Institute of Physics Publishing | Environmental Research Letters

Environ. Res. Lett. **1** (2006) 014004 (6pp) doi:10.1088/1748-9326/1/1/014004

Risks of the oil transition

A E Farrell and A R Brandt

Energy and Resources Group, University of California, Berkeley, CA 94720-3050, USA

E-mail: aef@berkeley.edu and abrandt@berkeley.edu

Received 4 July 2006
Accepted for publication 8 September 2006
Published 30 October 2006
Online at stacks.iop.org/ERL/1/014004

Abstract
The energy system is in the early stages of a transition from conventionally produced oil to a variety of substitutes, bringing economic, strategic, and environmental risks. We argue that these three challenges are inherently interconnected, and that as we act to manage one we cannot avoid affecting our prospects in dealing with the others. We further argue that without appropriate policies, tradeoffs between these risks are likely to be made so as to allow increased environmental disruption in return for increased economic and energy security. Responsible solutions involve developing and deploying environmentally acceptable energy technologies (both supply and demand) rapidly enough to replace dwindling conventional oil production and meet growing demand for transportation while diversifying supply to improve energy security.

Keywords: energy, climate change, unconventional petroleum, synfuels

1. Introduction

A transition in global oil production has begun; transportation fuels are increasingly coming from sources other than conventional petroleum. Some observers have defined the challenge of the oil transition as solely encouraging investment in new sources of fuel (Southern States Energy Board 2006). Others have looked to 'communities ratcheting down their dependence on overstretched and oil-dependent lines of supply that mark a globalized economy' through steps like local food production and the development of a barter economy (McKibben 2005). However, the former view ignores the costs of the environmental damage that may accompany increased supply, while the latter view does not appear feasible for the billions of people who in live in the world's cities.

Here, we identify the challenge of the oil transition as shifting to substitutes for conventionally produced petroleum while managing the environmental, economic, and strategic risks this change will bring. We show why it is crucial to see this as an integrated problem, so that as we act to achieve one goal we unavoidably affect our prospects in dealing with the others.

2. The future of conventional oil

Much attention has been given to one aspect of the oil transition, the date of maximum production of conventional petroleum, or 'peak oil'. In our view, however, multiple uncertainties suggest that while the peak of conventional oil production is inevitable, its exact timing is less important than understanding the long-term implications of the oil transition.

Following Greene *et al* (2006), we make a distinction between conventional and unconventional petroleum resources based on density and viscosity of the oil, as well as the presence of contaminants. In the wide spectrum of fossil fuels, petroleum resources run from light oils through a series of increasingly lower grade and difficult-to-extract resources such as extra-heavy oil and tar sands. Unconventional oil occupies the heavier end of this spectrum and is harder to extract and refine into products like jet fuel.

Several observations support the current interest in the date of peak conventional oil production. First, the occurrence of conventional oil in the Earth's crust is fixed and production can only reduce that amount. Second, the discovery of these occurrences peaked near the middle of the 20th century (the exact year is subject to controversy) and few very large oil fields have been discovered since the mid-1970s. Third, yearly production now exceeds the volumes found in newly discovered fields.

Hubbert (1956) developed the most common method of predicting the peak. Applied on a global scale, this approach requires an estimate of the amount of petroleum that will be produced over all time, called estimated ultimate recovery (EUR), and fitting a curve (often a logistic or Gaussian distribution) to both past production data and the EUR forecast (Bentley 2002, Campbell 2005).

Note that Hubbert's method does not use the more common metric, proved reserves, which is quite different than EUR. Although reserve estimates have grown over time, EUR estimates have been fairly stable for decades, ranging from 1000 to 4000 billion barrels (Gbbl) with little obvious trend (Andrews and Udall 2003, Ahlbrandt 2005). The US Geological Service's mean EUR estimate of about 3000 Gbbl is in the middle of recent values and is widely accepted (Ahlbrandt 2002). This value includes undiscovered oil, including resources in very deep offshore locations (such as the recently reported discoveries in the Gulf of Mexico) and in the arctic.

However, EUR estimates remain uncertain due to disputes about future discovery rates, incomplete geologic knowledge, poorly documented data from many large producers, and other factors (Bentley 2002). A probabilistic comparison by Greene *et al* (2006) illustrates how differences in EUR assumptions lead to dramatically different perspectives on the oil transition. Pessimistic assumptions imply that the peak in non-OPEC, conventional oil production will almost certainly occur before 2010, while optimistic assumptions suggest it is most likely after 2020.

However, these estimates offer little help in projecting the date of the global peak in conventional oil production, because this date will be essentially determined by investments in new oil-producing capacity in OPEC countries, particularly in the Middle East. The consultancy CERA has a fairly optimistic view of OPEC capacity expansion, foreseeing about a 2.5% annual increase through 2020 and no peak phenomenon by then (Yergin 2006). In contrast, some observers maintain that the reserves reported by some OPEC countries (and therefore their EUR values) are overstated (Bentley 2002) or that the very large oil fields in Saudi Arabia cannot maintain current levels of production for long (Simmons 2005). Most importantly, Gately (2004) argues that OPEC has little incentive to increase production rapidly; revenues needed for social spending would be hurt by falling prices if they expanded production as much as CERA projects.

Another key assumption behind these projections is that global demand for liquid hydrocarbon fuels will continue to grow rapidly. Over the last several decades, world demand for oil has grown at about 1.6%/year. Most forecasters expect this trend to continue due to population and economic growth, although it may be tempered if high oil prices remain, or if government policies such as higher vehicle efficiencies were to limit demand growth, as they did in the 1970s and early 1980s.

Given these compounding uncertainties about the future of conventional oil, an approach that focuses less on the peak in conventional oil production and more on the long-range implications of the oil transition seems more useful. This means considering substitutes for conventional petroleum (SCPs).

3. Substitutes

Pessimistic forecasts imply that a decline in conventional production will result in a decline in the availability of liquid fuels. Although unconventional oil and gas are sometimes acknowledged in these studies, they are typically excluded from the quantitative analysis or only discussed as a possible post-peak option (e.g. Bentley 2002). Further, synthetic fuels have been underemphasized, even in relatively optimistic forecasts of world oil (e.g. International Energy Agency 2005, EIA 2006).

These narrow views ignore the fact that a transition to SCPs has already begun. These resources can be classified as (1) fossil-based liquid hydrocarbons—either unconventional crude oils or synthetic liquid fuels (synfuels), (2) biologically derived fuels, or (3) energy carriers that eliminate the need for hydrocarbon fuels (such as electricity or hydrogen). In this paper we discuss only the first category, fossil-based SCPs. Although SCP production may affect environmental issues such as water use, land disturbance and air pollution, for simplicity we focus here on the greenhouse gas (GHG) implications.

Unconventional petroleum is recovered through a variety of processes, many of which involve injection of materials into the reservoir, often carbon dioxide or thermal energy (e.g. steam) (Lake 1989). Sometimes these processes are applied to depleted conventional oil reservoirs, in which case the term enhanced oil recovery (EOR) is used. However, the majority of current unconventional production is heavy oil and tar sands, which are currently produced with steam stimulation, requiring additional energy inputs, or by mining in the case of some tar sands deposits (National Energy Board of Canada 2004). Then they must be chemically upgraded and often cleaned of impurities.

Synthetic crude oil can be extracted from oil shale, a sedimentary rock that contains a solid hydrocarbon-like substance. Oil shale is often considered a 'backstop' for conventional petroleum production because the resource endowment is large (Rattien and Eaton 1976). The standard approach to oil shale production is to mine and crush the rock, and then heat it in a retort, releasing synthetic oil and gas (Bartis *et al* 2005). This process requires more capital, energy, and water than conventional oil production and has higher GHG emissions. A new *in situ* process developed by Shell Oil may reduce these challenges, but it is still in the development stages (Mut 2005).

Synthetic liquid fuels (e.g. synthetic diesel) can also be produced, typically either from natural gas or coal, in a two-step process (Wilhelm *et al* 2001). First, a syngas comprised mainly of CO and H_2 is created through catalysis (in the case of gas-to-liquids, or GTL) or gasification and reformation (in the case of coal-to-liquids, or CTL). Second, the syngas is converted into liquid fuel similar to diesel using the Fischer–Tropsch (FT) catalytic process. CTL synfuels are likely to be more costly than GTL synfuels because of the difficulty in handling and processing the coal, and they have higher GHG emissions due to the higher C to H ratio in coal (Dry 2002). Future energy systems that include significant GTL and CTL production seem plausible (Williams and Larson 2003).

Although some are concerned with the energetics of SCPs, they appear generally favorable, but less so than historic values for conventional oil (Cleveland 2005). The energy

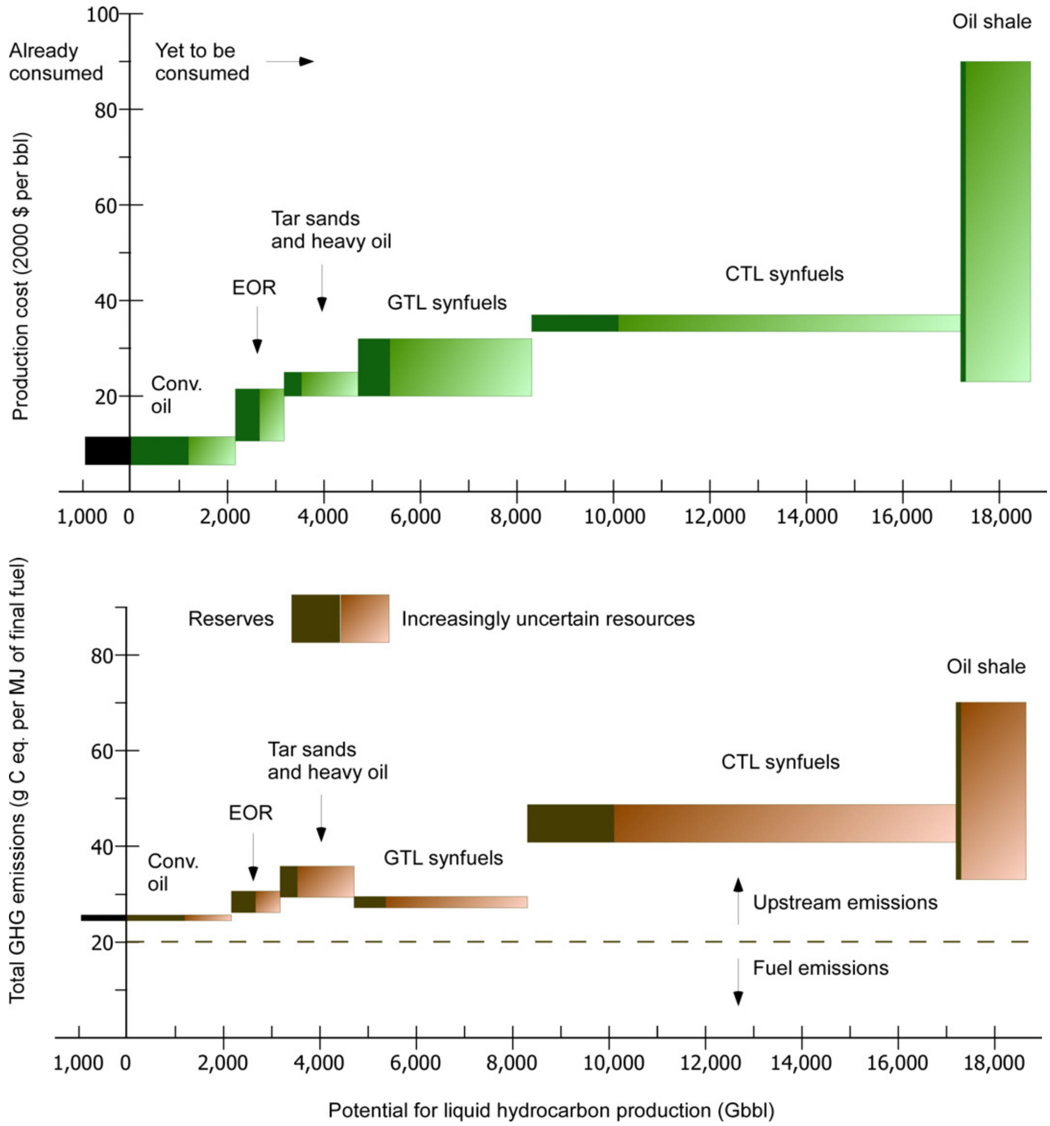

Figure 1. Global supply of liquid hydrocarbons from all fossil resources and associated costs in dollars (top) and GHG emissions (bottom). EOR is enhanced oil recovery, GTL and CTL are gas- and coal-derived synthetic liquid fuels. The CTL and GTL quantities are theoretical maxima because they assume all gas and coal are used as feedstock for SCPs and none for other puposes. The lightly shaded portions of the graph represent less certain resources. GHG emissions in the lower figure are separated into fuel combustion (downstream) and production and processing (upstream) emissions by a dashed line. Results are based on costs and conversion efficiencies of current technologies available in the open literature. Gas hydrates are ignored due to a lack of reliable data. The GTL cost estimates assume a range of \$0.5 to \$2 per MBTU. See Brandt and Farrell (2006) for details.

returned on energy invested (EROI) from SCP technologies is relatively low and differs across specific processes, but US coal production has an EROI of over 80, so conversion to liquid fuels should not doom this large resource to a negative energy return. The prospects for oil shale seem somewhat more dubious because it has a lower energy density than coal. A Shell executive recently claimed that their process had an EROI of 3.5 based on direct energy inputs (Mut 2005).

To illuminate some of the economic and environmental implications of the oil transition, we collected estimates from the open literature of the following data: SCP production costs and efficiencies, associated GHG emissions for SCPs, and global reserves and resource estimates of fossil fuels (Brandt and Farrell 2006). These data are plotted in two 'supply curves' shown in figure 1.

For each resource type, the quantity of liquid hydrocarbon fuels that could be produced with current technologies is plotted on the horizontal axis, accounting for losses in conversion to liquid fuel. The dark portion of each resource segment represents a conservative estimate of the amount of that resource available (typically, reserves), while the lighter portion represents a less certain estimate. The CTL and GTL quantities are theoretical maxima because they assume all gas and coal are used as feedstock for SCPs and none for other purposes. Nonetheless, this figure illustrates that synfuels represent a larger 'backstop' to conventional oil production than does oil shale, even if only a modest fraction of global gas and coal resources were used for this purpose. We ignore methane hydrates due to a lack of reliable data, but if technologies for producing these resources were developed, the potential for liquid hydrocarbon production would be greatly extended.

The monetary and GHG 'costs' are plotted for each resource on the vertical axis, given in dollars per barrel (top) and carbon emissions in grams of carbon equivalent emitted per megajoule of refined product (gCeq MJ^{-1}, bottom). The vertical dimension for each segment of the curve represents the range of variability or the uncertainty associated with the implications of utilizing each resource.

4. Managing the transition

Whatever the course of development of biofuels, hydrogen, or electric vehicles, the fossil portion of the liquid fuels will become increasingly supplied by SCPs and because of the enormous demand for liquid fuels, this component will be important for years to come. Currently, fossil-based SCP production equals about 2.5 million barrels per day (Mbbl/day), of which the largest portion is tar sands and extra-heavy oil production, and experts forecast global additions of SCPs by 2010 to be almost 0.5 Mbbl/day annually (National Energy Board of Canada 2004, Lynch 2005, Moritis 2006, Simbeck 2006). Thus, SCPs now account for about 3% of global oil production and could double within the next five years.

Some experts suggest that the main problem associated with the oil transition is economic: to ensure adequate investment to make up for declining production of conventional oil (Hirsch *et al* 2005). However, this view is incomplete, as SCPs will contribute to environmental damage such as global warming, which will have its own costs. Other analysts argue or imply that environmental restrictions will prevent the use of fossil resources, for example, 'I hate to say it, but we likely will be forced to choose either increased pollution from coal or doing without a significant portion of our present-day energy supply' (Deffeyes 2005, p 98). The choice need not be this stark; it is more useful to see the challenge as simultaneously managing the environmental, economic, and strategic risks of the oil transition.

4.1. Environmental risks

SCP technologies may lead to major environmental damage. Using GHG emissions as a proxy, the potential environmental effects from production of SCPs could be quite large, possibly twice those of conventional oil production per unit of fuel delivered.

One partial solution is carbon capture and storage (CCS) which could place some of the additional upstream GHG emissions from SCP production in deep underground locations under long-term monitoring (Intergovernmental Panel on Climate Change 2005). However, CCS would only go so far; emissions due to fuel combustion would remain (see figure 1). For some SCPs, the difference would be small (e.g. 10%–20% reductions for tar sands, EOR and GTLs) but for others, CCS could significantly lower total emissions (reductions up to 50% for CTLs and oil shale).

Crucially, the vast resource base of fossil SCP resources that could be turned into liquid fuels implies very large GHG emissions even if CCS is used. For instance, using a quarter of the world's coal endowment as CTL would increase atmospheric GHG concentrations by approximately 300 parts per million (ppm). This would be larger than the effect from combusting all of the world's conventional petroleum, and would by itself more than double pre-industrial atmospheric concentrations of GHGs. With CCS, the effect is still large, about 150 ppm. (Put another way, using 1% of the global coal endowment as CTL yields roughly a 10 ppm increase in atmospheric GHG concentrations, perhaps half that if CCS is used.)

Several different GTL and CTL production processes have been proposed, whose costs depend crucially on prices for fuel, electricity, and liquid fuels (Yamashita and Barreto 2005). However, they all have similarities to hydrogen production, for which the cost of adding CCS has been estimated as an additional 5%–30% of production costs (Intergovernmental Panel on Climate Change 2005). Thus, total costs for most of the available resources would likely remain below \$50 per barrel even with CCS. Note, however, that the prospects of large scale carbon storage are not assured (Wilson *et al* 2003), and other environmental issues would remain to be addressed even if CCS were used.

GHG emissions have no market value today, so SCPs are currently being produced without CCS. This phenomenon is not captured in current forecasts of GHG emissions, so actual emissions may be worse than 'business as usual' scenarios (Intergovernmental Panel on Climate Change 2005). Given the expense involved and the realities of the market, government policies to internalize the cost of GHG emissions will be needed to induce CCS (the exception being CCS used for enhanced oil recovery, which will likely be developed due to the salable coproduct produced). However, developed nations with large SCP resources (e.g. the US and Australia) have so far proven unwilling to limit their GHG emissions. Among developing countries the greatest interest is in China, whose combination of rapid development, large coal resources, and exclusion from the Kyoto protocol suggest the potential for significant GHG emissions.

Overall, figure 1 shows that the oil transition is not a shift from abundance to scarcity: fossil fuel resources abound. Rather, the oil transition is shift from high quality resources to lower quality resources that have increased risks of environmental damage, as well other risks.

4.2. Economic risks

Because SCPs require greater initial capital per unit of production relative to conventional oil, and are also more expensive in the long run, SCP projects are financially risky to investors and may become uneconomical should oil prices fall, as they have in the past. Indeed, investment in SCPs moves the global supply curve for liquid hydrocarbons out and will tend to cause world oil prices to fall. Of course, falling prices benefit consumers. Adding the costs of environmental controls exacerbates the risk to investors.

Hirsch *et al* (2005) performed the most in-depth analyses of investment challenge of the oil transition and are deeply concerned about major economic upheaval without mitigating steps that start 10–20 years before the peak. Their conclusions rest critically on an assumption of high decline rates (about 5% per year). While such declines have been observed empirically in some areas (and even higher levels in a few regions such as the North Sea), there has been no systematic analysis of what the global decline rate of conventional oil production is likely to be. One of the authors tested a large number of exponential decline rates using detailed production data and found that across 74 post-peak regions at various levels of aggregation, best-fitting rates tend to be lower, averaging around 2% on a production-weighted basis (Brandt 2006). (This analysis excludes the North Sea and other recently past-peak regions because of insufficient post-peak data to fit an adequate exponential decline curve.)

Assuming conventional oil production declines at a rate of 2%/year and annual growth in demand is 1.6%, aggregate annual additions of SCPs capacity will have to be about 3 Mbbl/day to meet demand. This is equal to today's total SCP capacity and about five times the current rate of capacity addition. Investments of this magnitude, in some cases in technologies with which we have limited experience, will be a challenge, especially given the risk of stranded capital should oil prices fall.

Thus, the key economic risk of the oil transition is not about coping with economic collapse, but managing complementary risks to consumers and investors. Oil consuming countries face the risks of high and volatile prices, which investments in SCPs might mitigate. However, potential investors in SCP production would then face the risks of new technologies, plus low and volatile prices. Government policies to mitigate some economic risks may be needed, but they should involve moderate costs and should also address environmental or strategic risks.

4.3. Strategic risks

The increasing concentration of conventional petroleum production in OPEC countries not only gives them market power, but may present strategic risks as well (Yergin 1991). The development of SCPs might mitigate both to some degree.

One of these strategic risks is the potential for oil supply disruptions, which could significantly affect the course of the oil transition over the long run. Energy system disruptions are not uncommon and they have tended to have lasting impacts because they can help mobilize capital (both financial and political), spur investment in new technologies, create new infrastructures, and change the institutional and regulatory landscape. Thus, one important question is how a disruption in today's energy system might affect the oil transition? Would it, for instance, create a 'dash to gasification' as nations scrambled to find new supplies?

The historical record of energy crises suggests responses are likely to consist of significant support of new liquid fuel supplies (including SCP technologies), lesser efforts to reduce demand, and possibly relaxations of environmental controls. Some current proposals already embody a supply-first approach without regard for GHG emissions (e.g. Southern States Energy Board 2006). Because technological adoption and diffusion is nonlinear and path dependent (especially where large infrastructures are involved), the path of technological change could be altered significantly by decisions made quickly in a time of crisis. The compounding of experience and technological learning, combined with the inertia of large technical systems, can cause technologies with minor initial advantages or political support to become favored in the end, even if they are not ideal from first principles. And it is all too possible that the political capital needed to confront the environmental effects of the oil transition might be spent responding to an energy crisis.

Developing fossil SCPs within in a policy framework without GHG emissions control brings additional strategic risks. First, this approach will make national consensus more difficult, possibly delaying the implementation of fossil SCP development and thereby reducing or delaying any positive effect on strategic risks. Second, continuing to ignore climate change in this way would tend to encourage disrespect for international processes and agreements on common problems, and would inhibit the development of the global agreement necessary to solve the climate change problem. Third, doing so increases the size of future environmental damages and future mitigation costs.

5. Conclusion

In our view, therefore, the oil transition brings more long-term environmental concerns than long-term economic or security threats because tradeoffs have strong potential to be resolved by accepting increased environmental damage in order to avoid economic or security risks. The global petroleum industry has begun to recognize this interaction, but strategies to deal with them have not yet emerged (World Economic Forum 2006).

Fortunately, some approaches can address all three risks. Perhaps most interesting is to employ the first principle of energy security, diversification of supply. Fossil-based SCP technologies with CCS could provide supply diversity in the near term if adequate investments were made. Because of the fuel-related GHG emissions, fossil SCPs might be appropriate only as a short-term response, although the path dependence of energy system investments suggests there may be no such thing as a purely short-term response. Of course, other technologies could also diversify the supply of transportation energy such as advanced, environmentally friendly biofuels; hydrogen; or partially or fully electric vehicles utilizing low carbon electricity (possibly including fossil fuels plus CCS, renewables, or nuclear power). Demand reduction, through fuel efficiency and better transportation planning should also play a role. These other approaches have their own challenges, but at least they do not have the climate change risks of fossil SCPs.

The true challenge of the oil transition is to develop and deploy environmentally acceptable energy technologies (both supply and demand) rapidly enough to replace dwindling conventional oil production and meet growing demand for transportation energy. To the degree that these technologies diversify energy supplies, they will also tend to reduce market power and provide energy security benefits. The incremental costs of avoiding a disrupted climate and other environmental problems associated with the oil transition seem modest compared to the costs of failing to do so. Because of the large environmental and security externalities involved, markets alone will not respond to this problem, so government policies to manage the all three risks of the oil transition are needed now.

Acknowledgments

This research was supported in part by the Climate Decision Making Center, which was created through a cooperative agreement between the National Science Foundation (SES-034578) and Carnegie Mellon University, and in part by the Energy Foundation. The authors thank D G Hawkins, J Romm, and two anonymous reviewers for helpful comments. All opinions and any remaining errors are ours alone.

References

Ahlbrandt T S 2002 Future petroleum energy resources of the world *Int. Geol. Rev.* **44** 1092–104

Ahlbrandt T S 2005 Global overview of petroleum resources *Workshop on Trends in Oil Supply and Demand and Potential for Peaking of World Oil Production* (Washington, DC: National Academy of Sciences)

Andrews S and Udall R 2003 Oil prophets: looking at world oil studies over time *International Workshop on Oil Depletion* (Paris: Association for the Study of Peak Oil)

Bartis J T, LaTourrette T, Dixon L, Peterson D J and Cecchine G 2005 *Oil Shale Development in the United States: Prospects and Policy Issues* (Santa Monica, CA: RAND)

Bentley R W 2002 Global oil & gas depletion: an overview *Energy Policy* **30** 189–205

Brandt A R 2006 Testing Hubbert *Energy Policy* under review

Brandt A R and Farrell A E 2006 Scraping the bottom of the barrel: CO_2 emissions consequences of a transition to low-quality and synthetic petroleum resources *Clim. Change* under review

Campbell C J 2005 *Oil Crisis* (Brentwood, Essex: Multi-science Publishing)

Cleveland C J 2005 Net energy from the extraction of oil and gas in the United States *Energy* **30** 769–82

Deffeyes K S 2005 *Beyond Oil: The View from Hubbert's Peak* (New York: Hill and Wang)

Dry M E 2002 The Fischer–Tropsch process: 1950–2000 *Catal. Today* **71** 227–41

EIA 2006 *Annual Energy Outlook* (Washington, DC: Energy Information Administration)

Gately D 2004 OPEC's incentives for faster output growth *Energy J.* **25** 75–96

Greene D L, Hopson J L and Li J 2006 Have we run out of oil yet? Oil peaking analysis from an optimist's perspective *Energy Policy* **34** 515–31

Hirsch R L, Bezdek R and Wendling R M 2005 *Peaking of World Oil Production: Impacts, Mitigation, and Risk Management* (San Diego, CA: SAIC)

Hubbert M 1956 Nuclear energy and the fossil fuels *Drilling and Production Practice* (Spring) (Houston, TX: Shell Development Company) pp 5–75

Intergovernmental Panel on Climate Change 2005 *IPCC Special Report on Carbon Dioxide Capture and Storage* (Cambridge: Cambridge University Press)

International Energy Agency 2005 *Resources to Reserves: Oil & Gas Technologies for the Energy Markets of the Future* Paris

Lake L W 1989 *Enhanced Oil Recovery* (Upper Saddle River, NJ: Prentice-Hall)

Lynch M C 2005 Unconventional oil: Filling the gap or flooding the market? *Energy Outlook and Modeling Conf.* (Washington, DC: Energy Information Agency)

McKibben W 2005 Mad Max meets American Gothic *Orion* (November/December) 5–6

Moritis G 2006 Special report: EOR/Heavy oil survey *Oil and Gas J.* **17** 37–57

Mut S 2005 *Statement to the Committee on Energy and Natural Resources* (Washington, DC: United Stated Senate)

National Energy Board of Canada 2004 *Canada's Oil Sands: Opportunities and Challenges to 2015* Calgary

Rattien S and Eaton D 1976 Oil Shale: the prospects and problems of an emerging energy industry *Annu. Rev. Energy* **1** 183–210

Simbeck D R 2006 Emerging unconventional liquid petroleum options *Energy Outlook and Modeling Conf.* (Washington, DC: Energy Information Agency)

Simmons M R 2005 *Twilight In the Desert: The Coming Saudi Oil Shock and the World Economy* (New York: Wiley)

Wilhelm D J, Simbeck D R, Karp A D and Dickenson R L 2001 Syngas production for gas-to-liquids applications: technologies, issues and outlook *Fuel Process. Technol.* **71** 139–48

Williams R H and Larson E D 2003 A comparison of direct and indirect liquefaction technologies for making fluid fuels from coal *Energy and Sustainable Development* **7** 103–29

Wilson E J, Johnson T L and Keith D W 2003 Regulating the ultimate sink: Managing the risks of geologic CO_2 storage *Environ. Sci. Technol.* **37** 3476–83

World Economic Forum 2006 *The New Energy Security Paradigm* Geneva

Yamashita K and Barreto L 2005 Energyplexes for the 21st century: Coal gasification for co-producing hydrogen, electricity, and liquid fuels *Energy* **30** 2453–73

Yergin D 1991 *The Prize: The Epic Quest for Oil, Money, and Power* (New York: Simon and Schuster)

Yergin D 2006 *Statement before the House Government Reform Subcommittee on Energy and Resources* (Washington, DC: US House of Representatives)

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	

Notes for Table 2:

a – These figures are provided by the GREET model, which calculates upstream emissions from petroleum production, as well as 0.4gCeq./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 corporation (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 gCeq./MJ 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, Canada (2004) 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 tonnes 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 (Kovscek, 2002), who notes that the volumetric density of carbon as CO_2 at typical reservoir conditions is about 1/4th that of oil (164 kgC/m^3 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 (1/4th 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 gC/MJ 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 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 4 times the total emissions from conventional oil and approximately 16 times the upstream emissions(!)

h – This datum calculated from Wang, Weber *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 percent 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 in tables 6 and 7. These upstream emissions are for 1995 GTL diesel.

k – Datum from Marland (1983), for Sasol type F–T process, as cited in table 11. 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)