**COMMENTS OF THE**
**CENTER FOR NORTH AMERICAN ENERGY SECURITY**
**ON**
**DRAFT AB 32 SCOPING PLAN DOCUMENT**
**AUGUST 1, 2008**

The Center for North American Energy Security ("the Center") is an organization dedicated to environmentally sound development of so-called "unconventional" petroleum resources in North America. The Center submits the following comments on the Draft AB 32 Scoping Plan Document (June 2008 Discussion Draft).

The Draft Scoping Plan recommends adoption of a low carbon fuel standard (LCFS), and indicates that implementing regulations are scheduled to be proposed for Board consideration in late 2008. The Center's comments are limited to the LCFS and are based on the Proposed Concept Outline for the California Low Carbon Fuel Standard Regulation issued March 20, 2008. The Proposed Concept Outline indicates that the default estimates of lifecycle greenhouse gas emissions from unconventional petroleum sources will be developed separately from the estimates for conventional sources, and a mechanism is proposed for adjustment of the default value based on actual data (pp. 13-15). However, it is not clear how mitigation measures or offsetting carbon credits or fees will be considered in developing either the default value or the adjusted values.

For the following reasons, the Center urges adoption of a LCFS that does not discriminate between fuels derived from conventional and unconventional petroleum resources. If a discriminatory approach is adopted, it is essential that full credit be allowed for greenhouse gas and other mitigation measures employed at facilities that extract or process unconventional resources. Offsets and/or carbon credit purchases or fees must be considered as part of the mitigation measures.

Discrimination among petroleum-based fuels is not necessary to achieve the purposes of the AB 32 program and would in fact be counterproductive. It is not needed to control development of unconventional resources in California, as they are controlled directly by applicable state and federal laws and regulations. The primary effect would be to discourage imports to California of fuels derived from other unconventional resources in North America, such as oil sands in Canada or oil shale in the Western U.S. This would have an inflationary effect on fuel prices in California, as these cost effective North American fuels would not be available. The adverse economic impacts would affect low income citizens disproportionately, an effect that AB 32 expressly seeks to prevent. While the legislation states a goal of contributing to worldwide greenhouse gas reductions, a discriminatory LCFS would not assist in attaining that goal. Fuels barred from California would simply be sold elsewhere, to other states or foreign countries where controls may be more lax and emissions from fuel transportation increased. The California economy would suffer, but worldwide emissions would not be reduced and in some cases would be increased. This is precisely the situation that AB 32 and AB 1007 seek to avoid, in requiring a regulatory program "that is equitable, seeks to minimize costs and maximize total benefits," and "minimizes the economic costs to the state" (secs. 38562(b)(1), 43866(b)(2)).

Further, an arbitrary distinction between conventional and unconventional categories is an over-simplification of the suite of petroleum-based refinery feedstocks currently available. The global reality is that feedstocks in general are becoming heavier and sourer regardless of whether they are derived from so-called conventional or nonconventional sources. The past decade has seen significant changes in this regard that can be expected to continue even more markedly over the period when the LCFS takes effect. Many refineries currently are undergoing substantial modification to process these heavier feedstocks.

A primary concept underlying the proposal to adopt a discriminatory LCFS is the notion that fuels derived from unconventional sources are inherently “dirtier” than fuels derived from conventional sources. This is a common misconception that appears to be based on analyses that do not consider promising new technologies or application of mitigation measures or carbon credits or offsets to unconventional fuels operations. The current scientific literature indicates that emission rates from production of unconventional fuels are extremely uncertain, but can be reduced to levels the same as or lower than conventional fuels when such measures are considered.

This is demonstrated by two studies cited in a letter sent earlier this year from Rep. Henry Waxman to Defense Secretary Robert M. Gates.[1] The first, a paper by Williams, et al.[2] discusses coal-based fuels produced using the Fischer-Tropsch process. The paper states that “making F-T liquids from coal could help mitigate oil supply security concerns and would be profitable at sustained high oil prices” (p. 4). The paper also finds that “without CCS [carbon capture and sequestration], this option would lead to a large increase in GHG emissions relative to hydrocarbon fuels derived from crude oil” (id.). However, the paper then concludes:

> With CCS, the GHG emission rate for coal F-T liquids could be reduced to about the rate for crude oil-derived fuels. The net GHG emission rate could be reduced further, to near zero, via coprocessing biomass and coal

[1] Letter from Henry A. Waxman, Chairman, House Committee on Oversight and Government Reform to Honorable Robert M. Gates (January 30, 2008).
[2] Robert H. Williams, Eric D. Larson, and Haiming Jin, *Synthetic fuels in a world with high oil and carbon prices*, Table 1., prepared for the 8th International Conference on Greenhouse Gas Control Technologies, Trondheim, Norway (June 19-22, 2006)(copy attached)

> with CCS so as to exploit the negative emissions of storing photosynthetic CO2 . . . CO2-EOR opportunities in the USA (and perhaps elsewhere) are sufficiently large to make the CO2-EOR application an attractive way to gain extensive near-term experience with gasification-based energy and CCS technologies and the opportunity to 'buy down' the costs of these technologies substantially as a result of learning by doing (p. 5).

Accordingly, the Williams paper stands for the proposition that appropriate mitigation measures may be able to reduce emissions from coal-based fuel production to levels at or below those from production of conventional fuels.

The second paper, prepared by Brandt et al.,[3] discusses unconventional fuels more broadly and concludes that potential emissions are extremely uncertain. The paper investigates three key uncertainties in emissions caused by a transition to unconventional fuels: (1) poorly defined emission factors for unconventional fuels; (2) lack of knowledge of the amount of conventional petroleum remaining; and (3) the possibility of production of unconventional fuels from natural gas and coal feedstocks (p. 242). The paper notes that all of these are major determining factors in the estimation of potential emissions from unconventional fuels production, and attempts to estimate the uncertain values based on mathematical uncertainty analysis.

However, the estimates based on uncertainty analysis do not consider "the issue of technological progress [which] looms large . . . such progress would likely also affect the [unconventional fuels] discussed here, and would allow for the potential for mitigation of some of their excess emissions" (p. 260). For example, the report notes:

> A new process developed by Shell Oil, wherein the shale is heated in place without mining, promises to produce synthetic crude oil from oil shale at significantly reduced cost and emissions compared with mining-based oil shale production processes. However, this technology is still in the

[3] See Adam R. Brandt and Alexander E. Farrell, Scraping the Bottom of the Barrel: Greenhouse gas emission consequences of a transition to low-quality and synthetic petroleum resources, forthcoming in Climatic Change (copy attached).

> development stages and quite uncertain. For these reasons, emissions from the Shell oil shale process are not included, and cost estimates are included only as a lower bound (p. 246).

The uncertainty estimates also do not include potential mitigation measures. The report states that "first and most broadly, this analysis assumes that no climate polices are put into place, and so might be thought to speak most directly to estimates of 'business as usual' scenarios" (p. 260). Thus, the report concludes only that "the analysis presented in this paper suggests that unconventional petroleum production could be a significant source of additional CO2 emissions *unless mitigation steps are taken*" (p. 261, emphasis added).

Additional detail on emerging technologies and potential environmental impacts is provided in the 2007 Report of the Federal Task Force on Unconventional Fuels.[4] The Report concludes that more than 30 companies are moving new technologies toward commercial-scale development of unconventional resources. These technologies are discussed in detail in the Report. A recent presentation at the 2008 Unconventional Fuels Forum provides a detailed look at nine of the more promising in situ technologies currently in development.[5] These include: electric heater (Shell), microwave (Phoenix Wyoming), fuel cell (IEP), hot gas (Petro Probe), hot CO2 (Chevron), steam (EGL), planar (Exxon/Mobil), radio frequency (Raytheon) and hot gas (Mountain West).

These technologies are at various stages of development, but it is already apparent that they have the potential for significant reductions in environmental and water

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[4] U.S. Department of Energy, *Secure Fuels from Domestic Resources: The Continuing Evolution of America's Oil Shale and Tar Sands Industries* (June 2007). The Task Force Report can be accessed through the DOE webpage on fossil fuels.

[5] *Comparing North American Oil Shale Technologies*, William H. Pelton, Ph.D., President, Phoenix Wyoming, Inc. The presentation can be accessed at http:// www.syngasrefiner.com /UNCON/ Pres05282919.asp.

consumption impacts. This is documented in the Task Force Report, which draws the following conclusions:

> (1) environmental monitoring, control, and remediation technologies have become more effective, reliable, and less costly;
>
> (2) more efficient in-situ and surface retorting processes leave less residual carbon behind, both increasing product yield and improving the environmental safety of the spent shale or residual subsurface formations;
>
> (3) technologies to reduce water requirements, to use previously unsuitable water resources, and to capture, clean-up and re-use water have improved dramatically, reducing water demand estimates significantly;
>
> (4) technologies to capture, concentrate and use or store produced carbon dioxide are advancing and the locations, opportunities, and strategies for storing produced carbon dioxide are far better understood.

Yet another reason to avoid a discriminatory LCFS is that it would be extremely difficult to administer fairly and effectively. Many refinery feedstocks are produced, transported, stored, blended and otherwise altered in ways that may not be readily apparent to those conducting the assessments or auditing the work of producers, brokers and other types of vendors. In this system, domestic producers and those from countries with comprehensive reporting systems would be disadvantaged. Similarly, the focus on the carbon footprint alone would work to the disadvantage of feedstocks with low sulfur content or other environmental advantages but higher emissions of greenhouse gases. These aspects of the proposed system are likely to result in undesirable outcomes such as discrimination in favor of products from foreign countries with substandard environmental or human rights policies, and against products that have other desirable environmental attributes or emanate from countries with highly developed reporting systems.

For all of these reasons, a discriminatory LCFS is both unnecessary and undesirable. Major North American resources are, or soon will be, subject to detailed mitigation requirements, well before the LCFS takes effect. Examples include new Canadian regulations for oil sands production, requiring the equivalent of carbon capture and sequestration, and the program that the Bureau of Land Management within the Department of Interior is developing for leasing and control of oil sands and oil shale resources on federal lands. Others may include the need for offsets or allocation purchases for the carbon emissions associated with production. AB 32 calls for a program that is "feasible . . . complementary, nonduplicative, and can be implemented in an efficient and cost-effective manner" (sec. 38561(a)). The program also must "minimize the administrative burden of implementing and complying with these regulations" (sec. 38562(b)(7)). A LCFS that discriminates against North American unconventional resources would not be consistent with these requirements.

If a discriminatory standard is proposed, it is essential that the host of national and international mitigation measures potentially employed are considered, both for the reasons discussed above and because various provisions of AB 32 require consideration of mitigation measures. For example, Sections 38561 and 38562 include the following requirements, among others:

- The state board must consider all relevant information pertaining to greenhouse gas emissions reduction programs in other states, localities, and nations, including the northeastern states of the United States, Canada, and the European Union;

- The state board must identify opportunities for emission reductions measures from all verifiable and enforceable voluntary actions, including, but not limited to, carbon sequestration projects and best management practices;

- The regulations must be designed in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California, and encourages early action to reduce greenhouse gas emissions;

- The state board must consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health.

In addition, the earlier requirements of AB 1007 provide that "full fuel-cycle assessment means evaluating and comparing *the full environmental and health impacts* of each step in the life cycle of a fuel . . ." (sec. 43867(b), emphasis added). No full and complete assessment of such impacts could fail to consider effective mitigation and other emission reduction measures.

The requirement to consider effective mitigation measures also is reinforced by the August 2007 U.C. Davis analysis of the LCFS. For example, the report includes the following discussion of CCS technologies:

> In the future, GHG emissions may be reduced by a variety of *carbon capture and storage* (CCS) technologies that are currently under development (Intergovernmental Panel on Climate Change 2005). More research in measurement, monitoring and verification of CCS is needed, as well as into the long-term trapping mechanism, but we expect these challenges will be overcome. There are also concerns about siting CCS facilities and environmental justice. Once these issues are resolved, CCS projects in the transportation sector should be included in the LCFS . . . One significant approach to CCS is to capture $CO_2$ from fuel combustion or industrial processes, and to compress it and inject it into appropriate rock formations deep underground where it can be stored for many years, perhaps permanently. This geologic CCS is similar to the current practice of $CO_2$ flood enhanced oil recovery ($CO_2$-EOR) in which the underground formation is an oil reservoir from which no more crude oil can be economically produced. The $CO_2$ can liberate significant quantities of oil from the rock, restoring once-depleted fields to productivity (Damen et al. 2005). Oil produced in this way may have a lower net GWI than conventional crude oil and in such instances should be considered a low-carbon fuel (Jessen, Kovscek, and Orr 2005; Parson and Keith 1998)(Part 2, p. 62).

Conclusion

The proposal to adopt a LCFS that discriminates against fuels derived from unconventional resources is not necessary to effectuate the purposes of AB 32 and is likely to work against them. The Center urges that this proposal should be abandoned in favor of a single standard for all fuels derived from petroleum-based resources, including those from heavy-oil reserves, EOR resources, oil sands and shale oil. If a discriminatory standard is retained, full credit for all deployed mitigation measures should be allowed, including offsets and/or carbon credit purchases or fees.

Respectfully submitted,

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# Scraping the bottom of the barrel: greenhouse gas emission consequences of a transition to low-quality and synthetic petroleum resources

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**Abstract** We investigate uncertainties about conventional petroleum resources and substitutes for conventional petroleum, focusing on the impact of these uncertainties on future greenhouse gas (GHG) emissions. We use examples from the IPCC Special Report on Emissions Scenarios as a baseline for comparison. The studied uncertainties include, (1) uncertainty in emissions factors for petroleum substitutes, (2) uncertainties resulting from poor knowledge of the amount of remaining conventional petroleum, and (3) uncertainties about the amount of production of petroleum substitutes from natural gas and coal feedstocks. We find that the potential effects of a transition to petroleum substitutes on GHG emissions are significant. A transition to low-quality and synthetic petroleum resources such as tar sands or coal-to-liquids synfuels could raise upstream GHG emissions by several gigatonnes of carbon (GtC) per year by mid-century unless mitigation steps are taken.

## 1 Introduction

Scenarios of future climate change must necessarily project future fossil fuel use in order to estimate anthropogenic carbon dioxide ($CO_2$) emissions. However, the future of fossil-based energy is full of uncertainties – observed patterns of energy consumption rarely match prior expectations, which, in any case, vary among forecasters. One important set of uncertainties includes the amount of conventional petroleum remaining and the possible substitutes for conventional petroleum. These uncertainties are vigorously debated, but a transition to substitutes for conventional petroleum is inevitable, whatever the timing and whether motivated by geologic, economic, environmental, or political difficulties (Adelman 1995; Odell 2004; Deffeyes 2005; Huber and Mills 2005; Kunstler 2005; Simmons 2005).

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This paper investigates how uncertainties about conventional petroleum supplies and substitutes for conventional petroleum may affect estimates of $CO_2$ emissions in greenhouse gas (GHG) emissions scenarios. We use the IPCC Special Report on Emissions Scenarios (SRES) results as a baseline for comparison because these scenarios are detailed and widely known (Intergovernmental Panel on Climate Change 2000).

To evaluate these uncertainties, we consider the development of fossil-fuel-based substitutes for conventional petroleum (which we will call SCPs). Because petroleum dominates the transportation fuel sector and most petroleum is itself consumed in the transport sector, we focus on liquid transportation fuels. Also, because these fuels have nearly equivalent emissions of $CO_2$ at the point of use (i.e. nearly all of the differences are upstream of the refinery gate), we focus on upstream emissions from these fuels

We first compare estimates of the remaining conventional oil to the modeled petroleum production in three SRES scenarios, as projected by three different SRES modeling teams. Because SRES projections for liquid fuels production from petroleum are larger than estimates of remaining conventional oil in nearly all of our studied cases, a transition to SCPs is implicitly required in the scenarios studied, whether or not it is explicitly described. To understand these substitutes for conventional petroleum, we compare conventional petroleum and SCPs on the basis of cost, carbon emissions, and amount of resource. We then use this information to investigate three uncertainties in GHG emissions caused by a transition to petroleum substitutes:

- uncertainty caused by poorly defined emissions factors for SCPs
- uncertainties resulting from lack of knowledge of the amount of conventional petroleum remaining
- uncertainties due to the possibility of production of SCPs from natural gas and coal feedstocks, which are not included in all SRES models

## 2 Background

### 2.1 Conventional petroleum and possible fossil-based substitutes

The US Energy Information Agency (EIA) reports that petroleum accounts for about 40% of global energy supply today and about the same fraction of $CO_2$ emissions. This amounts to about 3.2 GtC (gigatonnes of carbon) per year. Petroleum production in the year 2004 was approximately 80.2 million barrels per day, or 29.2 Gbbl (gigabarrels) annually (British Petroleum 2005). Over 95% of this is conventional petroleum (Energy Information Administration 2004).

The longstanding interest in the future of petroleum production has recently been re-invigorated. Understanding these efforts, and associated uncertainties, depends critically on nomenclature. Two key terms that must be differentiated are *reserves* and *resources* (Klett 2004). Reserves represent oil that has been identified and is producible with current technology and prices. Resources, on the other hand, are concentrations of hydrocarbons in the earth's crust, a portion of which will become economic over time due to discovery, technological progress, or changing prices and market conditions. Reserves are a small subset of resources, and estimates of both have increased over time due to advances in knowledge. Technological innovation has allowed us to locate more resources, and has allowed an ever-greater fraction of resources to be economically extracted. Another key term is *estimated ultimate recovery* (EUR), which is an estimation of the total amount of conventional petroleum that will be able to be produced economically over all time. EUR is necessarily a larger measure than reserves, as additional oil will be discovered and production technology will expand boundaries of current reserves, but it is necessarily smaller than resources. Some projections of EUR represent EUR by a certain date, such as the USGS World Petroleum Assessment 2000, which provides estimates for recoverable volumes by 2030 (US Geological Survey World Energy Assessment Team 2000).

Failing to pay appropriate attention to differences among these terms can create a great deal of confusion. This is particularly important for climate change scenarios, because reserve estimates focus on potential production in the near-term under existing conditions, while climate scenarios are long-term and must allow for the exploitation of resources that are currently considered uneconomic (Intergovernmental Panel on Climate Change 2000).

Given these considerations, there is a wide variety of opinion regarding future petroleum availability. Cumulative production from 1859 to the end of 2004 was approximately 954 Gbbl (US Geological Survey World Energy Assessment Team 2000; British Petroleum 2005). Current reserves are about 1,200 Gbbl (British Petroleum 2005). If we sum cumulative production to date, current reserves, and estimated future additions to reserves, we arrive at a value equivalent to EUR, several estimates of which are shown in Table 1.

Although not directly comparable, Table 1 also includes an estimate by Rogner (1997) of the remaining portion of the total petroleum resource. Rogner's estimates are the basis for the petroleum resource estimates used in all six of the IPCC SRES models. Rogner's estimate is meant to count hydrocarbons broadly defined and "without immediate reference to recoverability" and so is very large. A detail of Rogner's estimates is shown in Fig. 1, with the amounts in each petroleum resource category shown. By using Rogner's estimates, all of the SRES teams allowed for the adoption of unconventional oil after the depletion of conventional oil.

Rogner explains that petroleum resources occupy a spectrum of varying quality and ease of extraction, and he divides petroleum resources into eight categories. Ultimate recovery

**Table 1** Selected estimates of reserves, estimated ultimate recovery (total and remaining), and resource endowment

| Source and date | Type of estimate[a] | Amount (Gbbl) |
|---|---|---|
| British Petroleum (2005) | Reserves | 1,188 |
| Campbell and Sivertsson (2003) | EUR (remaining EUR) | 1,825 (871)[b] |
| Deffeyes (2001) | EUR (remaining EUR) | 2,100 (1,146) |
| US Geological Survey World Energy Assessment Team (2000) | EUR (remaining EUR) | 2,193/3,021/3,843 (1,239/2,067/2,965)[c] |
| Odell (1999) | EUR (remaining EUR) | 3,000/6,000 (2,046/5,046)[d] |
| Rogner (1997) | Remaining resource | 2,162/19,336[d, e] |

[a] Remaining EUR is EUR less cumulative production until the end of 2004. Cumulative production to date is summed from US Geological Survey World Energy Assessment Team (2000) and British Petroleum (2005), and equals 954 Gbbl.

[b] Excludes petroleum from shale, coal, bitumen, heavy oil, deepwater and polar regions, as well as natural gas liquids. Note that the remaining portion of Campbell and Sivertsson's EUR figure is less than current reserves. This is because they view some current reserves as falsely stated, particularly from OPEC nations.

[c] 95% likely/mean/5% likely

[d] Conventional/conventional plus unconventional

[e] Remaining resource endowment from Rogner is from 1997. This estimate, of course, has been lessened by production since 1997.

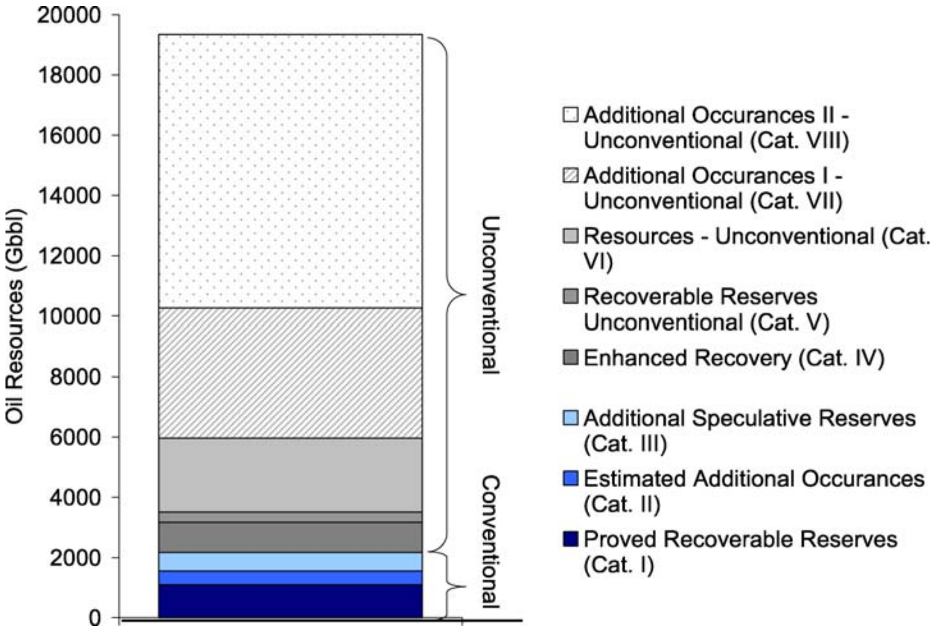


**Fig. 1** Global petroleum resource, all resource categories (Rogner 1997). Notes: Categories *I–III* represent, approximately, "proved and probable reserves" as well as the potential for additional discovery of conventional oil. Category *IV* represents enhanced or tertiary recovery techniques. To use oil industry jargon, Categories *I–IV* are roughly equivalent to reserves, expected reserve growth, and expected new discoveries of conventional oil. Categories *V–VIII* are an amalgamation of tar sands, extra heavy oil, and oil shale. The last two categories (*VII* and *VIII*) are lower-grade resources, including oil that is irretrievably contained in depleted reservoirs. Category *VIII* is "not expected to be technically recoverable or economically feasible before the end of the twenty-first century" (Rogner 1997)

will be limited by the decreasing economic viability of low-quality resources, due to increasing capital and energy costs of extraction, or by increasing environmental externalities, such as the increased carbon intensity of low-grade resources. Rogner constructs production cost estimates for his eight resource categories, and these are used in the SRES models. However, Rogner does not discuss the carbon emissions increases associated with the utilization of unconventional petroleum resources.

## 2.2 Comparison with SRES petroleum production estimates

The Special Report on Emissions Scenarios is the collective effort of six modeling teams. These teams produced six models which project emissions of GHGs in scenarios based on four broad storylines (Intergovernmental Panel on Climate Change 2000). For this study, the IMAGE, MESSAGE, and MiniCAM models were studied. Only these models were studied because of the complexity involved in analyzing the methodology of each model. Therefore, conclusions drawn should not be extrapolated to the other three SRES models. For each model, we studied the "A" scenarios (A1B, A1F, A2), as the "B" scenarios represent more environmentally benign futures that are not compatible with significant adoption of low-grade oil (although it should be noted that all four SRES scenarios preclude policies meant to stabilize the climate). Cumulative oil production for the years 2000–2100 is shown in Fig. 2 for the scenarios studied.

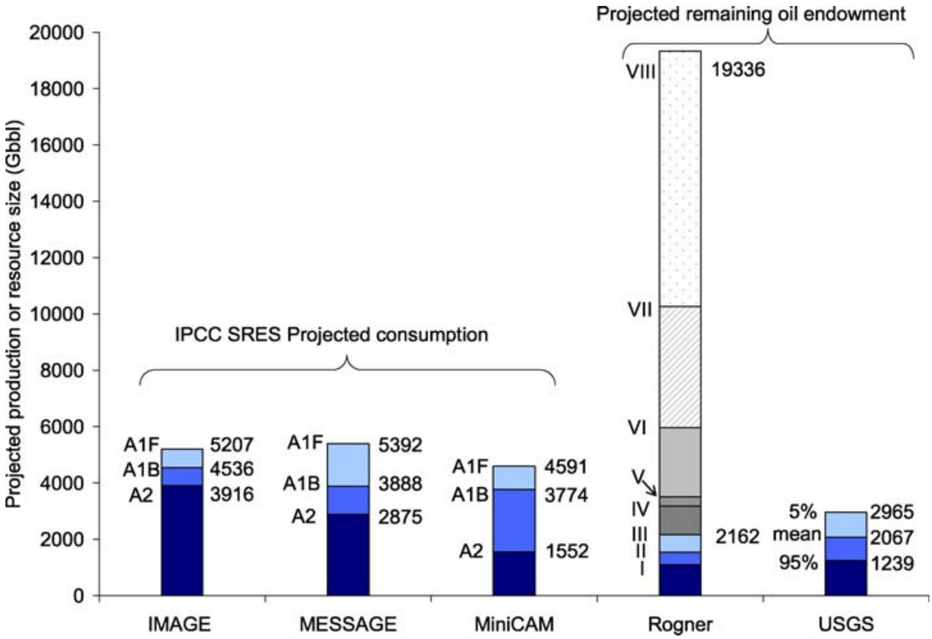


**Fig. 2** Comparison of projected petroleum production in three studied SRES models in three scenarios (*A2*, *A1B*, *A1F*) to two estimates of remaining petroleum resources. Notes: Projected production for IMAGE from IMAGE (2001), and for MESSAGE and MiniCAM from Intergovernmental Panel on Climate Change (2000). Values for Rogner and USGS are from Fig. 1 and Table 1. Rogner's categories explained in Fig. 1, USGS categories are 95% likely to be achieved (low estimate), mean probability, and 5% likely to be achieved (high estimate). Note that projected production in the SRES models is significantly higher in the high-consumption scenarios than even the low-probability USGS estimates for remaining conventional oil, and are much higher than Rogner's estimates of remaining conventional oil (categories *I–III*). This implies production of significant amounts of unconventional oil (Rogner's categories *IV–VIII*, or unconventional resources not estimated by USGS)

By comparing Table 1 and estimates of petroleum production in the three studied SRES models (see Fig. 2), we see that petroleum production modeled in all nine SRES scenarios exceeds conservative estimates of remaining EUR from Table 1, and all but one scenario (MiniCAM A2) exceeds the mean USGS EUR forecast. And, for the most fuel intensive scenario (A1F), all three models project production far above the least-likely USGS estimate and well into Rogner's unconventional resources category (cat. VI). Clearly, if oil production reaches these projected values, we will require significant amounts of unconventional oil by the end of the century. These amounts are on the order of or larger than total cumulative conventional oil production to date. Because of this, it is important that we understand the nature of these unconventional oil resources.

## 2.3 The properties of fossil-based substitutes for conventional petroleum

In this paper we study only fossil-based substitutes for conventional petroleum (SCPs). These can be classified into two groups: synthetic crude oils, currently produced primarily from low-grade petroleum resources, and synthetic liquid fuels (synfuels) created through gasification and catalytic reforming. Synfuels can be made by gasifying and reforming one of the other primary fossil fuel types, such as coal or natural gas, or even from gasified low-grade petroleum resources or biomass. For the purposes of the rest of this paper "SCPs" will refer specifically to the SCPs studied in this paper, which consist of: enhanced oil recovery (EOR), tar sands and extra-heavy oil, gas-to-liquid synfuels (GTLs), coal-to-liquid synfuels (CTLs), and oil shale.

SCPs are already produced in significant quantities. EOR represented about 10% of total US oil production in 2004 (Moritis 2004). Production of oil from Canada's tar sands reached 1 Mbbl/d, or about 1.25% of global production, in 2004 (NEB 2004). Production from Venezuela's extra-heavy oil reached about 0.6 Mbbl/day in 2000 (Williams 2003). In addition, approximately 150,000 bbl/day of synthetic fuels are produced, primarily from coal (Fleisch et al. 2002). Synthetic crude oil produced from oil shale is only produced in minor quantities around the world in small facilities, with total world output estimated at 10,000–15,000 bbl/day (Bartis et al. 2005).

Heavy and extra-heavy oil are very viscous and require the injection of steam (or another source of thermal energy) to reduce the viscosity and allow flow out of the reservoir, and they must also be chemically upgraded and often cleaned of impurities such as heavy metals and sulfur before use. Tar sands are currently produced by either mining or steam stimulation, with the former being more common. In tar sands mining, the mined tar sand is washed of its bitumen content, which is upgraded into a synthetic crude oil that can be refined along with conventional oil. Tar sands production requires large energy inputs for three major activities: transport of oil sands and waste material; separation of bitumen and sand, commonly with warm water and detergent; and upgrading of the resulting hydrocarbon. These steps result in the additional carbon emissions associated with tar sands production (NEB 2004).

It is often thought that oil shale, a very low-grade resource, is a "backstop" for conventional petroleum production because the resource endowment is large. Oil shale is sedimentary rock that contains a hydrocarbon-like substance, and it is thought to be the same material from which oil was naturally created (Rattien and Eaton 1976). However, oil shale must be processed in a retort to produce usable hydrocarbons, which involves crushing and heating the oil shale and disposal of the waste material. These steps consume energy and therefore add cost and carbon emissions. Retorting of oil shale can also release inorganic $CO_2$ from carbonate minerals present in the shale, possibly resulting in very high emissions (Sundquist and Miller 1980; Sato and Enomoto 1997). A new process developed by Shell Oil, wherein the shale is heated in place without mining, promises to produce synthetic crude oil from oil shale at significantly reduced cost and emissions compared with mining-based oil shale production processes. However, this technology is still in the development stages and quite uncertain. For these reasons, emissions from the Shell oil shale process are not included, and cost estimates are included only as a lower bound (Bartis et al. 2005).

In addition to synthetic crude produced from low-grade or unconventional petroleum resources, synthetic liquid fuels can be produced, typically either from natural gas or coal. These fuels are currently manufactured in two steps: first, a syngas comprised mainly of CO and $H_2$ is created through catalysis (in the case of GTL) or gasification and reforming (in the case of CTL); and, second, the syngas is converted into liquid fuel using the Fischer–Tropsch process, a catalytic process that "chains together" the carbon atoms from the CO and can produce a variety of hydrocarbon products depending on the catalyst and operating temperature. CTL synfuels are more costly than GTL synfuels because of the difficulty in handling and processing the coal for gasification (Dry 2002). Also, the higher carbon to hydrogen ratio of coal causes more emissions of carbon from CTL production than GTL production. GTL synfuels are currently produced in Malaysia and South Africa, with significant capacity under construction in Qatar and Nigeria. CTL synfuels are produced in South Africa (Wilhelm et al. 2001; Fleisch et al. 2002). Given current production capacity and great interest in the technology in nations such as China, future energy systems that include GTL and CTL seem feasible (Williams and Larson 2003). Indeed, GTL and CTL may be a less expensive backstop to conventional petroleum production than oil shale.

Also, GTL and CTL synfuels are amenable to carbon dioxide capture and sequestration (CCS, Parson and Keith 1998; Anderson and Newell 2004). A large fraction of the emissions from low-grade oil production result from dispersed processes such as mining, transport of oil-bearing material, or steam generation. However, emissions from GTL and CTL production are from a single source and are already concentrated, because the syngas produced from the feedstock fuel must be cleansed of excess $CO_2$ before entering the Fischer–Tropsch reactor. This process rejects concentrated $CO_2$. This eliminates the expensive $CO_2$ separation phase of CCS. (CCS is also possible in conjunction with enhanced oil recovery, in which $CO_2$ is injected into petroleum formations to boost recovery.)

Williams and Larson (2003) note that for indirect coal liquefaction (the process described above, and the most viable CTL production process), $CO_2$ could be captured, transported and stored at costs between \$24 and 31/tC for dimethyl-ether production, a type of CTL synfuel. Williams and Larson go further and suggest even lower costs might be possible, given co-capture and co-storage of $CO_2$ with acid gases such as $H_2S$ that must be disposed of in any case. Interestingly, such estimates are lower than many of those cited in the literature for carbon capture in electricity generation: Johnson and Keith (2001) suggest that in a dynamic model of the electricity market, CCS technologies are not built until the cost of carbon is \$60 per tonne and 50% carbon capture does not occur until the carbon price is \$100 per tonne. There is another important distinction; because electricity is a carbon-free energy carrier while CTLs and GTLs are not, these fuels result in significant anthropogenic $CO_2$ emissions at the point of use, while electricity does not. Therefore the introduction of CCS could dramatically lower GHG emissions below “business as usual” in the electricity sector, whereas its application in GTL and CTL production would only address the additional emissions beyond those associated with production of transportation fuels from conventional petroleum. Whether such a reduction changes business as usual estimates depends on how (or if) the additional upstream emissions are represented to begin with.

## 3 Materials and methods

### 3.1 Construction of a cost and carbon emissions supply curve

We collected from the open literature estimates of the production costs and full fuel-cycle carbon emissions for all SCPs described above. Costs are given in units of dollars per barrel (corrected for inflation to 2000). Carbon emissions are calculated in units of grams of carbon equivalent emitted per mega-joule of refined product (gCeq./MJ). Nearly all of the additional $CO_2$ emissions occur in the production and refining stages. The total GHG burden over the full fuel cycle is compared between SCPs using a normalized emission parameter, which compares the full fuel-cycle emissions of SCPs to those of conventionally produced petroleum.

These cost and emissions results are used, in part, to build an aggregated supply curve for conventional petroleum and the SCPs considered in this paper. The supply curve is constructed as a "supply curve" with two dependent dimensions: it considers the supply of petroleum substitutes available at a given monetary cost as well as the supply available at a given carbon emissions "cost."

## 3.2 Calculating uncertainty in emissions from petroleum substitutes

After constructing the supply curve and table of emissions properties, we use this information to study three uncertainties in $CO_2$ emissions caused by a transition to SCPs:

- uncertainty caused by poorly understood emissions factors for SCPs
- uncertainties resulting from poor knowledge of the remaining amounts of conventional petroleum
- uncertainties due to the possibility of production of SCPs from natural gas and coal feedstocks

We first review how each of these uncertainties were accounted for in the three SRES models studied (IMAGE, MESSAGE, MiniCAM). Then, for each of these uncertainties, calculations are performed using the IMAGE model projections as the baseline. This should not reflect poorly on the IMAGE model, but instead results from the accessibility of IMAGE documentation and data, as well as the cooperation of the IMAGE modeling team.

### *3.2.1 Calculation one – uncertainty resulting from poorly understood emissions factors for SCPs*

Most methods of producing SCPs emit more GHGs than production of conventional oil. But, because of the variation in the resource base of each SCP, uncertain technologies, and the early stage of development of many of these technologies, emissions factors from these processes are uncertain. Because the transition to SCPs is but one detail among many facing the SRES modelers, it is not modeled in great detail in the SRES models, although some, like MESSAGE, vary the emissions for each of Rogner's eight resource categories. To calculate the magnitude of additional carbon emissions possible because of the adoption of SCPs, and the potential amount of uncertainty involved, calculations were performed using the IMAGE data as a baseline.

For the baseline emissions estimate, a globally averaged emissions factor is calculated from IMAGE model output for each year of the model (2000–2100). The data used from IMAGE include the emissions from production of oil as well as the amount of oil refined, as refining emissions are significant. The baseline emissions are compared to emissions that would result if Rogner's resource categories were consumed in order and our detailed emissions factors were used.

For our alternate emissions estimates, the amounts of petroleum produced in the three IMAGE baseline scenarios are used, but we vary the emissions factors based on the type of resource. In this calculation, we assumed the resources were consumed from Rogner's categories in sequential order (that is, all of resource cat. IV is consumed before cat. V is consumed), and that synthetic fuels are not produced. Composite emissions factors were computed for each of Rogner's resource categories using the makeup of each category and

**Table 2** Emissions from fuels produced from conventional and unconventional petroleum and synfuels

| | Emissions (gCeq./MJ of refined product) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Gasoline[a] | | Diesel[a] | | Tar sands/extra heavy oil | | | |
| | | | | | Low emissions | | High emissions | |
| Upstream emissions | 5.6 | (22%) | 4.4 | (17%) | 9.3[b] | (31%) | 15.8[c] | (44%) |
| Combustion emissions | 20.1 | (78%) | 21.1 | (83%) | 20.1 | (69%) | 20.1 | (56%) |
| Total emissions | 25.7 | (100%) | 25.5 | (100%) | 29.4 | (100%) | 35.9 | (100%) |
| Normalized emissions | 1.00 | | 1.00 | | 1.14 | | 1.4 | |
| | Enhanced oil recovery[d] | | | | Oil shale | | | |
| | Low emissions | | High emissions | | Low emissions | | High emissions | |
| Upstream emissions | 6.1[e] | (23%) | 10.6[e] | (35%) | 13 | (39%) | 50 | (71%) |
| Combustion emissions | 20.1 | (77%) | 20.1 | (65%) | 20.1 | (61%) | 20.1 | (29%) |
| Total emissions | 26.2 | (100%) | 30.7 | (100%) | 33[f] | (100%) | 70[f,g] | (100%) |
| Normalized emissions | 1.02 | | 1.19 | | 1.28 | | 2.72 | |
| | Gas-to-liquids[m] | | | | Coal-to-liquids[m] | | | |
| | Low emissions | | High emissions | | Low emissions | | High emissions | |
| Upstream emissions | 7.1[h] | (26%) | 9.5[j] | (32%) | 20.7 | (50%) | 28.6 | (59%) |
| Combustion emissions | 20.2[I] | (74%) | 20.2[i] | (68%) | 21.1 | (50%) | 20.1 | (41%) |
| Total emissions | 27.3 | (100%) | 29.7 | (100%) | 41.8[k] | (100%) | 48.7[l] | (100%) |
| Normalized emissions | 1.07 | | 1.16 | | 1.64 | | 1.89 | |

[a] These figures are provided by the GREET model, which calculates upstream emissions from petroleum production, as well as 0.4 gCeq./MJ emissions from natural gas leakages, 0.16 gC/MJ from natural gas flaring, and refining emissions that vary based on the product produced (Wang 1999, Volume 2, page 8).

[b] These emissions are reported by the Syncrude (2004), which reports 5.03 gCeq./MJ upstream emissions per barrel of synthetic crude oil produced. To this, refining emissions are added. Wang (1999) reports the emissions from refining of gasoline and diesel to be 4.2 and 3.0 gCeq./MJ respectively. The emissions from refining gasoline are used here. Estimates are also available from Suncor, another tar sands producer (Suncor 2003).

[c] The National Energy Board (2004), Canada notes that the upstream emissions to produce a barrel of synthetic crude oil are reported at 11.54 gCeq./MJ, of which over half are methane emissions. Refining emissions are added to this as in note b.

[d] Because these scenarios assume no climate policies, CCS through $CO_2$-induced-EOR is not included here. The amount of CCS capacity available through EOR projects is highly field-specific and still a matter of debate. Stevens et al. (2001) cite $CO_2$ injection ratios of 0.3 tonne $CO_2$ per bbl of EOR output. However, much of this $CO_2$ is recycled in the production process, so all of it does not stay sequestered. A better figure is provided by Kovscek (2002), who notes that the volumetric density of carbon as $CO_2$ at typical reservoir conditions is about one fourth that of oil (164 vs 686 kgC/$m^3$ for oil). This suggests that approximately 5 g of carbon per MJ of oil produced through EOR can be stored in the same volume that the oil originally occupied (one fourth the C content of the produced oil).

[e] Green and Willhite (1998) cite numerous thermal enhanced oil recovery projects in California, Canada and Venezuela. If oil is used as the steam generating fuel, incremental emissions for thermal EOR range from between 0.34 and 7.2 gC/MJ of crude produced. If natural gas is used, emissions will be approximately 25% lower, if coal is used, approximately 25% higher. These emissions are highly variable depending on the characteristics of the project. As a low-end estimate, a 0.5 gC/MJ penalty over conventional oil production is used, and as a non-extreme high-end estimate, a 5 gC/MJ penalty over conventional production is used.

[f] Emissions from oil shale are highly uncertain. These figures are from Sundquist and Miller (1980), and Sato and Enomoto (1997) corroborate the order of magnitude. To these emissions 4.2 gC/MJ are added for refining to gasoline (see note b). The low end of the range is for low-temperature retorting, and the high estimate is high because of emissions of $CO_2$ from decomposition of carbonate minerals contained in the shale, which occurs at high temperatures sometimes achieved in the retorting process (above 550°C). Sato and Enomoto (1997) also see some inorganic carbon release at low temperatures in bench-scale experiments, meaning the low estimate of emissions may be too low.

[g] This figure is the high-end emissions estimate for high-grade oil shale resources. Sundquist also estimates emissions from low-grade oil shale resources, which are cited as 104 gC/MJ, or over four times the total emissions from conventional oil and approximately 16 times the upstream emissions(!)

[h] This datum calculated from Wang et al. (2001), figure ES-1.4, page 10, using central estimates for Non-North American FT-diesel. Wang's estimate of emissions from GTLs includes credits for co-produced electricity, which might not always occur. See further critiques of the GREET method in Greene (1999, pp. 28–29).

[i] Greene (1999) states that "On the basis of the energy equivalent of a gallon of petroleum-derived diesel fuel, GTL diesel should have about 4.4% less carbon." Wang's estimate of the carbon content of diesel (see note a) is decreased by 4.4%.

[j] Greene (1999) cites two estimates of upstream emissions. These upstream emissions are for 1995 GTL diesel.

[k] Datum from Marland (1983), for Sasol type F-T process. It should be noted that Williams and Larson (2003) cite lower emissions when credit for electricity co-production is given to the production of methanol or dimethyl-ether (DME).

[l] Datum from Williams and Larson (2003), from Bechtel/Amoco estimates, for direct coal liquefaction. Refining emissions were added from Wang (1999) as in note b above, because direct CTL produces a synthetic crude, not a synthetic fuel. There is uncertainty with the high-end emissions from CTL processes. For example, Marland (1983) describes the Mobil methanol-to-gasoline (MTG) process. MTG emissions are comparable to this estimate if all energy products produced are counted, but emissions per MJ of *gasoline delivered* are much higher (64.69 gC/MJ of gasoline).

[m] GTL and CTL processes are amenable to CCS, which would reduce emissions by about 90%. This potentiality is not included here but is discussed in detail by Williams and Larson (2003).

the emissions factors from Table 2. For example, Rogner's category VI is 53% oil shale and 47% tar sands and heavy oil, and thus the composite emissions factor is weighted by these percentages. For each of Rogner's categories, a composite emissions factor is computed using the low and high emissions factors from Table 2, as well as the mean of the low and high emissions factors.

### *3.2.2 Calculation two – uncertainty resulting from variable estimates of EUR*

All of the SRES models use Rogner's estimate of the remaining resource of conventional oil. As was shown in Table 1 above, however, there is considerable disagreement over the amount of conventional oil remaining. If we instead have a different amount of conventional oil remaining, the transition to the fossil-based SCPs studied here would certainly occur at a different time. How would using a different estimate for remaining conventional oil affect the emissions we project over the coming century?

In this calculation we calculate the sensitivity of emissions to the amount of conventional oil remaining. We compare the effect of using four estimates of remaining conventional oil: Rogner's estimates of categories I–IV, as used in the SRES models, and the three USGS EUR estimates. Rogner's category IV (EOR) is included because EOR is included in the USGS assessment. Rogner's estimate for remaining oil in categories I–IV is 3,172 Gbbl. This value is slightly higher than the remaining portion of the USGS low, mean, and high probability estimates (2,995, 2,097, and 1,269 Gbbl, respectively).

The emissions consequences of this uncertainty are calculated in an analogous fashion to *calculation one* above. We again use IMAGE data as a baseline, and IMAGE petroleum production projections for the years 2000–2100 were used and assumed to be consistent across all cases. In this case the mean of the emissions factors from Table 2 for each SCP is used. Cumulative emissions over the years 2000–2100 are then calculated using the four EUR estimates described above, under the assumption that Rogner's resource categories are consumed in sequential order.

There is an unavoidable difficulty with this calculation. If the amount of remaining conventional oil were less than that cited by Rogner and used in the IMAGE model, there would be an earlier transition to the higher-cost unconventional resources. This would dampen demand if all else is held equal and result in less consumption. Unfortunately, because of the non-linear nature of the model, the size of such dampening effects cannot be determined except by re-running the IMAGE model with new input data. Thus, the estimates from this calculation should be considered only as an upper bound on potential emissions.

### *3.2.3 Calculation three – petroleum substitutes from other fossil feedstocks*

Another source of uncertainty in future emissions is the potential for the use of synthetically produced liquid fuels in place of low-grade petroleum. The IMAGE model structure does not allow for the conversion between coal and natural gas to liquid fuels, but the MESSAGE and MiniCAM models do allow for the production of synfuels. Because the IMAGE model does not allow the development of synfuels, we perform basic calculations to determine the potential magnitude of emissions increases above IMAGE projections that would result from development of synfuels.

To obtain an estimate for petroleum demand, primary production of petroleum is extracted from the IMAGE scenarios. The production projections for each of the IMAGE scenarios are adjusted to minimize the error between actual world production from 2000 to 2003 and IMAGE modeled production from those years (British Petroelum 2005).

Data from Hallock et al. (2004) are utilized to model production of conventional oil. Hallock et al. (2004) project the course of conventional petroleum production for the case where recoverable conventional oil is equal to the USGS high estimate. The USGS high estimate is very close to Rogner's estimate of resources available from categories I–IV, so these Hallock projections are used as a proxy for production of conventional oil in the comparison. The Hallock et al. (2004) projection is also adjusted to match actual production of all fuels from 2000–2003, so that IMAGE and Hallock projections are normalized in the years 2000–2003.

The adjustment procedure performed with the Hallock et al. (2004) data amounts to an assumption that the share of unconventional oil production remains at the current percentage, because BP data include unconventional oil. Thus, the question we are able to ask with these data is: "if production of unconventional oil remains only at today's percentage of total oil production, how much synfuel would needed to meet IMAGE demand, and what would the carbon consequences of this be?" This question is, of course, somewhat artificial in the context of modeling, but it can illustrate the potential consequences of using synthetic fuels in a hypothetical case where low-quality oil production remains at today's comparatively low rates.

The difference between the adjusted Hallock et al. (2004) production curve and the three adjusted IMAGE demand scenarios represents a shortfall that can be filled with synthetic fuels. The magnitude of the shortfall is reduced by 10% to account for the fact that 1 barrel of synfuel represents a finished product, whereas one barrel of oil converted to diesel or gasoline loses 9–14% of the energy content in refining (Wang et al. 2004). If this shortfall is filled with synfuels, we can analyze an "envelope" of potential emissions effects for each IMAGE scenario. The lower edge of this envelope is given by 100% adoption of GTL synfuels, while the upper edge of the envelope is given by 100% adoption of CTL synfuels. These emissions are compared to IMAGE projected emissions from petroleum production.

Although demand could potentially decline with the introduction of synfuels (see discussion in *calculation two*), this effect is not as important for this uncertainty as compared to that in *calculation two* because synfuel production is not significantly more expensive than production of a mix of tar sands and oil shale (the category V resources it is replacing).

# 4 Results

## 4.1 Supply curve with cost and carbon emissions

The GHG emission factors for the SCPs considered in this paper are shown in Table 2. The constructed supply curve, with both monetary and carbon dimensions of "cost" included, is shown in Fig. 3. This supply curve should be seen as the total potential for liquid fuels production, and does not represent what we believe is a likely amount of liquid fuel production. For each segment of the supply curve, a range of variability (for current technologies) and uncertainty (for current and future technologies) in cost of production was determined. These cost ranges are represented by the vertical dimension of the curve.

Also in Fig. 3, the uncertainty in the amount of each resource is represented by the color intensity of the horizontal dimension. The dark portion of each segment represents a conservative estimate, typically reserves, while the lighter portion represents a generous estimate, such as resources (see the notes for Fig. 3 for specific sources and definitions). Thus, the actual amount of each resource able to be produced will likely fall between the dark and light portions of each segment, and a conservative estimate can be made by adding only the dark portions of each curve.

Note that the GTL and CTL portions of the curve assume that all natural gas and coal reserves or resources are converted to liquid fuels, so these portions of the curve represent the upper bound on GTL and CTL potential. Note that these values account for the energy lost in processing. Clearly, the production of the entire resource represented (up to nearly 19,000 Gbbl) is very unlikely, but instead represents a general upper bound on liquid fuel development. Note that in Fig. 3 the traditional, very-high cost backstop (oil shale) is now displaced to the right by large (but uncertain) estimates of potential GTL and CTL production. See also that potential volumes of CTL synfuels are larger than volumes of shale, which has been traditionally thought of as the most plentiful petroleum substitute. Thus, the dollar-denominated supply curve is longer and flatter than many that have been constructed in the past without these fuels.

Also of importance is the role of resource aggregation in construction of the curve and the order of extraction. Within each of our resource categories are a number of resources that have varying emissions and costs associated with their production. For example, a significant portion of the tar sands resource will not be accessible by mining due to the depth of the resource. This deep tar sands resource will have a different emissions and cost profile than near-surface tar sands, as a different process will be required for extraction. The aggregation of resource types we performed results in a curve with large steps, while a more detailed supply curve would have smaller steps within each of our large categories.

We must also emphasize that this supply curve is not meant to imply that these resources will be consumed in order. As stated above, significant amounts of SCPs are currently produced, and many non-economic factors will influence the order of extraction. Some SRES models, such as MESSAGE, account for some of this uncertainty, although the documentation available does not offer details of how the model operates to account for this behavior.

## 4.2 Calculations of uncertainty due to petroleum substitutes

### *4.2.1 Calculation one – uncertainty resulting from variable emissions factors for unconventional oil*

The SRES models differ in their approach to modeling emissions from different classes of petroleum, but none of them evaluate this uncertainty in detail.

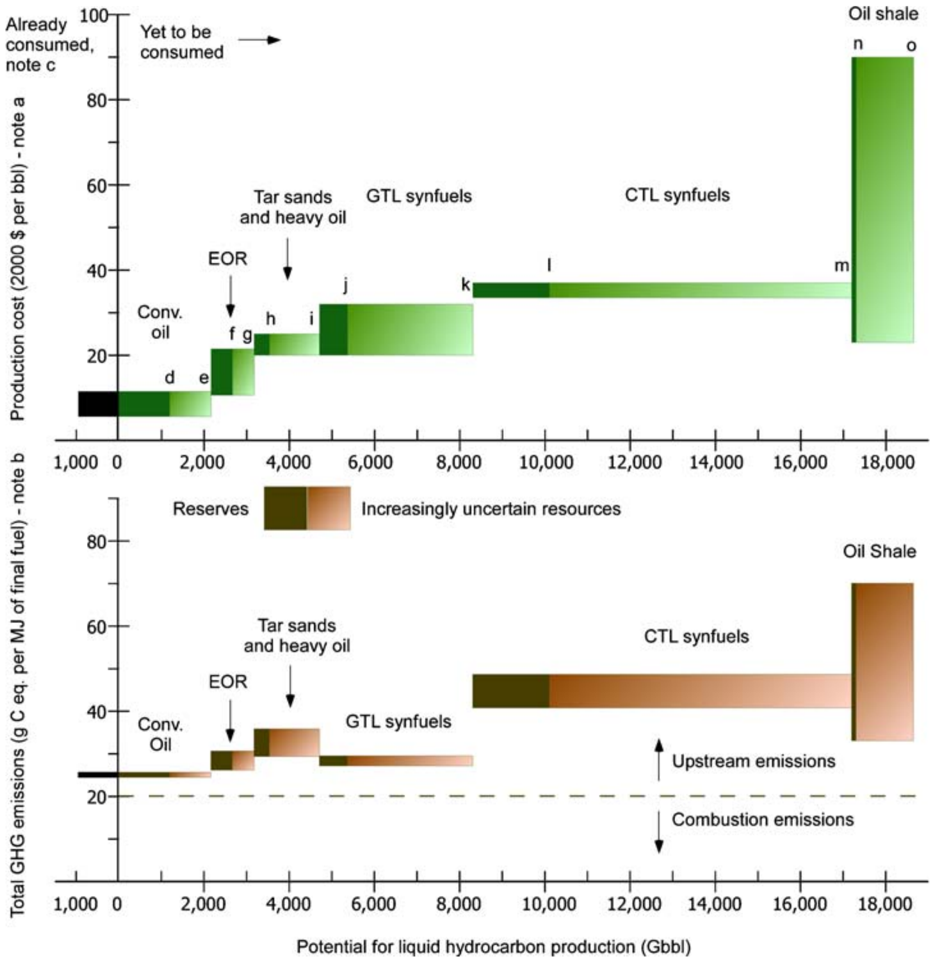


**Fig. 3** Global supply of liquid hydrocarbons in dollars (*top*) and carbon emissions (*bottom*). Note that *lightly shaded* portions of the graph represent less certain resources, so a more conservative estimate is available by counting only the *dark* portions of each resource category. Notes *d* through *o* correspond to the horizontal width of the *bars* and apply to both curves

Notes for Fig. 3:

a – Costs of production represent crude oil or crude oil equivalent costs:

Conventional oil – High estimate is from Energy Information Administration (2005), and is the sum of finding and lifting costs reported for “worldwide”. Low estimate combines a lower estimate for development costs for Middle East producers (Stauffer 1994) combined with the lifting costs for the Middle East from Energy Information Administration (2005).

EOR – This estimate is calculated from Green and Willhite (1998), who provide energy inputs for California thermal EOR projects. Thermal EOR is currently the most common EOR technique. For oil ($50 per bbl) burned as steam generating fuel, the additional cost in fuel ranges between $0.6 and $15 per induced barrel of production, not including additional capital. As this cost is highly dependent on the particular project, a low-end estimate of $5 per barrel above conventional oil is used, and a high-end estimate of $10 per barrel is used in this figure. For other types of EOR, Gharbi (2001) found in an optimization model that optimal chemical inputs in a chemical flood EOR project ranged from $4 to $11 per bbl, and $CO_2$ EOR required a price of between $10 and $15 per barrel to sustain a profit. Thus a range of $5 to $10 dollars incremental cost is reasonable for EOR in general.

Tar sands and Heavy Oil – Supply cost for integrated mining and upgrading, converted to US dollars (NEB 2004). Note that other tar sands or heavy oil production techniques have different costs, with slightly lower costs for cold production and higher costs for cyclic steam stimulation and steam assisted gravity drainage (NEB 2004). This estimate is in agreement with CERI (2004), who estimate a crude oil equivalent price at approximately \$25 per barrel after accounting for quality.

GTLs – The cost of GTLs is highly dependent on natural gas prices. Estimates are crude oil equivalent prices (which reflect that GTLs are refined products) from Bechtel (1998). The low estimate is for natural gas costs of \$0.50 per MMbtu, while the high cost is for gas at \$2.00 per MMbtu. Note that Greene (1999) and Corke (1998) estimate costs as low as \$16.00/bbl with gas at \$0.50 per MMBtu, with \$5 per bbl added for each \$0.50 per MMbtu added to the gas price.

CTLs – Low and high costs are crude oil equivalent prices from Bechtel (1998). There is disagreement with regard to cost of CTL technology: Barbiroli and Mazzaracchio (1995) cite \$46–48 per bbl, while using variable and operating costs from Barbiroli and Mazzaracchio plus the lowest coal prices from Energy Information Administration (2005)(South African coal at \$4.77 per tonne), production costs could potentially be as low as \$28 to \$32 per bbl.

Oil Shale – Costs are cited as "\$50 and up" in Rogner (1997). Bartis et al. (2005) cites costs of potentially as low as \$25–\$30 per bbl for the recently developed Shell ICP process, but they estimate costs from a first-of-a-kind mine and retort plant at \$75–\$95 per bbl. Clearly, costs estimates are extremely variable for oil shale.

b – Carbon emissions data from Table 2, sources for each resource explained in notes to Table 2.

c – Already consumed oil is summed from US Geological Survey World Energy Assessment Team (2000) and British Petroleum (2005), and equals 954 Gbbl.

d – Proven reserves of 1,188 (British Petroleum 2005).

e – Rogner's (1997) remaining conventional petroleum in categories I–III (2,162 Gbbl, producible with primary and secondary recovery technologies).

f – Author's estimate based on applying Rogner's ratio of primary plus secondary production to EOR production (about 2:1) to British Petroleum (2005) proven reserves to estimate about 500 Gbbl from EOR.

g – Rogner's (1997) estimate of production from EOR, category IV (1,011 Gbbl).

h – Rogner's (1997, Table 3) reserves of heavy oil, plus NEB (2004) proved reserves of tar sands.

i – Rogner's tar sands and heavy oil resources, except categories VII–VIII, "additional occurrences". Rogner states that the "additional occurrences II" category (VIII) is not likely to be exploitable anytime in the twenty-first century. Because of these uncertainties, categories VII and VIII resources are not included. Note that Meyer and Attanasi (2003) cite the sum of "technically recoverable" heavy oil and tar sands at 1,085 Gbbl, significantly less than Rogner's resources in place (about 6,000 Gbbl).

j – British Petroleum (2005) proved reserves of natural gas, converted to synfuels at 58% conversion efficiency (Greene 1999). Note that this is only to show the *potential* for GTL synfuels and assumes that all reserves of natural gas are converted to liquid fuels.

k – Rogner's (1997) estimate of natural gas resources in categories I–VI. Categories VII and VIII were not included because they are of dubious economic viability and contain large amounts of methane hydrate resources, which are very uncertain. Resource is converted to Gbbl of synfuel using 58% conversion efficiency (Greene 1999).

l – British Petroleum (2005) proved reserves of hard plus brown coal. Converted to GTOE using energy content of hard and brown coals from British Petroleum (2005). GTOE converted to Gbbl synfuels using 52% conversion efficiency (Marland 1983).

m – Rogner's (1997) estimate of coal resources, hard plus brown coal for categories A–D. Category E was not included due to the uncertain economic viability of category E coals. Resource is converted to Gbbl synfuel using 52% conversion efficiency (Marland 1983).

n – Rogner's (1997) estimate of oil shale proved reserves.

o – Rogner's estimate of oil shale resources, except categories VII and VIII. See note *h* above.

MESSGE accounts for these differences by dividing resources into "grades," (equivalent to Rogner's categories) which have individual formulas for cost and efficiency of production from primary fuel feedstock. Carbon is accounted for at the point of primary resource extraction, and lower-grade resources are made more carbon-intensive by reducing the amount of final fuel produced per unit of primary carbon extracted (Messner and Strubeggar 1995, 2001). However, the efficiencies used in MESSAGE are not well documented in the available literature.

MiniCAM has two emissions intensity values, one for conventional petroleum and the other for unconventional (Brenkert et al. 2003), which allows it to account for some of the variability in emissions from unconventional oil production.

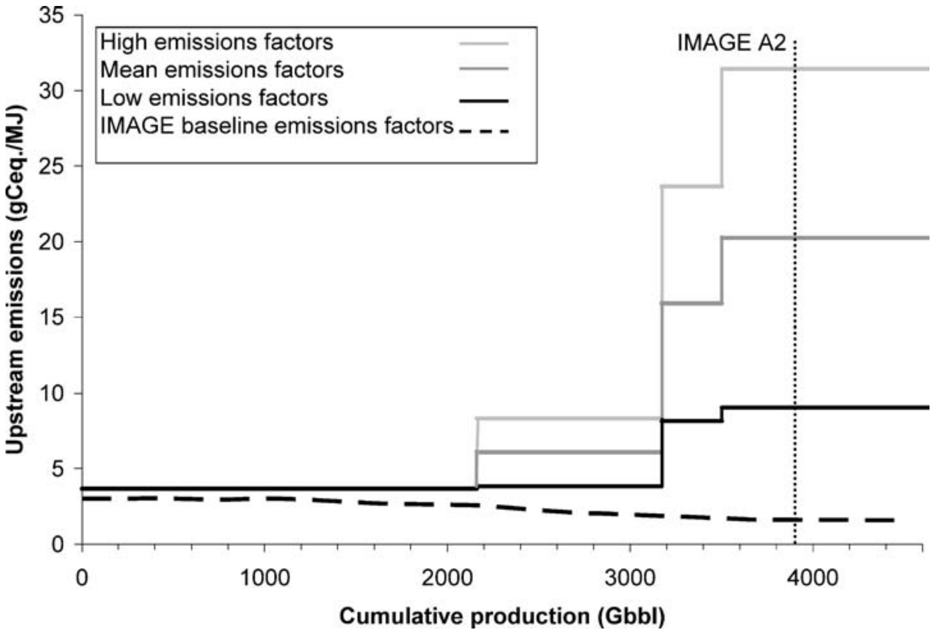


**Fig. 4** Emissions intensity as a function of cumulative production for baseline IMAGE A1B emissions path and three calculated emissions paths. Notes: The total additional emissions resulting from including the emissions factors for unconventional oil are equal to the area between the baseline IMAGE emissions factor curve and the variable emissions curve of interest. All *curves* are adjusted for percent of petroleum refined as given by IMAGE. Note the great uncertainty that arrives with the production of resources from Rogner's categories V and VI (last two segments of the three calculated curves). Total production for scenario A2 is given by the *dotted line*, while total production in scenario A1F is beyond the scope of the figure

The most detailed information was available for IMAGE, which uses an emissions factor from EDGAR (an emissions database) for fugitive methane emissions from petroleum production for all petroleum types, as well as a minor amount of fugitive emissions from oil trade (Olivier et al. 1999; de Vries et al. 2001). In addition, emissions from the fuel consumed in conversion from crude oil to refined products are counted (van Vuuren 2005). The emissions from petroleum production are valued at between 0.2 and 1.7 gCeq./MJ for fugitive methane emissions, depending on the IMAGE model region. The production-weighted global emissions factor is 1.14 gCeq./MJ in the year 2000, and declines to 0.21 gCeq./MJ in 2100. The initial figure agrees very well with other estimates of emissions from production, such as the GREET model. However, no allowance is made in the IMAGE model for the carbon intensive nature of low-grade petroleum. Emissions factors for refining are constant over time.

We now focus on our calculations performed using IMAGE data for a baseline comparison. The IMAGE globally averaged emission factor is shown as the dashed line in Fig. 4. Overall emissions drop over time due to better control of fugitive methane emissions, but refining emissions stay constant. In all IMAGE scenarios studied, the fraction of oil refined begins at approximately 67% and decreases to between 45 and 50% by 2100. This IMAGE emissions factor is compared in Fig. 4 to the emissions that result from applying the emissions factors in Table 2 to Rogner's resource categories. The area between each curve and the IMAGE baseline curve represents the cumulative additional emissions due to using detailed emissions factors.

**Table 3** Upstream emissions from oil production, three IMAGE scenarios under baseline and variable emissions factors (cumulative GtC emitted, 2000–2100)[a]

| | With IMAGE emissions factors | With varying unconventional emissions factors[b, c] | | |
|---|---|---|---|---|
| | | Low | Mean | High |
| A2 upstream emissions | 61 | 110 | 168 | 225 |
| A1B upstream emissions | 63 | 146 | 246 | 346 |
| A1F upstream emissions | 70 | 183 | 329 | 475 |

[a] These estimates use weighted emissions factors (from Table 2). Weights are derived from Rogner's (1997 p. 235) breakdown of categories I–VI, and all categories use the average value of gasoline and diesel for refining emissions. Categories I–III contain 100% conventional oil; IV contains 100% EOR oil; V contains 30% oil shale, 70 % tar sands and extra heavy oil; VI contains 53% oil shale and 47% tar sands and extra heavy oil.

[b] The low and high emissions factors were derived from the low and high estimates in Table 2, the mean is the mean of the high and low emissions factors from Table 2.

[c] These emissions are adjusted according to percentage of oil refined, using percentage refined data from the equivalent IMAGE scenario.

There is a large divergence in cumulative emissions between IMAGE projections and our simple model. Part of this difference (about 10 GtC) can be attributed to the difference in baseline emissions factors for conventional oil production (in Fig. 4, the emissions from conventional oil are slightly below those of our estimates). Another portion of the

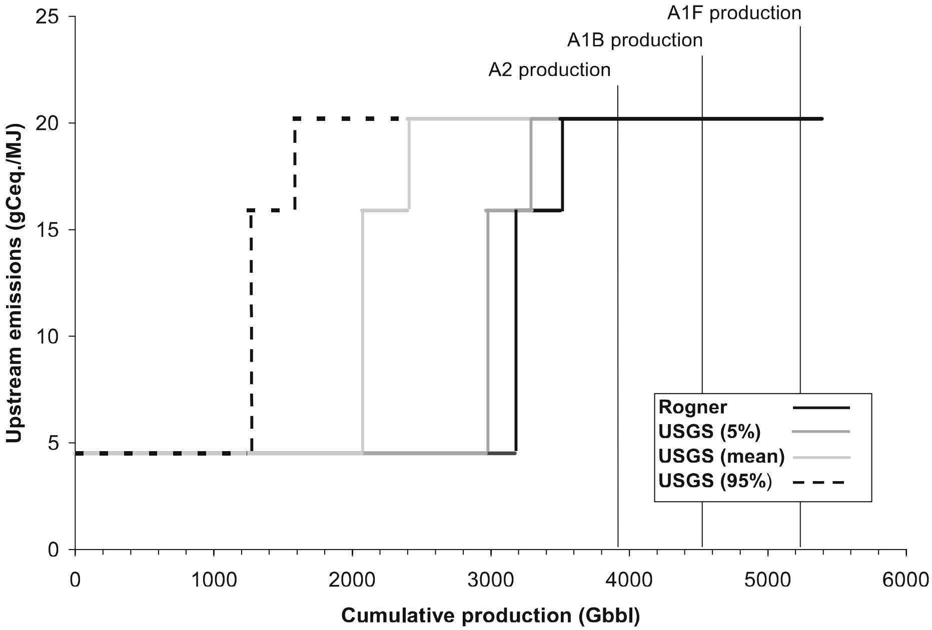


**Fig. 5** Dependence of emissions on assumed amount of remaining conventional oil. Notes: The smaller the amount of conventional oil, the sooner unconventional resource will be developed. The emissions factor for conventional oil and EOR (the *lowest line segment*) is a weighted average of conventional and EOR emissions factors from Fig. 4 (66% conventional, 33% EOR)

**Table 4** Emissions variability with respect to varying estimates of ultimately recoverable conventional oil, using mean emissions factors (cumulative emissions GtC, 2000–2100)

| | A2 upstream emissions | A1B upstream emissions | A1F upstream emissions |
|---|---|---|---|
| Rogner (1997)[a] | 170 | 246 | 329 |
| USGS 5% probability | 187 | 263 | 346 |
| USGS mean probability | 273 | 349 | 432 |
| USGS 95% probability | 352 | 429 | 511 |

[a] Emissions from Rogner's resource base are calculated using the mean composite emissions factors from Fig. 4 , not the emissions factors used in IMAGE. This is to separate the effects of calculaltion 1 from the results of this calculation.

difference (about 13 GtC in IMAGE A1B) is due to the decrease in methane emissions over time from oil production as modeled in IMAGE. The largest portion of the difference, however, results from the radically different emissions factors for unconventional oil. When Rogner's category V, which contains the first amounts of oil shale, begins to be produced at just past 3,200 Gbbl, the emissions factors increase and uncertainty increases greatly.

These estimates of excess emissions are highly dependent on the order of resource extraction. In our model, Rogner's categories are exploited in sequential order. This means, for example, that unconventional reserves (i.e. category V) are exploited before unconventional resources (category VI). If one instead assumes that the resources will be exploited by order of resource type, such as strictly along the supply curve shown in Fig. 3, then excess emissions would be considerably lower, as all EOR would be exploited before any tar sands were exploited, and oil shale would only be exploited after all other resources were completely depleted. Currently, tar sands and synthetic fuels are being

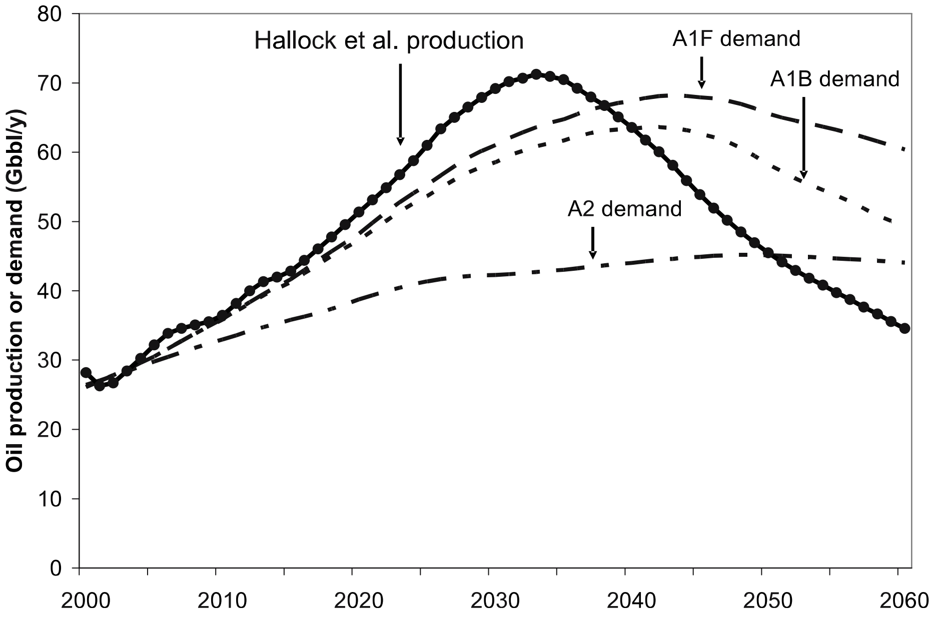


**Fig. 6** Hallock et al. (2004) adjusted production projection vs IMAGE demand projections for scenarios *A1B*, *A1F* and *A2*

produced while large reserves of conventional oil remain, so a model that moved strictly up the supply curve could not be considered more realistic than exploitation of Rogner's categories in order.

The emissions increases calculated over the twenty-first century are shown in Table 3. The emissions over this 100 year period are significantly higher in the case where variable emissions factors are used, and are much more variable than the baseline scenarios. Much of the emissions burden, as well as the uncertainty, comes from the production of oil shale. If oil shale is produced in significant quantities with retorting temperatures that cause carbonate mineral decomposition (as in our high emissions factor), the potential emissions effects are very large, on order of hundreds of GtC over the twenty-first century.

### *4.2.2 Calculation two – uncertainty resulting from variable estimates of EUR*

This calculation estimates the potential uncertainty resulting from our poor knowledge of the amount of conventional oil remaining. The mean emissions factors for SCPs (the middle curve from Fig. 4) were used to calculate emissions paths that vary with cumulative production. Total emissions over the years 2000–2100 were then calculated for four cases, each of which uses one of four EUR estimates. Figure 5 illustrates the emissions consequences of varying the value for EUR. Results are presented in Table 4, which shows cumulative carbon emissions from the upstream petroleum sector for the years 2000–2100 given the four estimates of EUR.

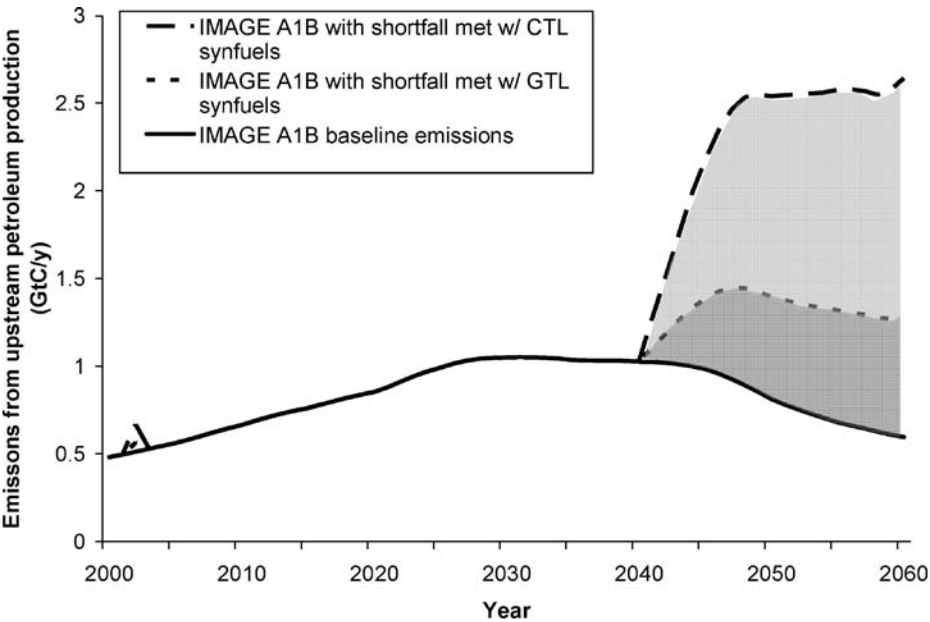


**Fig. 7** Upstream emissions from liquid fuel production in A1B scenario, in a calculation only allowing synthetic fuels without emission mitigation. Notes: The *solid curve* represents the baseline, in which all demand is met with petroleum, using yearly emissions factors from the IMAGE model. The two *dashed curves* represent the upper bounds on additional emissions resulting from the introduction of GTLs (*lower*) or CTLs (*upper*). Note that the *upper* edge of each *shaded* envelope represents complete adoption of synfuels (all shortfall is filled with synfuels), and is improbable

**Table 5** Cumulative upstream emissions from liquid fuel production, 2000–2060 for IMAGE scenarios with shortfall filled with only synfuels and excluding mitigation (Cumulative GtC, 2000–2060)[a]

| | IMAGE A2 | IMAGE A1B | IMAGE A1F |
|---|---|---|---|
| Baseline[b] | 40 | 51 | 58 |
| Shortfall filled w/ low emissions synfuels[c] | 43 | 61 | 75 |
| Shortfall filled w/ high emissions synfuels[d] | 47 | 81 | 110 |

[a] Calculated to 2060 because data of Hallock et al. (2004) only go to 2060. As calculated these show the effects of complete synfuel adoption. A more likely outcome is the adoption of some synfuels and some low-grade oil.

[b] For conventional production IMAGE emissions factors for upstream emissions from petroleum production and refining were used (varies yearly, from IMAGE data output).

[c] For the low emissions synfuel, the mean GTL emissions factor from Table 2 was used (8.3 gC/MJ).

[d] For the high emissions synfuel, the mean CTL emissions factor from Table 2 was used (24.65 gC/MJ).

Again, as in *calculation one*, the cumulative uncertainty over the twenty-first century is large. In each of the scenarios, if we have only the USGS low estimate of conventional oil remaining (1,239 Gbbl), as compared to the USGS high estimate (2,965 Gbbl), emissions increase by approximately 150 GtC. As above in *calculation one*, this is largely due to the introduction of oil shale into the fuel mix.

### *4.2.3 Calculation three – uncertainty due to petroleum substitutes from other fossil feedstocks*

The adjusted Hallock et al. (2004) production projection is shown with the three adjusted IMAGE demand projections in Fig. 6. The distance between Hallock et al. (2004) and the IMAGE projections equals the shortfall in oil production that is filled with synfuels in this calculation. The emissions effects of filling this shortfall with synfuels are shown in Fig. 7, which shows the potential emissions range given low carbon and high carbon synfuels in the IMAGE A1B scenario. The edges of the emissions uncertainty envelope were calculated using the emissions factor for mean-emissions GTL synfuels (low-end), and mean-emissions CTL synfuels (high-end). The cumulative emissions from 2000 to 2060 are shown in Table 5 for all three scenarios in the baseline case, with low emissions synfuels, and with high emissions synfuels.

It can be seen that the emissions consequences of this uncertainty are smaller than the other two calculations. This is because the modeled time period only goes to 2060, as opposed to 2100 in the other calculations. This is also because these scenarios only allow synthetic fuels from coal and natural gas, and do not allow oil shale, which was responsible for a significant portion of the emissions effect seen in calculations one and two. The total emissions uncertainty produced by this effect is still on the order of tens of GtC before 2060, and so is still significant.

## 5 Discussion

The supply curve produced above has two key implications for the current discussion of the future of petroleum. The first is that, according to the best estimates of sources cited here, it does not appear that an absolute shortage of hydrocarbon or fossil energy will threaten our society in the near future. There are significant and important concerns regarding stability during a transition from conventional oil to SCPs, including issues of politics, investment, and the speed of infrastructure transition, but absolute resource scarcity appears to be relatively unimportant. This is particularly the case when we allow the possibility of production of liquid fuels from coal and natural gas. However, our analysis does not address concerns that the rate at which investment in the capital needed to produce SCPs might be needed or the likelihood of such investments being made (Hirsch et al. 2005). This may be a significant concern and is left for future analysis.

Second, we see from the supply curve that the upstream emissions from SCPs are significantly higher than those from conventional oil production, assuming no mitigation. And, the potential emissions from resources that are very uncertain, such as oil shale, appear both high and highly uncertain. Thus, one of the main consequences of the transition away from conventional oil, although not discussed often enough, is that it may force us into production of low-quality carbon intensive fuels.

The three calculations shown here are meant to be illustrative, not projections of future emissions pathways. These calculations can be thought of as “slices” along three dimensions of uncertainty in the models in which we attempt to hold all else equal in order to isolate the potential effect from the each of the three uncertainties. While we are not able to re-run the models with changed assumptions as would be ideal, these calculations show that the magnitude of the potential emissions effects is undeniably significant.

A few major points of discussion that cut across all three calculations deserve to be addressed. First and most broadly, this analysis assumes that no climate polices are put into place, and so might be thought to speak most directly to estimates of “business as usual” scenarios. Another interpretation is that this analysis begins to indicate the magnitude of mitigation strategies (e.g. CCS) that would be necessary to deploy SCPs in a carbon-constrained world. Further analysis of this issue is left for future work.

Most modeling efforts assume least-cost-based patterns of extraction (as do we). This is a tractable approach, but it cannot capture a number of important factors that govern resource extraction. Perhaps the most important non-economic factor in determining the rate and order of resource extraction is politics, most obviously illustrated by the role of the OPEC cartel. Given that OPEC nations hold a significant amount of the remaining conventional oil resource, the rates of production chosen by the OPEC cartel will exert large influence on the rates of extraction of SCPs: if OPEC produces at a lower rate (which Gately (2004) suggests is likely) and all else is held equal, the world will shift more quickly to these carbon intensive resources. Indeed, the fact that quite large quantities of SCPs are currently being produced at high cost, while large amounts of low-cost conventional resources remain untapped, reinforces that the order of resource extraction is only approximated by a supply curve such as Fig. 3.

More specifically with regard to the SRES models, one important shortcoming in the SRES models as a whole was not addressing the variations in estimates of conventional oil. Given that the amount of conventional oil will strongly govern the rate of transition to alternatives, and is of general interest to policymakers and others, this parameter should be explored in detail in future models. An earlier transition to carbon intensive substitutes both suggests higher cumulative consumption of low-grade petroleum resources and would allow less time to prepare for their increased carbon intensity. This would result in significant increases in the level of carbon emissions, on order tens to hundreds of GtC over the next century.

The issue of technological progress also looms large. In the IMAGE model, the emissions from conventional oil production decline over time, a result of improving control technologies. Such progress would likely also affect the SCPs discussed here, and would allow for the potential for mitigation of some of their excess emissions. However, these fuels are physically of lower quality, and exist naturally in less useful form than conventional oil, and thus are likely to have an excess of emissions even in the presence of technological progress. This suggests that it is important to develop ways to estimate how much cleaner unconventional and low-grade resources can be made through technical progress.

Another area of key importance, and one that should be studied in greater detail, is the projection of tar sands and oil shale production. While the emissions consequences shown here for these resources are significant, what is unknown about them is more important. First, tar sands production is currently significant, but producers have naturally focused first on production of easy tar sands resources (shallow and high bitumen concentration), the proverbial "cream" of a large and varied resource pool. Production of hundreds of Gbbl of tar sands over the next century (as implied by all models studied) would require development of lower-grade tar sands with potentially different emissions profiles. And, even more importantly, oil shale is very poorly understood. First, emissions will likely vary greatly depending on process and operating conditions (in situ vs. mine and retort, as well as retorting temperature). Second, the oil shale emissions figures cited here are for high grade oil shale (greater than 25 gal of oil per ton), while development of low-grade oil shale (less than 10 gal of oil per ton) could emit over 100 gC/MJ (Sundquist and Miller 1980), almost 50% higher than even the high estimates shown here. Understanding these two resources in more detail should be part of future analysis.

The possibility of a transition to low-quality and synthetic petroleum resources, such as tar sands or GTL and CTL technologies, is becoming increasingly likely. Indeed, there is great interest in these technologies because they may help avoid the unsettling futures that are sometimes predicted to result from a peak and decline in conventional petroleum production. However, this comfort must be lessened because the analysis presented in this paper suggests that unconventional petroleum production could be a significant source of additional $CO_2$ emissions unless mitigation steps are taken.

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# Synthetic fuels in a world with high oil and carbon prices

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## Abstract

Four carbon management options are investigated for making Fischer-Tropsch fuels plus electricity: three processing coal and one co-processing coal and biomass. Energy and carbon balances are estimated. Economic analyses are carried out for carbon prices of $0 and $100 per tonne of carbon. Both levelized costs and internal rates of return on equity are estimated with $CO_2$ vented, and with $CO_2$ captured and stored in saline aquifers, and with $CO_2$ captured and used for enhanced oil recovery. Comparisons are made with coal integrated gasifier combined cycle power plants. When the carbon price is $100 per tonne of carbon, the co-processing option is the most economically attractive option for making Fischer-Tropsch liquids. Even at zero carbon price enhanced oil recovery applications of captured $CO_2$ will often be economically attractive where such opportunities exist. Enhanced oil recovery is a sufficiently large and economically interesting niche in the USA (and perhaps elsewhere) that it could enable wide near-term experience with gasification-based energy and carbon capture and storage technologies.

**Keywords:** coal, biomass, Fischer-Tropsch, gasification, $CO_2$, EOR

## Introduction

Carbon management options are investigated for Fischer-Tropsch (F-T) liquids—synthetic fuels that have attracted interest in light of high oil prices and oil supply security concerns.

The system configurations investigated are "polygeneration" units that use commercial "once-through" liquid-phase reactors with iron-based catalyst for synthesis of F-T fuels from syngas. The syngas unconverted in a single pass is used to make co-product electricity in a combined cycle power plant. Liquid-phase synthesis reactors and once-through synthesis configurations are well-suited for use with CO-rich syngas—such as that derived from coal via gasification.

Three carbon management options for systems using only coal are considered: one that vents the $CO_2$ coproduct (C-FT-V); one (Figure 1a) that captures $CO_2$ and stores it underground (C-FT-C); and one that involves co-capture and underground co-storage of $CO_2$ and $H_2S$ (C-FT-CoC). In a fourth option (Figure 1b) coal and biomass are co-processed with co-capture and underground co-storage of $CO_2$ and $H_2S$ (C/B-FT-CoC). For the co-processing option $H_2$ from biomass supplements $H_2$-deficient coal syngas in

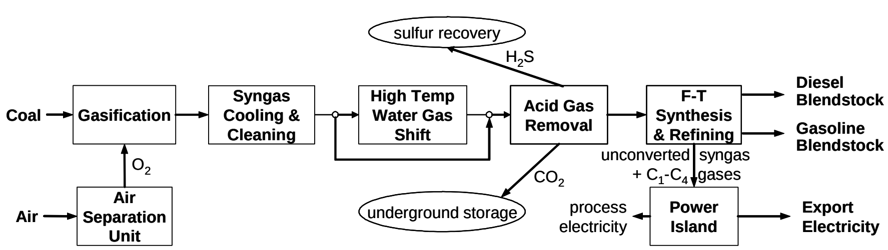


Figure 1a: Process configuration for C-FT-C energy system.

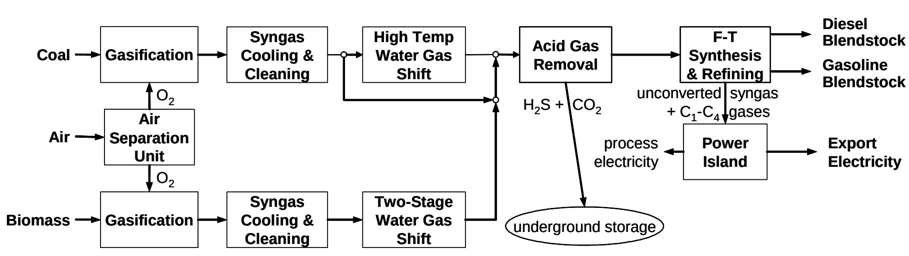


Figure 1b: Process configuration for C/B-FT-CoC energy system.

making F-T liquids, exploiting the negative emissions potential of $CO_2$ capture and storage (CCS) for biomass [1].

The biomass calculations are for switchgrass, which was also investigated in a companion bioenergy study [1]. Results for crop residues (an early market opportunity for biomass) are likely to be similar to the findings presented for switchgrass.

Energy and carbon balances are estimated. The economic analyses include calculations of both levelized costs and internal rates of return on equity. In the economic analyses aquifer storage ($CO_2$-AqS) and enhanced oil recovery ($CO_2$-EOR) are considered as alternative storage options. For $CO_2$–EOR, comparisons are made to using $CO_2$ from coal integrated gasifier combined cycle (IGCC) power plants.

**Methodology**

F-T liquids plants were modeled using: (*i*) AspenPlus chemical process simulation software to estimate detailed mass and energy balances and (*ii*) AspenPinch software for system heat integration. A GE pressurized, $O_2$–blown, entrained flow, quench gasifier (commercially available) is modeled for coal. C/B-FT-CoC involves modeling a separate pressurized, $O_2$–blown, fluidized bed gasifier based on GTI's technology (not yet commercial) for biomass but a sharing of other process equipment between coal and biomass.

For C-FT-V, syngas from the gasifier is shifted to the extent that $H_2$:CO = 2.25 for syngas entering the synthesis reactor—the value that maximizes conversion to liquid fuel. For CCS cases, $H_2$:CO = 2.75—a value at which essentially all carbon (except in $CH_4$) entering the synthesis reactor leaves as F-T products, and syngas conversion to liquids is only slightly below the maximum value.

After shifting the syngas, $CO_2$ and $H_2S$ are captured using Rectisol technology. The $CO_2$ is dried and compressed or the $CO_2$ + $H_2S$ are dried and compressed to 150 bar and transported 100 km to a site for storage in a saline aquifer 2 km underground or in conjunction with $CO_2$-EOR.

The products of F-T synthesis (light gases, naphtha, middle distillates, and waxes) are sent to an integrated refinery area, the final liquid products from which are gasoline and diesel blendstocks; the light ($C_1$-$C_4$) gaseous byproducts of refining plus the unconverted syngas exiting the synthesis reactor are burned for power generation in a combined cycle plant.

For simulated energy and mass balances, installed capital costs were estimated for the four F-T plant configurations, assuming commercially-ready components for coal and future mature $N^{th}$ plant technology components for biomass. Capital costs were developed by sub-unit in each major plant area using a database developed from prior work [1,2,3,4], literature studies, and discussions with industry experts.

Energy quantities are expressed on a lower heating value (LHV) basis, except energy prices are on a higher heating value (HHV) basis—the norm for US energy pricing. All costs are in 2003$. It is assumed that prices for coal and biomass (20% moisture content) are $\$1.35/GJ_{HHV}$ and $\$3.0/GJ_{HHV}$ (which is likely to be typical for many residue and dedicated energy crop applications), respectively. Energy system costs are estimated for greenhouse gas (GHG) emissions having monetary values of $0 and $100 per tonne of carbon equivalent ($tC_{equiv}$).

In systems producing both F-T liquids and electricity, allocation of GHG emissions[1] and costs between the products is arbitrary. For the present analysis it is assumed that the GHG emission rate assigned to electricity ($gC_{equiv}$/kWh) is that for a stand-alone coal IGCC plant with $CO_2$ vented (C-IGCC-V) in the C-FT-V case and for a coal IGCC plant with $CO_2$ captured (C-IGCC-C) in all capture cases. In estimating F-T liquids production costs at a given monetary value for GHG

[1] The GHG emissions include $CO_2$ emissions from the plant and ultimate combustion of the F-T liquids and the $CO_2$-equivalent GHG emissions upstream of the conversion plant. From the GREET model of the Argonne National Laboratory these are estimated as 1.00 $kgC_{equiv}$ and 2.06 $kgC_{equiv}$ per GJ for coal and switchgrass, respectively.

emissions, it is assumed that the value of the co-product electricity ($/kWh) equals the generation cost for the least-costly stand-alone C-IGCC power plant for that monetary value of GHG emissions.

**Table 1: F-T liquids production with $CO_2$ vented or aquifer storage of $CO_2$ (Base Case financing)**

| **Conversion Option** | **C-FT-V** | | **C-FT-C** | | **C-FT-CoC** | | **C/B-FT-CoC** | |
|---|---|---|---|---|---|---|---|---|
| Carbon flows (power balances) | | | | | | | | |
| Coal input, kgC/s (MW) | 74.2 (2946) | | 77.7 (3085) | | 77.7 (3085) | | 56.4 (2241) | |
| Switchgrass input, kgC/s (MW) | | | | | | | 24.7 (886.8) | |
| F-T liquids output, kgC/s (MW) | 21.1 (1035) | | 21.0 (1032) | | 21.0 (1033) | | 20.9 (1032) | |
| Electric power output ( MW) | (461.3) | | (429.9) | | (428.3) | | (459.5) | |
| Unconverted coal char, kgC/s | 0.74 | | 0.78 | | 0.78 | | 0.56 | |
| Coal $CO_2$ emissions from plant, kgC/s | 52.5 | | 8.27 | | 6.94 | | 6.64 | |
| Coal $CO_2$ captured & stored, kgC/s [$CO_2$ capture rate for coal ($CCR_C$), t $CO_2$ /$GJ_{FTL}$] | | | 47.6 [0.169] | | 49.0 [0.174] | | 28.3 [0.101] | |
| Switchgrass $CO_2$ captured and stored, kgC/s [$CO_2$ capture rate for switchgrass ($CCR_S$), t $CO_2$/$GJ_{FTL}$] | | | | | | | 22.3 [0.0791] | |
| Fuel cycle GHG emissions, $kgC_{equiv}/GJ_{LHV}$ F-T liquids (relative to crude oil-derived hydrocarbon fuels) | 46.73 (1.80) | | 27.98 (1.08) | | 26.68 (1.03) | | 5.53 (0.21) | |
| Fuel cycle GHG emission rate, $gC_{equiv}$/kWh electricity | 219.4 | | 28.8 | | 28.8 | | 28.8 | |
| Price of GHG emissions, $/$tC_{equiv}$ | 0 | 100 | 0 | 100 | 0 | 100 | 0 | 100 |
| Electricity co-product value, ¢/kWh | 4.75 | 6.94 | 4.75 | 6.94 | 4.75 | 6.94 | 4.75 | 6.94 |
| Overnight construction cost, $\$10^6$ | 1647 | | 1797 | | 1639 | | 1678 | |
| $CO_2$ transport/storage cost, $/t $CO_2$ | | | 6.59 | | 6.47 | | 6.50 | |
| **F-T Liquids Production Cost, $/$GJ_{LHV}$** | | | | | | | | |
| Capital | 10.63 | | 11.63 | | 10.60 | | 10.87 | |
| Operation and maintenance | 2.52 | | 2.76 | | 2.52 | | 2.58 | |
| Coal input | 4.01 | | 4.21 | | 4.20 | | 3.06 | |
| Switchgrass input | | | | | | | 2.86 | |
| Electricity co-product credit | -5.88 | -8.59 | -5.49 | -8.03 | -5.47 | -7.99 | -5.87 | -8.58 |
| $CO_2$ transport/storage cost (CTSC) | | | 1.11 | | 1.12 | | 1.17 | |
| GHG emissions cost | - | 7.38 | - | 3.14 | - | 3.00 | - | 3.07 |
| Credit for bio-$CO_2$ storage | | | | | | | | -2.16 |
| Net production cost, $/$GJ_{LHV}$ (NPC = $NPC_V$ for venting and $NPC_C$ for capture) | 11.28 | 15.96 | 14.22 | 14.82 | 12.97 | 13.46 | 14.65 | 12.85 |
| F-T liquids prod cost, $/liter gasoline equivalent (ge) | 0.355 | 0.502 | 0.447 | 0.466 | 0.408 | 0.423 | 0.461 | 0.404 |
| Breakeven crude oil price, $/barrel | 50.4 | 61.7 | 66.2 | 55.6 | 59.6 | 48.2 | 68.6 | 44.9 |
| Plant-gate $CO_2$ cost = ($NPC_C$ - CTSC - $NPC_V$)/($CCR_C$ + $CCR_S$), $/t $CO_2$ | | | 10.7 | -13.3 | 3.3 | -20.9 | 12.3 | -23.8 |

Cost estimates are for plants with an 80% capacity factor, financing with 55% debt (4.4%/y real cost) and 45% equity, a 30-year (20-year) plant (tax) life, a 38.2% corporate income tax rate, a 2%/y property tax/insurance rate, and an owner's cost of 5.5% of the total installed capital cost. Base Case financing involves a 14.0% real rate of return on equity (ROE), so that the discount rate (real weighted after-tax cost of capital) is 7.8%/year, and the levelized annual capital charge rate is 15.0%/year. Plant construction requires four years, with the capital investment committed in four equal payments, so that interest during construction is 12.3% of the overnight construction cost.

Costs for $CO_2$ transport and for aquifer storage are based on a model developed by Ogden [5], assuming that the maximum $CO_2$ injection rate per well for the AqS-$CO_2$ storage cases is 1000 t/day, a typical value for mid-continental aquifers.

Breakeven crude oil prices are estimated assuming that the F-T gasoline and diesel products (38% and 62% of liquids output, respectively) compete with gasoline and low-sulfur diesel derived from crude oil. The refining cost increment for this mix is $10.4 per barrel.

For the $CO_2$-EOR cases, captured $CO_2$ is transported 100 km and sold for EOR at a price in $ per $10^3$ scf (1 tonne = 19 x $10^3$ scf) equal to 3% of the oil price in $/barrel—a "rule of thumb" for Permian Basin $CO_2$-EOR (Vello Kuuskraa, ARI, private communication, December 2005).

With Base Case financing, the economic analysis identifies the crude oil price at which F-T liquids are competitive with gasoline and diesel. Electricity costs for coal IGCC power with $CO_2$–EOR are also estimated with Base Case financing. The economic analysis is extended beyond Base Case financing to estimate the ROE as a function of oil price—assuming all financial parameters other than the ROE are the same as with Base Case financing.

**Findings**

Table 1 summarizes energy and carbon balances and the economic analysis with Base Case financing for systems with venting and aquifer storage of $CO_2$. With $CO_2$ vented, the GHG emission rate is 1.8 times that for crude-derived hydrocarbon (HC) fuels displaced, but for coal with CCS the rate is about the same as for these HC fuels, and for C/B-FT-CoC the rate is only 0.2 times that for displaced HC fuels.

Notably, only 0.86 GJ of biomass is needed to make 1 GJ of F-T liquids via C/B-FT-CoC. This is far less than the biomass required to make conventional liquid biofuels[2] and thus offers an attractive way to use scarce biomass resources to make liquid fuels with near-zero net GHG emissions.

At $0/tC the C-FT-V option competes at $50 a barrel crude oil, but the CCS options require a much higher oil price to be economically interesting. However, at $100/tC [the GHG emissions price at which C-IGCC-C ($CO_2$-AqS) becomes competitive with C-IGCC-V—see Table 3], the C/B-FT-CoC option would compete at a $45/barrel oil price and provide F-T liquids at a plant-gate cost of $0.40/liter ($1.5/gallon) of gasoline equivalent (ge).

Plant-gate costs of $CO_2$ are low—$3-$12/t (Table 1), lower than for C-IGCC-C plants (see Table 3)—suggesting that F-T liquids plants might be attractive sources of $CO_2$ for EOR projects. Table 2 presents an economic analysis for F-T plants coupled to $CO_2$-EOR with Base Case financing, showing that breakeven crude oil prices are in the range $37-$42/barrel for $0/tC (much lower than for C-FT-V, Table 1). Similarly, Table 3 shows that C-IGCC-C supporting $CO_2$-EOR could provide less costly electricity than C-IGCC-V at $0/tC.

Projects coupling gasification energy and $CO_2$-EOR could help establish CCS technologies in the market even at a carbon price of $0/tC. Recent studies [8] estimated for 10 US basins/regions the economic (technical) $CO_2$-EOR potential based on state-of-the-art technology to be 47 (89) billion barrels. The economic potential could support 4.3 million barrels/day of crude oil production for 30 years (a typical lifetime for a gasification energy plant that might provide the needed $CO_2$). At the average $CO_2$ purchase rate of 0.21 t $CO_2$/barrel estimated in these studies, the required $CO_2$ could in principle be provided by 60 C-FT-C plants (Table 2) or 126 C-IGCC-C plants (Table 3). Although coupling gasification energy and $CO_2$–EOR projects will not always be feasible, this “niche activity” would nevertheless be large enough to gain extensive early experience and technology cost buydown (learning by doing) for both gasification energy and CCS technologies.

Figures 2a and 2b show the ROE as a function of oil price at $0/tC and $100/tC, respectively. At $0/tC, the $CO_2$-EOR-supporting options would almost always be more profitable than C-FT-V; C-IGCC-C supporting $CO_2$-EOR is the most profitable option at low oil prices but FT-C options supporting $CO_2$-EOR are more profitable at high oil prices. At $100/tC, C-IGCC-C with $CO_2$-EOR is the most profitable option, and C/B-FT-C (characterized by near-zero GHG emission rates for both F-T liquids and electricity) is more profitable than any C-FT option at all oil prices and for both storage options ($CO_2$-EOR and $CO_2$-AqS).

**Conclusions**

Making F-T liquids from coal could help mitigate oil supply security concerns and would be profitable at sustained high oil prices. But without CCS, this option would lead to a large increase in

[2] For comparison, the net biomass required to make 1 GJ of F-T liquids from switchgrass with $CO_2$ vented is 1.56 GJ [1], while the net biomass required to make 1 GJ of cellulosic ethanol from corn stover is 2.89 GJ with vintage 2000 technology (58.4 gallons per dry short ton) [6] and 1.77 GJ with advanced technology (89.8 gallons/ton) [7].

GHG emissions relative to hydrocarbon fuels derived from crude oil.

With CCS, the GHG emission rate for coal F-T liquids could be reduced to about the rate for crude oil-derived fuels. The net GHG emission rate could be reduced further, to near zero, via co-processing biomass and coal with CCS so as to exploit the negative emissions of storing photosynthetic $CO_2$. At a carbon price of \$100/tC the co-processing option is the most economically attractive of all the options considered for F-T liquids production and requires far less net biomass input to realize near zero GHG emissions than conventional biofuels such as cellulosic ethanol.

If the $CO_2$ captured in F-T or IGCC plants were used for $CO_2$-EOR, the economics of $CO_2$ capture and storage would often be attractive even at a carbon price of \$0/tC. $CO_2$-EOR opportunities in the USA (and perhaps elsewhere) are sufficiently large to make the $CO_2$-EOR application an attractive way to gain extensive near-term experience with gasification-based energy and CCS technologies and the opportunity to "buy down" the costs of these technologies substantially as a result of learning by doing.

**Table 2: Economics of F-T liquids production if $CO_2$ is used for EOR (Base Case financing)**

| **Conversion Option** | **C-FT-C** | | **C-FT-CoC** | | **C/B-FT-CoC** | |
|---|---|---|---|---|---|---|
| $CO_2$ available for EOR, t $CO_2$/hour | 628.4 | | 646.0 | | 667.5 | |
| Barrels of crude EOR/barrel of F-T liquids (ge) | 4.00 | | 4.11 | | 4.25 | |
| Price of GHG emissions, \$/$tC_{equiv}$ | 0 | 100 | 0 | 100 | 0 | 100 |
| Electricity co-product value, ¢/kWh | 4.75 | 6.94 | 4.75 | 6.94 | 4.75 | 6.94 |
| Price at which $CO_2$ is sold for EOR, \$/t $CO_2$ | 23.6 | 19.6 | 20.9 | 16.5 | 23.9 | 15.2 |
| $CO_2$ transport cost (100 km), \$/t $CO_2$ | 2.94 | | 2.89 | | 2.84 | |
| **F-T Liquids Production Cost, \$/$GJ_{LHV}$** | | | | | | |
| Capital | 11.63 | | 10.60 | | 10.87 | |
| Operation and maintenance | 2.76 | | 2.52 | | 2.58 | |
| Coal input | 4.21 | | 4.20 | | 3.06 | |
| Biomass input | | | | | 2.86 | |
| Electricity co-product credit | -5.49 | -8.03 | -5.47 | -7.99 | -5.87 | -8.58 |
| $CO_2$ transport cost | 0.50 | | 0.50 | | 0.51 | |
| GHG emissions cost | - | 3.14 | - | 2.92 | - | 3.07 |
| Credit for EOR | - 3.99 | - 3.31 | - 3.63 | - 2.86 | - 4.30 | - 2.73 |
| Credit for bio-$CO_2$ storage | | | | | | -2.16 |
| Net F-T liquids production cost, \$/$GJ_{LHV}$ | 9.61 | 10.89 | 8.73 | 9.89 | 9.70 | 9.46 |
| F-T liquids production cost, \$/liter, ge | 0.302 | 0.342 | 0.274 | 0.311 | 0.305 | 0.298 |
| Breakeven crude oil price, \$/barrel | 41.4 | 34.4 | 36.6 | 28.9 | 41.9 | 26.7 |

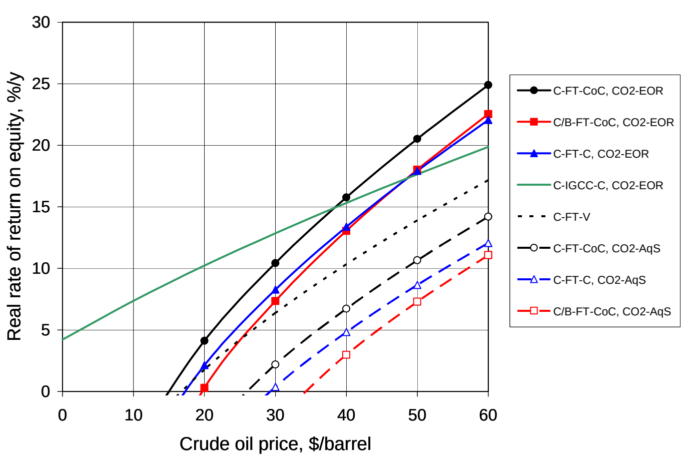


Figure 2a: ROE vs. oil price @ \$0/tC.

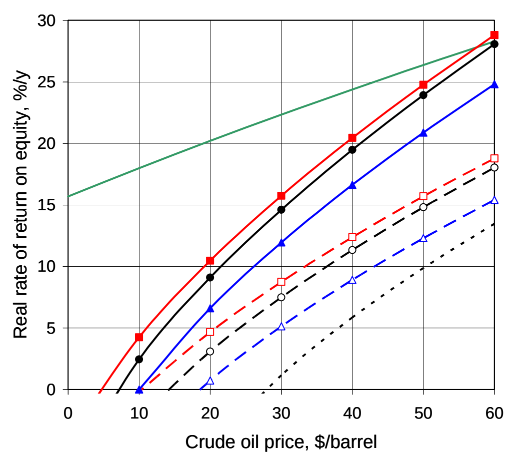


Figure 2b: ROE vs. oil price @ \$100/tC.

| Table 3: Performances and costs for coal IGCC power plants[a] (Base Case financing) | | | | | | |
|---|---|---|---|---|---|---|
| **Conversion Option** | **C-IGCC-V** | | **C-IGCC-C** | | | |
| Storage mode | | | $CO_2$-AqS | | $CO_2$-EOR | |
| Price of GHG emissions, \$/t$C_{equiv}$ | 0 | 100 | 0 | 100 | 0 | 100 |
| Installed capacity, $MW_e$ | 390.1 | | 361.9 | | | |
| $CO_2$ storage rate, t $CO_2$/hour | | | 297.3 | | | |
| Barrels of crude EOR per day/$GW_e$ of C-IGCC-C capacity | | | 74,700 | | | |
| $CO_2$ emission rate from plant, t $CO_2$/hour | 301.5 | | 25.2 | | | |
| Fuel cycle GHG emission rate, g$C_{equiv}$/kWh | 219.4 | | 28.8 | | | |
| Efficiency at design point, LHV | 42.95 | | 36.79 | | | |
| $CO_2$ transport cost, \$/t $CO_2$ | | | 4.33 | | | |
| $CO_2$ storage cost, \$/t $CO_2$ | | | 3.84 | | - | |
| Price at which $CO_2$ is sold for EOR, \$/t $CO_2$—assumed to be the same as for the C-FT-C option in Table 2 (assumed crude oil price, \$/barrel) | | | | | 23.6 (41.4) | 19.6 (34.4) |
| Overnight construction cost (OCC), \$/$kW_e$ | 1187 | | 1531 | | | |
| **Generation Cost, ¢/kWh** | | | | | | |
| Capital | 2.85 | | 3.68 | | | |
| Operation and maintenance | 0.68 | | 0.87 | | | |
| Fuel | 1.22 | | 1.42 | | | |
| $CO_2$ transport | | | 0.36 | | | |
| $CO_2$ storage | | | 0.31 | | - | |
| Credit for EOR | | | | | - 1.94 | - 1.61 |
| GHG emissions | 0 | 2.19 | 0 | 0.29 | 0 | 0.29 |
| Total | 4.75 | 6.94 | 6.64 | 6.93 | 4.39 | 5.01 |
| Plant-gate $CO_2$ cost, \$/t $CO_2$ | | | 14.8 | - 8.3 | | |

[a] Based on [4] except that (as for the F-T polygeneration analysis) the coal is assumed to have a heating value of 23.5 $GJ_{LHV}$/tonne and a C content of 25.2 kgC/$GJ_{LHV}$.

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