of new energy production and utilization technologies relating to large domestic energy resources currently considered commercially unexploitable in the United States;

3. Consideration of a wider-than-normal diversity of domestic energy alternatives, permitting more credible/conservative individual energy alternative production goals; and

4. Maintenance of modest levels of oil imports (rather than complete elimination of imports), striving for an energy market philosophy based on "advantageous interdependence" rather than "energy independence."

Background estimates for U.S. energy supply and demand have been derived from the *AEO'07* "High (Oil) Price Case." In forecasting the supply prospects of energy alternatives, it needs to be recognized that the primary U.S. forecasting entity, EIA, is constrained from forecasting meaningful supply from energy alternatives that are not currently considered technically available and commercially producible by industry.

As qualified in the current *AEO'07* report:

> The projections are business-as-usual trend estimates, given known technology and technological and demographic trends.

EIA is also constrained from projecting legislation, such as energy conservation alternatives, which are not presently supported by existing legislation:

> AEO 2007 generally assumes that current laws and regulations are maintained throughout the projections. Thus, the projections provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. Most laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

For the first time, however, the *AEO'06* forecast included a CTL energy component in the "Reference Case" and also included marginal contributions from oil shale and cellulosic ethanol in the "High (Oil) Price Case." This was maintained in *AEO'07*, although CTL in the "Reference Case" was reduced by approximately 40 percent, reportedly due to higher capital cost projections.

Recognizing the EIA's constraints on forecasting yet-to-be-commercialized technologies, this analysis offers the opportunity to envision future energy possibilities of the United States, acknowledging its historic capacity to develop important technologies and ability to change legislation to support meaningful goals, such as energy security.

Oil price assumptions play a critical role in forecasting energy supply and demand; this report relies on the *AEO'07* "High (Oil) Price Case," as displayed in figure 3.[1] Given recent oil price trends, difficulties foreseen in adequately increasing spare oil production capacity, persistent geopolitical tensions within key energy exporting regions, increasing worldwide trends toward energy resource nationalization, and reduced confidence in the future discovery of large oil fields, the forecasting of a net decline in real oil price over the next 24 years (per the *AEO'07* "Reference Case") does not appear either likely or representative of today's energy security concerns.

With regard to the *AEO'07* "Reference Case" forecast, EIA makes the following statement:

> In the AEO2007 reference case, real world crude oil prices, expressed in terms of the average price of imported light, low-sulfur crude oil to U.S. refiners, are projected to decline gradually from their 2006 average level through 2015, as expanded investment in exploration and development brings new supplies to the world market. After 2015, real prices begin to rise as demand continues to grow and higher cost supplies are brought to market. In 2030, the average real price of crude oil is projected to be above $59 per barrel in 2005 dollars, or about $95 per barrel in nominal dollars.

[1] EIA, *Annual Energy Outlook,* February 2007.

With the Organization of Petroleum Exporting Countries (OPEC) production cuts in October and December 2006 already appearing successfully aimed at maintaining prices in the $60 per barrel range, recent healthy global economic performance—despite $60 per barrel oil—suggesting a decline in elasticity of global energy demand, and with volatile geopolitical events overhanging key energy producing States, a projection of stagnant to declining real oil prices over the next 24 years currently appears overly optimistic. The "Reference Case" forecast eventually follows a linear regression trend line dating back to the mid-1980s. The early period of this timeframe included a world energy status that is not reflective of today's energy environment and is unlikely to be repeated. During this period, new world oil production included large growth from such sources as Prudhoe Bay, the North Sea, and Cantarell in Mexico. The period began with a significant excess of OPEC oil production capacity estimated to represent over 10 MMbd,[2] which they used aggressively to try to regain market share from growing non-OPEC sources. The period was also opportune from the standpoint of U.S. electricity production capacity growth, which commercialized 156 GW of new coal-fired generation and 70 new nuclear plants from 1973 through 1985, reducing oil-fired power generation.

A more recent 16-year trend line of actual oil prices beginning in 1990 approximates most closely the "High (Oil) Price Case." Of concern is the trend line of actual oil prices over the last 8 years which points to the potential for $100 per barrel prices by 2013.

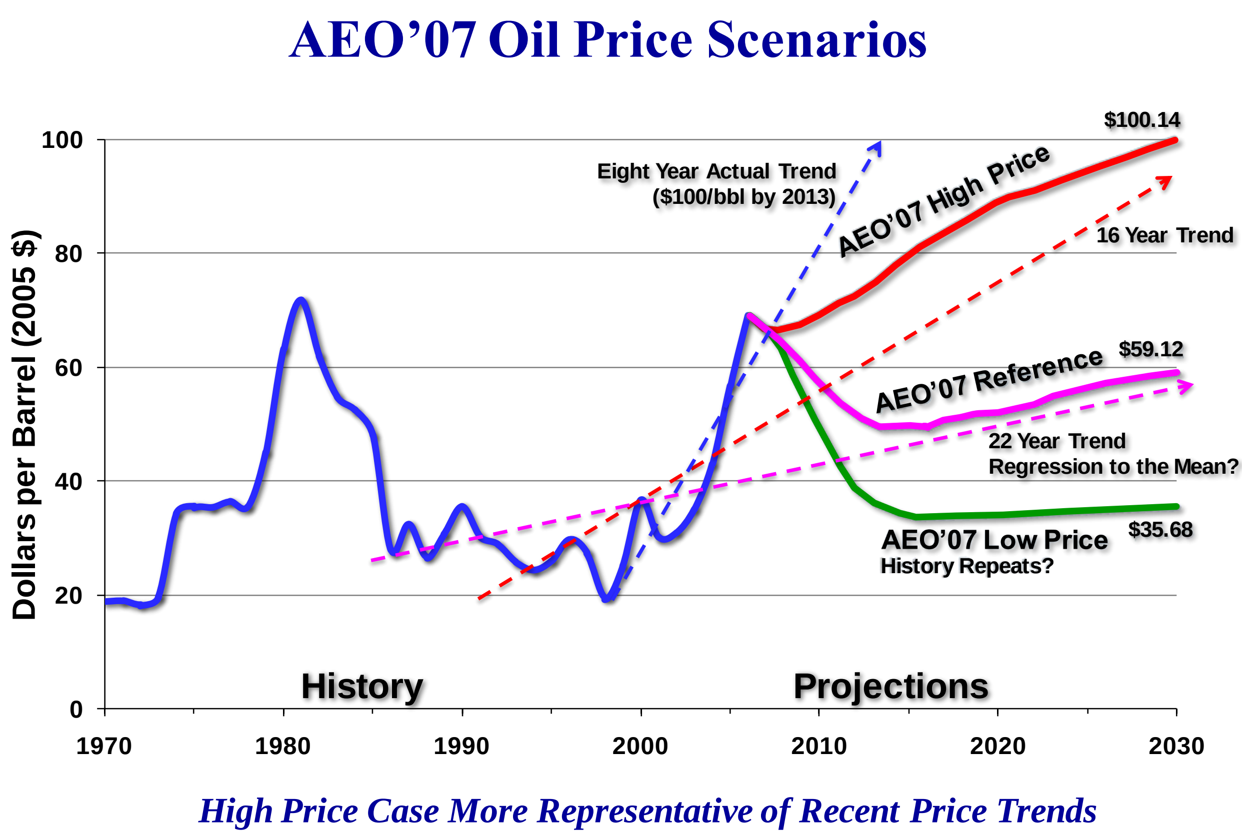

Figure 1

[2] IMF, *World Economic Outlook*, September 19, 2006, figure 1-16.

The *AEO'07* "Reference Case" (see figure 4) forecasts a rise in global conventional oil production of 25 MMbd by 2030, more than 1 MMbd on average, each year for the next 24 years. It also reflects a parallel rise of 8 MMbd in non-conventional oil production. Remarkably, the total increase of 33 MMbd would require a growth in world oil supply larger than OPEC's present day production.

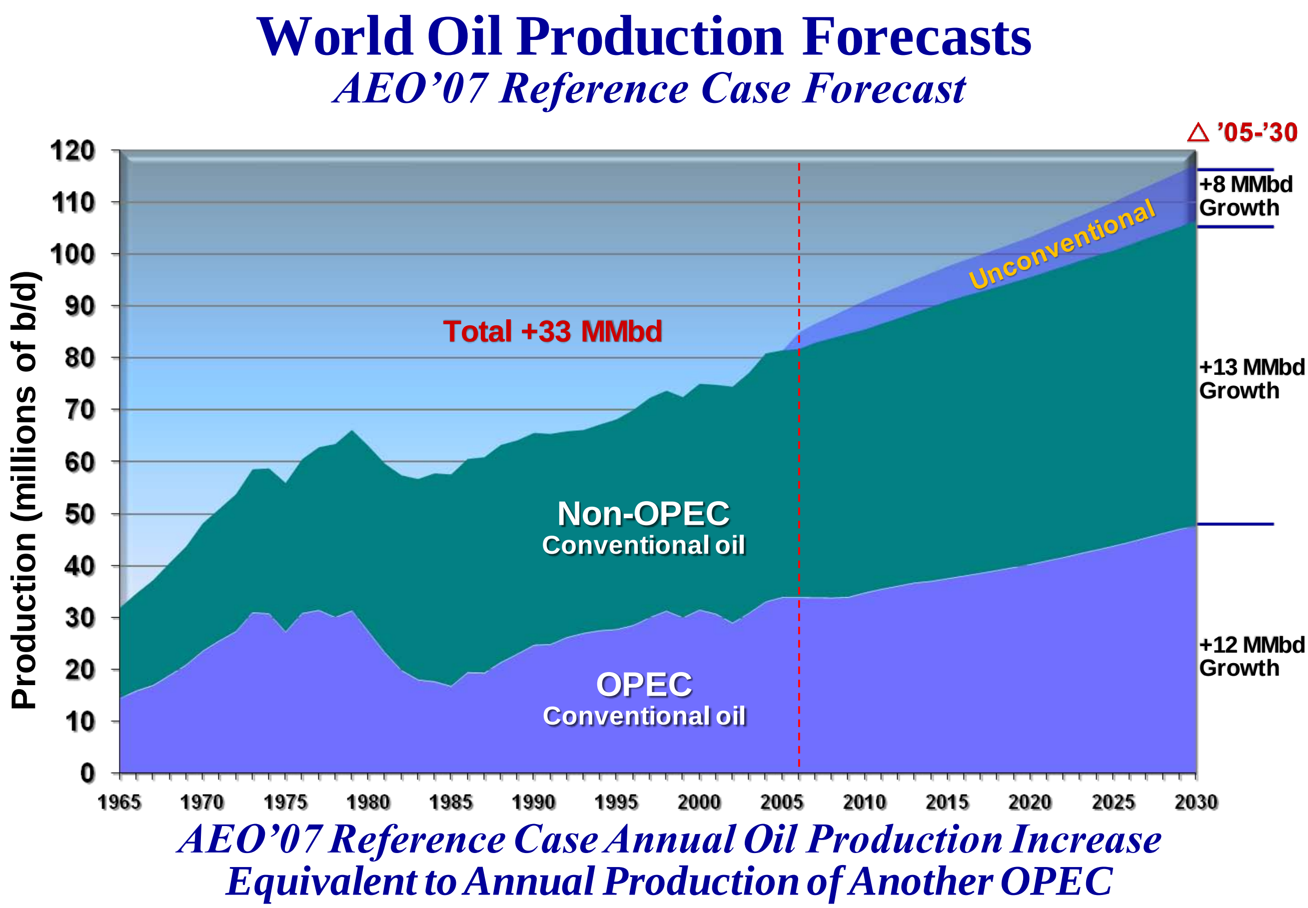

Figure 2

In stark contrast, the *AEO'07* "High (Oil) Price Case" (see figure 5), more in line with a conventional energy constrained world, forecasts stagnant total conventional oil production (remaining near 81 MMbd total) but more than doubles the non-conventional oil production growth forecast to 17 MMbd. Approximately 16 MMbd of demand is lost.

In total, the "High (Oil) Price Case" projects 13 percent less total global oil production in 2030 than the "Reference Case" (102 MMbd compared to 117 MMbd) but includes a much higher proportion of global non-conventional supply, at 17 percent versus 7 percent; again, a forecast more closely reflecting a world grappling with energy security concerns. As a result of these considerations, the *AEO'07* "High (Oil) Price Case" was determined to be a more relevant case to utilize for this energy security-focused analysis.

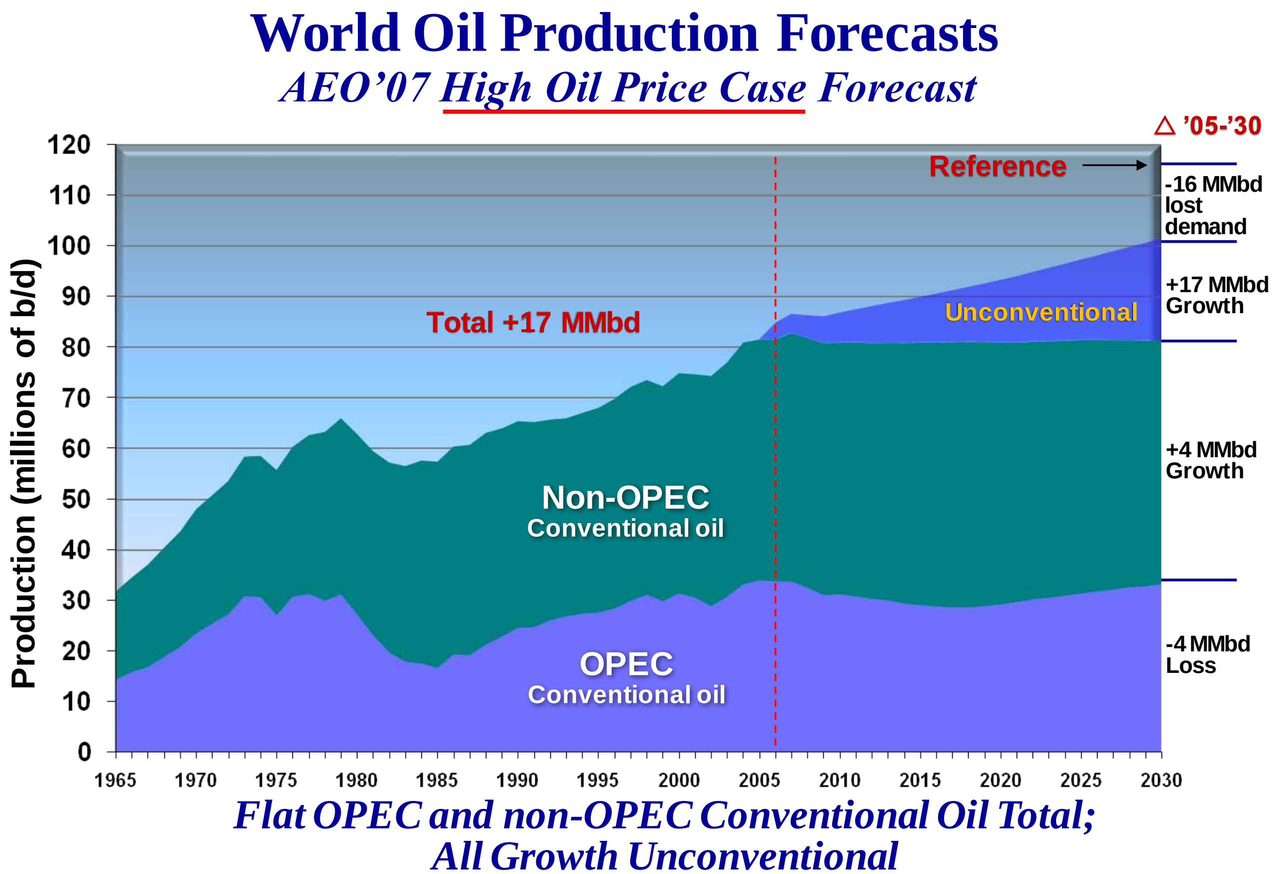

Figure 3

B. *Geologic and Geopolitical Uncertainties*

The rapid escalation and volatility of U.S. energy prices over the last few years, combined with increasing dependence on foreign energy supplies and growing violence in key energy supply regions, has generated a renewed sense of urgency concerning the state of the Nation's energy security. Fast growth in global energy demand has not been met with commensurate supply growth, resulting in diminishing oil production capacity margins and increasing prices due to the tightness of the market. Uncertainty exists as to whether decreasing oil production capacity margins, worldwide, represent an early sign of geologic problems and depletion of major conventional fields or the adoption of a supply philosophy by major oil producers, such as Saudi Arabia, to constrain incremental supply in order to garner higher prices. The answer to this question is difficult to derive due to the highly secretive nature of production and reserve data among major oil producers. Reflecting concern with this lack of crucial energy information, Amy Jaffe, Wallace S. Wilson Fellow in Energy Studies from Rice University's Baker Institute, recently expressed her opinion relative to Saudi Arabia's unsubstantiated claims to be able to increase production over the next several years to 15 MMbd:

> They [the Saudis] are not investing enough to get to 15 million barrels a day. Don't tell me the number of rigs they have. I want to know, where are the new fields they are opening, and when will they come on line?[3]

Recent OPEC decisions supporting production cuts will inevitably prolong the uncertainty concerning this crucial information on actual potential for world oil production capacity growth.

Representing a need to confront the lack of such important information regarding the real world energy production capacity, energy industry investment banker Matthew Simmons has conveyed a strong sense of urgency that the missing information might confirm the possible peaking of global oil supply:

> Get real energy data even if it takes spies and armed forces to steal the data. Panics create instant "call to arms." If we wait a day longer, we risk losing everything we cherish by DEFAULT and then the global lights dim . . . twilight turns into era of darkness.[4]

Regardless of the reason for supply constraints—geologic or geopolitical, including conscious producer decisions to hold back production—the result is the same. The combined effect of high energy prices, lack of meaningful knowledge of the world's reserve status, questionable production intentions of major energy producers and the dearth of sufficient domestic energy alternatives has given rise, in the United States, to a sense of energy insecurity not experienced since the peak prices of the last oil crisis in 1981.

Today, geopolitical events in energy-rich regions of the world are felt to extract a significant "fear premium" on energy costs, considered by some analysts to be in the range of $20 per barrel of oil (or roughly 50 percent higher than necessary cost). Ironically, as in the early 1980s, much of the recent "fear premium" volatility for oil prices has been related to apprehension concerning the potential for an Iranian oil supply shock.

C. *Diverse Energy Alternatives and Large Potential Resources*

Numerous analyses of U.S. energy alternatives have been undertaken over the last several years that have considered the increased use of domestic U.S. energy resources to resolve the Nation's energy needs. Proposed energy alternatives are usually confined to the proponents' areas of energy interest, and optimistic forecasts of resulting incremental energy production are frequently cited. An inclination toward narrowly focused energy solutions can leave the United States vulnerable to inadequate results with no meaningful near-term alternatives. In addition to heightened risk of failure, limited alternative efforts also delay the development of other potentially important domestic energy alternatives. Limitations in considering a variety of energy alternatives may stem from perspectives involving the absence of current commercial technology, prejudged environmental consequences, the limited scale of smaller alternatives, and unrealistic economic hurdles due to overly optimistic conventional energy-commodity forecasts.

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[3] Michael Kanell, "Saudi Arabia's Oil a Huge Question," *Atlanta Journal-Constitution*, July 21, 2006.
[4] Matthew Simmons, "The Energy Crisis Has Arrived" (presentation, Energy Conversation Series—Department of Defense, Alexandria, VA, June 20, 2006).

As a result, the wide variety of energy alternatives that may be available to the United States are rarely represented simultaneously, and some significant domestic resources, such as methane hydrates, usually do not have their vast energy potential even minimally acknowledged as a possible contributing factor.

A comparison of the energy value of prospective U.S. fossil energy resources to global proved oil reserves portrays the vast potential of untapped and often unconsidered domestic resources[5] (see figure 6). Global proved oil reserves are currently estimated at about 1.2 trillion barrels, with about 75 percent of these reserves controlled by OPEC.[6]

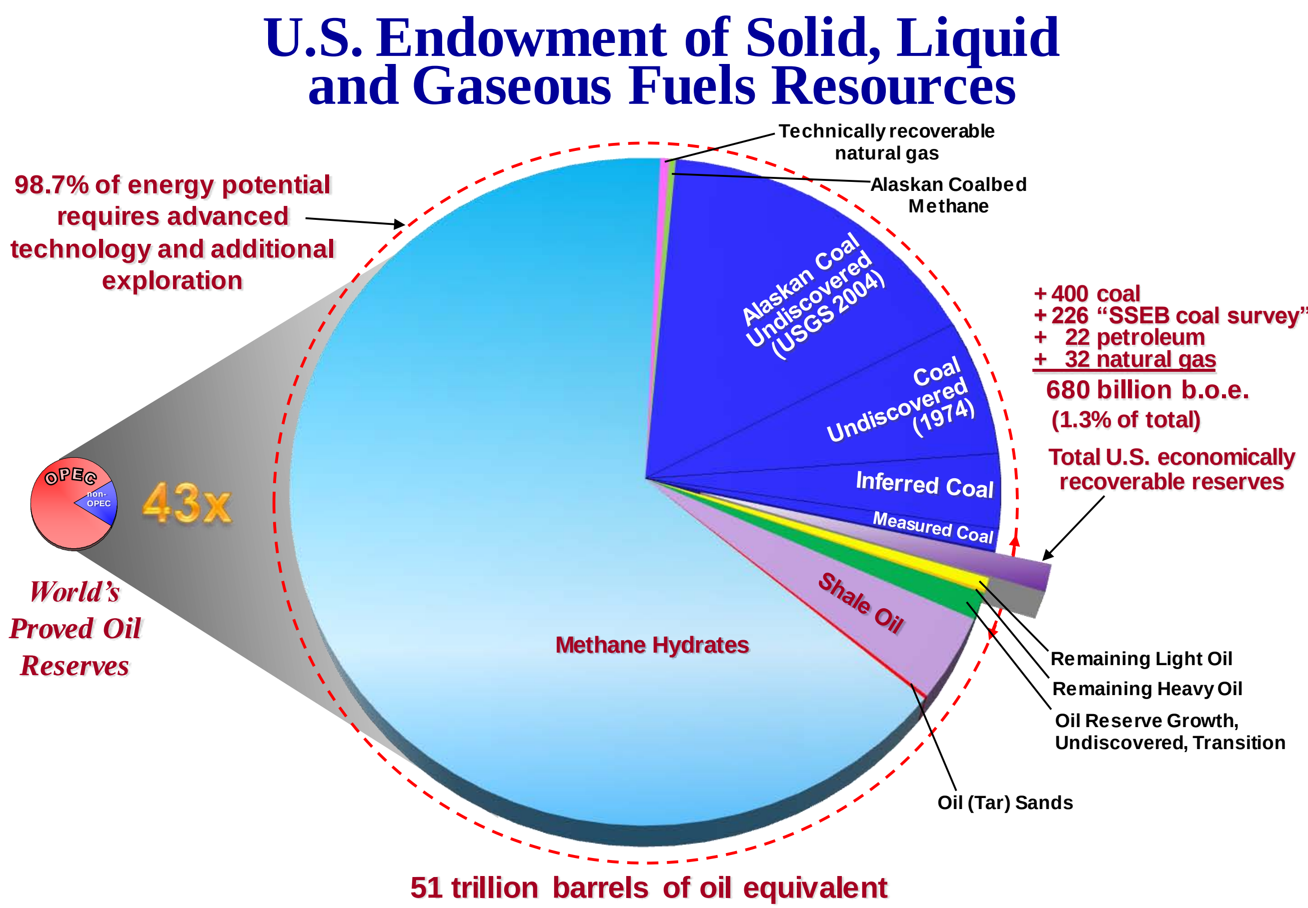

Figure 4

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[5] EIA 2004 Demonstrated Reserve Base for U.S. coal resources.
Romeo M. Flores, Gary D. Stricker, Scott A. Kinney, "Alaska Coal Resources and Coalbed Methane Potential," Bulletin (U.S. Geological Survey (USGS), 2003).
USGS estimate of 200,000 Tcf of U.S. in-place hydrate resources (statistical mean).
Southern States Energy Board (SSEB), *American Energy Security— Building a Bridge to Energy Independence and a Sustainable Energy Future*, July 2006, appendix C.
David Garman, "Addressing America's Petroleum Dependence," (presentation, Center for Strategic and International Studies, Washington, DC, June 15, 2006). Estimates (DOE/National Energy Technology Laboratory (NETL)) for shale, EOR, heavy oil, and oil sands.
[6] BP, *Statistical Review of World Energy*, Historical data series, June 2006.

Estimates of U.S. fossil energy resources are quite large. Even the amount of resources considered technically and economically recoverable may be expected to have an energy content equivalent to over half of the prevailing estimate of the energy content of global oil reserves if updated.[7] More significantly, however, the total estimate of potential U.S. fossil energy resources is nearly 100 times this amount and roughly 43 times today's estimate of proved oil reserves worldwide. The vast majority of this energy potential (≈99 percent overall) will require extensive additional exploration and technology development to become classified as technically and economically recoverable. Clearly, a large proportion of this resource estimate will never be deemed economically recoverable. It is important to also recognize, however, that for each 2.4 percent of this total energy potential that could eventually be confirmed as economically recoverable, the United States would increase its recoverable energy reserves by the energy equivalent of the world's proved oil reserves.

Although important resources such as methane hydrates and oil shale alternatives are discounted from key U.S. energy analyses and forecasts, an oil shale contribution entered into the *AEO'06* for the first time and appears only in the "High (Oil) Price Case" of the forecast. With the lack of attribution in forecasts of meaningful energy potential for these vast energy resources, funding support for necessary exploration and technology development languishes or fails to develop altogether.

The large potential resource shown in figure 6 for Alaskan undiscovered coal is equivalent to approximately 5.5 trillion tons and has been identified by USGS[8] subsequent to the last significant U.S. coal resource estimate in 1974. This estimate of undiscovered Alaskan coal resources has the energy potential of 8.25 trillion barrels of oil, equivalent to nearly seven times the world's current proved oil reserves. As in the case of methane hydrates, much of the estimated resource available will not prove to be technically and economically recoverable; however, the SSEB report has indicated that it is possible that 500 billion tons of this resource could be added to the U.S. reserve base from Alaska alone[9] more than tripling the current estimate of U.S. recoverable coal reserves. Combined with the aforementioned estimated increase in coal resources represented in the SSEB coal survey, U.S. coal resources could be found to be 143 percent larger than the amount estimated in the 1974 U.S. coal resource estimate (see figure 11).

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[7] SSEB, *American Energy Security*, appendix B, table 3. "SSEB Coal Survey" represents 19 State survey updating coal reserve estimates. The adjusted economically recoverable coal reserves shown applies a standard EIA percentage for estimated recovery of coal reserves. Various perspectives offered in the SSEB report were found quite useful in supporting aspects of this report. The SSEB goal of securing energy independence and the use of the *AEO'06* "Reference Case" for imports to be displaced forced the SSEB report to seek higher levels of targeted alternatives and in some cases, such as CTL, the resultant alternative production forecast was more than double the estimate considered herein. Due to significant parallel demands on coal supply, including growth for electricity, syngas for industry and CTL, a more moderate targeting of individual alternatives was felt to produce a more achievable growth in demand for resources. Even in the *AEO'07* "High (Oil) Price Case," the growth in domestic coal demand approaches 2X today's production by 2030, a significant challenge for the producers and transporters of coal

[8] Romeo M. Flores, Gary D. Stricker, and Scott A. Kinney, *Alaska Coal Geology, Resources, and Coalbed Methane Potential*, Data Series (USGS, 2004).

[9] SSEB, *American Energy Security*, appendix B, 18.

In addition to coal and methane hydrates, oil shale represents a third U.S. energy resource which, individually, promises the potential to create energy reserves larger than the current estimate of global proved oil reserves. Conservative estimates, focused only on the richest deposits of oil shale in the Green River Basin, are felt to represent three times the estimates of Saudi proved oil reserves. The primary end product of oil shale processing is, with modest refining, directly applicable in displacing oil imports. Much of the United States resource is highly concentrated in three Western States: Colorado, Utah, and Wyoming, with approximately 85 percent of the resource available on Federal land. Once again, U.S. energy companies are confronting the unmet challenge of developing a viable commercial technology for oil shale. Under the Bureau of Land Management Oil Shale R&D Program, R&D project proposals from Chevron Shale Oil Company, EGL Resources, Inc., and Shell Frontier, were all judged eligible for further consideration and analysis under the National Environmental Policy Act. This renewed approach may benefit from the successful example set by Canadian oil sands development, with analogous technical and project development issues. Oil shale has historically been omitted from U.S. energy forecasts due to lack of an economically viable process; however, the *AEO'06* "High (Oil) Price Case" included an estimate of roughly 410,000 bpd by 2030, which was carried over in the *AEO'07* "High (Oil) Price Case." Once oil shale production is seen as economically viable, it is probable that its use will grow as rapidly as the price of oil will allow, due to the vast quantities of the resource in densely concentrated fields. In a similar vein, the success of Canadian oil sands development may directly inspire the development of large U.S. resources of oil sands but requiring somewhat different technology due to varied properties of the U.S. resource.

This analysis attempts to consider the potential energy contribution from the broadest variety of domestic energy alternatives, including fossil and non-fossil sources, in mitigating U.S. liquid fuel import dependence. The uncertainties and technical difficulties of each alternative is acknowledged and discussed in subsequent sections, along with an estimate for reasonable production contribution timing for each. Because of the diversity of options, the forecasts of contributions from each alternative can be made more conservative and credible than those in other analyses with a narrower range of solutions.

Although there may be winners and losers among the energy alternatives selected, the overall credibility of the Nation's strategy and its ability to achieve its energy security goals is enhanced by the diversity of domestic alternatives being pursued and the determination with which exploration and technology development is supported. This enhanced credibility provides leverage for the United States to influence other nations to pursue similar paths, and cumulative energy alternative successes within several key countries can lead to significant incremental global supply, aiding improved energy security not only for the United States but for the world in general.

III. Contribution of Diverse U.S. Energy Alternatives

This analysis focuses on energy security benefits to be derived from new, domestic energy alternatives that could collectively support U.S. liquids fuels requirements primarily serving the transportation industry. Liquid fuel dependence remains the largest energy security vulnerability for the United States, with roughly 60 percent of all petroleum and petroleum products being imported today. The approach used in the analysis reflects methods and considers estimates employed in a July 2006 energy alternative whitepaper produced by NETL[10] and a similar approach employed in the SSEB report of July 2006.[11] Key differences of the analysis used herein follow:

- reliance on the *AEO'07* "High (Oil) Price Case" (which projects a lower level of oil demand and imports by 2030 than the "Reference Case")
- envisioning commercialization of new technologies relating to all major U.S. energy resources within reasonable time frames
- a broader diversity of domestic energy alternatives is considered, permitting more credible/conservative individual energy alternative production goals
- maintenance of modest levels of oil imports (rather than complete elimination of imports), striving for an energy import philosophy based on "advantageous interdependence" rather than "energy independence"

A. *Perspective of AEO'07 "High (Oil) Price Case"*

The *AEO'07* "High (Oil) Price Case" forecast of total primary petroleum supply to 2030 is displayed in figure 7. Because of the higher energy prices predicted in the case, total demand by year 2030 at 24.6 MMbd is lower than the *AEO'07* "Reference Case" by 2.4 MMbd.

[10] Roger H. Bezdek, Robert M. Wendling, and Robert L. Hirsch, *Economic Impacts of U.S. Liquid Fuel Mitigation Options*, NETL, July 2006.
[11] SSEB, *American Energy Security*, 133.

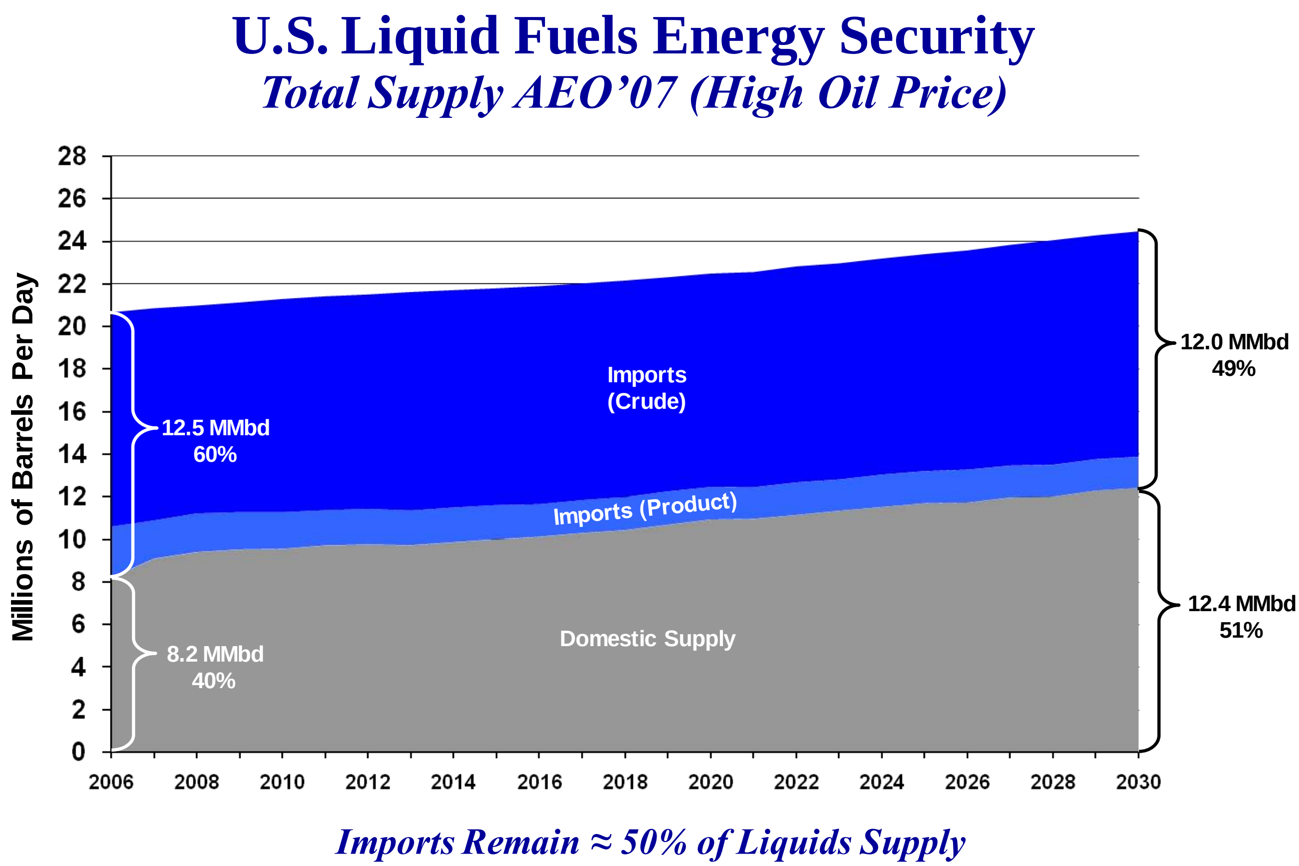

Figure 5

In this "High (Oil) Price Case," with 2030 oil prices reaching $100 per barrel in 2005 dollars, the forecast, nevertheless, maintains an expectation of reliance on imports for nearly 50 percent of the Nation's liquid fuel energy supplies. Given the present status of geopolitical events, particularly with respect to the world's dominant energy producing regions, concern must be raised relative to the ability to reliably and sustainably meet such a high level of U.S. liquid fuel energy demand based on such a high level of imports.

B. *Limitations in Forecasting of Energy Security Options*

The Nation's primary annual energy forecast, the *AEO*, tends to be conservative in projecting the full ability to convert to more aggressive use of important domestic energy alternatives for technology and policy reasons. Limitations exist for EIA in portraying energy forecasts that may more fully capture the potential for achieving greater U.S. energy security from some of its most significant energy resources. Figure 8 portrays the limited use of new energy alternatives portrayed by *AEO'07* "High (Oil) Price Case."[12] By 2030 these alternatives make up approximately 2.1 MMbd, or about 8.5 percent of supply. One problem faced by EIA is the constraints on forecasting energy technologies that are not yet deemed commercially viable and

[12] Corn-based ethanol forecast is included in the domestic supply component because it is not considered a new energy alternative.

competitive today. Also, policy-related alternatives, such as VFE standards, that may appreciably support energy security by lowering demand are constrained from entering into the forecast if the requisite policy is not in place.

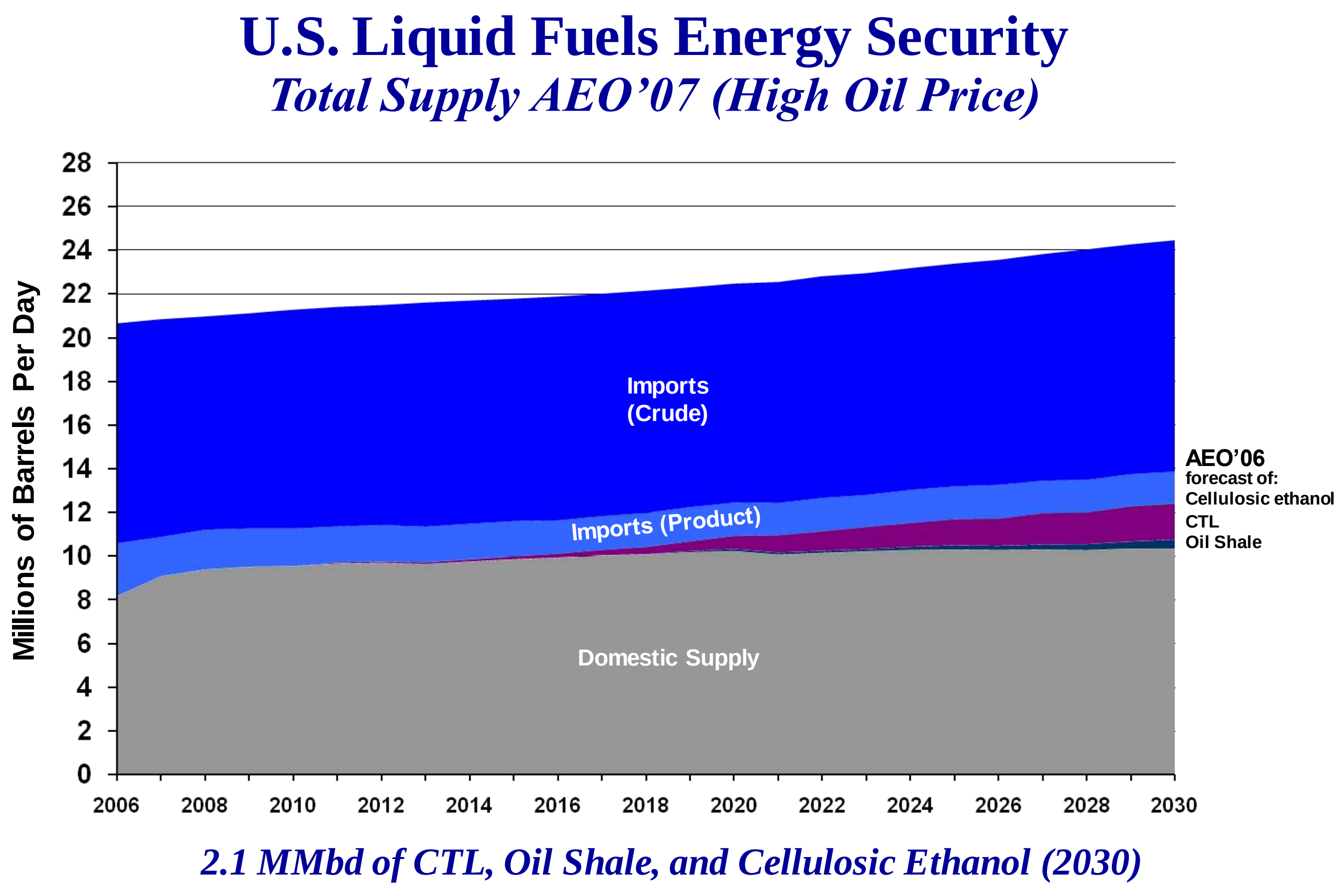

Figure 6

CTL technologies, which have been commercially viable for nearly 20 years in South Africa, appeared for only the first time in the "Reference Case" forecast of *AEO'06*. CTL is more aggressively represented in the *AEO'07* "High (Oil) Price Case" with 1.65 MMbd by 2030, as portrayed above. The "High (Oil) Price Case" also includes modest forecasts of cellulosic ethanol (20,000 bpd in 2030, not visible) and oil shale (410,000 bpd in 2030). These assumptions are far below the estimates of other recent energy security analyses. For instance, the National Coal Council's (NCC) estimate[13] for CTL production capacity in the United States by 2025 is 2.6 MMbd, which is 216 percent of the *AEO'07* "High (Oil) Price Case" forecast (1.2 MMbd) by 2025. The SSEB report[14] forecasted that 5.6 MMbd of CTL production is achievable by 2030, which is 339 percent of the *AEO'07* "High (Oil) Price Case" forecast for CTL in 2030. This reflects a significant difference of opinion, involving just one important domestic alternative energy resource, a difference potentially equivalent to 16 percent of total petroleum supply and nearly 33 percent of forecast imports by the end of the forecast period.

[13] NCC, *Coal: America's Energy Future*, 1 (March 2006) 31.
[14] SSEB, *American Energy Security*, 133.

Oil shale, which is included in the *AEO'07* "High (Oil) Price Case" forecast at a level of 410,000 bpd by 2030, is, in contrast, forecast to represent 3.0 MMbd by SSEB, a difference of 730 percent. The 2.6 MMbd difference in forecasts by 2030 represents over 11 percent of forecast demand and 21 percent of imports for this resource alone. Thus, differences of opinion on just two key domestic energy resources can represent the energy equivalent of 54 percent of the forecast for the Nation's liquid fuel imports by 2030.

Secretary of Energy Samuel Bodman recently announced[15] the goal of making ethanol a practical and cost-competitive alternative by 2012 and displacing 30 percent (60 billion gallons) of 2004 transportation fuel consumption with biofuels by 2030. This goal was set in response to the President's Advanced Energy Initiative. The targeted amount represents a remarkable 3.9 MMbd of ethanol by 2030 (2.9 MMbd gasoline equivalent gallons) which is expected to be derived predominantly from cellulosic ethanol once basic technological hurdles are overcome. The *AEO'07* "High (Oil) Price Case" only projects about 560,000 bpd (gasoline equivalent gallons) from ethanol by 2030, representing about 20 percent of the stated goal, of which 540,000 bpd (96 percent) is corn-based. This analysis does not consider corn-based ethanol as a new energy alternative and does not project significant growth from levels of production already forecast in the *AEO'07*. If cellulosic ethanol is expected to make up the difference between the *AEO'07* "High (Oil) Price Case" forecast and the DOE goal for ethanol by 2030, it will be required at a level nearly 168 times higher than the current cellulosic ethanol forecast of 20,000 bpd. More recently, the President announced during the 2007 State of the Union Address, a proposal to set Alternative Fuel Standards[16] aimed at achieving a 20 percent reduction in gasoline demand by 2017 ("20 in 10"). This has been associated with up to 35 billion gallons of alternative fuels by 2017 (based on ethanol energy content), but the exact proportion of ethanol is currently undetermined as other alternative fuels may qualify.

Other important but commercially unproven or immature alternative energy technologies, which correspond to tremendous domestic energy resources, are forecast to have negligible energy contribution in *AEO'07*, due to their technology status. These include such important resources as methane hydrates, oil sands, and EOR tied to CO_2 sequestration. Plug-in hybrid electriv vehicle (PHEV) technology has become an increasingly recognized alternative within the media, promising to employ a significant source of traditional U.S. energy competitiveness—electricity—to cross over to support transportation energy. PHEV technology represents a mechanism by which surplus existing domestic electricity supply capacity could bring a significant transportation energy alternative quickly and competitively into the homes of U.S. transportation fuel consumers. A key issue for PHEVs, however, remains battery costs, weight, and technology for adequate range. In the longer term hydrogen from coal and renewable sources should also remain a potential candidate as an energy carrier used in transportation, due to its CO_2 emission advantages, although its contribution may be muted by the advent of PHEVs and comparatively more difficult distribution and storage issues.

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[15] DOE, "DOE Publishes Roadmap for Developing Cleaner Fuels: Research Aimed at Making Cellulosic Ethanol a Practical Alternative to Gasoline," news release, July 7, 2006, http://www.doe.gov/news/3804.htm

[16] President, Address to the Nation, "State of the Union," *Weekly Compilation of Presidential Documents* 43, no. 4 (January 2007), 57. The President's "Twenty In Ten" plan would help reduce America's dependence on oil by cutting gasoline consumption 20 percent over the next 10 years.

Lack of attention to these important energy resources in energy forecasts presents the United States with an inadequate vision of the energy security opportunities that may exist.

C. *Cumulative Potential of Diverse Domestic Energy Alternatives*

A graphical portrayal of the energy contribution and potential timing for commercialization of several of the Nation's leading candidates for domestic energy alternatives discloses the remarkable potential for their cumulative energy contribution in improving U.S. energy security (figure 9). Significant to the credibility of this energy security vision, the diverse energy alternatives represented may substantially reduce liquid fuel import requirements while targeting conservative goals for each. The level of import reduction based on additional domestic energy alternatives is approximately 8.4 MMbd, or 70 percent of the imports forecast for 2030. The total of new energy alternatives, including those already forecast in the *AEO'07* "High (Oil) Price Case," represent 10.5 MMbd, or slightly more than the forecast of traditional domestic supply at 10.4 MMbd in 2030. The remaining import level of 3.7 MMbd is approximately 15 percent of total demand in 2030, representing a substantial improvement in energy security over the *AEO'07* forecast assumption of 49 percent imports by that year. The United States has not experienced this proportion of imports as a share of total demand for liquid fuel since before 1970. Further, given the vast resources of the United States, the chosen domestic energy alternatives promise to create a new long-term energy security paradigm for the United States even if only one or two of the key domestic energy alternatives begin to contribute economically in meeting transportation energy demand. The 3.7 MMbd figure, representing 15 percent of demand from imports, is illustrative and, considering the currently proposed 1.5 billion barrel target for the SPR by 2027, would represent 405 days or 1.1 years of import coverage. Under such circumstances the need for total energy independence could be seen as less imperative and the value of continued import of liquid fuel products desirable, if competitive.

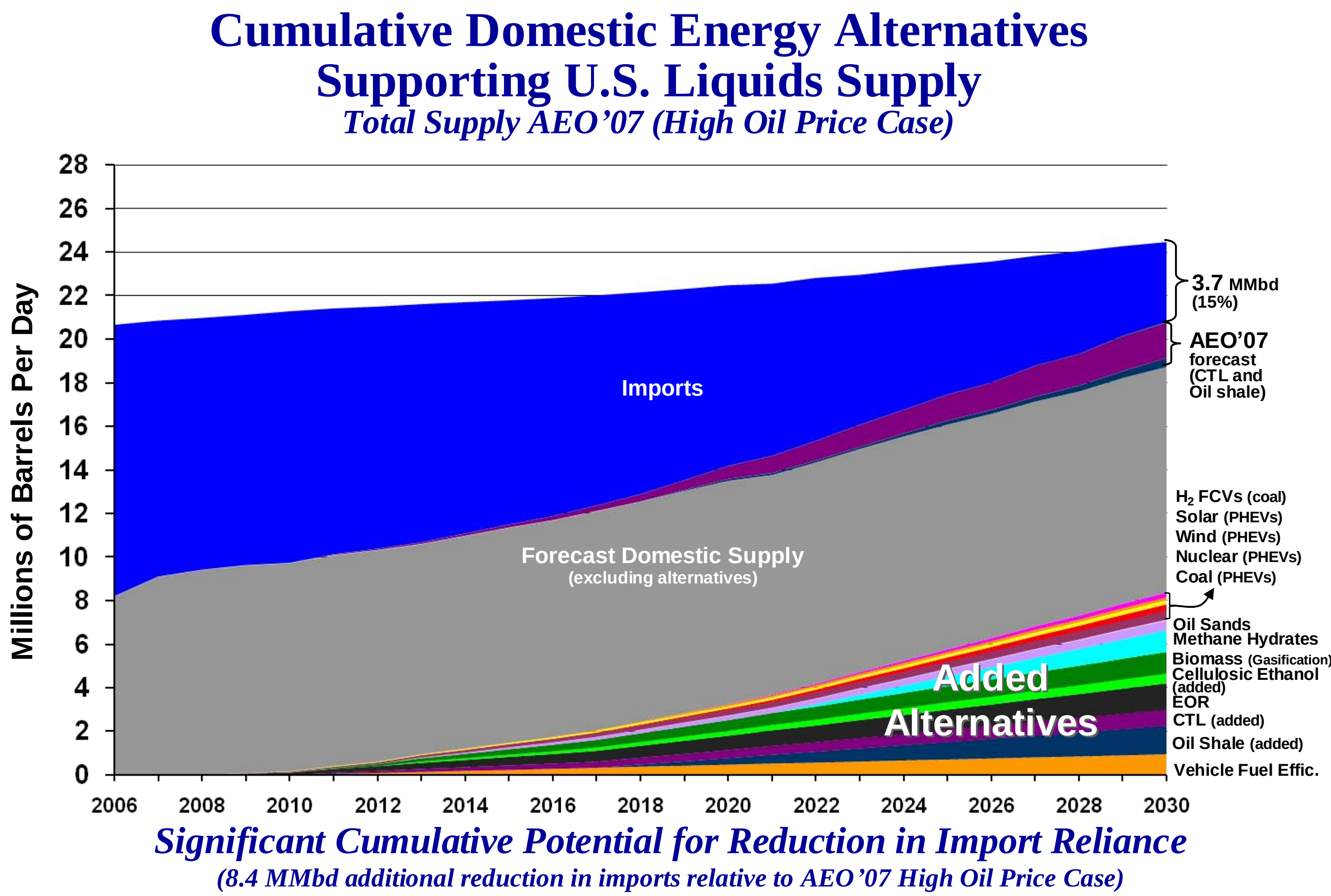

Figure 7

The added domestic energy alternatives shown represent 34 percent of domestic demand in 2030 but, in most cases, include substantially lower individual alternative contributions compared to other forecasts for each alternative (see figure 10). The potential would exist for a significant reduction in global energy prices, in the example shown, considering a total 10.5 MMbd reduction in U.S. import demand (including 2.1 MMbd in *AEO’07*) from foreign sources due to domestic alternatives. Many of the energy alternatives described are likely to be mirrored by the energy strategies of other energy consuming nations equally committed to improving their countries’ energy security. In particular, two of the fastest growing countries from an energy consumption standpoint, China and India, are already seeking similar energy alternative solutions to those described herein for the United States. If China and India could achieve the same 34 percent level of import demand reduction in 2030 through domestic energy alternatives, this would result in a further removal of 5.4 MMbd[17] from the conventional world oil market. Similarly, just a 10 percent reduction of imports from Western Europe and Japan would represent another 2.0 MMbd removed from the world market. Combined, a parallel effort among key energy consuming countries for achieving more energy security through reliance on alternative

[17] EIA, *AEO’07*, “High (Oil) Price Case,” table 19.

energy sources could compensate for 17.9 MMbd or 18 percent of a 102 MMbd market forecast for 2030. This figure would be remarkably close to the 17 MMbd growth in unconventional fuels represented in the *AEO'07* "High (Oil) Price Case." The resultant 84 MMbd contribution in 2030 from conventional sources is nearly equal to present day total supply, to which the energy alternatives discussed have a small contribution.

D. *Diversity Supports Credibility of Individual Goals*

The logic of pursuing multiple energy alternatives in parallel greatly enhances the credibility of an overarching energy strategy when the potential of cumulative contributions is recognized. Production targets for individual alternatives can be less aggressive, reducing perceived challenges while still achieving a significant overall reduction in imports. In the current analysis, liquid fuel imports forecast for 2030 were reduced from 49 percent of total demand to 15 percent through a cumulative added contribution of 8.4 MMbd (34 percent of demand) from new energy alternatives. Required contributions from individual energy alternatives are substantially lower than contributions reported in other recent analyses:

- VFE is approximately one-third the SSEB target.
- Total oil shale is approximately 57 percent of the SSEB target by 2030.
- Total CTL by 2030 is 8 percent lower than the NCC target by 2025 and less than half the SSEB target within the same 2030 time frame.
- EOR is approximately 40 percent of the SSEB and NCC targets.
- Cellulosic ethanol (biochemical) and biomass-gasification (thermochemical) conversion are, in total, approximately one-half the current DOE target for all biofuels by 2030 and 39 percent of the total SSEB estimate.
- Hydrogen from coal is approximately 40 percent of the NCC target by 2025.

A comparison representing the diverse energy alternatives in this and other analyses is portrayed in figure 10.

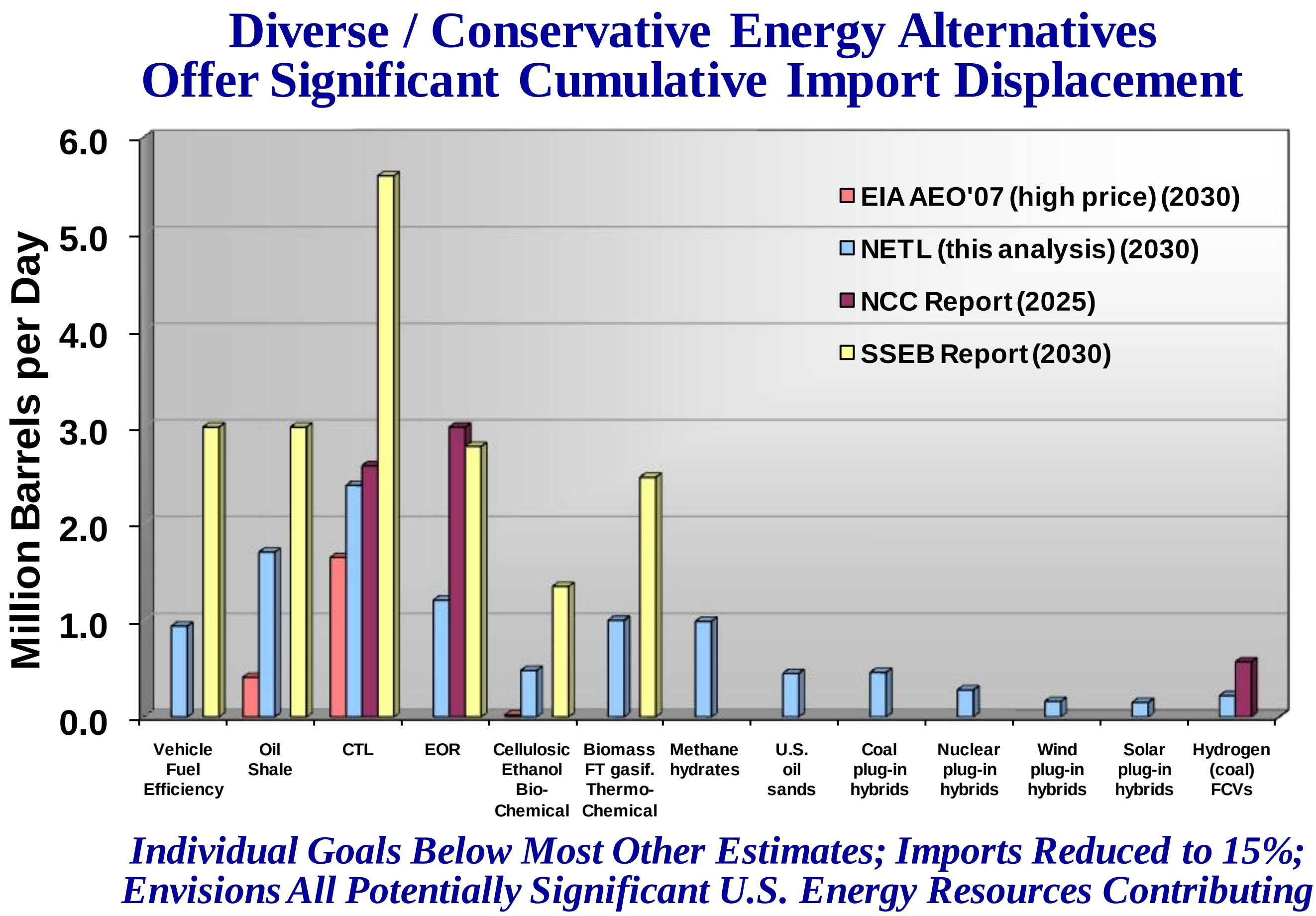

Figure 8

There are numerous avenues by which the United States could increase its energy security with respect to transportation fuels. Given the Nation's tradition of technology development, it would be shortsighted in a 24-year forecast to not include a modest but meaningful contribution from some of the largest potential domestic energy resources, including methane hydrates and oil shale. If production economics could be proven acceptable for these energy resources, commercialization efforts would escalate rapidly, with an enormously positive impact on U.S. energy security. Keeping these alternatives visible in energy alternative analyses, even with a future contribution at modest scale, provides a means of recognizing challenges and timing required but also establishes a vision of eventual success in their utilization.

IV. Achieving Advantageous Interdependence

A. *Choosing a Strategy*

In the recurring debate over the appropriate energy strategy for the United States, the central focus usually revolves around the acceptable level of dependence on foreign energy supplies. Philosophies vary between two extremes: on the one hand, charting a course toward achieving total U.S. "energy independence"; on the other hand, sustaining the Nation's historic approach of "interdependence" with the global energy market. The debate is typically presented as an either-or choice, ignoring the possibility of a middle ground.

This analysis posits the existence of an advantageous middle ground for the future U.S. energy market relationship that recognizes its ability to develop a diverse array of new, often over-looked, domestic energy alternatives. Successful execution of such a diverse alternative strategy would enable the United States to achieve a much higher level of energy self-sufficiency, characterized as "advantageous interdependence." The conclusions leading to this middle ground position were simple. Historic interdependence has not served the interests of energy-consuming nations well, with rapidly increasing prices over the last several years, decreasing supply security including lost access by International Oil Companies (IOCs) to a large share of the world's proved oil reserves, and a reluctance to aggressively develop non-conventional liquid fuel alternatives. Energy independence for the United States, on the other hand, would necessitate the displacement of 12 to 16 MMbd of global imports with U.S. alternatives, representing a 12 percent to 14 percent share of the world market. This would most likely lead to lower prices and the economic desirability, at some point, of maintaining a level of imports for competitive advantage. Advantageous interdependence acknowledges that foreign energy imports would not be totally displaced; their continued utilization, however, would depend on competitive pricing with alternatives developed in the United States. Such an approach has the advantage of reducing the targeted demand for domestic alternative energy sources from the goals required to achieve complete energy independence. A recognizable consequence of advantageous interdependence would be the revived ability of the United States to assert market power in world energy markets, in contrast to current conditions in which the United States is vulnerable to external market forces, as it has been for more than 30 years.

B. *Estimating a Target for Success*

The level of U.S. energy self-sufficiency necessary to achieve advantageous interdependence in liquid fuel is untested, as yet undetermined, and will vary with time and world market conditions. In this analysis, an illustrative level of 15 percent of liquid fuel imports by 2030 is chosen as the target to reflect a scenario with a significant reduction in foreign energy dependence and a meaningful but modest residual import demand. For comparison, in the *AEO'07* "Reference Case," the liquid fuel import share in 2030 remains stable with today at 61 percent of consumption, whereas, the chosen "High (Oil) Price Case," forecasts a declining share of 49 percent for imports by 2030, due to higher prices. In order to achieve 15 percent import target by 2030, U.S. consumption would need to develop 8 to 12 MMbd of incremental domestic liquid fuel alternatives depending on the forecast case analyzed. A level of 8 MMbd would be comparable to the incremental oil production from the North Sea, Prudhoe Bay, and Cantarell fields in the mid-1980s that supported a significant moderation in world oil prices at that time. It can be expected that, in a similar manner, oil imports can be driven to more competitive price levels adequate to maintain imports in the Nation's energy mix (advantageous interdependence). Whether an advantageous level of imports occurs at 25 percent or 15 percent or 5 percent of demand will depend not only on world oil prices but also geopolitical considerations and evolving views of the value of and need for energy security. Assessing the minimum level of imports should remain less important, however, than attaining the key objective of substantially reducing U.S. liquid fuel import vulnerability from the unacceptably high range of 60 percent of consumption.

C. *Desirability of Energy Independence*

Energy independence can be seen as holding diminishing value as the goal is eventually approached. A contemporary indication of evolving U.S. views of the need for energy security has been the February 2007 proposal by the Administration to double the current capacity of the SPR to 1.5 billion barrels by 2027. This represents a provision of approximately 97 days of net oil import protection by 2027 (assuming 15.5 MMbd imports in 2027, according to the *AEO'07* "Reference Case"). By reducing the U.S. import requirement via domestic alternatives to a level of 4 MMbd, the level of import protection would begin to exceed 1 full year of imports. M of maintaining 15 percent liquid fuel imports achieves this enhanced level of at least 1 year of SPR security. Thus, under such circumstances, if imports could be reduced to 4 MMbd or less, the need for achieving complete energy independence is likely to become less relevant than the desirability of maintaining access to competitive energy imports. This recognition can aid in lowering long-term domestic energy alternative targets and help improve the credibility associated with such an enhanced energy security program.

D. *Historic Interdependence*

Traditional concepts of energy interdependence suggest the need to maintain involvement in world oil and gas markets with supply predominantly represented by conventional resources. Interactions with reliable, long-term oil suppliers, such as Saudi Arabia—where "security of supply," technical collaboration, and sanctity of contracts characterize market relationships—reflect a more favorable vision of interdependence. Interactions with countries such as

Venezuela, Iran, and Russia, on the other hand, provide a much less compelling argument for interdependence. Yet the Saudi's represent only 15 percent of non-U.S. world oil production. In the Saudi example, they have portrayed themselves as sharing a compatible need for "security of demand" in order to justify the increased capital investments and technology development necessary to grow production adequately. The implication is that overzealous attempts to achieve more security of supply by key energy consuming nations like the United States represent a significant and balanced threat to the security of demand of producers such as Saudi Arabia. Historically, the threat has clearly been disproportionately greater for energy consumers who, in worst case scenarios, bear the risk of substantial, unanticipated cutoff of foreign energy supply, virtually overnight, due to political circumstances or other extraterritorial events beyond their control.

Calls for demand security ring hollow in light of efforts by producing nations to increase the nationalization of energy assets and to defend market prices with production cuts at the $60 per barrel level—two to three times the price level of only a few years ago. Historic interdependence has led to a continued dwindling of access to global oil reserves by IOCs and increased control of global reserves by National Oil Companies (NOCs). The long commitment by IOCs to energy interdependence has resulted in a world where "only about 6 percent of the world's oil reserves are actually fully accessible to equity participation by the IOCs. About another 12 percent is accessible under terms negotiated with the NOCs, leaving 77 percent under exclusive control of the NOCs."[18] The result of historic interdependence for the United States has been steadily increasing energy prices over the last 8 years and declining energy security. Additionally, calls for historic energy interdependence have tended to discourage development of unconventional energy alternatives and can prolong energy security disadvantages for the United States by presupposing a perpetual U.S. military presence in the Persian Gulf, which helps to confer market power to producing nations.

E. *Attaining Advantageous Interdependence*

Attaining advantageous interdependence with the world energy market is achievable for the United States, based on vast unconventional energy resources and a diverse array of domestic energy alternative technologies that can be developed in parallel. The technical challenges are recognized as difficult in some cases, but reflect challenges of a level that U.S. ingenuity has repeatedly met in the past. The world energy market appears to be entering a period of sustained tight supplies and high prices that will support and justify the development of domestic alternatives. To insulate (but not isolate) itself from the uncertainties of the world energy market, the United States should consider a domestic energy strategy that remains interdependent with the global energy community but only to the extent that such interdependency remains "advantageous."

Although the residual 15 percent import reliance could conceivably leave the United States vulnerable to import curtailments in the mid-term, two key distinctions should inure to a U.S. position of advantageous interdependence for energy supply:

[18] American Petroleum Institute, "Achieving Energy Security in an Interdependent World," http://www.api.org/aboutoilgas/security/achieving-energysec.cfm, March 16, 2007.

First, the extent to which energy-producing nations can exercise leverage over the United States and other consuming nations will have been greatly reduced. The detrimental nature of historic energy interdependence—which allowed major suppliers, collectively or individually, to substantially influence world energy prices by acting or threatening to reduce supply—will have been substantially mitigated by developing important new domestic sources of supply. Second, failure to act as a reliable supplier under such altered circumstances would eventually prove economically harmful to producing nations. In effect, the "security of demand" side of the energy interdependence equation will have acquired real meaning and influence. To the extent conventional oil production capacity margins actually increase due to non-conventional energy alternatives being developed, the competitiveness of the world oil market would improve enormously and the influence of alternative energy programs should be recognized in stable or reduced energy prices.

The act of developing the energy technologies that convert the large potential of U.S. alternative energy resources to useable reserves will have an enormous impact on the Nation's long-term leverage in world energy markets. It will become clear that the United States has the energy resources and the financial and technical capability to achieve energy independence if necessary. While there should be no need to revert to this extreme, this recognition would herald a paradigm shift in global market psychology, removing the threats and insecurities that currently create the perceived need for complete energy independence.

Finally, recognizing that energy alternative successes of the United States will be replicated in other key energy-consuming (importing) countries, such as China and India, the cumulative result of a diverse set of new energy alternatives will have a magnified impact on the global energy market. The impact of multiple nations simultaneously becoming more self-reliant for energy is certain to improve the market power of energy-consuming nations.

V. Conclusion

The extent of energy resources potentially available to the United States is massive, yet insufficiently recognized by the American people. The speculation that the United States may have access to energy resources equal to 43 times the world's proved oil reserves, may be seen as exaggerated, due the scale of technical challenges that have prevented their utilization. Such thinking too readily discounts the Nation's long track record for successfully developing technologies that have eventually become recognized as critical to its economic health and national security. Considering the scale of the energy opportunity available, a success in converting only a modest fraction of this energy potential to useable reserves could transform our Nation's energy vision from one of unsustainable reliance on foreign energy imports to that of a global energy resource leader.

The potential scale of domestic energy resources represents a latent asset that should not be ignored. The early verification of technical and economic feasibility for commercial use of major energy resources can serve as a valuable insurance policy for the United States against the geologic and geopolitical doubts surrounding future energy demands being met by imports. The U.S. endowment of energy resources, with modest success, can be converted to significant levels of reserves that can sustain the economic growth and well-being for the United States for generations to come.

The logic of pursuing multiple energy alternatives in parallel greatly enhances the credibility of an overarching energy strategy when the potential of cumulative contributions is recognized. Production targets for individual alternatives can be less aggressive, reducing perceived challenges while still achieving a significant overall reduction in imports. In the current analysis, liquid fuel imports forecast for 2030 were reduced from 49 percent of total demand to an illustrative 15 percent through a cumulative contribution of 8.4 MMbd from added domestic energy alternatives.

Key energy market developments support the view that a window of opportunity may have opened for the development of domestic liquid fuel energy alternatives, with less risk than traditionally envisioned. The greatly reduced excess of conventional oil production capacity represents a key distinction between today's market and that of the mid-1980s. Current excess capacity is estimated in the 2 MMbd range (2.4 percent of demand), a surplus level that has only recently been increased due to OPEC production cutbacks, attempting to maintain prices above $60 per barrel for West Texas Intermediate. Additionally, the ability for world economies to continue to grow at a healthy rate despite oil prices approaching $80 per barrel in 2006 reflects a surprising decrease in demand elasticity, suggesting less susceptibility for recession and demand destruction that could undercut the economics of new energy technology development. Additionally, the options of key OPEC countries, such as Iran and Venezuela, to cut prices merely as a means to undercut unconventional alternative energy development appears to be problematic, as these countries' own economies have become tremendously dependent on the high income levels currently being generated by oil exports and could not readily bear the loss of income from a significant price reduction or production curtailment.

Thus, the window for domestic alternative fuels development is supported by evidence that the world economy will support prevailing oil prices deemed adequate for attractive returns on investment by most alternatives. Also, it is apparent that issues such as an overhanging excess of supply capacity or the prospects for significant conventional oil discoveries are no longer realistic concerns. While world economies are healthy and growing, the opportunity for developing, financing, and integrating the energy alternatives remains at its highest. If the lack of alternatives were to persist in parallel with inadequate conventional energy supply growth, the prolonged tight markets and continuation of energy price increases of the last 8 years could lead global economies to reach a point where they are no longer healthy enough to finance and support the development of alternative energy technologies.

Rising energy prices, particularly for gasoline, have prompted many calls for "energy independence" in the United States. Reaching such an objective, however, is unnecessarily challenging and unrealistic. A benefit of an energy alternative program seeking "advantageous interdependence," in which price competitive imports continue to contribute but at more modest levels, is that the draw on domestic energy alternatives is reduced and the credibility of reaching meaningful but realistic levels of alternative production is enhanced. A successful alternative energy program in the United States is likely to be emulated throughout the world, including key developing nations, such as China and India, with a consequential impact on world energy markets. As the United States develops significant unconventional resources, such as methane hydrates and oil shale, China and India will increasingly look to such alternatives as well. As a result, global oil prices can be expected to become more competitive, implying the United States would to need to remain engaged at some level in the global energy market to maintain its competitiveness.

While a complete divorce from international energy markets resonates emotionally with the American public, the path toward significantly increased energy self-sufficiency will be long, and the technical and economic ramifications associated with such a separation would be immense. The advantageous interdependence approach proposed herein represents a middle-ground philosophy more attuned to the diverse options available to a country rich in energy resources and technical skill, with high productivity and economic competitiveness. Regaining global energy market leverage through an effort aimed at advantageous interdependence would reduce the Nation's exposure to the volatility of oil markets around the world, while capitalizing on the benefits associated with domestic resources.

Improved energy security for the United States is not likely to "happen" simply due to evolving market forces or by chance. Consideration should be given to a national effort to oversee and track the status and potential contribution of a diverse set of domestic energy alternatives necessary to substantially reduce domestic imports over a specified period. The ongoing analysis should consider technologies beyond near commercial energy technologies or current energy efficiency legislation, with a view to exploiting major U.S. energy resources. Important resources such as oil shale, methane hydrates, U.S. oil sands, and electricity applied to PHEVs should be included in a reasonable manner with an appropriate time scale. The effort should periodically evaluate and maintain updated perspectives regarding (i) forecasts for the Nation's energy supply and demand, (ii) reasonable supply targets encompassing all domestic energy alternatives, (iii) a commercialization timeline for technologies relating to key domestic energy alternatives, including a contemporary view of technology and environmental challenges and other issues that need to be addressed for each alternative, (iv) the forecast of cumulative impact of energy alternatives on imports, and (v) a perspective of the level of increasing U.S. energy security, as measured by the ability for the United States to gain a leveraged position of advantageous interdependence in its global energy trade.

Appendix A

Domestic Energy Alternatives and Resources Supporting Them

One of the important advantages in pursuing a diverse set of domestic energy alternatives is in the ability to keep goals and challenges reasonable while attempting to develop commercial technologies to utilize key domestic energy resources. Below is a review of each of the domestic energy alternatives identified, including a discussion of the U.S. energy resource base that supports it, the status of related technologies for use of the energy resource, the prospective timing to reach commercialization, and the production targets, and potential cumulative use of U.S. resources that, in some alternatives, cross over a number of alternatives. The current overview of these alternatives does not concentrate on economic analyses, comparative or otherwise. Due to some potentially large domestic energy resources having little current perspective of the cost of an eventual commercial production technology, meaningful comparative analyses are not yet possible. Nonetheless the inclusion of these resources in a long-term production scenario offers a useful vision of domestic supply opportunities usually overlooked due to the absence of such data. Under consideration is the gradual updating of the perspective herein with respect to the individual alternatives offered, providing more detail on production economics, technical challenges, environmental issues, and estimated schedule to commercialization. In such case this analysis could be maintained as a working document, inviting outside views and offering an ongoing perspective of the contemporary status of domestic energy alternatives for liquid fuel production and the cumulative potential to support increased energy security in an environmentally acceptable manner.

A. *Coal-to-Liquids*

Coal-to-liquids (CTL) technology is forecast herein to have a large potential contribution to mitigating U.S. liquid fuel imports by 2030, at 2.4 MMbd including the *AEO'07* "High (Oil) Price Case" forecast. The key advantages for the United States to use CTL as an energy security alternative relate to its large reserves of coal, the proven commercial viability of CTL technology, and the direct applicability of the end product of the technology in meeting liquid fuel demand. Numerous domestic energy companies have indicated intentions to devote significant attention to near-term development of business opportunities surrounding CTL technology. Gregory H. Boyce, President and Chief Executive Officer of the Nation's largest coal producer, Peabody Energy, made the following comments in announcing a new joint venture with Rentech, Inc., for CTL project development:

> We're seeing an overwhelming need for coal-to-liquids developments in the United States to offset reliance on expensive imported oil, and projects like these represent a major part of our energy solutions.[19]

[19] Peabody Energy, "Peabody Energy and Rentech Partner to Develop Major Coal-to-Liquids Projects," news release, July 18, 2006.

Other companies, including Syntroleum Corporation, DKRW Advanced Fuels, and Arch Coal, have also announced intentions to pursue CTL-based business opportunities. In February, 2007, CONSOL Energy indicated it will partner with Headwaters, Inc., for CTL production projects. According to Hunt Ramsbottom, Rentech president and CEO, fuels from CTL technology can be produced and finished for $36 to $42 per barrel.[20]

1. U.S. Coal Resources

As portrayed in figure 6 (America's Endowment of Solid, Liquid, and Gaseous Fuel Resources), the estimate of U.S. coal resources is by far the largest component of U.S. energy resources presently tied to commercially viable energy technologies for liquid fuel alternatives. The coal resources shown (indicated as "SSEB Coal Survey") reflect a combination of the "official" (2004) Energy Information Administration (EIA) report on U.S. coal resources combined with recently reported results of a Southern States Energy Board (SSEB) survey of U.S. State coal reserve estimates[21] added to technically and economically recoverable resources. The coal resources also include a remarkably large component of undiscovered (hypothetical) coal, attributed by the U.S. Geological Survey (USGS) to Alaska,[22] but not included in the EIA coal resource assessment, that continues to predominantly rely on a U.S. coal resource assessment done in 1974, using data from 1972 or earlier. The recent National Research Council report, focusing on lower-48 reserves, briefly acknowledges the vastness of Alaskan resources but otherwise dispenses with their potential contribution to the energy reserves of the United States.[23]

If the upwardly revised estimates are applied to the traditional EIA coal resource pyramid,[24] graphically representing the U.S. coal resources, the additional coal resources would add 143 percent to the previous U.S. coal resource estimate as shown in figure 11. For perspective, based on the SSEB survey of State coal reserve estimates, the reported 276 billion tons (+56 percent) of coal are added to the Demonstrated Reserve Base (DRB), reflecting the potential impact if these survey values can eventually be confirmed. The survey additions to the DRB were performed using EIA percent age estimates for recoverable reserves by State. If 151 billion tons could be added to the estimate of recoverable reserves overall, within the DRB, the current estimate of years of economically recoverable coal reserves available (at the 2005 consumption rate of 1.13 billion tons per year) would extend from 236 years to 369 years. With regard to the Alaskan resource base, the SSEB report also speculated that 500 billion additional tons of Alaskan coal could be added to the U.S. reserve base[25] implying the estimate of years of coal reserves at current consumption rates could extend to 811 years, and the related energy equivalent in barrels of oil (1,377 billion BOE) could exceed estimates for the total of the

[20] Coal Trader, July 24, 2006, 3-4.
[21] SSEB, *American Energy Security: Building a Bridge to Energy Independence and a Sustainable Energy Future*, July 2006, 32.
[22] Romeo M. Flores, Gary D. Stricker, and Scott A. Kinney, *Alaska Coal Geology, Resources, and Coalbed Methane Potential*, Data Series (USGS, 2004).
[23] National Research Council, 2007, *Coal: Research and Development to Support National Energy Policy*, p.46 (prepublication copy); http://www.nap.edu/catalog/11977.html. The NRC does not address how any additional amount of Alaskan coal from the estimated 3.9 - 5 trillion ton resource base could be added to the US reserve total.
[24] EIA, *U.S. Coal Reserves: 1997 Update*, February 1999, 5.
[25] SSEB, *American Energy Security*, appendix B, 18.

world's proved oil reserves. As coal becomes an important resource for varied U.S. energy alternatives, such as coal gasification, CTL, and plug-in hybrid electric vehicles (PHEVs) based on electricity from coal, annual consumption will increase rapidly.

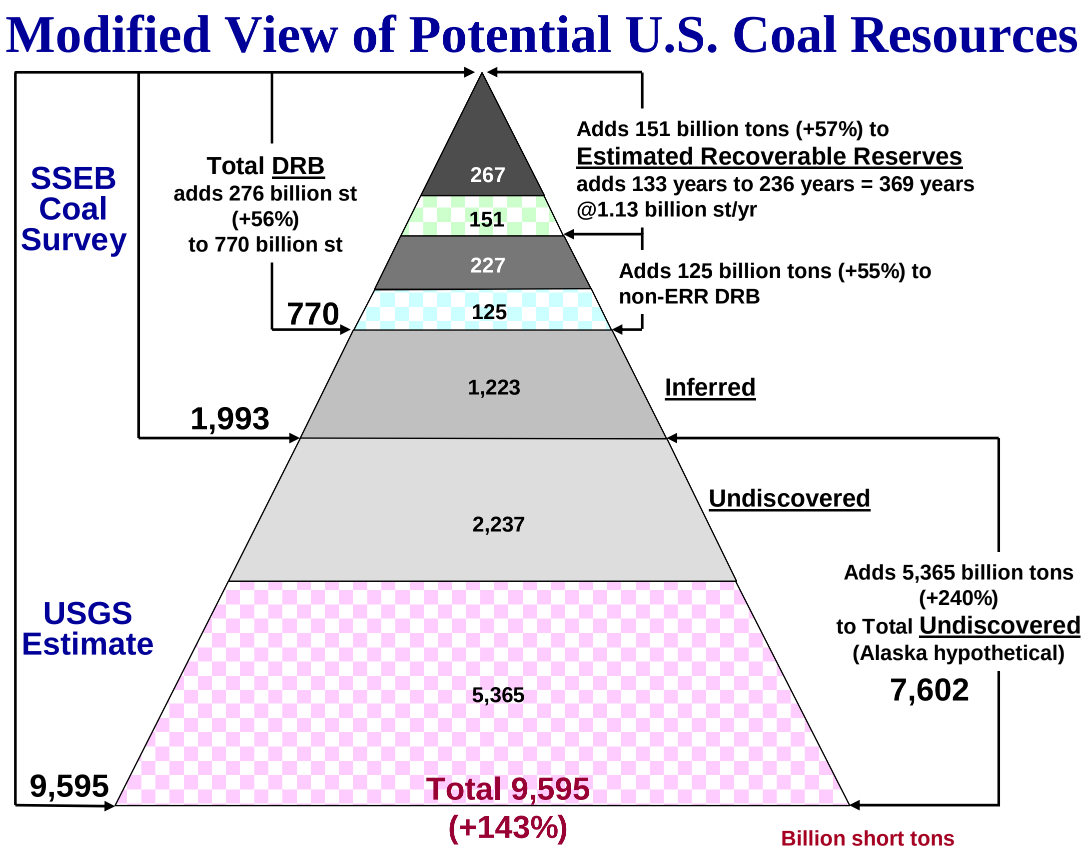

Figure 9

Coal will remain a vital component of the Nation's energy mix with potential to strongly support the Nation's energy needs for many generations to come. The establishment of the true nature and scale of U.S. coal resources will lend significant credibility to the Nation's alternative energy programs relating to coal and will bring important leverage to future energy trade supporting the development of advantageous interdependence.

2. Status of CTL Technologies

South Africa has utilized CTL technology since 1955 to produce transportation fuels and chemical by-products. The SASOL facilities at Secunda currently are capable of producing 160,000 bpd using the Lurgi fixed-bed gasification technology and SASOL Advanced Synthesis Fischer-Tropsch (FT) reactors. The technology at one time served 40 percent of South Africa's fuel needs, but today it satisfies 28 percent.[26] Although widely considered to represent commercial technology, there are no commercial facilities operating in the United States, which results in risk perception that can inhibit rapid deployment. Nevertheless, as mentioned above, significant announcements of commercial CTL project developments are appearing within the United States. Additionally, Shell and SASOL have signed a deal with state-owned China Shenhua Group to study two CTL plants, each with a capacity of 80,000 bpd, for northwestern China with an investment of up to US$12 billion.

The U.S. Department of Energy (DOE) is currently funding a CTL project under Round 1 of its Clean Coal Power Initiative Program to demonstrate the feasibility of an integrated gasification combined cycle polygeneration plant using low-cost feedstock and coal wastes. The Gilberton Coal-to-Clean Fuels and Power project will utilize Shell gasification technology in combination with SASOL's low-temperature FT process to produce 5,000 bpd of ultra-clean FT liquids and either electric power or steam coproducts.

One of the key concerns for CTL technology is the incremental production of CO_2 compared to traditional crude oil refining. With sequestration added to the process, this disadvantage can be substantially mitigated. An important prospect for greatly improving the environmental performance of the CTL process, from a CO_2 emissions standpoint, may be the combination with biomass gasification; a subject discussed further in appendix A, section H.

3. Timing to Commercial Implementation

Since the technology is presently deemed commercial, the current timing to begin implementation of this energy alternative is primarily limited by time necessary for financing, permitting, engineering, and construction. In support of financing, the Energy Policy Act of 2005 has offered significant tax incentives, as well as potential for loan guarantees for CTL projects. Within the legislation was also a section authorizing up to $425 million in support of a FT demonstration project, from 2006 through 2010, using Illinois coal.[27]

The CTL component commercial production is estimated to begin contributing to U.S. energy supply in 2011, which represents a reasonable period within which CTL projects announced today will become commercially active.

4. Targeted Results for CTL

Due to persistently high oil prices, CTL technology was included for the first time included in the "Reference Case" forecast of *AEO '06*. The *AEO'07* "High (Oil) Price Case" used in this analysis included 1.65 MMbd of supply from CTL by 2030 (for liquids and heat/power). This report assumed the ability to produce an additional 750,000 bpd from CTL technology for liquids by 2030, for a total CTL capacity of 2.4 MMbd. A higher level of capacity for CTL (2.6 MMbd)

[26] Ari Geertsema, "Barriers and Opportunities Relating to the Production of Coal Liquids and its Environmental Issues," (presentation, Richard G. Lugar Purdue University Summit on Energy Security, West Lafayette, IN, August 29, 2006).
[27] *Energy Policy Act of 2005*, 109th Cong., 1st sess., 2005, H. Rep. 109-190, Title IV, subtitle B.

was estimated to be possible by the National Coal Council (NCC)[28] by 2025, 5 years sooner. In the analysis performed by the SSEB,[29] the estimated potential for CTL production by 2030 was 5.6 MMbd, or 133 percent higher over the same period.

Although CTL remains one of the most credible domestic energy alternatives due to the technology status and the availability of U.S. coal resources, the diversity of energy alternatives considered in this analysis allowed a less aggressive target for CTL to still contribute to a meaningful cumulative result.

5. Cumulative Use of U.S. Coal Resources Anticipated

In the *AEO'07* "High (Oil) Price Case" scenario forecast, approximately 404 million tons of coal is expected to produce 1.65 million bpd of CTL by 2030, representing a ratio of approximately 1.5 barrels per ton of coal. In contrast, the NCC's estimate[30] of coal required for their estimated 2.6 MMbd of CTL by 2025 is 475 million tons, representing a ratio of 2.0 barrels per ton. The EIA has estimated that approximately 72 percent of incremental coal from 2005 through 2030 will be derived from Western coals. The average Btu content of incremental coal over this period will be approximately 9,650 Btu per pound. As a result, estimates of coal requirements for alternative forms of energy production need to take into account lower levels of energy production per ton of the incremental coal likely to be available. The additional CTL production envisioned herein, above the *AEO'07* estimate of 1.65 MMbd, represents 750,000 bpd of CTL for liquids production by 2030. Using the EIA ratio of 1.5:1 barrels to ton would imply the need for 182 million tons per year of additional coal for the CTL industry by 2030, for a total of 586 million tons of coal for CTL. The additional CTL tonnage would result in approximately a 9 percent increase in the *AEO'07* "High (Oil) Price Case" estimate of approximately 2 billion tons of U.S. coal production by 2030 to approximately 2,130 million tons. Combined with other *AEO'07* "High (Oil) Price Case" growth assumptions for coal consumption, such as electricity, this would represent a significant increase over 2006 coal production (+85 percent).

B. *Oil Shale*

1. U.S. Oil Shale Resources

Oil shale resources represent one of the largest U.S. energy assets with potential to establish reserves that would rival or surpass current estimates of total proved global oil reserves, once related technologies are deemed commercially viable. Recent summary estimates of the potential yields from U.S. oil shale resources surpass 2.0 trillion barrels of oil; 70 times the amount of today's U.S. proved petroleum reserves and nearly double the total proved oil reserves for the world[31] (table 1).

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[28] NCC, *Coal: America's Energy Future*, 1 (March 2006) 15.
[29] SSEB, *American Energy Security*, 133.
[30] NCC, *Coal*, 2, 65.
[31] John R. Dyni, *Geology and Resources of Some World Oil-Shale Deposits*, Scientific Investigations Report (USGS, 2006), 42, 37.

Table 1. Summary of U.S. Oil Shale Resources

	Age	In-Place Oil Shale Resources MM bbls	Date of Estimation	Source of Information
United States				
Eastern Devonian Shale	Devonian	189,000	1980	Matthews & Others (1980)
Green River Formation	Tertiary	1,466,000	1999	Dyni (2005)
Phosphoria Formation	Permian	250,000	1980	Smith (1980)
Heath Formation	Mississippian	180,000	1980	Do
Elko Formation	Tertiary	228	1983	Moore & Others (1983)
	TOTAL	2,085,228		

The resources are predominantly located in the Green River Formation including Utah, Wyoming, and Colorado (figure 12). Approximately 72 percent of Western resources are on Federal land. Oil shale represents the Nation's most concentrated energy resource with up to 2 million barrels per acre in the richest deposits. Half of Western resources are estimated to be able to produce 25 gallons per ton (0.6 barrels per ton), currently analogous to the production ratios of Canadian oil sands, which have proven very economic to produce in today's market. About one trillion barrels of oil are estimated to exist in the 1,200 square mile area of the Piscean basin in Colorado. Thus, in an area of roughly 30 by 40 miles, oil shale resources exist that are roughly equivalent to the current total estimate of proved oil reserves. Within this basin, over 500 billion barrels, roughly double the estimate of proved oil reserves of Saudi Arabia, are contained in deposits containing more than 30 gallons per ton, 20 percent richer than Canadian oil sands.

2. Status of Oil Shale Technology

Efforts to commercialize oil shale in response to the oil crisis of the 1970s and 1980s were attempted by a number of major oil firms including Exxon, Shell, Mobil, Occidental, Atlantic Richfield, Chevron, and Unocal; however, the last effort of these commercialization efforts was terminated by Unocal in 1991. Among the most promising recent technology development efforts is the "in situ" approach being developed by Shell Oil. Shell's In situ Conversion Process, or ICP, eliminates fracturing in favor of slowly heating isolated shale strata over an extended period of time. This technology utilizes extensive drilling of numerous heating, production, and isolation wells. The thermal conduction of heat generates slower heat-up rates and results in lower process temperatures, reducing oil losses from thermal cracking and coking reactions, as well as decomposition of carbonate rock. Pressure from the production of gases and vapors creates permeability and allows transport of oil vapors to the production wells. The process has been tested for feasibility, and Shell is now in the process of initiating a large-scale demonstration to prove technical, environmental, and commercial viability. In 2005, Terry

O'Connor, Shell Vice President of External Affairs,[32] indicated that a decision to move forward commercially could be expected from Shell by 2010.

Location of Key Oil Shale Resources

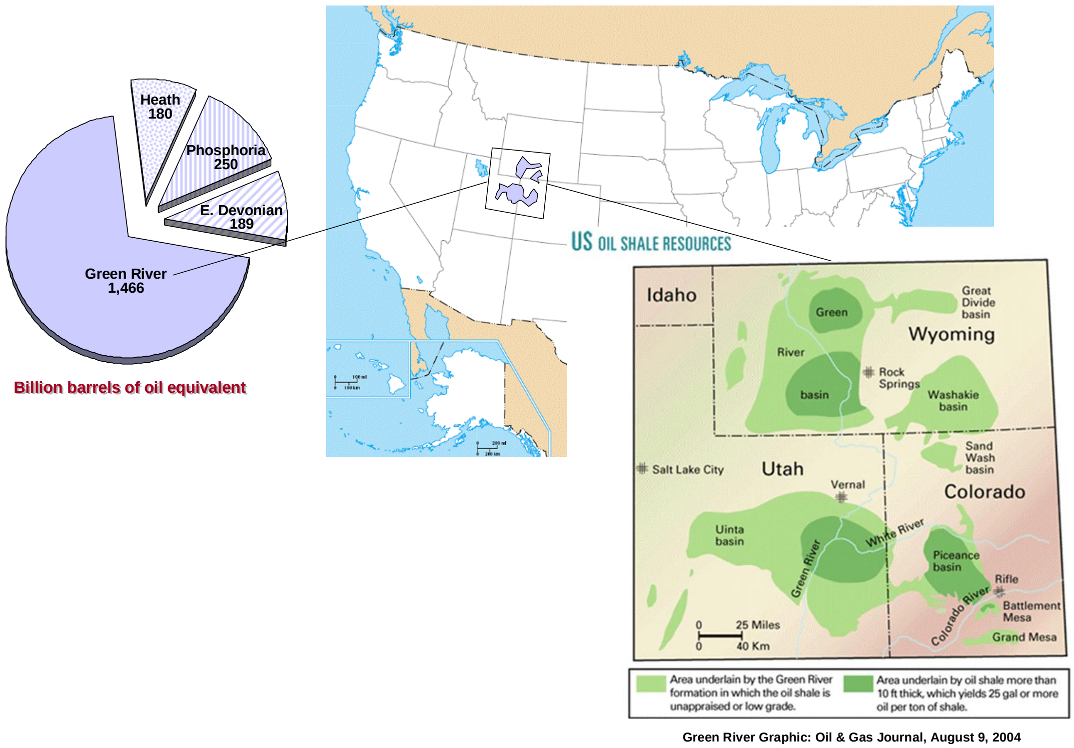


Figure 10

3. Timing to Commercial Implementation of Oil Shale

Estimates used in this analysis for oil shale to begin contributing commercially to the Nation's energy security are 11 years, by 2018. This is 1 year sooner than the EIA's estimate of 2019 for initial commercial oil shale production in the "High (Oil) Price Case" of *AEO'07*. The 2005 RAND report[33] on oil shale had a similar view to EIA, indicating that a firm decision to commit funds is at least 6 years away with an additional 6 to 8 years before commercial operation, implying a 2018 to 2020 time frame. Shell Oil's focus on timing recently became less focused on their decision point to move toward commercialization (2010) and more on the actual point of significant commercial production. According to Shell Vice President of External Affairs Terry O'Connor,[34] if the tests and necessary government approvals go well, Shell expects the company will be ready to start large-scale, commercial oil production by about 2015, 3 years sooner than

[32] Associated Press, "Shell Oil Hopes to Begin Shale Oil Production by 2010," April 8, 2005.
[33] James T. Bartis et.al., *Oil Shale Development in the United States, Prospects and Policy Issues*, RAND for DOE's National Energy Technology Laboratory (NETL), 2005, 22.
[34] Robert Collier, "Coaxing Oil from Huge U.S. Shale Deposits," *San Francisco Chronicle*, September 4, 2006.

the estimate of initial commercial production used in this analysis. At the same time, however, Shell acknowledges this time frame is associated with unhurried progress:

> We believe that we can produce large amounts of oil with no adverse environmental impact, but we're proceeding slowly and responsibly to make sure this is true, to cover all contingencies.[35]

4. Targeted Results for Oil Shale

Oil shale's estimated contribution to U.S. supply in the *AEO'07* "High (Oil) Price Case" was 410,000 bpd by 2030. This analysis assumed another 1.3 MMbd to be feasible for a total estimated oil shale supply of 1.7 MMbd by 2030. In comparison, the SSEB report estimated 76 percent more, or 3.0 MMbd,[36] to be possible in the same time frame.

The economics of oil shale processing may be greatly impacted by the success of an in situ process such as Shell's. Recent estimates for commercialization of the oil shale mining and retorting process require prices in the $70 to $95 per barrel range (2005 dollars),[37] which prices are surpassed in 2010 and 2025, respectively, in the *AEO'07* "High (Oil) Price Case" forecast (2005 dollars). More positively, Shell expects that in situ processing could only require prices in the low $30 per barrel range[38] for commercialization, which would represent an attractive investment alternative for development under any of the EIA price scenarios. Ultimately, due to the abundance and concentration of this domestic energy resource, attractive production economics could lead to much higher production levels.

5. Cumulative Use of U.S. Oil Shale Resources Anticipated

The cumulative production of oil products from oil shale resources assumed herein is approximately 4.1 billion barrels through 2030. Assuming 2 tons of oil shale per barrel of production, the related consumption of the oil shale resource would represent 8 billion tons. This would represent less than 1 percent of the U.S. oil shale resource estimated in the Green River Formation alone.

C. *Methane Hydrates*

1. U.S. Methane Hydrates Resources

While methane hydrates have been recognized as a laboratory phenomenon since the turn of the century and as a pipeline-plugging nuisance since the 1930s, it was only in the 1960s and 1970s that the idea of naturally occurring accumulations of methane hydrate concentrated in deepwater sediments and permafrost began to circulate internationally. Then, in 1982, scientists onboard the *Glomar Challenger* retrieved a 1 m (3.28 ft) long sample of pure methane hydrate from

[35] Ibid.
[36] SSEB, *American Energy Security*, 133.
[37] Bartis, *Oil Shale Development*, 15.
[38] Collier, "Coaxing Oil," September 4, 2006.

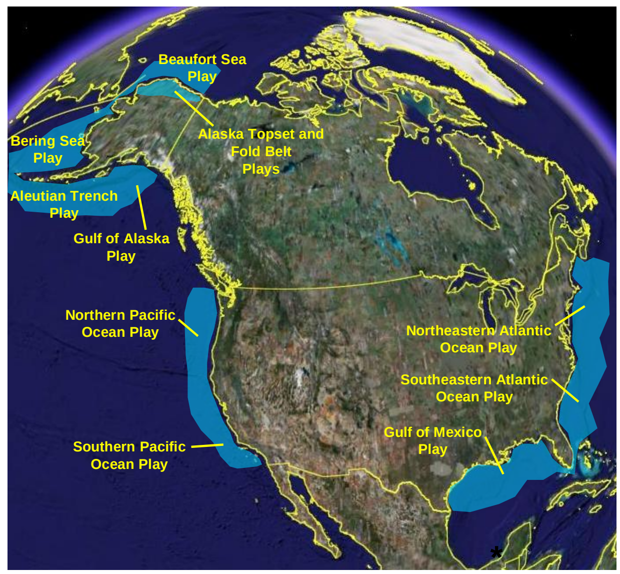
deepwater sediments. This core became the impetus for the first federally funded R&D program dedicated to hydrates.

Figure 13 shows the USGS estimates[39] from the plays around the United States, with Alaska having more than 50 percent of the initially estimated 320,000 Tcf reserves. In the United States, offshore deposits have been identified in Alaska, all along the West Coast, in the Gulf of Mexico, and, most notably, along Blake Ridge, about 250 miles east of South Carolina. Onshore gas hydrates have been found in permafrost regions such as the North Slope of Alaska at a range of depths from 130 to 2,000 meters below the surface.

Location of Methane Hydrate Occurrences

Estimated Gas Hydrate Resources in Place in the U.S.

	Mean Resource in Place (Tcf)
Atlantic Coast Province	**51,831**
Northeastern Atlantic Ocean Play	30,251
Southeastern Atlantic Ocean Play	21,580
Gulf of Mexico Province	**38,251**
Gulf of Mexico Play	38,251
Pacific Ocean Province	**61,071**
Northern Pacific Play	53,721
Southern Pacific Play	7,350
Alaska Offshore Province	**168,449**
Beaufort Sea Play	32,304
Bering Sea Play	73,289
Aleutian Trench Play	21,496
Gulf of Alaska Play	41,360
Offshore Provinces Subtotal	**319,602**
Alaska Onshore Provinces	**590**
Topset play -- state lands and waters	105
Topset play -- federal waters	43
Fold Belt Play -- state lands and waters	414
Fold Belt Play -- federal waters	28
U.S. TOTAL	**320,192***



*** - Subsequent to this report, analysis of core samples taken on the Blake Ridge, off the coast of S. Carolina, collected as part of the National Science Foundation's Ocean Drilling Program, indicated that a reduction in the assumed values for hydrates was needed, which would result in a revised, as-yet unofficial, estimate of 200,000 Tcf**

Figure 11

Subsequent to the work described above, analysis of core samples taken on the Blake Ridge, off the coast of South Carolina, and collected as part of the National Science Foundation's Ocean Drilling Program, indicated that a reduction in the assumed values for hydrates was needed, which would result in a revised, as-yet unofficial, estimate of 200,000 Tcf.[40] This methane hydrates resource potential still represents approximately 1,000 times the current estimate for recoverable reserves of natural gas in the United States.

[39] D.L. Gautier, G.L. Dolton, K.I. Takahasi, and K.L. Varnes, *National Assessment of United States Oil and Gas Resources: Results, Methodology, and Supporting Data*, Data Series, (USGS 1995).
[40] Advanced Resources International, Inc., (ARI), *Review of Non-technical Issues Relating to Methane Hydrate Production, Final Report*, for DOE/NETL, September 2004.

2. Status of Methane Hydrates Technologies

The National Methane Hydrate R&D Program produced a roadmap for interagency R&D development activities in July 2006.[41] The document outlines the current goals of the program over two time frames. By 2015, the program will:

- demonstrate viable technologies to assess and mitigate environmental impacts related to hydrate destabilization resulting from ongoing "conventional" oil and gas exploration and production (E&P) activities;

- document the risks and demonstrate viable mitigation strategies related to safe drilling in hydrate-bearing areas; and

- demonstrate the technical and economic viability of methane recovery <u>from arctic hydrate</u>.

By 2025, the program will:

- demonstrate the technical and economic viability of methane recovery <u>from domestic marine hydrate</u>;

- document the potential for and impact of natural hydrate degassing on the environment; and

- assess the potential to further extend marine hydrate recoverability beyond the initial producible areas.

Congress has recognized the long-term strategic importance of this resource by authorizing appropriations of $155 million over 5 years for further research to promote the development of promising technologies for methane hydrates resource production within the Energy Policy Act of 2005. In August 2006, China announced plans to invest $100 million over the next 10 years in methane hydrates research.[42] Reportedly, China plans to work with German researchers to sample hydrates deposits in the northern part of the South China Sea within a year.

3. Timing to Commercial Implementation of Methane Hydrates

The timing assumed herein for methane hydrates' initial contribution to commercial production is 2022. The aforementioned roadmap established as a goal to demonstrate technical and economic viability of methane recovery from Arctic hydrates by 2015, which would leave adequate time for commercial production to commence by 2022. Additionally, the roadmap document indicates the following with respect to timing:[43]

[41] Technical Coordination Team, National Methane Hydrate R&D Program, *An Interagency Roadmap for Methane Hydrate Research and Development*, DOE, July 2006.
[42] China's National Development and Reform Commission announcement, August 2006.
[43] Technical Coordination Team, *Roadmap for Methane Hydrate*, 13.

DOE and the ICC member agencies recognize that the Nation may have a need for the gas resources that hydrate might provide earlier than these stated milestone dates. Consequently, the Program will investigate every opportunity to supplement current work with projects that promise to shorten the program's time lines, particularly with respect to:

- Exploratory assessment wells on the outer continental shelf and

- Field production tests in both arctic and marine settings.

Options that will be pursued may include working directly with State agencies, international programs, and others with the means and desire to support such efforts.

Figure 14 portrays the current National Methane Hydrate R&D Program goals as they pertain to Arctic hydrates production.[44]

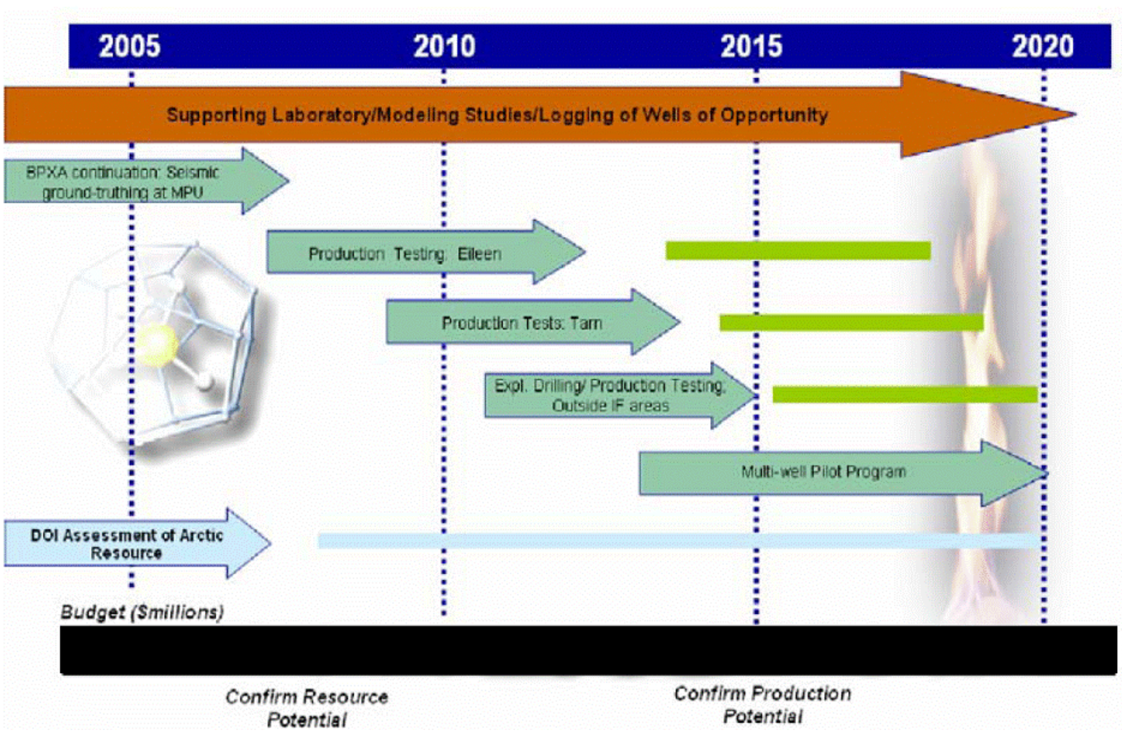


Figure 12

DOE's goal is to have pilot-tested technologies for the production of Arctic hydrates available by 2015, which would initially confirm the production potential of tens of Tcf, from well characterized and geologically favorable sandstones on the North Slope of Alaska. This would be broadened to hundreds of Tcf of resource across a broader range of North Slope resources and then to confirming the production potential of marine hydrates, with thousands of Tcf of potential resources.

[44] Technical Coordination Team, *Roadmap for Methane Hydrate*, 25.

4. Targeted Results for Methane Hydrates

The estimate used for methane hydrates, herein, assumes the equivalent of approximately 100,000 bpd of oil equivalent by 2022 increasing to approximately 1 MMbd of oil equivalent methane hydrates production by 2030. It is deemed feasible provided that the initial production potential of Arctic hydrates can be established by 2015, with broader technology development, including marine hydrates, by 2025.

5. Cumulative Use of U.S. Methane Hydrates Resources Anticipated

A ramp up in production from 100,000 bpd in 2022 to 1 MMbd by 2030 would result in cumulative production of about 1.8 billion BOE production by 2030. This represents roughly 10 Tcf, a fraction of the initial 2015 Arctic hydrates resource confirmation goal of the program and a small percentage of the potential for thousands of Tcf of marine hydrates resources that are targeted for production as early as 2025.

D. *Enhanced Oil Recovery*

1. U.S. Resources Applicable to EOR

Reports produced on behalf of DOE concerning the potential for EOR in the United States have recently reflected remarkable potential for incremental oil production in the United States due to improvement in the EOR technology used (figure 15).

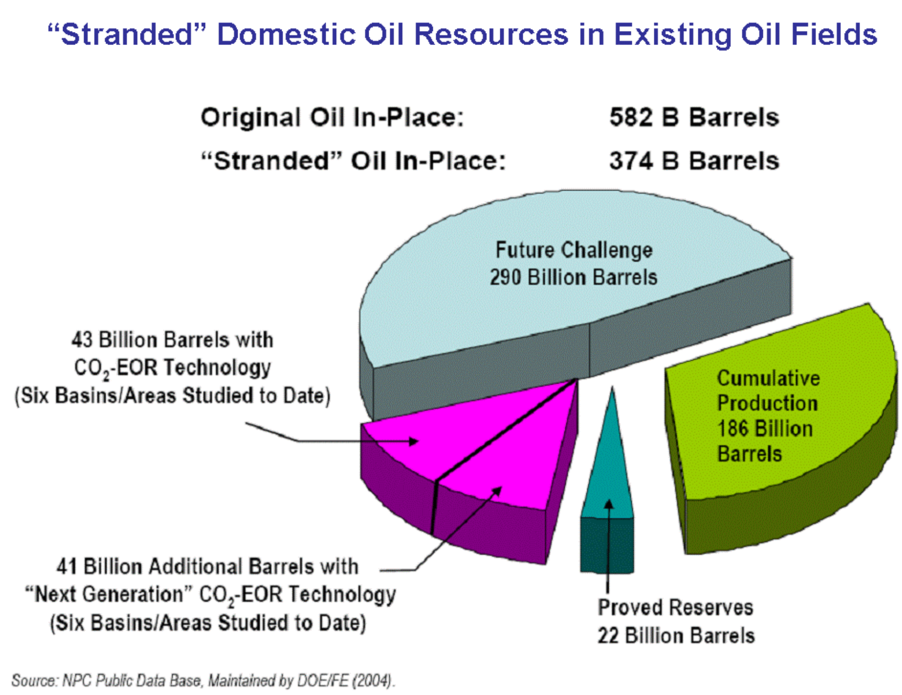


Figure 13

Of the original 582 billion barrels of oil-in-place in already discovered fields, 208 billion barrels have already been produced or are included in the 22 billion barrels of proved reserves.[45] Subtracting this produced or producible portion leaves 374 billion barrels of "stranded" oil that can be targeted by improved CO_2-EOR technologies. Within the stranded oil from discovered fields estimates are that, in 6 specific basins analyzed, 84 billion barrels of additional oil can be made technically recoverable with current and next-generation EOR technologies—an amount nearly 4 times current proved reserve for the United States.

Further estimates indicate that undiscovered fields and future reserve growth will eventually add 570 billion barrels of additional oil-in-place of which 190 billion barrels will be produced at traditional recovery rates (estimated at 33 percent). This would result in an additional 380 billion barrels of stranded oil that could be targeted with EOR. In total, if the data of 6 basins analyzed are extrapolated to the other stranded oil resources in the United States, estimates are that improved EOR technologies can result in 160 billion barrels of total incremental oil becoming technically recoverable.[46]

2. Status of EOR Technologies

EOR is currently commercially deployed as a production technology in the United States resulting in over 200,000 bpd, according to an *Oil & Gas Journal* 2004 industry survey. "Next generation" technology promising greater recovery ratios involves CO_2-EOR technologies, which inject higher volumes of CO_2, adopt innovative CO_2 flood and well design, and add mobility control. ARI estimates that new technologies can improve CO_2-EOR recovery ratios from roughly 10 percent with today's technology to as much as 80 percent in some applications.

Current use of anthropogenic CO_2-EOR technology in North America is portrayed in table 2:

[45] ARI, *Evaluating the Potential for "Game Changer" Improvements in Oil Recovery from CO_2 Enhanced Oil Recovery*, for DOE's Office of Fossil Energy (FE), February 2006. The estimates of remaining recoverable domestic oil resources from undiscovered and reserve growth are from the latest national resource assessments by the USGS and the U.S. Minerals Management Service (provided in appendices 3A, 3B, and 4. The estimates of recoverable oil resources using EOR technology on "stranded" oil and oil sands are based on work by ARI for DOE/FE's Office of Oil and Natural Gas.

[46] Ibid., 4.

Table 2. Existing North American Anthropogenic CO_2 EOR with CCS

CO_2 EOR CCS Using Anthropogenic CO_2[47]				
State/Province	**Plant Type**	**CO_2 Million t/yr**	**EOR Fields**	**Operator**
Texas	Gas Processing	1.6	Sharon, Ridge, etc.	ExxonMobil
Colorado		1.3	Rangely	Chevron/Texaco
Oklahoma	Fertilizer	0.7	Purdy, Sho-Ven-Tum	Anadarko/Chaparell
Wyoming		3.6	Lost Soldier, Salt Creek	ExxonMobil
Alberta	Ethylene	0.5	Joffre Viking	Numac Energy
Saskatchewan/North Dakota	Coal Gasification	2.0	Weyburn	Encana
North American Total		**9.7**	**Million tons per year CO_2***	
* This is almost 30 percent of the total North American EOR of about 35 million t/y. For comparison North Sea Sleipner Aquifer CO_2 injects only 1.0 million t/y.				

In comparison to the total CO_2 challenge, the EIA estimate for total CO_2 emissions in the United States from fossil fuels for 2006 was approximately 6 billion metric tons.[48]

3. Timing to Commercial Implementation of EOR

Although EOR technology is already a commercially viable technology for oil production, ongoing technology development offering improved recovery efficiencies will continue to occur as newer technology is deployed. One important element of support for this technology will be the addition of a new generation of coal-fired power plants that produce rich streams of CO_2 as a result of the gasification or oxygen-rich combustion process. Past CO_2-EOR processes were often less efficient due to less than optimal CO_2 use influenced by the scarcity and high cost of CO_2. Developing plans for next generation coal-fired plants that will seek to sequester CO_2 by-products promise a win-win opportunity for using this CO_2 in the new EOR applications.

4. Targeted Results for EOR

The estimate for incremental CO_2-based EOR contribution used in this analysis is 1.2 MMbd by 2030. Recognizing that roughly 200,000 bpd may already be blended into the EIA's domestic production forecast and not broken out, the increment identified here results in a total of 1.4 MMbd. Considering the promise of much higher recovery efficiencies for new EOR technologies, a several-fold increase in production by 2030 would appear conservative. In the NCC March 2006 analysis of energy alternatives, CO_2-EOR was estimated to potentially produce 2 to 3 MMbd by 2025.[49] The SSEB estimate for CO_2-based EOR was 2.8 MMbd (2.6 MMbd incremental) by 2030. Again, due to diversity of energy alternatives, the estimate for the EOR contribution by 2030 is 33 percent to 40 percent of other estimates, while still supporting a significant cumulative reduction in imported liquid fuels.

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[47] Dale Simbeck, "Emerging Unconventional Liquid Petroleum Options," (presentation, EIA Energy Outlook and Modeling Conference, Washington, D.C., March 27, 2006).
[48] EIA, *AEO'07*, table 18.
[49] NCC, *Coal*, 84.

5. Cumulative Use of U.S. EOR Opportunities Anticipated

The cumulative estimate herein of oil production through 2030 using advanced CO_2-EOR technologies is approximately 5 billion barrels. Taking into account that prospective technically recoverable domestic oil, using improved CO_2-EOR technologies, can eventually amount to 160 billion barrels, including future discoveries, this estimate would only imply use of 3 percent of the opportunities available over the next 24 years. The significant benefits to this production process to be derived from planned CO_2 sequestration efforts within the U.S. coal-fired power generation industry could place the United States in a unique and advantageous position in terms of CO_2 availability and for using CO_2-EOR to develop additional energy resources.

E. *Vehicle Fuel Efficiency*

1. Diminished Demand for Liquid fuel Due to VFE

Increasing Vehicle Fuel Efficiency (VFE) standards for U.S. vehicles is a proven mechanism for reducing import demand by reducing overall liquid fuel demand. VFE represents a unique energy alternative among the contributing import, reducing options proposed in this analysis because, unlike the other energy-producing alternatives, the impact of VFE is to reduce the overall liquid fuel demand in the forecast. In the energy alternative summary chart (figure 9), for consistency with other alternatives, VFE is shown as contributing a segment of incremental domestic liquid fuel capacity equal to the fuel savings generated, even though its contribution is to actually reduce overall forecasted demand by the amount reflected.

2. Technology for VFE

Automotive VFE technology improvements stem from either improvement in powertrain technologies or in load reduction via a decrease in weight or wind resistance, etc. Such technologies continue to make significant progress with time, allowing for either improved VFE or vehicle performance or a combination of the two. In a 2002 study by the National Research Council (NRC) of the National Academies of Science on the effectiveness of corporate average fuel efficiency (CAFE) standards, two distinct periods of technology improvements were described for automotive transport, as mentioned within one of the key findings:[50]

> **Finding 4**. In the period since 1975, manufacturers have made considerable improvements in the basic efficiency of engines, drive trains, and vehicle aerodynamics. These improvements could have been used to improve fuel economy and/or performance. Looking at the entire light-duty fleet, both cars and trucks, between 1975 and 1984, the technology improvements were concentrated on fuel economy: it improved by 62 percent without any loss of performance as measured by 0-60 mph acceleration times. By 1985, light-duty vehicles had improved enough to meet CAFE standards. Thereafter, technology improvements were concentrated principally on performance and other

[50] NRC, National Academy of Sciences, *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards* (Washington, D.C.: National Academy Press, 2002), 112.

vehicle attributes (including improved occupant protection). Fuel economy remained essentially unchanged while vehicles became 20 percent heavier and 0-60 mph acceleration times became, on average, 25 percent faster.

The NRC graphic relating to this finding for passenger cars[51] is portrayed in figure 16, which has been highlighted to portray the distinct periods of technology improvement.

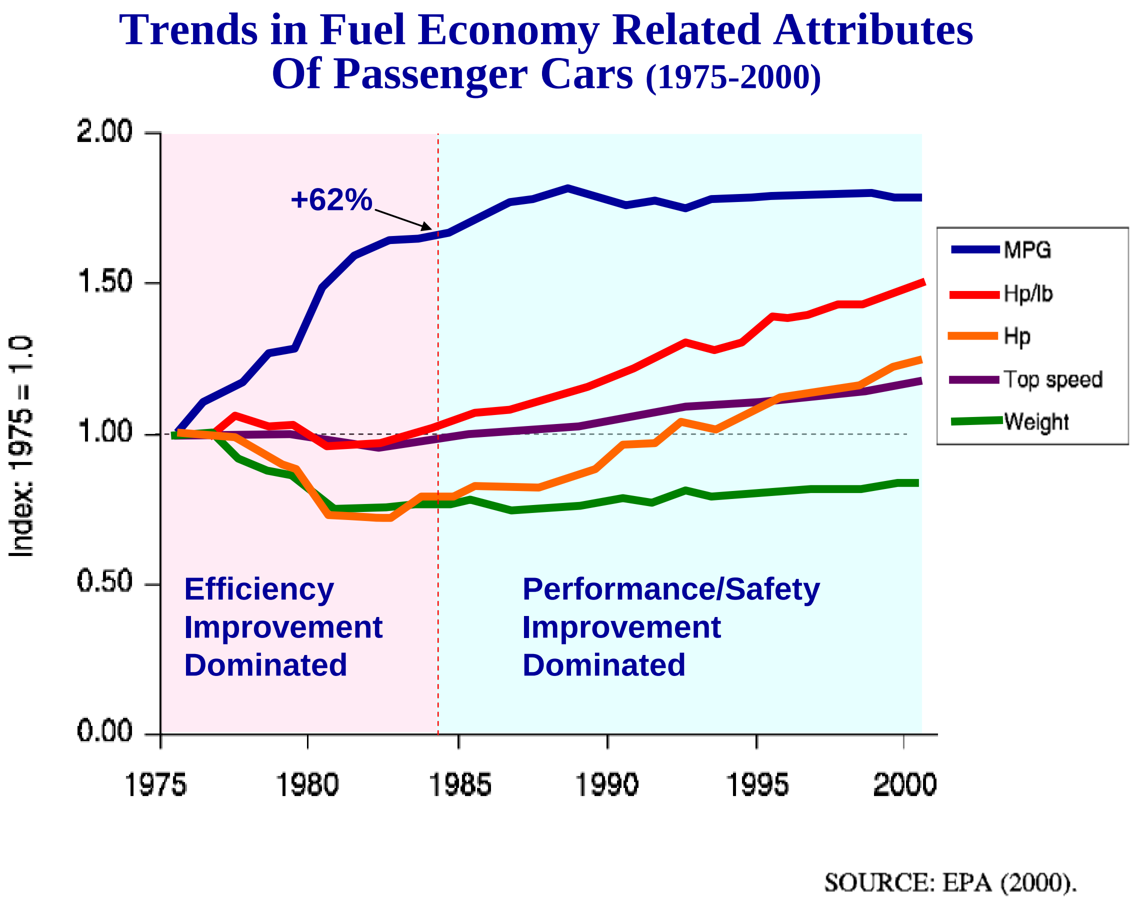

Figure 14

A basic conclusion is that consumer preferences tend to drive the application of technology improvements in the automotive industry toward better performance and safety standards, unless superseded by regulatory requirements for efficiency or pressured by high fuel costs. Recent evidence of the rapid decline of low-mileage SUV sales and a preference for higher mileage vehicles confirms the U.S. consumers' readiness to react to higher energy prices with a decided preference toward better fuel efficiency. Under the "High (Oil) Price Case" scenario selected for this analysis, fuel prices increase steadily in real terms to 2030, supporting a continuing consumer psychology that would favor higher fuel mileage vehicles.

[51] Ibid., 3.

3. Timing of Implementation of Improved VFE

Within the *AEO'07* "Reference Case," the light-duty stock (combined cars and light trucks "on the road" estimate) mpg efficiency increases from 19.7 to 22.2, during the period 2006 through 2030. In the *AEO'07* "High (Oil) Price Case" efficiency during the same period increases from 19.7 to 23.9 mpg, only a 21 percent increase in fuel efficiency and only a 4 mpg improvement over 24 years. Since light-duty vehicles retain a lead position in using nearly 60 percent of energy consumed for transport, this is the most significant segment indicating transportation efficiency improvement. The second leading form of transport consists of freight trucks, representing 20 percent of transport energy in 2030 and which improve efficiency by 25 percent during the period. The added impact of VFE assumed herein is due to anticipation of a higher degree of consumer sensitivity to higher oil prices, leading to earlier preferences for higher mileage vehicles. The incremental VFE impact, above *AEO'07*, is assumed to begin in 2011 and to gradually increase through 2030.

4. Targeted Results for VFE

The additional savings estimated for more aggressive VFE standards are 940,000 bpd (in 2030) above the estimate of VFE savings in the *AEO'07* "High (Oil) Price Case." The estimate for VFE savings herein represents only 33 percent of the 3 MMbd savings reflected in the SSEB[52] analysis of potential impact of VFE by 2030. The SSEB study had evaluated the energy savings without assuming an explicit change in CAFE standards and based its assumed efficiency improvements on all transportation modes, including aircraft and heavy-duty trucks, as well as light-duty vehicles. SSEB considered that the light-duty vehicle category of transportation would benefit from improvement in existing internal combustion and diesel technologies, as well as from new hybrids and PHEV technologies. PHEV technology is considered as a separate energy alternative technology herein, because a significant share of the liquid fuel energy savings PHEV technologies derive stems from electric power fuel sources such as nuclear, wind, and coal, and it would be reasonable to reflect on this benefit separately, as it is useful to discuss each incremental resource of fuel for power generation. The higher VFE of PHEV vehicles is factored into the reduced electricity demand per gallon of gasoline equivalent.

5. Reduction of U.S. Energy Liquid fuel Demand Anticipated from VFE

The total incremental and cumulative reduction in liquid fuel demand, due to the VFE assumptions herein, represents 3.6 billion barrels through 2030, above that of the *AEO'07* "High (Oil) Price Case." Over the same period, *AEO'07* high oil case expects transportation to consume roughly 143 billion barrels. Thus, the incremental demand reduction from VFE represents a modest 2.5 percent of anticipated consumption.

F. *Plug-In Hybrids*

PHEVs are becoming increasingly recognized as a unique transportation fuel alternative option for the United States due to its significant electricity infrastructure and a surplus of overnight

[52] SSEB, *American Energy Security,* 133.

capacity. It may, however, still remain an underestimated opportunity regarding its near-term potential to mitigate U.S. liquid fuel requirements. PHEVs substitute electricity for gasoline in providing much of the vehicle's motive force. By using more batteries and a smaller internal combustion engine than conventional hybrid vehicles, a greater fraction of a vehicle's miles traveled can be powered using electricity only. Conceivably, at speeds below about 34 mph, a commuter could drive for 50 or 60 miles without recharging and without engaging the gasoline engine. PHEVs would predominantly be recharged at night, during off-peak generation hours when electricity is less expensive and excess electrical generation capacity is readily available. More than 40 percent of the generating capacity in the United States sits idle or operates at reduced load overnight. PHEV technology represents an ideal opportunity to allow the Nation's ubiquitous, electricity infrastructure to immediately begin to play an important role supplying electricity as a transportation fuel with this alternative placing most of its incremental demand on the energy grid, precisely at the time when it is most available. And, of course, the substitution of electricity for petroleum can have a large carbon reduction cobenefit.

1. U.S. Electric Generation Resources for PHEVs

The *AEO'06* "Reference Case" forecasted that roughly 310 GW of coal-fired generation has the capability of increasing average capacity factors by about 10 percentage points from 72 percent in 2004 to 82 percent in 2013, representing average coal-fired unit operation for 876 more hours per year. In total this would represent 272 billion kWh of additional generation, primarily in off-peak hours that could immediately be utilized to support overnight charging of plug-in hybrids. Based on an analysis of Electric Power Research Institute (EPRI) data for PHEVs, referred to in table 5, the average ratio of kWh expended per gallon of fuel savings as PHEV technology progresses from HEV20 (20-mile, all-electric range) to HEV60 (60-mile, all-electric range) would be 13.4 kWh per gallon saved. Thus, the gasoline savings potential of 272 billion kWh, solely from increased coal-fired capacity by 2013, could represent a savings of 1.3 MMbd if such added coal capacity factor were applied exclusively to PHEV technology.

The potential for PHEV technology is not appreciably considered in the *AEO'07* estimates of increasing electric power generation requirements. Thus, predicting the use of a significant share of generation from capacity factor growth for PHEVs could underestimate demand from other sources of electricity use. As a significant new and efficient source of electricity demand in the transportation sector, PHEV technology will warrant that adequate incremental generation capacity be developed in advance of the introduction of PHEV vehicles. A unique infrastructure development opportunity can arise, wherein the significant intrinsic value of the kWhs dedicated to PHEVs would help to justify the use of higher cost generation sources, with the added benefit of no CO_2 emissions. In this case, wind, solar, and nuclear power generation options would provide zero carbon emission electric generation in support of a very low carbon emission form of transportation. Another unique advantage is that nuclear capacity and wind power are traditionally underutilized and undervalued at night, and PHEV technology would allow for much more effective utilization of these resources. Conceivably, policies could be implemented so that dispatching at night to serve PHEV loads would allow for full utilization of nuclear and renewable resources before fossil generation is deployed, minimizing the carbon content associ-ated with PHEV electric transportation. Solar power could become a valuable source of energy, on or off the grid, with potential for home-based or car-mounted solar panels contributing directly to serving the vehicle's energy demand. Although competitiveness of solar energy has been a fundamental issue for its widespread adoption, the end-use of off-grid solar power charging for PHEVs may make it a significant transportation energy contributor, particularly in southern and western regions of the United States.

2. Status of PHEV Technologies

As reflected in a growing number of news releases, the initiation of early production of non-OEM PHEV technology has begun. The popularity of hybrid electric vehicles (HEVs) has led to several announcements of efforts to convert existing HEVs, such as the Toyota Prius, to PHEVs[53] by inserting the requisite rechargeable batteries. Recently Hybrid-Plus, Inc., has begun offering conversions of the Toyota Prius which they characterize as a HEV-30, meaning the vehicle is capable of traveling 30 miles on fully charged batteries. Such conversions remain very costly and the warranties accompanying such products are either non-existent or are not commensurate with normal industry standards.

The status of commercial introduction of PHEV technology remains dependent on the successful development of batteries having longer life, lighter weight, better charge/discharge cycling capability, high power delivery capacity, and lower cost. Early experience with non-plug-in hybrid vehicle technology has supported the developmental progress of nickel-metal-hydride (NiMH) battery technology regarding specific power and better high-temperature operation.[54] Considerable attention is being paid to developing lithium-ion (Li-ion) battery technology for PHEV applications due to power and energy density advantages over NiMH, which promises that, for a given amount of energy storage, they can take up 25 percent of the space and weigh half as much.[55] Cost, durability, and safety remain key Li-ion battery technology concerns.

During a 2003 EPRI workshop on PHEVs, Mark Duvall, EPRI Technology Development Manager,[56] characterized theoretical well-to-wheels benefits of PHEV technology as shown in figure 17.

[53] Ibid.
[54] James Kliesch and Therese Langer, *Plug-In Hybrids: an Environmental and Economic Performance Outlook,* The American Council for an Energy-Efficient Economy, September 2006.
[55] Ibid.
[56] Mark Duvall, "Emissions, Global Warming, and Energy Security," (presentation, Plug-in Hybrid Electric Vehicle Workshop, November 15, 2003).

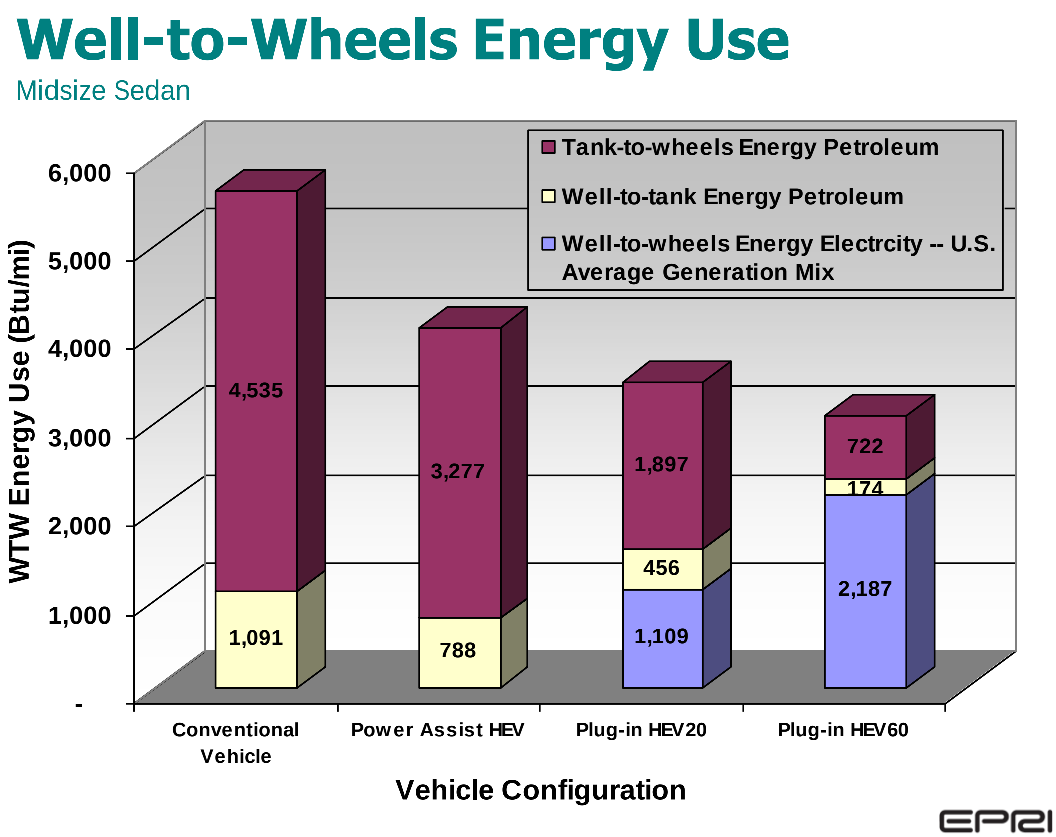

Figure 15

Even in the case of early PHEV battery technology (PHEV-20), aside from the nearly doubled fuel economy, the petroleum displacement per mile is roughly 60 percent of that used by a conventional vehicle per mile. Should PHEV60 technology become commercially available, the conventional vehicle petroleum displacement per mile is expected to approach 85 percent.

3. Timing to Commercial Implementation of PHEVs

The analysis herein assumes that a modest amount of PHEV contribution to liquid fuel demand displacement can begin as early as 2008. Thereafter, escalating growth in the introduction of PHEV units over the next 22 years would lead to approximately 37 million vehicles in operation by 2030. Current hybrid sales in the United States, which can be used as a proxy for PHEVs, were approximately 212,000 in 2005. In its most recent hybrid-electric vehicle outlook, J. D. Power and Associates forecasts hybrid vehicles sales to increase to 780,000 by 2012 and the hybrid share of the market to increase from 1.3 percent in 2005 to 4.2 percent in 2012. Extrapolating this level of growth (straight line) through 2030 results in an annual hybrid vehicle sales estimate of about 2.2 million by 2030 and a cumulative hybrid total of more than 31 million vehicles between 2005 and 2030. Considering the unique PHEV convenience of refueling at home and starting each day without the need to visit a service station, PHEV technology can be expected to overtake HEV sales, and, given their popularity, straight line growth projections for PHEVs are likely to prove conservative, especially in the "High (Oil) Price Case" posited here.

4. Targeted Results for PHEVs

The analysis herein assumes that total displacement of liquid fuels by PHEV technology will amount to 1.05 MMbd by 2030. The further assumption is that 44 percent (464,000 bpd oil equivalent) of the generation to power the charging of PHEVs will stem from coal-fired electricity, 27 percent (280,000 bpd oil equivalent) from nuclear power, 15 percent (157,000 bpd oil equivalent) from wind power, and 14 percent (150,000 bpd oil equivalent) from solar power. While these shares are to some degree arbitrary, they allow for regional variation in capacity additions to serve load growth caused by PHEVs.

In the case of coal-fired power generation, it is anticipated that the kWh equivalent necessary to provide 464,000 bpd of fuel displacement would be 95.2 billion kWh per year (table 3). This figure represents only 35 percent of the potential coal-fired generation increase anticipated through capacity factor growth of coal-fired generation through 2013. In addition the *AEO'07* "High (Oil) Price Case" anticipates 154 GW of incremental coal-fired capacity by 2030. Thus, for the coal-fired generation share of this PHEV demand, no additional new capacity is deemed necessary.

For nuclear to incrementally provide 280,000 bpd, as estimated in this analysis, approximately 6 additional 1,200 MW (7,200 MW total) nuclear plants operating at 92 percent capacity factor would be required. This would require 29 percent more new nuclear capacity in addition to the amount currently anticipated in *AEO'07* (24,300 MW), but considering growing interest for adding to nuclear power capacity, as reflected in industry permitting activity, the possibilities are promising. PHEVs provide a unique and attractive incremental market for overnight use of nuclear generation capacity which would enhance forecasts of project economics, supporting development of nuclear technology.

For wind to incrementally provide 157,000 bpd, as estimated in this analysis, approximately 9,200 MW of new wind generation would be required by 2026. Since it is estimated that over 1,800 MW of new wind power was added in 2005, an assumption of additions that average 460 MW per year for the next 20 years would appear conservative. The *AEO'07* "High (Oil) Price Case" forecasts the addition of only approximately 6,300 MW of wind capacity from 2006 through 2030, well below the required level. As is the case for nuclear, PHEV technology offers a unique overnight demand opportunity for wind power that can help increase the value of overnight load and can offer significant value to wind-power development economics. It is expected that with the realization of PHEV technology, the prospects for wind-power development will significantly improve and regulatory support recognizing the greenhouse gas (GHG) benefits of wind power applied to transportation energy could support capacity growth of the magnitude assumed herein.

For solar power to incrementally provide 150,000 bpd, as estimated in this analysis, it is estimated that by 2030 an average energy production representing 14 percent of the total annual energy use by PHEVs can be derived from either grid connected solar power, off-grid residential solar panels, or vehicle-mounted solar panels. Such an opportunity for vehicle application would represent a step change in currently forecast solar consumption for the United States. The annual electricity use estimated herein for PHEVs, at 31 billion kWh, is several times the current

AEO'07 "High (Oil) Price Case" forecast of 8 billion kWh for solar energy consumption by the electric, commercial, and industrial sectors. It is also expected that regulatory support recognizing the GHG benefits of solar power applied to transportation energy, particularly in the southern and western United States, could support capacity growth of the magnitude assumed herein.

5. Cumulative Use of U.S. Electric Generation Resources Anticipated

The assumed generation herein, required to support PHEVs in 2030 is 215 billion kWh, which is approximately 5 percent of today's annual power generation in the United States and roughly 3.9 percent of generation expected in year 2030. Provided PHEV technology can live up to its promise of substantially reducing oil-based fuel consumption via an economic, electricity-based alternative vehicle, securing increased electricity generation to power PHEVs should not be an issue on this level of demand and much of the required infrastructure would already be in place.

Table 3. Adapted from EPRI Well-to-Wheels Estimates[57]

Btu/mile	Conventional Vehicle	Power Assist HEV	Plug-in HEV20	Plug-in HEV60	
Well-to-wheels Energy Electricity -- U.S. Average Generation Mix			1,109	2,187	
Well-to-tank Energy Petroleum	1,091	788	456	174	
Tank-to-wheels Energy Petroleum	4,535	3,277	1,897	722	
Total Btu	**5,626**	**4,065**	**3,462**	**3,083**	
Total petroleum	**5,626**	**4,065**	**2,353**	**896**	
Petroleum displaced/mi vs LDV			**58.2%**	**84.1%**	
% better efficiency (vs LDV) Btu/mi basis	**0.0%**	**38.4%**	**62.5%**	**82.5%**	
% Btus from gasoline	**100.0%**	**100.0%**	**68.0%**	**29.1%**	
kwh per gallon saved			**11.3**	**15.4**	**13.4**
assume 12,000 miles per year					**avg.**
Petroleum gal	592.2	427.9	247.7	94.3	
electricity kWh	0		3,896.9	7,684.9	**5,790.9**
Annual cost @ $3/gal & $.1/kWh	$ 1,777	$ 1,284	$ 1,133	$ 1,051	**avg.**
	2030 Savings MMbd	**2030 Million kWh/d**	**2030 Billion kWh/yr**		
Coal plug-in hybrids *	0.5	260.9	95.2		
Nuclear plug-in hybrids **	0.3	157.3	57.4		
Wind plug-in hybrids ***	0.2	88.4	32.3		
Solar plug-in hybrids ****	0.2	84.2	30.8		
Total	**1.1**	**590.8**	**215.6**		
			37.2	million vehicles using average of 5,791 kWh/year	

Notes:

* - equals 35% of kWh from capacity factor growth from 2004 through 2013 (no new capacity)
** - equals 6 new 1,200 MW plants operating at 92% C.F. (7,200 MW total)
*** - equals 92 new 100 MW wind farms at 40% C.F. (9,200 MW total)
**** - equals 14% of PHEV total power by 2030 derived from off-grid or car mounted solar panels

57 Btu/mile data from Duvall, "Emissions," 2003.

G. *Cellulosic Ethanol*

In 2006, the United States produced an estimated 4.9 billion gallons of ethanol in 97 ethanol plants.[58] By 2012, the Energy Policy Act of 2005 requires that at least 7.5 billion gallons per year of renewable fuel be blended into the Nation's fuel supply. In his testimony, Alexander Karsner, Assistant Secretary for the Office of Energy Efficiency and Renewable Energy (EERE), cited the Renewable Fuels Association's estimate of an increase in ethanol capacity by 2008 of 45 percent (to nearly 7 billion gallons per year), with the addition of 42 new plants, bringing the United States close to the 2012 goal by 2008. Corn is the primary feedstock used to produce today's ethanol. However, future production of ethanol from corn will be limited by the amount of corn available, its use as food, and other considerations. According to Mr. Karsner:

> Given land area required for corn production and growing United States demand for transportation fuel demand, we estimate that the maximum amount of corn ethanol that the United States could produce on a sustainable basis is approximately 18 billion gallons, or about 13 percent of current transportation fuel use (by National Corn Growers Association estimates). Clearly, producing ethanol cost competitively from other feedstock is essential to helping reduce our dependence on oil.

A DOE goal, announced in 2006, for the production of ethanol is referred to as "30 by 30", representing the theoretical potential of replacing 30 percent of current U.S. gasoline consumption with ethanol by the year 2030. This translates to producing about 60 billion gallons of ethanol per year, 12 times today's production, and more than three times the maximum estimate of sustainable corn-based ethanol.

A new form of ethanol production, cellulosic ethanol, is expected to offer larger capacities for production, as well as economic and emission advantages over corn-based ethanol. Cellulosic ethanol may have an energy balance (i.e., ratio of units of energy out over energy inputs) that is as much a three times more favorable than corn-based ethanol.[59] Corn-based ethanol likely would become less competitive once cellulosic technology is adequately developed and commercially available, but current costs of cellulosic ethanol production represent a key prohibiting factor. Thus, to make a significant incremental impact on U.S. petroleum consumption, it is expected that development of processes for using cellulose-based feedstock will be an important factor. The analysis herein is focused on examining the potential for incremental future contribution of cellulosic ethanol to the Nation's fuel supply, with corn-based ethanol assumed to be a continuing contributor to domestic supply at the level (538,000 BOE per day by 2030) already forecast in the *AEO'07* "High (Oil) Price Case."

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[58] "Industry Statistics," Renewable Fuels Association, http://www.ethanolrfa.org/industry/statistics/#B
[59] U.S. Senate Committee on Environment and Public Works, *Federal Renewable Fuels Programs: Oversight*, 109th Cong., 2nd sess., September 6, 2006.

Cellulosic ethanol represents a key technology supporting the biochemical approach to using the Nation's biomass resources (figure 18).[60]

Biochemical Path to Biomass Conversion

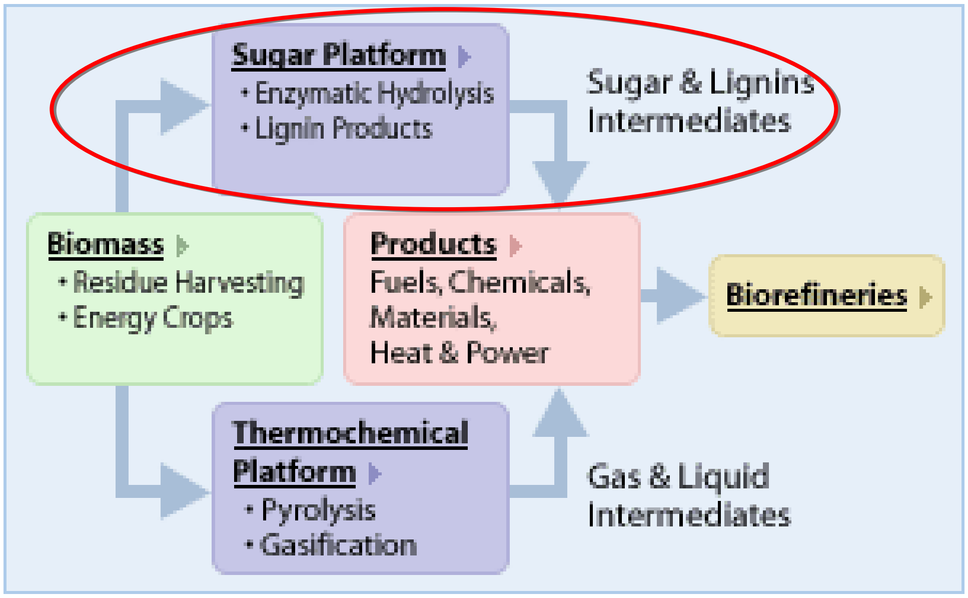

Figure 16

The other path, using the thermochemical approach, employs biomass gasification and is discussed in the next energy alternative appendix A, section H, "Liquids from Biomass Gasification."

1. U.S. Biomass Resources

Cellulose-containing feedstock consists of agricultural and forest residues, such as corn material left on the field (stover) or tree thinnings and lumber waste, urban wastes, and energy crops (fast-growing trees and grasses, such as poplars and switchgrass). These materials can be collected or harvested and the cellulosic material converted into sugars which are fermented to produce ethanol. Estimates of the amount of cellulosic material that is available for production of ethanol vary, with cost and ability to recover the feedstock representing two important factors. Another important factor is competing uses for these materials, such as in thermochemical conversion (gasification) to ethanol, electricity generation, and use as a natural fertilizer or in soil erosion control.

A study of potential for U.S. biomass resources was conducted in 2005 by the Oak Ridge National Laboratory (ORNL), on behalf of DOE and the U.S. Department of Agriculture

[60] Graphic from EERE, Biomass Program website, http://www1.eere.energy.gov/biomass/

(USDA).[61] The study, commonly referred to as the “Billion-Ton Biomass Study” supports the prevailing DOE goal for ethanol by suggesting that the annual potential of biomass from U.S. forest and cropland exceeded 1.3 billion tons, an amount estimated to be able to produce ethanol equivalent to about 33 percent of current U.S. transportation fuel demand. The study represented a biomass resource potential study and was not intended to analyze the economic viability of collection and utilization of the biomass resources.[62]

In the billion-ton annual biomass case, the following sources of biomass are necessary to achieve 60 billion gallons by 2030:

- 446 million dry tons of crop residues per year
- 87 million dry tons of grains to biofuels
- 87 million dry tons of process residues
- 377 million dry tons of perennial crops

The total represents a 400 percent increase (about 800 million dry tons) over the baseline (2001) estimate of sustainable U.S. biomass resources of about 200 million dry tons, comprised predominantly of corn grain (50 percent) and manure and municipal solid (mostly wood) waste (approximately 25 percent of total). The largest source of incremental biomass over the current (baseline) production is from the new category of perennial crops (377 million dry tons of biomass from agricultural products, such as switchgrass and woody crops) which is estimated to require 55 million acres (86,000 square miles) of land, not yet applied to such use. The incremental land for perennial crops is indicated to be derived predominantly from land areas consisting of 25 million acres of uncultivated pasture-land and 10 million fewer acres each of grassland, hay crops, and soybean crops.

The next largest area of biomass production increase is from the use of crop residues, which accounts for an incremental 332 million dry tons of sustainable biomass production. If economically achievable, without significant environmental concerns such as soil degradation, this would represent a significant incremental source of U.S. energy supply roughly equal to 10 percent of today’s transportation fuel demand. The viability of this large increase in biomass resource potential is closely tied to the economics of production and, for biochemical conversion, the technology associated with cellulosic ethanol. In total the ORNL/USDA analysis suggests the added productive area required for the increased biomass production, over the 2001 baseline, would represent 106,000 square miles, an area approximately two-thirds the size of California.

2. Status of Cellulosic Ethanol (Biochemical) Technologies

Currently, the President’s Advanced Energy Initiative includes an objective to “foster the breakthrough technologies needed to make cellulosic ethanol cost competitive with corn-based ethanol by 2012.” EERE has established the cellulosic energy cost goal for 2012 at $1.07 per gallon. EERE’s research on behalf of cellulosic ethanol focuses on three areas: feedstock infrastructure, improving cost and quality of biochemical processes, and the biorefinery system.

[61] Robert D. Perlack et al. *Biomass as Feedstock for a Bioenergy and Bioproducts Industry: The Technical Feasibility of a Billion Ton Supply*, ORNL for DOE and the USDA, 2005.
[62] Ibid., 1.

At a March 2006 Biomass Research & Development Technical Advisory Committee Meeting in Golden, Colorado, the "state of technology estimates" for biochemical conversion technology was shown in figure 19.[63]

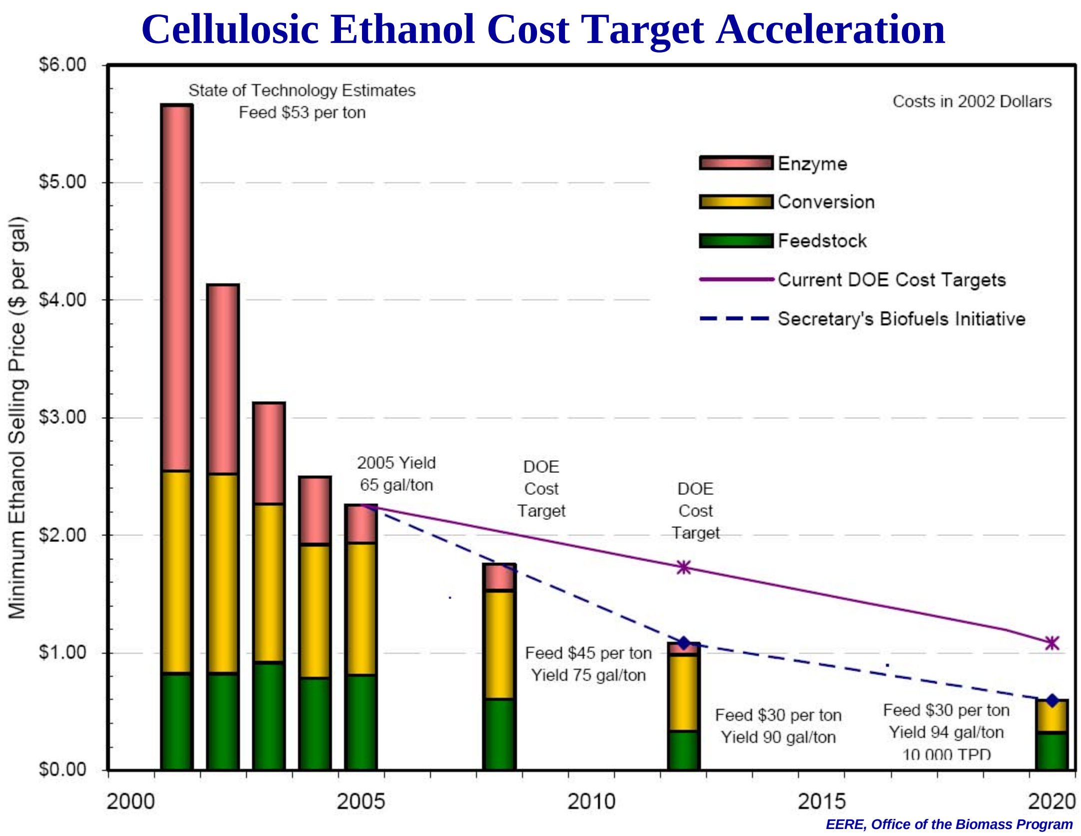

Figure 17

Notably, the costs of enzymes for cellulosic ethanol production are represented to have been significantly reduced in recent years, allowing for significant progress in approaching program goals. Even given the 30 percent to 35 percent energy content disadvantage of ethanol compared to gasoline, the selling price targets appear on track for becoming competitive.

Although the cost of enzyme treatment is shown (above) to have been significantly reduced, much of the fundamental research for cellulosic ethanol remains associated with further improving the enzymatic and pretreatment processes that can be associated with key potential biomass resources, particularly in the perennial crop category.

[63] *Summary: Biomass Research & Development Technical Advisory Committee Meeting, March 2–3, 2006,* National Biomass Initiative, April 21, 2006, 45.

3. Timing to Commercial Implementation of Cellulosic Ethanol

The *AEO'07* "High (Oil) Price Case" begins a modest introduction of cellulosic ethanol by 2009, but the overall estimate of contribution remains quite small, limited to 23,000 bpd (oil equivalent) by 2030 in a 25 MMbd market. The current DOE goal is to have cellulosic ethanol commercially competitive by 2012. The Renewable Fuel Standard, in addition to requiring 7.5 billion gallons of ethanol to be blended with gasoline by 2012, also requires that a minimum of 250 million gallons (10,000 bpd, oil equivalent) of ethanol be derived from cellulosic biomass sources by 2013.

DOE has issued a solicitation in 2006 covering the *Commercial Demonstration of an Integrated Biorefinery System*, authorized under Section 932 of the Energy Policy Act of 2005. According to Secretary Karsner's recent testimony:[64]

> This solicitation was designed to develop industrial-scale demonstration of an integrated biorefinery system using a wide variety of lignocellulosic feedstocks such as trees, switchgrass, and corn stover, including the collection and treatment of the feedstock. The aim of the biorefinery demonstration program is to show that such a facility could be operated profitably without Federal subsidies, once initial construction costs are paid, and easily replicated. The Department plans to select the best proposals and begin funding projects with Fiscal Year 2007 appropriations.

Questions may arise concerning the effect of successful commercialization of cellulosic ethanol on the corn-based ethanol industry and related investments. Due to advantages for cellulosic ethanol, such as the potential for lower production costs, better energy balance, and greater CO_2 benefits, it is not clear that grain-based ethanol production would remain competitive. The cellulosic ethanol industry would then need to make up for reduced corn-based ethanol production in order to meet ethanol production targets.

4. Targeted Results for Cellulosic Ethanol

The *AEO'07* "High (Oil) Price Case" forecast includes 1.23 quads per year of domestic ethanol by 2030, of which 96 percent is corn-based and 4 percent is cellulosic. The more aggressive cellulosic ethanol case portrayed in this analysis represents additional cellulosic ethanol of 460,000 bpd (oil equivalent) by 2030 for a total of approximately 483,000 bpd (oil equivalent) by 2030. This represents a significant increase over the *AEO'07* "High (Oil) Price Case" forecast but the total of roughly 7.4 billion gallons (oil equivalent) per year is only 17 percent of DOE's current target of MMbd or 44 billion gallons (oil equivalent) per year by 2030. In comparison, the SSEB report estimated the production of 1.35 MMbd from cellulosic ethanol by 2030 [65] (47 percent of the DOE target), 180 percent higher than the estimate used in this analysis.

[64] *Federal Renewable Fuels*, September 6, 2006.
[65] SSEB, *American Energy Security*, appendix G, 10.

Despite low estimates for cellulosic ethanol in *AEO'07*, EIA analyzes lower cost cases for cellulosic ethanol and makes the following observation:

> Although cellulosic ethanol technology currently is not a commercially proven process, researchers and developers are vigorously pursuing cost reduction goals in the technology and production processes that would substantially exceed those considered in the AEO 2007 'lower cost' cases. These even lower production cost goals may be possible, but it is uncertain at present whether, and when, the technology advances necessary to achieve the lowest of the production cost goals will occur. Nevertheless, even the relatively modest reductions in production costs assumed in the AEO 2007 'lower cost' cases can be seen to result in a significant increase in cellulosic ethanol production.

5. Cumulative Use of U.S. Cellulosic Resources Anticipated

The total amount of biomass resources required for cellulosic ethanol to meet the 483,000 bpd, as assumed herein for 2030, would be approximately 135 million tons per year, based on the ORNL estimate of 1.3 billion tons per year considered adequate to achieve 33 percent of today's transport fuel use.[66] This would represent only 10 percent of the 1.3 billion ton ORNL estimate of biomass potentially available domestically.

H. *Liquids from Biomass Gasification*

Technologies for biomass gasification represent the thermochemical path to biomass conversion in figure 20.

Thermochemical Path to Biomass Conversion

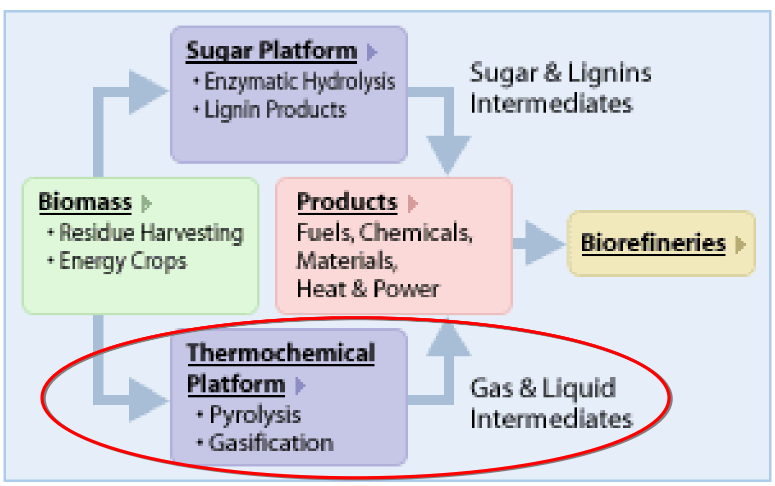

Figure 18

[66] Perlack et al, *Biomass as Feedstock*, 34.

1. U.S. Biomass Resources

The U.S. biomass resources for thermochemical conversion will draw on the same biomass resources as described for biochemical conversion in appendix A, section G. As a result, a healthy competition could develop between biochemical and thermochemical energy conversion processes for access to the Nation's biomass resources. Determination of the most favorable process will eventually be based on comparative economics of the processes, including capital and production costs as well as environmental factors, such as GHG impacts, which may eventually be monetized as well.

2. Status of Biomass Gasification (Thermochemical) Technology

Gasification technology is well established for coal and is currently seeing significant growth in interest for commercial-scale power generation, as well as CTL plants. Gasification technologies for biomass have a long history dating back to the mid 1800s.[67] The primary technical difficulty for biomass gasification in synthetic fuels production is the gas cleanup required to reach satisfactory levels of contaminants for catalytic conversion of synthesis gas.[68] The SSEB report notes that:

> There are scrubbing technologies available for removing most of these compounds, but these are considered too expensive for the scale of operation considered appropriate for biomass gasification, typically less than 500 ton/day.

The SSEB analysis of the technology status of biomass gasification is portrayed in the following excerpt:[69]

> A number of gasifier designs for effective gasification of biomass are currently under development for production of synthesis gas (without nitrogen). These include entrained flow, indirectly heated transport bed (Battelle design), oxygen-fed fluidized bed, and two-stage systems employing pyrolysis followed by steam reforming. The two-stage designs are attracting considerable interest because of their relative simplicity and lack of requiring an auxiliary oxygen plant. CHOREN Industries has attracted Royal Dutch Shell and Daimler-Chrysler as partners based on the performance of its pilot plant that has been in operation since 2004.[70] The design of this system would be the most amenable for co-processing biomass with coal, and the system can be sized to be compatible with moderate scale FT gas-to-liquids plants currently being deployed to exploit stranded natural gas. This type of plant was installed in Nikiski, Alaska, in 2002.[71]

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[67] SSEB, *American Energy Security*, 105.
[68] Ibid., 106
[69] Ibid., 107
[70] CHOREN Industries, "The Key Element in the Technology: The Carbo-V® Process," www.choren.com/en/biomass_to_energy/carbo-v_technology/
[71] M. Ashley, T. Gamlin, and J.F. Freide, "The Ultimate 'Clean' Fuel—Gas-to-Liquid Products," *Hydrocarbon Processing*, February 2003.

Recent analyses of gasification technology possibilities have indicated the potential for a significant advantage that could accrue to the use of biomass gasification along with CTL accompanied by carbon capture and sequestration (CCS). The conceptual biomass gasification system, portrayed by Professor Robert Williams, of Princeton University's Princeton Environmental Institute, indicates that cofeeding of coal and biomass into a FT liquefaction process could bring forth a number of distinct economic and environmental advantages (figure 21).[72]

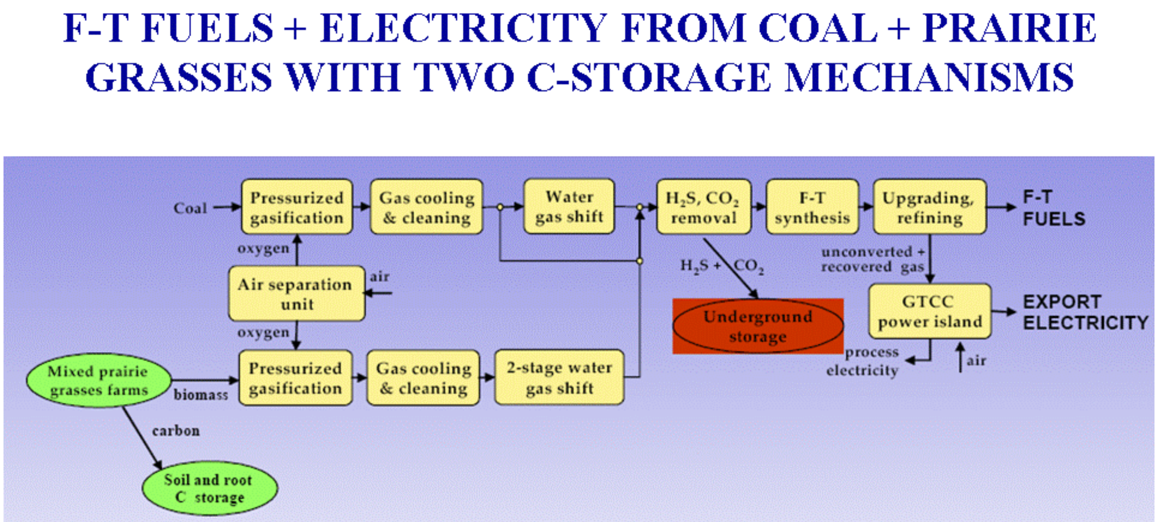
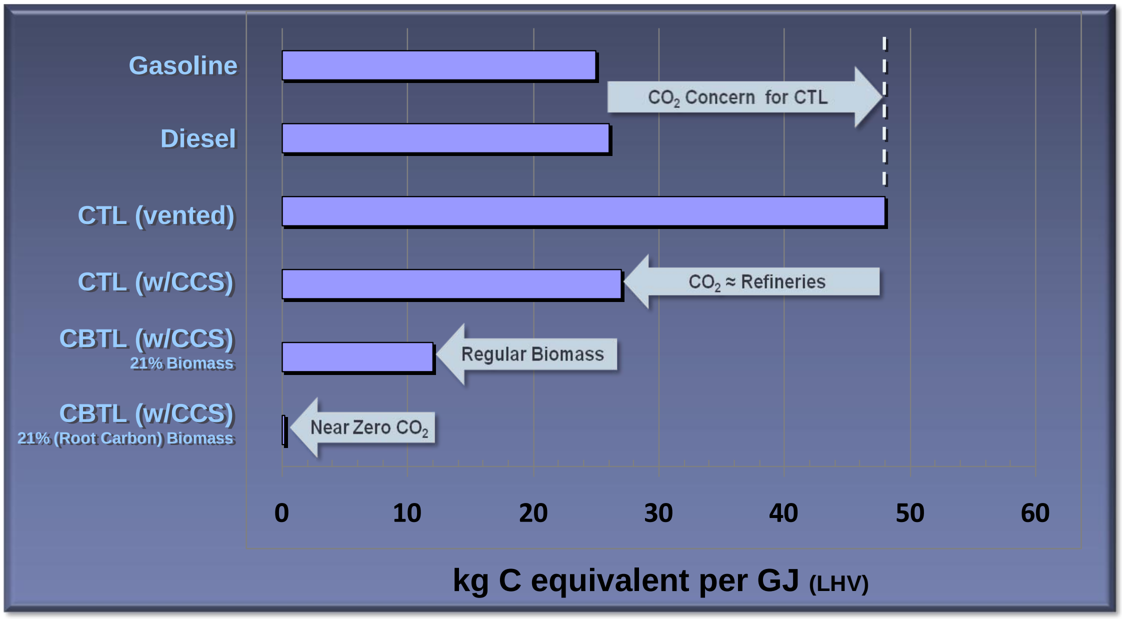


Figure 19

The conventional view of CTL technology without biomass is environmentally challenged because as much as 80 percent more CO_2 is produced per unit of liquid fuel product than produced from conventional crude oil refining (figure 22).[73] With CCS applied, however, CTL can be comparable to crude oil refining from a CO_2 emission standpoint, with the added value of using domestic energy resources. The thermochemical process benefits described by Professor Williams would derive from cofeeding of biomass with coal through gasification and FT synthesis with CCS, allowing for the significant reduction in carbon emissions. As indicated, the cofeeding of a proportion of biomass (equal to 21 percent by energy content shown) to a CTL process including CCS, a combined process referred to as coal-biomass-to-liquids, can substantially reduce the carbon emissions per unit of liquid fuel produced to a level well below that of typical crude oil refineries, due to the benefit of negative CO_2 credit for sequestered CO_2 from biomass.

[72] Robert Williams, "Toward Cost-Competitive Synfuels from Coal and Biomass with Near-Zero 'Well-to-Wheels' GHG Emissions by Simultaneous Exploitation of Two Carbon Storage Mechanisms" (Alternative Transportation Fuels, Session V: Carbon to Liquid Technologies, Center for Strategic and International Studies, Washington, DC, December 12, 2006).
[73] Robert Williams (presentation, Lawrence Livermore National Laboratory, Livermore, CA, January 12, 2007).

Greenhouse Gas Emission Rates For Fuel Production and Use



Coal/Biomass-to-Liquids May Better Ethanol w/o Sequestration

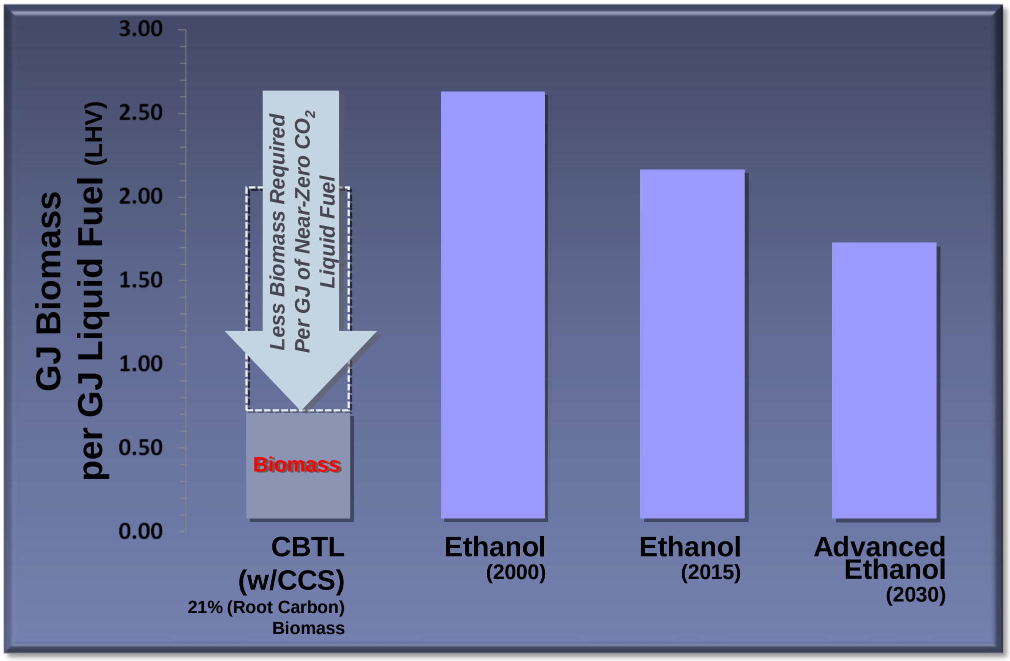
Figure 20

By further introducing the CO_2 benefits of specific biomass crops (involving low-input high-diversity (LIHD) mixtures of native grassland perennials) containing a high degree of soil/root carbon buildup, additional CO_2 benefit could be derived, due to up to 60 percent of quantity of the LIHD CO_2 being left in the soil when harvested. As a result of this additional CO_2 credit, employing the same 21 percent level of LIHD biomass by energy content could produce a near-zero carbon emitting domestic liquid fuel process.[74] This carbon-neutral result would not only apply to the CO_2 emissions from the plant but also would extend to the CO_2 neutrality of the product transportation fuel. Remarkably, if such a process could be established as technically and economically viable, a means will have been developed to address the Nation's most significant energy vulnerability with two key domestic resources, while simultaneously providing a spectacular improvement in the environmental consequences of traditional liquid fuel production and use.

As an added benefit, significant quantities of CO_2 neutral liquid fuel production could be generated with substantially smaller demands on the biomass industry per unit of liquid fuel produced (figure 23).[75] This evaluation reflects the combined liquid fuel production benefit of cofeeding abundant and high energy density coal through a FT liquefaction process with CCS and including the soil/root carbon CO_2 benefits of LIHD biomass crops.

[74] David Tilman, Jason Hill, Clarence Lehman, "Carbon-Negative Biofuels from Low-Input High-Diversity Grassland Biomass," *Science* 314 (December 8, 2006) 1598. Source of soil/root carbon analyses from LIHD mixtures of native grassland perennials.
[75] Williams, Lawrence Livermore, January 12, 2007.

Biomass Required to Make 1 GJ of Liquid Fuel



Domestic Near-Zero CO_2 Liquid Fuel w/o Land-use Biomass Issues

Figure 21

Professor Williams's analysis further concludes that, assuming the potential for a regulatory cost to be to be applied to CO_2 emissions (nominally \$100 per ton of carbon), the resultant value of LIHD crops and payments to farmers could be substantially higher than for biomass applied to cellulosic ethanol production.

3. Timing to Commercial Implementation of Biomass Gasification

The analysis, herein, assumes that, beginning in 2011, biomass gasification can combine with existing gasification for CTL to begin contributing to U.S. liquid fuel supply.

No identifiable forecast for biomass gasification is cited in the *AEO'07* report.

The SSEB report estimated that biomass gasification with liquid fuel production could begin as early as 2009.[76]

Both tax incentives and loan guarantees are available to gasification plant projects, including CTL applications under the Energy Policy Act of 2005, which should be conducive to early introduction of the technology.

[76] SSEB, *American Energy Security*, appendix G, 10.

4. Targeted Results for Biomass Gasification

This analysis estimates that 1 million bpd of alternative fuel production could be available from biomass gasification and liquefaction by 2030. This analysis estimates that there would be a nearly 2.4 times the CTL production than thermochemical biomass liquids production, allowing for a large proportion of the CTL production to be co-fed with biomass to derive the environmental benefits.

One important economic consideration for commercial viability of biomass derived fuels is the distance required for transport. It is, therefore, likely that biomass resources will often be dedicated to the type of process facility (biochemical or thermochemical) that is closest to the resource. Another consideration will eventually be the desirability of end products available from the biomass conversion process chosen.

In comparison, the SSEB total estimate for thermochemical processing of biomass using gasification represented 1.23 MMbd by 2030.[77] This report estimated 81 percent of this SSEB biomass gasification production estimate by 2030. The SSEB report also included a pyrolysis thermochemical biomass conversion component equal to 1.25 MMbd for a total thermochemical use of biomass amounting to 2.48 MMbd, 150 percent higher than the estimate for thermochemical conversion used herein.

5. Cumulative Use of Biomass Resources Anticipated

Assuming an estimated 65 gallons of biofuel production via gasification per dry ton biomass[78] the estimate of 1 million bpd of gasification-based biofuel production would require 646,000 tons per day of biomass. This would represent 236 million tons of biomass per year, about 18 percent of the ORNL annual estimate of 1.3 billion tons of U.S. potential biomass production. Combined with the estimate of 135 million tons per year from biochemical biomass conversion, the total biomass requirement per year for both processes represents approximately 371 million tons per year, or 28 percent of a 1.3 billion ton biomass supply.

I. *U.S. Oil Sands*

Previously referred to as “tar sands”, the term “oil sands” has gained more common usage as the large-scale commercial production of oil sands in Canada has adopted this terminology. Canadian oil sands have key properties that are significantly different from U.S. oil sands in that they are “water wetted” as opposed to U.S. oil sands which are “hydrocarbon wetted.” This leads to significant differences in production processes and the inability to readily transfer Canadian production know-how;[79] however, some developing Canadian oil sands technologies may eventually lend themselves to U.S. production.

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[77] Ibid.

[78] http://www.choren.com/en/faq/#faq_7. CHOREN website estimate for standard production plant with the following features: 200,000 metric tons/year of product using 1 million metric tons of dry biomass.

[79] NRC, Committee on Production Technologies for Liquid Transportation Fuels, *Fuels to Drive Our Future*, (Washington DC: National Academy Press, 1990), 71.

1. U.S. Oil Sands Resources

The United States is estimated to have approximately 60 to 80 billion barrels of oil sands resources, much of which, like oil shale, exists in western Utah.[80] The size and distribution of U.S. oil sands resources is represented in figure 24.

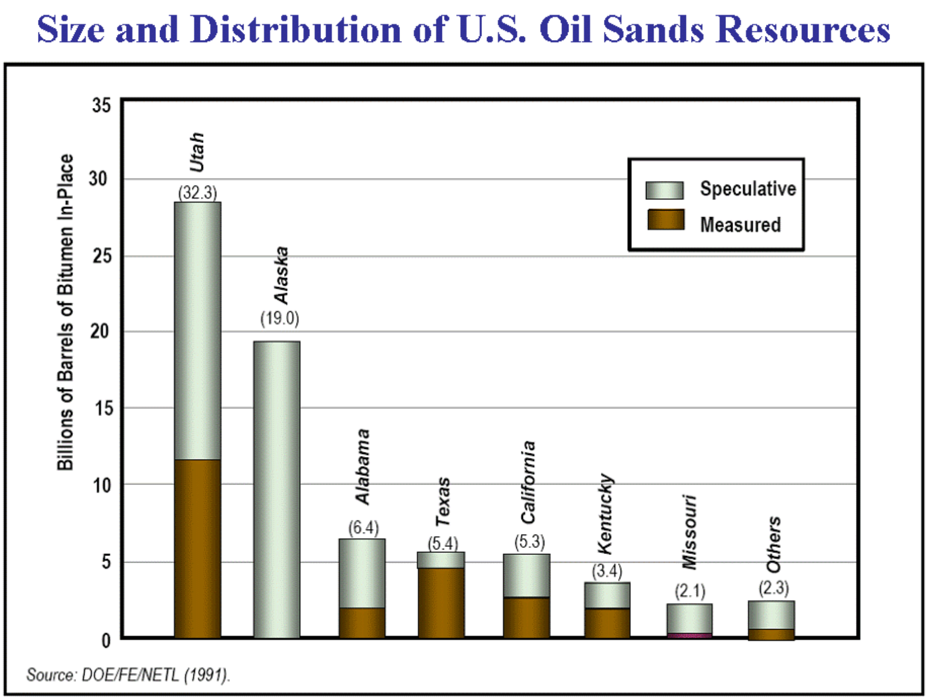

Figure 22

Notably, with U.S. oil sands resources estimated at 3 to 4 times current U.S. proved oil reserves, technologies that allow for the economic production from just 30 percent of these resources would double the amount of proved oil reserves in the United States.

2. Status of Oil Sands Technologies

The tremendous success of technology development for Canadian oil sands production creating a large-scale commercial industry serves as an inspiration to potential U.S. oil sands developers. Unfortunately, due to differing properties of the respective resources, Canadian technologies used in initial commercial production are not expected to be readily transferable to U.S. production. Because Canadian oil sands are "water wetted" and water soluble they are amenable to hot water solutions for emulsifying the oil from tar sands particles. U.S. oil sands, being "hydrocarbon wetted," are expected to rely on hydrocarbon solvents which can extract the oil from the sand particles with the solvents being separated and recovered for reuse.[81] More recent

[80] ARI, *Undeveloped Domestic Oil Resources: The Foundation for Increasing Oil Production and a Viable Domestic Oil Industry*, for U.S. DOE/FE, February 2006, 18.
[81] NRC, *Fuels to Drive*, 72.

developments of advanced technologies for in situ Canadian oil sands production are felt to have applicability to U.S. oil sands production. Steam-Assisted Gravity Drainage, or SAGD, VAPEX (a combination of solvent and heat), and "Top Down Combustion" are each thought to be potentially viable production technologies for U.S. oil sands, with the potential of turning 10 billion barrels of U.S. oil sands resources into technically recoverable reserves.[82] An additional oils sands technology concept, identified by ARI, entails "zero emissions" oil sands production upgrading and refining system involving gasification of the oil sands residues to produce steam, hydrogen, and electricity while using the by-product CO_2 for EOR in the sequestration process.[83]

3. Timing to Commercial Implementation of Oil Sands

This estimate assumed that production of up to 30,000 bpd from U.S. oil sands could begin by 2013 if the technology is pursued aggressively. As Vice President of ARI Michael Godek indicated in recent testimony before the House Committee on Resources,[84] U.S production from oil sands and heavy oil could reach 500,000 bpd by 2015.

4. Targeted Results for Oil Sands

The analysis herein assumes the potential for production from U.S. oil sands to reach 450,000 bpd by 2030. Production from heavy oil is assumed in this analysis to contribute to the conventional production levels forecasted in the *AEO'07* "High (Oil) Price Case." In testimony, industry experts[85] have estimated that with proper attention to resource evaluation and technology development, U.S. production from oil sands and heavy oil could reach 1 to 1.5 million bpd by 2025. Considering that both oil sands and heavy oil have roughly the same total resource estimates and recognizing that Canadian oil sands production targets are now reported to be approaching 3.5 million bpd by 2015,[86] the estimate for U.S. oil sands production by 2030 appears quite conservative.

5. Cumulative Use of U.S. Oil Sands Resources Anticipated

The cumulative production of oil from U.S. oil sands considered herein, by 2030, is only 1.5 billion barrels, a negligible portion of the estimated 60 to 80 billion barrels of resources.

J. *Hydrogen (from Coal) for Use in FCVs*

[82] ARI, *Undeveloped Domestic Oil*, 20.
[83] Ibid.
[84] House Committee on Natural Resources, Subcommittee on Energy and Mineral Resources, *The Vast North American Resource Potential of Oil Shale, Oil Sands, and Heavy Oils: Oversight Hearing*, 109th Cong., 1st sess., June 23, 2005.
[85] Ibid.
[86] "'Canadian oil sands developments under way or on the drawing board are valued at more than $100 billion. The investments are expected to more than triple production from the vast resource in northern Alberta to 3.5 million bpd by 2015,' the Canadian Association of Petroleum Producers said." Reuters, "BP Plans $3 Billion Indiana Refinery Upgrade," September 20, 2006.

In the January 2003 State of the Union Address, President George W. Bush proposed the concept of the hydrogen economy as a means to reduce foreign energy dependence and to reduce emissions in transportation. The initial expectations for hydrogen production predominantly focused on natural gas as a feedstock. It was increasingly recognized over following months that inadequate natural gas supply potential in North America and rapidly increasing costs for natural gas would inhibit use of natural gas for a feedstock for a large portion of the Nation's transportation industry. In the interim, in a review of the Freedom Car and Fuel Partnership,[87] NRC suggested that a diverse set of feedstock is required "to best enhance U.S. energy security." The review, however, focused on coal as a production feedstock due to its plentiful supply and hydrogen production competitiveness, emphasizing the importance of sequestration in securing the desired CO_2 reduction benefits.

1. U.S. Coal Resources

Coal resources in the United States represent a uniquely large and available resource to support hydrogen production. The estimates of U.S. coal resources are discussed under the CTL section (appendix A, section 1). Combined with increasing power generation demand, including PHEVs, CTL, and coal to support hydrogen for fuel cell vehicles (FCVs), the total of U.S. coal consumption, could theoretically reach 2 to 3 times today's consumption by 2030. This does not consider the significant new demand for coal that may be eventually required to cover 30 percent to 40 percent incremental energy demand of possible plant sequestration regulations. Although coal is an abundant and important domestic energy resource, diversity of energy alternatives can help alleviate over-dependence on any one resource and associated problems that can occur with a limited energy alternative focus.

2. Status of Hydrogen (from Coal) Technologies and FCVs

The use of coal in production of hydrogen for support of transportation fuel demand, involves two broad areas of technology development needs: the environmentally acceptable production of hydrogen from coal and the utilization and distribution of hydrogen in FCVs and FCV refueling infrastructure.

Hydrogen production from coal, via gasification, is well understood. In the 2004 NRC analysis of production technologies for hydrogen it was indicated that:

> In the committee's analysis, the current production cost of making hydrogen from coal in central station (i.e., large, centralized) plants is estimated to be $1.03/kg. . . . With success, the estimated hydrogen production cost can be reduced to $0.77/kg."[88]

Considering that the energy potential of a kg of hydrogen is approximately equal to a gallon of gasoline, such prices already appear very attractive compared to recent gasoline prices at $2 to $3 per gallon. The 2005 NRC report on hydrogen indicated:

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[87] NRC, *Review of the FreedomCar and Fuel Partnership* (Washington, DC: National Academies Press) August 2005.

[88] NRC, *The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs* (Washington, DC: National Academies Press) 2004, 93.

> The cost-effective, large-scale production of hydrogen may require that coal be the primary energy source.[89]

The intention is, however, to improve the efficiency and environmental performance of coal-based hydrogen production, and these represent fundamental goals of the current FutureGen project, a $1-billion, 10-year research project. The project is aimed at coproducing hydrogen and electricity from coal, in a state-of-the-art, 275-MWe coal gasification plant capable of sequestering CO_2 at a rate of 1 million metric tons per year. Although some elements of uncertainty exist, there are not expected to be any major technological breakthroughs necessary to make the FutureGen project a success. A key new element of the program from a utility standpoint is the goal of sequestering a major portion of the plant's CO_2 output. Substantial experience in piping and using CO_2 for EOR provides evidence that this portion of the program should not become an unmanageable hurdle. Although large, centralized plants will ultimately make the most economic sense for a sizable hydrogen-based transportation network, the early infrastructure during introduction of FCV technology will need to be smaller scale and more distributed. It is not yet clear what approach must be taken to maximize the chances of FCV transport technology succeeding.

FCV cost and technology goals, as well as hydrogen transportation and storage infrastructure, needs remain challenging. The 2005 NRC report on the FreedomCAR and Fuel Partnership research program indicated the following with respect to these issues:[90]

> The FreedomCAR and Fuel Partnership is an extremely challenging program, whose ultimate vision involves a fundamental transformation of automotive technologies and the supporting fuel infrastructure. Many technical barriers exist and need to be overcome to achieve this vision, and fundamental invention is probably needed to meet the program's technical performance and cost targets. Even if the technical targets are met, transitioning from the current fuel infrastructure, which is based on gasoline and diesel fuel, to one based on hydrogen derived from a variety of sources will be a formidable social and economic challenge.

More particularly, the NRC cited specific technology areas that need to be addressed:[91]

> The partnership has an extremely ambitious goal: to develop both vehicle and infrastructure technology that would make it possible for automotive companies to decide in 2015 whether or not to build commercially viable fuel cell-powered vehicles. The development of commercially viable fuel cells and onboard hydrogen storage is, without question, the most difficult vehicular aspect of this program. Multiple challenges are being addressed: performance, durability, efficiency, and cost, and they are being worked on at all levels: basic technology, the individual components, stacks, and systems. For fuel cells, durability and cost are the most difficult goals, and for hydrogen storage, the most difficult are size, weight, and cost. In most instances, solutions depend on yet-to-be

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[89] NRC, *Review of the FreedomCar*, 26.
[90] Ibid., 4.
[91] Ibid., 5.

conceived or proven component and manufacturing technology rather than incremental improvement. While this makes outcomes difficult to predict, the committee agrees with the strategy and research directions that DOE is taking to address both the fuel cell and hydrogen storage areas; however, some areas need greater effort.

3. Timing to Commercial Introduction of Hydrogen-Based FCVs

Hydrogen-based FCVs are foreseen as making a contribution to U.S. energy security beginning in 2020, herein. This is approximately 5 years behind the introduction of hydrogen FCVs as anticipated in the 2004 NRC study on the Hydrogen Economy. Once begun, the adoption of FCVs is slower than anticipated by the NRC. The initial market delay and slower introduction are due to the technical and economic issues relating to FCVs and related infrastructure and recognition of potential for stronger than anticipated competition from more established and accepted PHEVs. It is assumed herein that the fundamental technical challenges associated with batteries for PHEVs will be more readily overcome than the technical and economic hurdles remaining for commercialization of FCV technology. As a result, PHEV technology may enter the market more than a decade before hydrogen-based FCVs. It is also anticipated that the convenience of home recharging of PHEVs will eventually become a major influence in meeting future market expectations of consumers.

4. Targeted Results for Hydrogen for Use in FCVs

The estimate herein of 220,000 bpd of oil equivalent from hydrogen by 2030 equals 16 percent of the NCC estimate by 2025. The NCC estimate of coal use for hydrogen FCVs correlates to the 2004 NRC study estimates for coal use (NRC figure 6-14) and FCV market penetration assumptions (NRC figure 6-1),[92] which characterized the forecast of hydrogen FCVs' market penetration as the "optimistic case." The number of FCV vehicles supported by 2025 was estimated to be approximately 48.8 million, whereas the number supported by the reduced estimate herein would represent approximately 8 million. In addition, however, it is estimated herein that 37 million vehicles will be using PHEV technology by 2030, resulting in a similar total of approximately 45 million vehicles using either FCV (hydrogen) or PHEV technology, a slightly less optimistic but more diversified estimate of advanced vehicle technology market penetration.

The NRC analysis of remaining technology hurdles for hydrogen FCVs, in the 2005 FreedomCar report,[93] as mentioned above, combined with the previously unanticipated potential of significant competition from PHEVs, as considered herein, represent key reasons for the delayed and lowered introduction of hydrogen FCVs in this analysis. Nevertheless the environmental advantages and domestic feedstock diversity supporting hydrogen FCVs continue to provide a strong argument for their continued pursuit.

5. Cumulative Use of U.S. Coal Resources Anticipated

[92] Ibid.
[93] Ibid.

The cumulative total of coal use herein for transport-related hydrogen production through 2030 represents 480 million BOE, by 2030. Taking into account the estimated 2.4X multiplier for more efficient vehicle mileage anticipated for FCVs over conventional vehicles, the coal resources required per mile of conventional vehicle oil displacement are substantially lower. In this analysis the total cumulative incremental coal required for hydrogen for 11 years of production through 2030 would only represent approximately 65 million tons total or roughly 6 million tons per year versus the 70 million tons per year in the NCC report by 2025.