Vol. 1, No. 2, April 2015 Petroleum Analysis Centre

THE OIL AGE

Understanding the Past, Exploring the Future

Background & Objectives

This journal addresses all aspects of the evolving Oil Age, including its physical, economic, social, political, financial and environmental characteristics.

Oil and gas are natural resources formed in the geological past and are subject to depletion. Increasing production during the *First Half* of the Oil Age fuelled rapid economic expansion, with human population rising seven-fold in parallel, with far-reaching economic and social consequences. The *Second Half* of the Oil Age now dawns.

This is seeing significant change in the type of hydrocarbon sources tapped, and will be marked at some point by declining overall supply. A debate rages as to the precise dates of peak oil and gas production by type of source, but what is more significant is the decline of these various hydrocarbons as their production peaks are passed.

In addition, demand for these fuels will be impacted by their price, by consumption trends, by technologies and societal adaptations that reduce or avoid their use, and by government-imposed taxes and other constraints directed at avoiding significant near-term climate change. The transition to the second half of the Oil Age thus threatens to be a time of significant tension, as societies adjust to the changing circumstances.

This journal presents the work of analysts, scientists and institutions addressing these topics. Content includes opinion pieces, peer-reviewed articles, summaries of data and data sources, relevant graphs and charts, book reviews, letters to the Editor, and corrigenda and errata.

If you wish to submit a manuscript, charts or a book review, in the first instance please send a short e-mail outlining the content to the Editor. Letters to the Editor, comments on articles, and corrections are welcome at any time.

A subscription form is provided at the back of the journal.

Published by

Petroleum Analysis Centre,
Staball Hill,
Ballydehob,
Co. Cork,
Ireland

ISSN: 2009-812X

Design and printing: Inspire Books, Skibbereen, Co. Cork, Ireland

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Editorial

Welcome to the second issue of this journal. As mentioned previously, the main emphasis of the first few issues is on physical aspects of global oil and gas supply, and in particular on oil and gas forecasting. In this issue, as in Issue-1, two oil forecast models are described; again one top-down (Laherrère) and the other bottom-up by-field (Miller).

However the journal aims to cover all aspects of the Oil Age, both past and prospective; and in this issue there is an article on the coming energy transition, and one on the price of oil from 1861 to 1970.

The contents of this second issue are:

Opinion piece:

- *The Grand Challenge of the Energy Transition* by Ugo Bardi. This summarises the prospects and challenges of transitioning the world away from fossil fuels.

Peer-reviewed articles:

- An article by Jean Laherrère describing his global 'all-liquids' forecast model. Though the underlying data for this model come from detailed industry by-field databases, this model forecasts production using multiple 'Hubbert' curves at the global level by category of oil and other liquids.
- Richard Miller's description of his global bottom-up by-field 'all-oil' forecast model. This model derives from a model originally used within BP.
- An article, of which I am a co-author, which aims to explain the price of oil from 1861 to 1970. This points out the need to use reliable data

on the discovery of conventional oil, and to incorporate the 'mid-point' peak of this oil, if the oil price over this period is to be understood.

Charts:

- As mentioned previously, charts and graphs can be key to understanding any complex topic. In this issue, six charts are presented that focus on the global production of *conventional* oil, both past and prospective. As the charts show, large increases in the production of this class of oil look unlikely, such that marginal barrels to meet any future growth in global oil demand will have to come mostly or entirely from the non-conventional sources of oil.

Discussion:

(i). Global energy transition

It is good to be able to include here Professor Bardi's article on global energy transition. It sets the coming transition as a 'grand challenge' for humankind, rather than as the prospect of 'doom-and-gloom'.

But Bardi is not blind to some of the great difficulties ahead. For example, too many studies have looked at the *potential* for renewable energy (in particular solar, but also deep-geothermal) to supply all of humanity's energy needs, without paying sufficient (or often, any) attention to the net-energy difficulties such a transition raises.

Photovoltaics, for example, is an amazing technology, and undoubtedly has a key role to play in the world's energy future. But even at the more optimistic end of its EROI estimates, the technology has – *so far* – contributed no net energy for humankind. This is primarily not because of its fairly modest full-system EROI ratios, but because of the success of its very fast growth rate. (See, e.g.: Dale & Benson. *Energy Balance of the Global Photovoltaic (PV) Industry - Is the PV Industry a Net Electricity Producer?* Environ. Sci. Technol., 2013, 47 (7), pp 3482–3489; and also: Prieto & Hall: *Spain's Photovoltaic Revolution - Energy Return on Investment,* Springer, 2013, ISBN: 978-1-4419-9436-3.)

Professor Bardi's detailed article is in the general class of broad-ranging, slightly philosophical articles that I hope to include as 'opinion pieces' in most issues of this journal.

(ii). OPEC & FSU oil reserves data

On the narrower focus of oil forecasting, in this issue we return to the topic of the reliability of OPEC & FSU oil reserves data. Laherrère's model (like that of Campbell in Issue 1) in assessing the future production of *conventional* oil significantly reduces the size of oil reserves that some industry datasets hold for specific OPEC and former Soviet Union countries. This is a topic that probably most oil forecasting organisations will need to take a view on.

(iii). Net-energy

In Issue 1, I mentioned that Campbell's hydrocarbon forecast model had recently been expanded to account for net energy, and said that this was an important step making it, at least to my knowledge, the first detailed oil and gas forecast model to include this aspect.

I have subsequently been told that a European academic group applied net-energy ratios to an IEA forecast; but I do not have the details of this. Further information on this study would be welcome. As explained above, net-energy would seem to be a key factor in understanding the world's energy future (see also my comments in the *Editorial* of Issue 1).

(iv). Size of the URR for conventional oil

As also previously mentioned, when comparing current oil forecasts it would seem that a large part of the difference between these forecasts is in the assumptions made for the size of the global conventional oil URR. For example, look at the different conventional oil URRs implied by the forecasts given in the 'Charts' section of this issue vs. those in the articles. As mentioned, we will return to this topic in future issues.

(v). Conventional vs. non-conventional oil

It seems to your Editor that a lack of understanding of 'peak oil' is still fairly widespread. One contributor to this situation is the often-expressed view that 'the tank does not care what type of oil it is filled with'. This view is addressed in the appendix on conventional vs. non-conventional oil in the Bentley & Bentley paper.

I hope you find the articles in this second issue useful. By all means write to me should you have corrections, criticisms or comments.

- R.W. Bentley, May 2015.

The Grand Challenge of the Energy Transition

UGO BARDI

Introduction

Energy is the key factor that drives the economy. Without the abundant energy coming from sources other than human and animal muscles, society as we know it would be unthinkable. Energy is needed to power all kinds of machinery, but also for the vital task of supplying the industrial system with the mineral commodities that make it function. Energy is also fundamental for the food production system which can sustain billions of people only because it makes large use of energy coming from outside agricultural sources (Giampietro, 2002).

The first to realize the importance of energy for modern society was probably William Stanley Jevons, who wrote in his "The Coal Question" (Jevons, 1866) that: "*Coal in truth stands not beside but entirely above all other commodities. It is the material energy of the country — the universal aid — the factor in everything we do. With coal almost any feat is possible or easy; without it we are thrown back into the laborious poverty of early times*." Today, we can replace the term "coal" with "fossil fuels" in Jevons' statement and obtain a good description of our situation.

Our society is based on fossil fuels and for many purposes – such as for transportation – there exist no comparable energy sources that could drive the existing infrastructures. If fossil fuels were to disappear today we would be immediately thrown back into the "laborious poverty" of old times – or much worse than that. The question that Jevons was asking in his 1866 study was "how long can coal sustain British industry?" The same question can be asked today about fossil fuels and world industry. The answer cannot be any other that: "not forever" since, for all practical purposes, the amount of fossil fuels available to humankind is finite.

But, just as Jevons had argued for coal, the problem is not the physical running out of fossil fuels; it is the fact that we are gradually running out of the low-cost energy and mineral resources that had been used to build up our industrial system. As a consequence, industry is forced to extract fuels at increasingly higher costs from resources which are deeper, more remote, less practical, and in general of lower quality. As a consequence, we need to invest increasing amounts of energy to obtain the same amounts of energy as in earlier times. This problem is normally defined in terms of a parameter termed "energy return of energy investment" EROI or EROEI (Murphy and Hall, 2011) which, for fossil fuels, usually declines as a function of the extracted quantities (Bardi et al., 2011).

The result is the generalized increase of energy costs experienced during the past decade or so; an increase that has interrupted a decreasing trend that had been lasting for more than a century (Fouquet, 2011). Even taking into account the recent collapse of oil prices, the overall trend is still one of increase and the present low prices can only be seen as a temporary phenomenon. At the same time, the Earth's capability of absorbing the products of the combustion of fossil fuels is limited. As this text is being written, the concentration of carbon dioxide in the atmosphere has reached 400 ppm (Sweet, 2013); a value not known to have ever been reached on the Earth during the past few million years. In addition to the heating of the atmosphere generated by the greenhouse effect, there are several negative consequences of this increasing CO2 concentration: ocean acidification, sea level rise, extreme weather phenomena, and more.

Possibly the most worrisome of these effects is the release of more potent greenhouse gases: the methane trapped in the Northern Permafrost and in deep-sea hydrates. This event would then further accelerate the negative trends with truly catastrophic effects (Archer, 2007). At present, we cannot determine whether global warming or fossil fuel depletion is the more important problem we are facing, but we know that both are caused by our dependency on fossil fuels. As a consequence, it is imperative to reduce, and eventually eliminate, this dependency before it is too late. Given the situation, it is hard to think of a grander challenge for humankind than that of creating a society that can function without fossil fuels and at the same time maintain a level of prosperity and complexity comparable to the present one – and creating it in a relatively short time-span.

How are we going to meet this challenge? Whatever we decide to do, the transition is already in progress.

The Ongoing Energy Transition

The main ongoing trends can be listed as:

- The world production of oil has been basically static during the past few years (Staniford, 2013). Some areas are in an irreversible production decline (e.g., the North Sea) while others, mainly the continental US, are experiencing a true renaissance in the production of petroleum liquids owing to the exploitation of oil shales. Against this static trend of production, the consumption pattern is changing, with developing nations such as China, rapidly expanding consumption (Luft, 2007).
- Natural gas production is increasing worldwide (Zittel et al., 2013), especially in some regions of the world exploiting the so called “tight gas” resources. Coal production is rapidly growing in a trend that is not expected to slow down soon (Zittel et al., 2013). In general, energy production from fossil fuels seems to be still able to grow, although the high market prices are a clear indication that more effort is needed to keep even to rates of growth that are small in comparison to past trends.
- Worldwide mineral production is generally static for most mineral commodities; some are slowly increasing, others are declining (Brown et al., 2013). The mining industry is facing the problem of diminishing ore grades for most minerals and the consequence is the need of more energy to maintain the same levels of production. Several strategies are being pursued in order to counter depletion, e.g., recycling (Papp, 2010), mining from the seafloor (Bertram et al., 2011), and others. All these strategies, however, need large amounts of energy. These problems combined are causing a general increase in the cost of all mineral commodities (World Bank Global Economic Monitor Data, 2010; Bertram et al., 2011).
- Agriculture is facing an energy problem. The production of food and textiles is heavily dependent on fossil fuels for powering agricultural

machinery, for the supply of fertilizers, pesticides, and irrigation (Giampietro, 2002; Bardi et al., 2013). So far, food production shows no evident signs of decline. However, the increasing prices of fossil fuels are being reflected in higher prices for all agricultural products (Food Price Index, 2013); a phenomenon indicating that the problem exists and that it is growing.

- Nuclear energy faces considerable difficulties. The past decade had seen a minor renaissance in the start of the construction of new plants, although still in number insufficient to replace the old plants being retired. The trend, however, was interrupted with the Fukushima accident of 2011. At present, the production of nuclear energy worldwide is declining (Zittel et al., 2013). There are also worries about the capability of the mining industry to produce sufficient uranium if the number of plants worldwide were to be significantly increased above the present level (Dittmar, 2012).
- Renewable energy is seeing a truly explosive growth worldwide, especially with the diffusion of the "new renewables" in the form of photovoltaics (Kazmerski, 2006) and wind energy (Petersen and Madsen, 2004). The energy produced by the new renewables is still a minor fraction of the total of the world primary energy production, but it has been growing at exponential rates that, so far, show no sign of abating (Bardi, 2011). These sources can now produce electric power at prices that are nearly competitive with those of fossil fuels and have also reached EROI levels which can be considered acceptable (Raugei and Frankl, 2009), even though not on a par with those that fossil fuels had at the time of their rapid diffusion. However, even this rapid growth may not be sufficient for renewables to replace fossil fuels fast enough to avoid both depletion and disastrous climate change effects, unless either systems with much higher EROI ratios can be developed, or investments in renewable are considerably increased (Sgouridis and Csala, 2014).
- We see an evident trend toward higher efficiency in both production and end uses of energy. It is a trend particularly evident in the residential sector (Popescu et al., 2012), with buildings that reduce energy consumption by means of better insulation, passive solar heating, high efficiency lighting, and more. It is also evident in transportation with the diffusion of hybrid and purely electric road vehicles (Daziano and Chiew, 2012), as well as attempts to improve

public transportation while reducing the distance travelled by both goods and people.

Phasing Out Fossil Fuels

It is clear from the available data that an “energy transition” is in progress: we are facing more and more difficult times in maintaining the current system based on fossil fuels. The combined effects of depletion and of climate change are pushing humankind in the direction of replacing fossil fuels with cleaner and more abundant forms of energy, but the task is not an easy one. Renewable technologies could replace fossil fuels if we look at the transition only in terms of the amounts of energy that can be theoretically produced. Solar energy is ultimately limited by the solar irradiation and the amount beamed on the Earth’s surface (Kambezidis, 2012) is very large in comparison to the primary energy produced by humankind.

Indeed, it has been estimated that the land area needed for the complete replacement of fossil fuels by a mix of renewable energy in terms of mainly wind and solar would be of the order of 0.5% of the total (Jacobson and Delucchi, 2011), that is of the same order of magnitude of the present footprint of human-made structures (Schneider et al., 2009). Current renewable technologies also do not use mineral resources which are likely to be in short supply in the near future (e.g. silicon and aluminium are the main components of the present generation of solar systems). In comparison, the present commercial technologies for nuclear energy generation face much more difficult hurdles in terms of fuel availability and general management (Zittel et al., 2013). Nevertheless, it is not obvious that the transition to renewable energy can be made fast enough to replace fossil fuels before their cost becomes too high for their generalized use or the damage resulting from climate change becomes truly catastrophic (Sgouridis and Csala 2014).

At the core of the problem there is the fact that, still today, no existing “alternative” energy technology can compete with fossil fuels in terms of combining a series of features that are perceived as fundamental for our energy system. These are flexibility, low cost, safety, transportability, high energy density, and high EROI. It is true that the renewables such as wind and PV do not suffer of the enormous “external costs” typical of fossil fuels in terms of environmental degradation, but the present economic system is not geared to take these costs into account. The most promising new renewable technologies, wind and photovoltaics, produce electric power and have a variable output. Hence, these technologies are not easily accommodated in an energy system built on the basis on the capability of fossil fuelled plants to produce "on demand" and on liquid fuels for transportation.

Other renewable energy technologies do not suffer of the intermittency problem; but have their shortcomings nevertheless. The potential of geothermal and hydroelectric energy is limited (Fridleifsson, 2003), while biofuels have a low EROI and there are concerns about their impact on the environment and on the world's agriculture (Giampietro and Mayumi, 2009). Concentrating solar power is claimed to be able to produce on demand, at least in part, but the technology is still in its early stages of diffusion (Kuravi et al., 2013). Other forms of energy such as nuclear fusion (Ward et al., 2005; Dittmar, 2012), high altitude wind power (Archer and Caldeira, 2009), enhanced geothermal systems (EGS – also "heat farming") (Fox et al., 2013), space based solar power (SBSP) (Seboldt, 2004), and others show promise in many respects but none of these technologies has reached the industrialization stage, so far, and some are still only at the stage of theoretical possibility.

Finally, there do exist energy storage technologies that can be used to adapt the variable input from renewables to the existing infrastructure, from electrochemical batteries to hydrogen obtained by water electrolysis. All these proposed methods, however, are an additional cost that so far has prevented storage (with the exception of hydroelectric basins) to become an integral part of electrical grids worldwide.

The Role of Science and Technology for the Generation of a Smooth Transition

Clearly, the 'magic bullet' that allows humankind to get rid of its addiction to fossil fuels has not been found, and it doesn't seem likely that it will be found soon, if ever.

However, we are not necessarily condemned to returning to the "laborious poverty" of old times, as Jevons surmised long ago. Renewables are a growing technology which holds the promise of being able to produce amounts comparable, and even superior, to what we are producing at present with fossil fuels (Jacobson and Delucchi, 2011). At the same time, it is possible to base at least some forms of transportation on electric power, especially with the recent development of new and more efficient batteries (Gerssen-Gondelach and Faaij, 2012).

The problem is not so much a technological one, but it lies in the fact that the infrastructure of our society is not adapted to these new forms of energy. Adapting the electric grid to a variable input is possible by means of the "smart grid" concept (Clastres, 2011) but the transition will require a major effort. At the same time, if the whole energy system is to be adapted to a larger share of electric power, e.g., for powering electric vehicles, the grid should be scaled up, which is also a major cost. So, the transition is in progress but it turns out to be difficult, complex, and expensive. If we are to move in this direction, we must accept that substantial resources have to be allocated to the task and that it can't be done without sacrifices.

What role, then, for science in this transition? Traditionally, scientists have studied and developed new and improved energy technologies: better solar conversion methods, better energy storage systems, more efficient ways to use energy, and the like.

These are all valid strategies, but as scientists we need to do more in view of the urgency of the transition. We need to evaluate the new technologies in terms of their efficiency (using factors such as EROI, life cycle assessment, and others), and their impact on the environment and on economic activity. Then we need to develop strategies to optimize their benefits and minimize their unintended negative effects. The energy transition is first of all a systemic problem, in the sense that new technologies develop within an existing energy system, and that forces change and adaptation to both the system and to the new technologies.

Adaptation takes many forms; one is higher efficiency in the final uses of energy. On this point, however, we must remember that, as Jevons pointed out in *The Coal Question*, efficiency alone is unlikely to help solve the depletion problem. This was 'Jevons' paradox', that increasing the efficiency of use makes a fuel cheaper for a consumer, and hence total consumption is likely to increase. In short, better technology will not necessarily lead to a reduction in the consumption of a resource.

The energy transition is also an economic problem, since the present financial system tends to look only toward immediate profit, discounting medium and long term advantages. So, we have policy problems in the sense that we need to allocate economic resources for the transition and to consider also the social transformations that it will cause, and we cannot neglect the need of an equitable access to energy for everyone.

We need to build good models that can tell us where we are going and what measures have to be taken if we want to plan ahead. This is possible, as was shown in the past with the seminal "The Limits to Growth" study which was the first attempt at total world system modelling (Meadows et al., 1972; Bardi 2011).

We are not blind to the future; but we need to open our eyes if we are to see it. If we can manage the energy transition by taking into account technological, economic, and systemic factors, then we will be able to eliminate fossil fuels without a 'magic bullet', and arrive to a better, cleaner, and more equitable future.

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Note:

This article is a modified and updated version of an article originally published in *Frontiers in Energy Resources*. (Bardi U. *The grand challenge of the energy transition.* Energy Res., 29 August 2013; doi: 10.3389/fenrg.2013.00002.)

A Global Oil Forecasting Model based on Multiple 'Hubbert' curves and Adjusted Oil-industry '2P' Discovery data

J. H. LAHERRÈRE

Background

I was born in 1931, one year after the US giant East Texas field was discovered. Flush production from this field led to tumbling oil prices, which in turn led to US' pro-rationing. But later the field was a lifeline for allied oil supply during the Second World War.

In terms of my own career, I studied first mathematics and physics at the Ecole Polytechnique. This was originally a military school created by Napoleon in 1794 to train French military officers and civil servants. Then I took geology at Grenoble University, and finally petroleum studies at the Ecole Nationale du Pétrole in Paris, which is connected with the French Petroleum Institute. I joined Compagnie Française des Pétroles (now Total) in 1955, where I led seismic teams in Algeria and later in Australia, I then became Exploration Manager in Canada before returning to the Paris head-quarters to be in charge of various departments including Negotiations, Basin Studies, and finally Exploration Techniques. (For additional details see Chapter 11 of Campbell (Ed.) (2011), and my CV on the aspofrance web site.)

My interest in oil forecasting arose as follows: When I was in charge of Exploration Techniques at Total, activities included making studies of the geographical distribution of global oil and gas reserves (using Petroconsultants' data), and also monitoring the quantities of global oil and gas being discovered annually. As a consequence, I began to worry about where future oil might be found, and about the decline in the global discovery rates.

Indeed, as a result of this trend of declining discovery of conventional oil, one of my final recommendations at Total was that the company should take a 50% stake in the Gulf farm-out of the Athabasca tar sands Surmount project, which would have required an investment of $10 million for this SAGD pilot, of which half would be subsidized by the Canadian government. This would have let Total get access to 50% of an estimated recoverable oil resource of about 800 Mb. This suggestion was turned down in 1990 by Serge Tchuruk, then Chairman and CEO of Total, because it was seen as too long-term, but was taken up ten years later under Tchuruk's successor, Desmarest.

I was retired by company policy in 1991 when I was sixty, whereas I had wanted to retire at sixty-five. In retirement I became interested in natural distributions in the universe, and found - surprisingly, at least to me - that the size of such diverse phenomena as oil reserves, galaxies, earthquakes, and urban agglomerations all followed the same basic statistical distribution, that of the parabolic fractal (Laherrère, 1996, 1999, 2000a and 2000b; and Laherrère and Sornette, 1998).

I became involved in the sequence of major Petroconsultants' oil and gas supply studies that were produced between 1994 and 1996 because I had written a paper with Alain Perrodon in 1993. Alain was advising Petroconsultants, and I approached the company to suggest that they commission a report on the world undiscovered oil potential, which would be based on the main petroleum systems of the world. I saw this report as being able to draw on Perrodon's knowledge of the Petroleum System (he was the first to use this term), on Demaison's knowledge of quantifying the volumes of hydrocarbon generation by such petroleum systems (he was the first person to do so (Demaison and Huizinga, 1991)) plus his knowledge of English, and on my knowledge of global oil distribution.

Petroconsultants provided the data based on our selection of the areas to cover, and between us we did the work. Petroconsultants paid for the printing and marketing of the final report: *Undiscovered Petroleum Potential* (Laherrère, Perrodon and Demaison, 1994), and we were paid from royalties. Based on this report, I wrote papers for *World Oil*, *American Oil & Gas Reporter*, AFTP, and OPEC.

Subsequently I met Colin Campbell in Total's offices. His involvement, I believe, was because George Leckie, who was in charge of much of the oil discovery data entered into the Petroconsultants' database, had seen the Campbell / NPD book *The Golden Century of Oil: 1950-2050.* For its forecasts this book had used *O&GJ* proved oil reserves, and Leckie suggested the study should be re-done using the Petroconsultants' far better proved-plus-probable oil discovery data. At that time Demaison was back in California so I therefore asked Colin Campbell to join us in the next set of reports. These were: *The World's Oil Supply: 1930-2050* (Campbell and Laherrère, 1995), and *The World's Gas Potential* (Laherrère, Perrodon and Campbell, 1996). We also produced a fourth report, *The World's Non-conventional Oil and Gas* (Perrodon, Laherrère and Campbell, 1998), but Petroconsultants was not keen to publish this, so we published with the *Petroleum Economist.*

The main public outcome of these studies was the article *The End of Cheap Oil* published in Scientific American (Campbell & Laherrère, March 1998).

In 1998 Petroconsultants was bought out by IHS Energy after the death of former's founder, Henry Wassall. It was the end of our association with the company, and most of our contacts in Geneva were fired. IHS kept our three reports in their catalogue until 2010 (Figure 1), and presumably had sales, but never paid us any royalties!

Since working on these Petroconsultants' studies I have continued to model future oil and gas production as new data have become available (see the model described below), to publish widely, and to be an active member of ASPO-France.

2. Data

As all analysts know, any model is only as good as its data, and in the correctness of its methodology to capture enough of reality to be useful. Data for the oil forecast model presented in this paper are discussed in this section, and its methodology in the next.

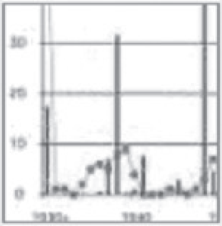
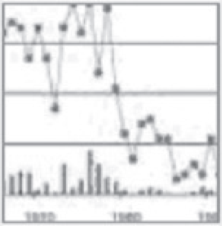
2.1 Data sources

The data used come from a wide variety of sources. For the quantity of oil *discovered*, the oil-industry data used are from several sources, and a number of corrections are then made to adjust the data to what seems to me to be the most-likely '2P' (proved-plus-probable) value, i.e., to be close to the mean value, which is the only value that can be aggregated correctly. It is often over-looked that simply summing the proved reserves

8.1.2 **World's Oil Supply, 1995**

The report has 3 parts; Volume 1 is a comprehensive world evaluation written in non technical language to be readily understood by all disciplines, Volume 2 is a regional evaluation and Volume 3 is a country-by-country analysis.

- *650+ page report.*
- *Illustrated with 650 graphics and 100 datasheets.*

8.1.3 **World's Gas Potential, 1996**

By combining the wealth of data available through the IHS Energy database with penetrative analysis by leading experts, this study forecasts not only the amount of reserves remaining to be found, but the number and size distribution of the fields and the number of wildcats required to discover them. The report assesses in detail seven selected provinces that together hold almost half the world's gas potential, then looks at North America, which has unique reporting practices and traditions, before going on to assemble a global assessment.

- *The study shows that the world has produced 2,200 Tcf (62 $T.m^3$) of gas; has reserves of 4,650 Tcf (132 $T.m^3$) and a realistic undiscovered potential of 2,400 Tcf (68 $T.m^3$).*
- *Discussion includes examination of the various ways to assess gas potential, such as field distribution analysis and derivative logistic or Hubbert curves.*
- *The seven areas discussed in detail are the Ahnet Timmoun System in Algeria, Barrow-Dampierre-Rankin, Australia; North of Western Siberia, Russia; Niger Delta, Nigeria; Anglo-Dutch Basin, UK, Netherlands and Germany; Po-Adriatic Gas. System, Italy; Qusaiba-Sudair Gas System, Middle East.*
- *Written in conjunction with three of the world's leading experts on the prediction of the world's resources: Jean LaHerrère, Alain Perrodon and Colin Campbell.*

Figure 1: IHS Energy Publications catalogue, 2009.

We apologise to readers that the text to this Figure, and Figure 2, is not very distinct, but hope that the general ideas conveyed are comprehensible

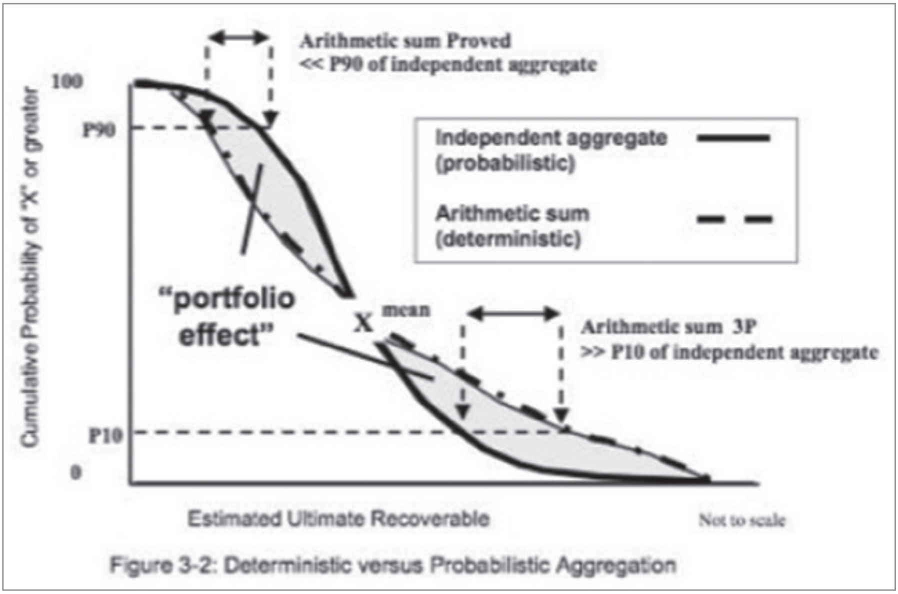


Figure 2: Illustration of the errors introduced when aggregating probabilistic data. Source: Society of Petroleum Engineers.

('1P') of individual fields does *not* give the aggregate 1P reserves of the fields as a group, but an under-estimation (Figure 2.)

For data on oil *production*, there is no consensus on the definition of conventional oil. But, in my view, the most available world source is USDOE/EIA, so I use the EIA definition (that of 'crude+condensate') for 'crude oil'; and then generate data for what might be classed as conventional oil by removing the 'extra-heavies' (XH = heavier than water = <10°API), to generate production data for "crude oil –XH". The latter 'extra-heavies' category applies primarily, in terms of where the data are available, to the two locations of the Athabasca tar sands oil in Canada, and the heavy oil produced from the Orinoco basin in Venezuela. The problem with the definition of 'condensate' is that some countries such as Norway (and as followed by the IEA) define condensate as being crude oil when sold with crude oil, or as natural gas liquids (NGLs) when sold with NGLs. As a result, the IEA global data for NGL production is 2 Mb/d greater than the US' EIA data for natural gas plant liquids (NGPLs).

2.2 Adjustments made to the oil-industry data

Importantly, when we carried out the consultancy studies for Petroconsultants from 1994 to 1996, we trusted their reserves data for OPEC countries. This was because at that time OPEC members were not buying the company's data studies, and also not reporting oil reserves by field.

But a senior employee of IHS Energy (which bought the Petroconsultants' database, as already mentioned) told me that in recent years the company are obliged to accept OPEC field data values, and also the countries' total reserves values. As an example, the current IHS data for Saudi Arabia (Figure 3) gives the country's cumulative discovery of oil as 400 Gb, which is 100 Gb more than the corresponding Petroconsultants' figure in 1998. The number of fields involved has barely changed in the intervening 15 years, and there is no evidence for higher recovery factors or field extensions on such a scale. Further, this 400 Gb is in agreement with the country's declared *proved* reserves as recorded in *OGJ* data, plus cumulative production since 1998. It is as though Saudi Arabia no longer deducts production from its official reserves.

This view of the need to reduce stated OPEC reserves data is supported by remarks made by Sadad Al-Husseini, former VP Aramco, at the 'Oil & Money' conference in London in 2007.

I therefore reduce the current IHS data for cumulative oil discovery as follows:

- By 300 Gb for OPEC discoveries, for the reasons given above.
- By removing 30% (~100 Gb) from FSU discovery data to reflect the fact that these data are ABC1, and are probably closer to 3P than 2P estimates. See Khalimov and Feign (1979), where ABC1 is estimated using the maximum theoretical recovery; and also Khalimov (1993) which indicates that ABC1 data are grossly exaggerated. This view is supported by extrapolation of production decline plots for individual fields (in particular Samotlor, Figure 4), and also by Gazprom audits reported in its annual reports (Figure 5).
- By 200 Gb for Orinoco heavy oil discoveries reported in the period 1936 to 1939.

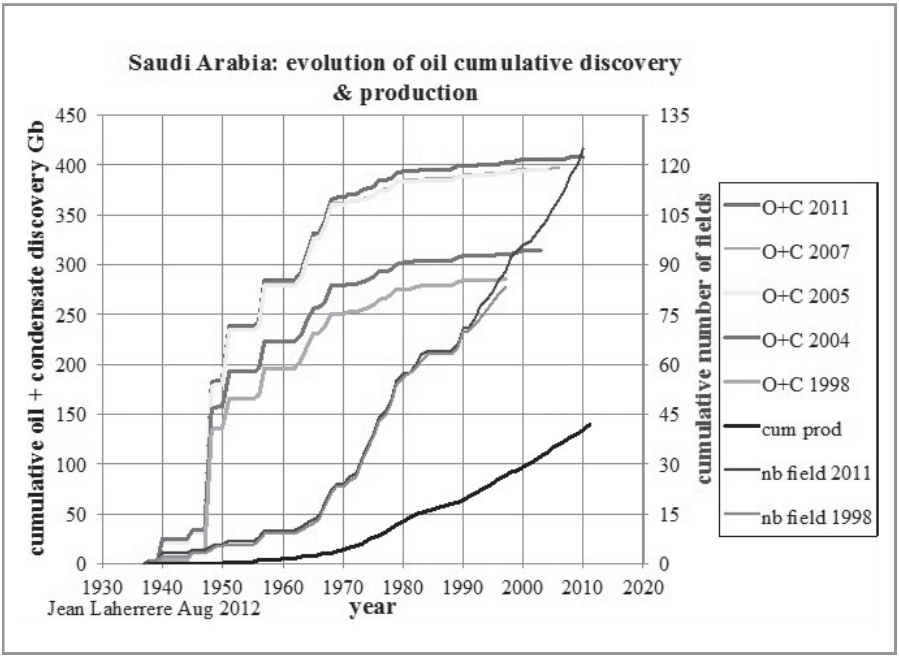


Figure 3: Cumulative plot of Saudi Arabian oil plus condensate 2P discovery and production data 1930 - 2011. Evolution of estimates vs. date.

Notes: O+C year: Oil plus condensate; and year estimate made.
cum prod: Cumulative production.
nb field year: Cumulative number of fields discovered by the year stated.

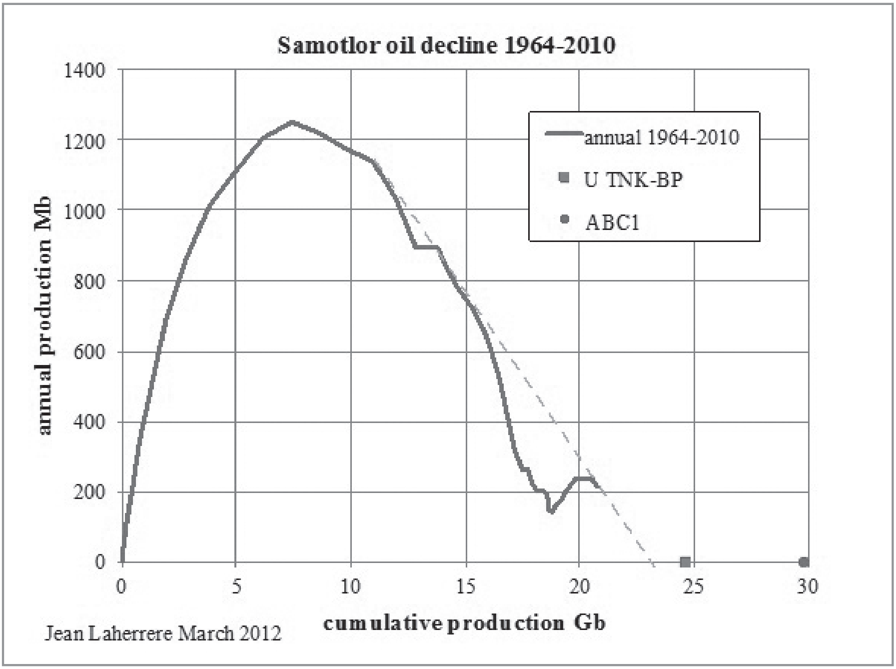


Figure 4: Samotlor field linearised production decline plot (annual prodn. vs. cum prodn.), indicating a possible 'ultimate' of ~23 Gb, in reasonable agreement with the TNK-BP published estimate of ~24.5 Gb; vs. the ABC1 estimate of ~ 30Gb.

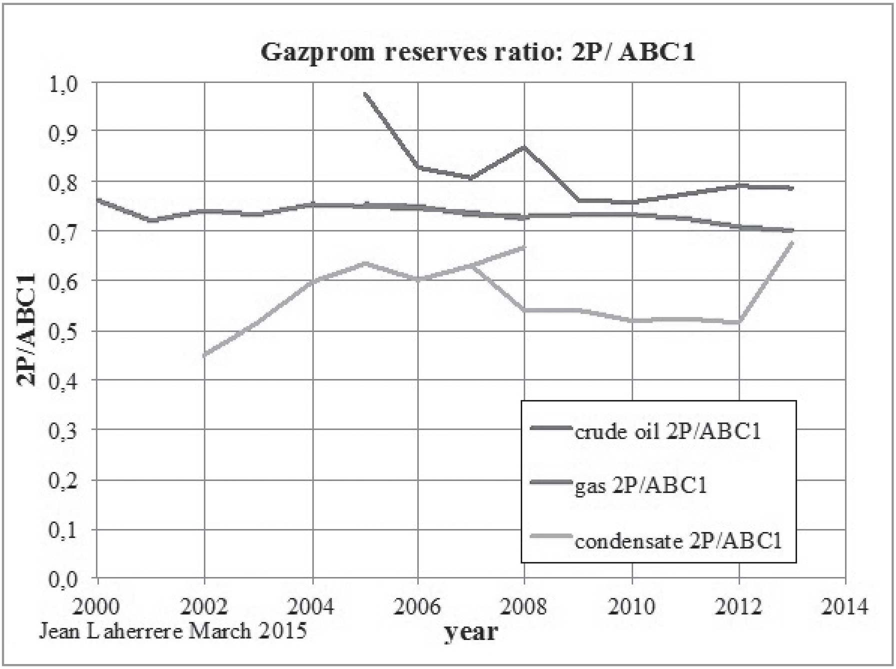


Figure 5: Evolution of ratios of 2P reserves data from Gazprom reports vs. ABC1 data held in industry databases.

3. Methodology

3.1 Determination of URR values

The global ultimate recoverable resource ('ultimate', 'URR') values for the various classes of oil and gas that the models use are found from extrapolation of 'creaming curves' that are modelled with multi-cycles.

A 'creaming curve' is generally a plot of cumulative discovery volume vs. cumulative exploration effort. The latter can be measured in a number of ways, for example, by the number of exploration wells ('new-field wildcats', NFWs) drilled in a region. (Note that the IHS Energy data for NFWs in China are not reliable). A different sort of creaming curve is a plot of cumulative annual discovery volume vs. cumulative annual number of fields discovered. A final type of creaming curve is simply a plot of cumulative discovery volume vs. date of discovery. (But note that this latter plot can be a less reliable indicator of URR, as discovery activity may have been interrupted or lessened for a variety of reasons, and hence an apparent trend of discovery towards asymptote may be misleading.)

To determine a region's URR, the creaming curves used are modelled as hyperbolas with several cycles, and where the number of these cycles is dictated by the data, and by knowledge of the region's exploration history. The URR is then determined by reasonable extrapolation, for example to about double the current number of NFWs, or alternatively double the current number of fields, to estimate the 'ultimate' of the final discovery cycle. Geological knowledge is also used to indicate if significant future discovery cycles are to be expected for the region considered.

Figure 6 gives the creaming curves of global cumulative discovery vs. date for conventional oil, and for gas; and also the corresponding cumulative production data curves. The oil curve is for 'conventional oil' (i.e. crude plus condensate, and excluding the extra-heavies), and where the discovery data shown are after reducing the industry 2P values for OPEC, FSU & Orinoco data as outlined above. The gas curves (discovery, and production) are both for 'all-gas', i.e., including tight gas that requires fracking for extraction.

For both 'conventional' oil and for gas three distinct main cycles of discovery are identified, and lead to corresponding estimates for URR when extrapolated, in this case, to the year 2100. For conventional oil, the discovery cycles correspond roughly to those of surface exploration alone; then with seismic; and finally including the recent deepwater discoveries.

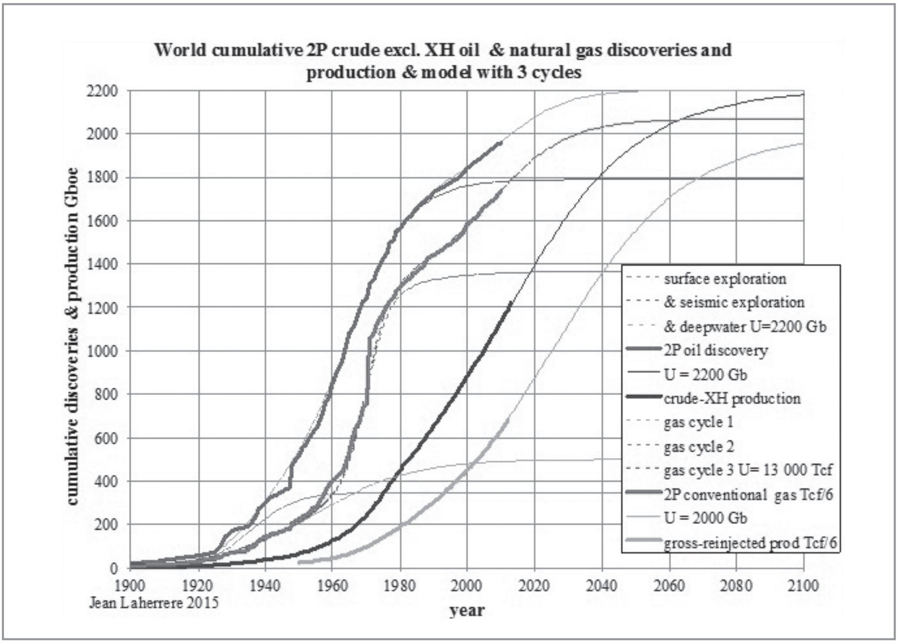


Figure 6: Oil & gas cumulative 2P Discovery & Production.

Solid lines:

Left: Judgement of the 'most probable' adjusted global backdated 2P cumulative global discovery data for 'conventional' oil (crude oil plus condensate, less the extra-heavy oils; the latter mainly tar sands and Orinoco oil; and not including NGPLs).

Next left: Corresponding data for 'all-gas', calculated as Tcf/6.

Next leftmost: Cumulative global production of 'conventional' oil, as defined above.

Rightmost: Cumulative global production of 'all-gas', Tcf/6.

Faint / dotted lines:

Indicate approximate cycles of discovery, three in each case, for oil and gas.

Notes:

The 2P oil discovery data are based on a number of industry sources, but reduced by: 300 Gb to allow for probable overstatement of OPEC Middle East original reserves data; by 30% of the FSU data (~100 Gb) to allow for datasets holding probably closer to 3P than 2P data; and by 200 Gb to allow for early Orinoco 2P discoveries reflecting non-conventional oil.

The three discovery cycles for conventional oil correspond to roughly pre-seismic, post-seismic and deepwater discoveries. The three discovery cycles for gas correspond to roughly pre- and post the giant Middle East gas discoveries, and to the wide variety of gas discoveries since, including most recently, tight gas deposits that requiring fracking for their extraction.

Extrapolation of the final discovery cycles shown, out to the year 2100 indicate likely URR values for 'conventional' oil and 'conventional' gas as 2200 Gb and 2000 Gboe, respectively.

For all-gas, the discovery cycles correspond roughly to discoveries prior to the major Middle-East gas discoveries; then with these discoveries (in particular the North field / South Pars field, which can be clearly seen on the plot); and finally with the wide range of more recent gas discoveries, where the latest data also includes tight gas projects (*projects*, as opposed to fields, since tight gas that requires fracking for its extraction is often extensive in nature, and its general location frequently long well known).

The total extrapolated discovery curves yield (see Figure 6) ~2200 Gb for 'conventional' oil (crude-plus-condensate less the extra heavies) and ~13000 Tcf (~2200 Gboe) for 'all-gas'.

The URR values then used in the oil & gas models are taken as 2200 Gb for 'conventional' oil, and 2000 Gboe for conventional gas (i.e., taking off something like 200 Gboe to allow for the tight gas from fracking that may be produced over the medium-term.)

3.2 General methodology

The global oil forecasting model described below in this paper combines a general 'multiple Hubbert-curves' approach with my judgement, discussed above, of what is necessary in the way of adjustments to both the industry (roughly) 'proved-plus-probable' oil discovery data, and to the production data. The model correlates global *discovery* of a class of oil to *production* of the same class of oil using multi-cycles.

Thus several peaks of production are modelled on the different cycles of discovery, and where the forecast for each class of oil must agree with past production in this cycle, and where the forecast slopes of the cycles must agree with the ultimates assumed. More detail on the approach is given in Laherrère (2000c, 2001 and 2002).

Note that this approach is different from that used by Colin Campbell, as described for example in *The Oil Age*, vol. 1, no. 1. Campbell models production of 'Regular conventional' oil by country, using the peak at 'mid-point' approach; and then adds on the production of the other classes of oil, such as deepwater, polar, NGLs, light-tight and the heavies (<17.5°API, but there is no consensus on definition of heavy and no world production data), etc. However the overall results for the global production of 'all-oil' from my model and that of Campbell are fairly close. This is probably in large part because both models take a more conservative view than most of the likely realistic URR for conventional oil, at least as this URR affects near and medium-term production, where the estimate of URR is driven in the main by extrapolation of 2P conventional oil discovery data. Likewise, both our models take a rather more conservative view than most 'mainstream' models on the rates that the various classes of non-conventional oil will be able to come on-stream.

The methodology of my model is now discussed by category of oil.

3.3 Modelling by category of oil:

(i). Conventional oil

Conventional oil generally refers to light oil that has migrated from its source rock to a reservoir from which it can be extracted without modification of either the oil itself, or the surrounding sand or rock, by own-pressure, pumping, or gas- or water-drive. As made clear above, 'conventional oil' as modelled here covers (primarily because of data availability) crude oil plus condensate, and excludes extra-heavy oil and also NGPLs. As mentioned, the data used for conventional oil discovery are 2P data from a wide variety of sources including IHS Energy, and where these values are reduced to reflect judgement of probable overstatements, as listed earlier.

When modelled with several cycles of discovery (and hence production), the mid-points of the URR values assumed *do not* exactly correspond to the production peaks, but such mid-points are usually not too far from the peak dates for many countries; except for the OPEC countries which are difficult to deal with because of variations in production due to quotas, and sometimes war.

(ii). Fallow fields

A fallow field is one that has been discovered, but which for some reason has not yet been scheduled for production. Some analysts (for example, see Miller in this issue) suggest that a significant quantity of the oil already discovered is in fields which are unlikely to go into production, at least in the near or medium term.

My view is that while the total *number* of such fields might be quite high, the total reserves that they hold are probably relatively small. For example, in Europe at end-2011, out of 5175 oil discoveries made (with total original oil reserves, URR, estimated at 84.2 Gb), 22% of these (some 1142 discoveries) were still on 'discovery' status (but containing only 2% of the region's original oil reserves), 9% were on appraisal (6% of original reserves), 1% were classed as awaiting development (1% of reserves), 2% as developing (1% of reserves), 41% as producing (85% of reserves), 4% shut in (2% of reserves), 20% abandoned (3% of reserves) and 1% had no data (0% of original oil reserves).

In the North Sea the majority (in numerical terms) of all discoveries are still in 'discovery' status, with probably most of these being far from current oil producing platforms, and hence uneconomic to produce (and even more uneconomic as and when the platforms are removed, even if the oil price goes high in the future). Thus my view is that while the number of such fallow fields is important, the volume of their reserves is not, being less than the uncertainty on the current value of the North Sea's total remaining reserves.

(iii). EOR, & Scope for 'reserves growth'

On the scope for enhanced oil recovery (EOR) to increase production, and hence for 'reserves growth', my view is as follows: Most of the IHS field original reserves data are estimates by geologists; and specifically by geologists who do not care about technology but who assume that producers will do the best to extract the oil that the geologists estimate as extractable.

Specifically, most of the reserve growth claimed by the USGS on their year-2000 Assessment study came from Petroconsultants 1996 data, where about 2000 fields were missing up to 1996, compared to present data. In my view, much of apparent 'reserve growth' is due to either poor practices in estimating the reserves, or in reporting the data. In the US, for example, the annual volume of oil production from EOR has been varying between about 0.6 and 0.8 Mb/d since 1986; and where the volume of EOR-produced oil in 2014 was about the same as that back in 1992, despite the large increase in oil price since then.

(iv). Heavy and Extra-heavy oils

a). Heavy oil needing thermal stimulation

Much heavy oil needs thermal stimulation if it is to be produced. One of the best examples is that of the Midway-Sunset field in California which was discovered in 1894, but which reached peak production only a century later; and where production increased with the number of wells drilled, and since the application of steam injection from the 1960s (Figure 7).

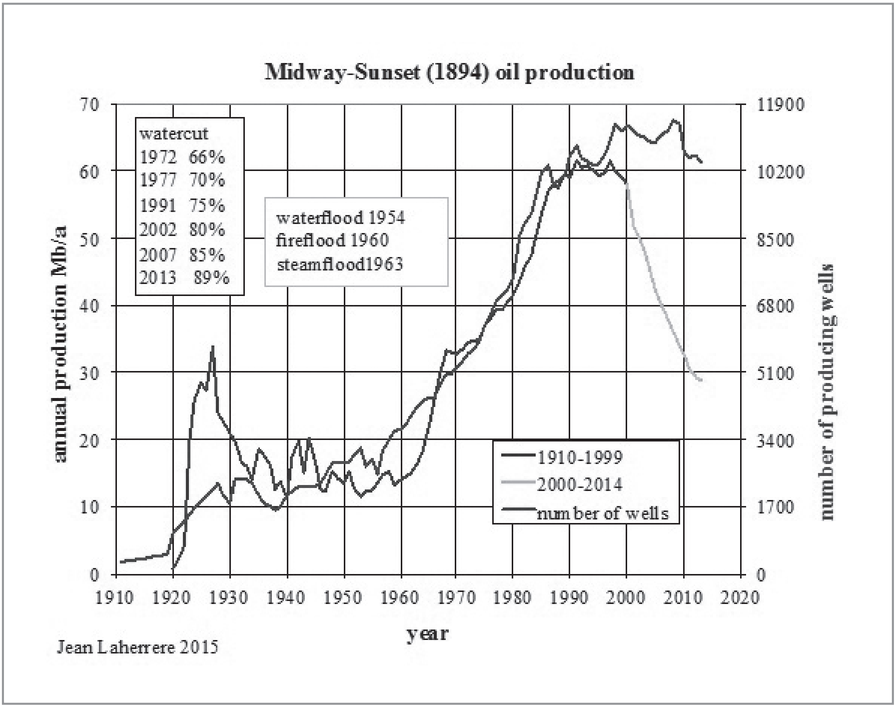


Figure 7: Production of Midway-Sunset heavy oil field, illustrating the increase in the number of producing wells, and the application of different oil extraction techniques.

b). Tar sands

The tar sands of Athabasca in Canada have been known since around 1750 when the area was opened up by the Hudson's Bay Company. Production of this oil started in 1956 (at 0.1 Mb/d), and reached 1 Mb/d by 2004, and 1.9 Mb/d by 2013.

About half of the oil produced is from open-pit mining, with the other half from *in situ* processing using steam injection (steam-assisted gravity drainage, SAGD). As of June 2014, the Canadian Association of Petroleum Producers (CAPP) forecasts Canadian tar sands oil production to be 2.3 Mb/d in 2015, 3.2 Mb/d in 2020 and 4.8 Mb/d in 2030. Note that this oil must be upgraded to reduce its viscosity before it can be run through a pipeline.

Constraints to current production are above-ground, i.e., economic constraints (the global oil price vs. tar sands cost to produce), pollution, authorization for pipelines, etc. The ultimate reserves (URR) of the Athabasca tar sands are about 250 Gb, but in terms of forecasting global oil production, as with some of the other non-conventional oils, the size of the non-conventional reserves does not matter so much as the size of the tap!

c). Orinoco oil

Orinoco extra-heavy oil is similar in gravity to Athabasca tar sands oil, but the former lies in reservoirs at a temperature of 55°C, against 5°C for Athabasca oil, giving the latter a high viscosity with no flow, and hence its classification of 'bitumen'. By contrast, Orinoco oil is fluid, and can be produced with cold production (for example, by a progressive-cavity pump, giving typically at start 1000 b/d per well), but with a much lower recovery (25%) than with steam injection.

The main problem of extracting the Orinoco oil is political. Chavez nationalised the efficient foreign companies such as Exxon and Total, and as a result production, which started in 1979 (and was sold as Orimulsion), rose from 0.1 Mb/d in 2000 to 0.8 Mb/d by 2008, but then has stayed below this level ever since. Note that the ultimate (URR) for Orinoco oil is about the same (in very round figures) as that for Athabasca oil.

d). Hence, total heavy oil

My rounded guess for the total URR of extra-heavy oil is 500 Gb, and with production modelled as peaking around 2060 at about 16 Mb/d. But note that the shape of the production profile of this oil, and hence the date of peak, and peak volume, is something of a wild guess.

(v). 'Light-tight' oil from fracking ('shale oil'), and oil retorted from kerogen

a). 'Light-tight' oil ('LTO') produced by fracking ('shale oil')

Our 1994 Petroconsultants report *Undiscovered Petroleum Potential* (with Perrodon & Demaison) was, as far as I know, the first to study the world's main petroleum systems, and hence to quantify the total generation of hydrocarbons, and also to derive an estimate for the ultimate of conventional oil.

Importantly, the report suggested that only about 1% or less of the total hydrocarbons ever generated will be produced, leaving 99% either in the original sediments, or lost at the surface. It is in part a reflection of this 99% figure that allows so many to now claim a huge potential for the shale oil plays, but where this confuses the up to 99% left as resources in the source rock with the *reserves* of this oil, accumulated mainly in fractures within the tight formations.

The US burst in production of LTO since 2009 was due to high price, and not to technology as horizontal drilling and hydraulic fracturing have been known for 50 years.

(Incidentally, US shale gas was produced in 1821 at Fredonia (New York State) for lighting to compete with whale oil costing about 1000 $2015/bbl. In recent times the production of shale gas was dropped when cheap oil occurs, and came back again with Barnett production when the gas price was high.)

b). Oil from kerogen ('oil shale' oil)

In contrast with light oil produced by fracking, this is the oil derived from the oil pre-cursor, kerogen, either by mining the rock in which it is held, followed by retorting; or by an *in situ* process.

Oil was produced from shale rock well over a century ago. For example, France produced oil from the Schistes d'Autun from 1831 to 1969, with a first peak in production at 250 b/d in 1866, a second peak at 250 b/d around 1900, and a last peak at 500 b/d in 1950. (Indeed, in 1859 France was producing ten time more oil than API records indicate was the case for the US!) China's oil shale production started in 1920 and peaked in 1960 at 16 000 b/d; while Estonia also started production in 1920 and reached 11 000 b/d in 1965.

In general the production of shale oil declined as the easier-to-extract oil from fields became available. Following the 1970s oil price shocks however, interest in shale oil returned, and in 1981 a potential 400 000 b/d project was reported by AAPG for the Piceance basin in the US. With the collapse of the oil price in the mid-1980s this project did not go ahead, but interest in shale oil never disappeared entirely, and a number of companies have pursued pilot projects over many years. Shell, for example, ran its US Mahogany project for over 25 years (using electric heaters in boreholes surrounded by frozen sediments) before it was closed in 2013 despite the return to high oil prices (an associated project continues in Jordan). An Australian oil shale project ran from 2000-2004.

The primary problem with shale oil is the economics, in part reflecting the technology's generally low return of energy to that invested (EROI). For example, in 2006 Shell reported that a full-scale plant using its then-current technology would return, over its full life cycle, about three to four units of energy for every unit of energy consumed.

c). Hence, total light-tight oil and oil from kerogen

In terms of data for the oil forecast model, I conclude that the world tight oil potential (both from fracking for 'light-tight' oil, and from retorting kerogen) is:

- small compared to the corrections needed for the 2P conventional oil reserves (for example, of fallow fields, and possible over-estimation of deepwater);
- already discovered; which is why I do not change the estimate of the 'crude less extra-heavy' ultimate;
- but where data on tight oil is indeed now included, in the sense that for example oil from the Bakken formation in Canada is included in conventional reserves.

(vi). GLTs, CTLs. Synthetic oil

For all these classes of oil (GLTs, CTLs and synthetic oil) I assume that, for reasons of production cost, production will be too small, at least over the near and medium term, to be included in the model.

(vii). Biofuels

Some have commented that agriculture is the process of 'transforming oil into food' thanks to fertilizer, tractors, irrigation, etc. Currently there is no clear agreement on the EROI ratio for corn ethanol, but it is likely to be close to or below 1; and only ethanol from sugar cane has a clear EROI ratio above 1. Nevertheless, in the model biofuels production is included, and is assumed to reach an asymptote of 3 Mb/d. (Note, I have reduced this figure; a few years ago my assumed biofuels asymptote was 6 Mb/d).

4. Model results

4.1 Global oil forecast results

Figure 8 shows the results from the oil forecast model described above for global 'all-liquids' production out to the year 2200, together with the corresponding forecasts for the various oil and other liquids components that sum to this 'all-liquids' total. As the figure shows, the model predicts that the peak of global 'all-liquids' production to be roughly about now, at around ~95 Mb/d or so.

Also shown in the figure, for comparison purposes, are 'all-liquids' forecasts from a variety of 'mainstream' institutions. As can be seen, the model presented here gives sharply different results to most of these other forecasts, as they show (except for the IEA's 450 ppm scenario) increasing 'business-as-usual' production curves, in contrast to the near-term peak of the model presented here.

A number of explanations for this difference between the model presented here and the other forecasts shown will be apparent from the discussions on the data used in this model, and its methodological approach, as set out in Sections 2 and 3 above. (I am given to understand that further exploration for the underlying differences in the various oil forecast results shown here, and also in comparison to a number of other current oil forecasts, will be covered in future issues of this journal.)

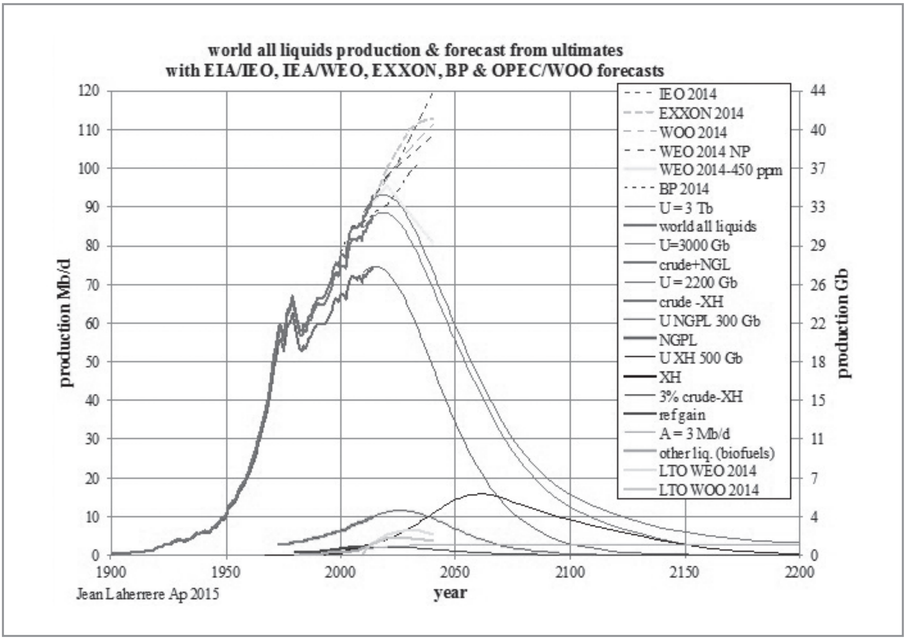


Figure 8: Production of global all-liquids supply, and forecast to 2200.

- Production of global all-liquids, 1900 - 2014.
- Forecast of global all-liquids supply 2015 - 2200, generated by the model presented in this paper, and based on URR values by category of liquid.
- Components of this forecast.
- Global all-liquids production forecasts generated by the US EIA, Exxon, OPEC, IEA and BP; and also IEA and OPEC forecasts for the production of 'light-tight' ('shale') oil.

Legend:

- IEO 2014: US EIA *International Energy Outlook* all-liquids forecast, 2014.
- EXXON 2014: Exxon all-liquids forecast, 2014.
- WOO 2014: OPEC *World Oil Outlook* all-liquids forecast, 2014.
- WEO 2014 NP: IEA *World Energy Outlook*, New Policies scenario all-liquids forecast, 2014
- WEO 2014-450ppm: IEA *World Energy Outlook,* Scenario to meet 450 ppm CO2, all-liquids forecast, 2014.
- BP 2014: BP *Energy Outlook* all-liquids forecast, 2014.

- U = 3 Tb: 'Hubbert curve' (logistic derivative curve) for a URR of 3 Tb *plus* addition of refinery gain plus production of 'other liquids' (modelled here as primarily biofuels, but conceptually including small amounts of oil from kerogen, GTLs and CTLs). This curve is drawn so that its upside roughly matches past actual all-liquids production, and its total area = 3 Tb *plus* the addition of refinery gain (increase in volume but not in energy) and other liquids. The figure of 3Tb itself results from summing a URR of 2200 Gb for 'conventional' oil (crude oil production including condensate but less the extra-heavies, and less NGPLs); plus a URR of 300 Gb for NGPLs; plus a URR of 500 Gb for the extra-heavy oils (primarily tar sands and Orinoco oil).
- world all liquids: World all-liquids actual production.
- U=3000Gb: 'Hubbert curve' for a URR of 3000 Gb (= 3 Tb) drawn so that its upside roughly matches past actual all-liquids production excluding refinery gain and 'other liquids', and its total area = 3 Tb.
- crude+NGL: Actual production of global all crude oil (comprising conventional oil, , heavy oils, tar sands and Orinoco oil and 'light-tight' oil), plus all NGLs.
- U NPGL 300 Gb: 'Hubbert curve' for a URR of 300 Gb drawn so that it matches past actual natural gas plant liquids (NPGL) production data, and its total area = 300 Gb.
- NGPL: Actual production of NPGLs.
- U XH 500 Gb: 'Hubbert curve' for a URR of 500 Gb drawn so that it roughly matches past actual extra-heavy oil production data (primarily tar sands and Orinoco oils), and its total area = 500 Gb.
- 3% crude – XH: A simulacrum of refinery gain, calculated as 3% of total crude production less the extra-heavies production.
- ref gain: Actual refinery gain data.
- A = 3 Mb/d: Modelled production of 'other liquids', i.e. liquids for fuels not included in the categories modelled above, and consisting primarily of biofuels, but also of assumed small contributions from GTLs, CTLs, synthetic oils, and oil retorted from kerogen either at the surface or in situ. Production is modelled as a curve reaching 3 Mb/d by ~2030, and holding constant thereafter.
- other liq. (biofuels): Actual production data for 'other liquids', primarily biofuels.
- LTO WEO 2014: The IEA World Energy Outlook 2014 forecast for production of 'light-tight' ('shale') oil.
- LTO WOO 2014: The OPEC World Oil Outlook 2014 forecast for production of 'light-tight' oil.

In summary, the global all-liquids forecast to 2200 shown in Figure 8 that results from the model described in this paper is derived from summing predicted production data based on ultimates ('URRs') for the different categories of oil, where the latter are estimated from extrapolation of adjusted industry 2P cumulative discovery data (creaming curves) where appropriate, and otherwise from extrapolation of cumulative production.

Specifically, the ultimates assumed are as follows:

- Crude oil (+condensate) less extra heavy oils: 2200 Gb, giving a production peak in 2010.
- Extra-heavy oils: 500 Gb, giving a peak in 2070.
- Natural gas plant liquids (NGPLs): 300 Gb, giving a peak in 2025.
- Refinery gain, calculated as 3% of crude production less the extra heavies production: 70 Gb.

A fifth and final contribution to all-liquids production is the 'other liquids', where here the main contribution is from biofuels. In this case the use of an 'ultimate' is not appropriate, being a renewable resource, and instead an asymptote of 3 Mb/d is assumed.

Taken together, these assumptions generate a global all-liquids production peak about now, and at a production level of roughly 95 Mb/d.

4.2 Oil forecast results by country

Currently, the model forecast is global. Though data are derived ultimately by field (or by project in the case of non-conventional oils), and hence also can in principle be split by country, currently no specific by-country forecast is generated.

4.3 Model uncertainty

The model described here gives a single-value prediction for what is intrinsically a very uncertain forecasting exercise, in part due to the poor quality of data currently available. This is true even within industry 2P databases, where for example as explained above, data on OPEC Middle East and FSU reserves are surprisingly uncertain.

In addition there is scope for considerable uncertainty on the rate that currently fallow fields may come into production; on the extra oil that EOR techniques will yield at a high oil price; on the likely rate that the various non-conventional oils will be brought on-stream; and on the effects of possible government-imposed limits on the production of the

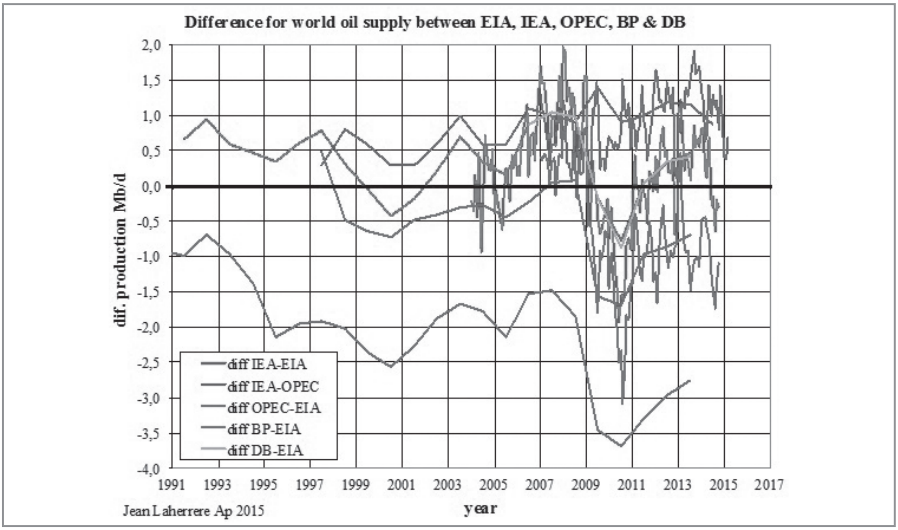


Figure 9: Differences in global oil production data from different sources.
We apologise to readers that the text of this Figure is not very distinct, though it does indicate the typical magnitudes of differences, in Mb/d, between the datasets. A clearer copy of this Figure will be provided in a future issue of this journal.

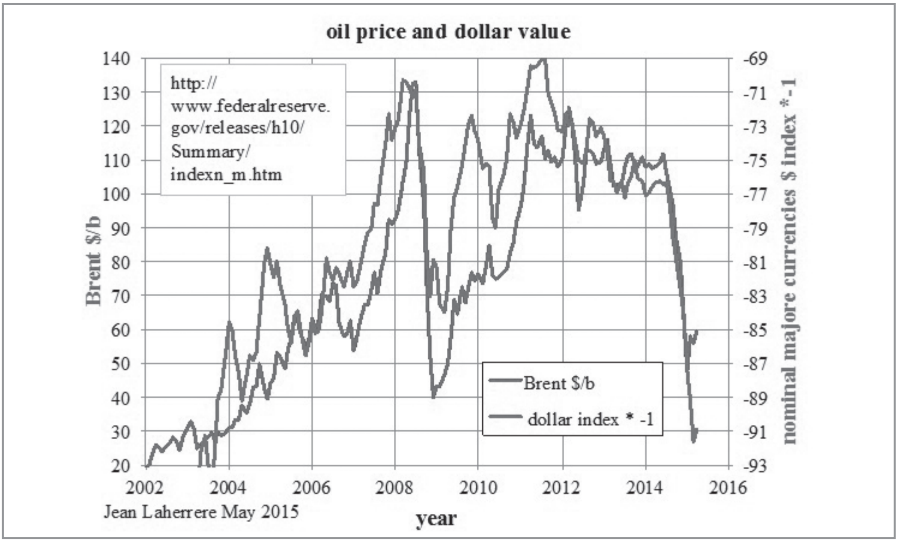


Figure 10: Correlation between Oil price and Inverse of US dollar index vs. other major currencies. Data source: see chart. Line starting at 2002: Brent price. Line reaching -69 in 2011: Inverse of dollar index.

non-conventional oils due to CO_2 concerns. Given these factors, I judge that the overall uncertainty on future oil production is probably of the order of 10 Mb/d.

Incidentally, the uncertainty on current oil production data, as derived from different sources, is not small at over 2 Mb/d, see Figure 9.

4.4 Demand

It is recognised that some analysts are not concerned about future oil supply on the assumption that global demand for oil will be less than the supply available. They see demand as rising less quickly than increasing supply, and falling in the near to medium term, due to increased vehicle efficiency, switching to alternative transport fuels (such as CNG or electricity), and to direct falls in demand resulting from a high oil prices, or from government fiat based on CO_2 concerns. Clearly such demand factors are in operation, or seem likely, but where the oil forecasting model described in this paper indicates that supply will be the near-term limiting issue.

5. Conclusions

This paper describes a global oil forecasting model based on multiple 'Hubbert' curves, and which uses adjusted oil-industry '2P' discovery data. The results indicate that a maximum ('peak') in the global production of 'all-liquids' is likely to be fairly close.

This peak is due primarily to 'below-ground' resource constraints. A high oil price can certainly encourage the discovery and production of additional oil, and also limit demand. It is also recognised that there is uncertainty in both the data, and the use of this relatively simple model.

The recent sharp decline of oil price is due to the weak demand, the strong LTO production and mainly the strong dollar value (see Figure 10 on the fairly good correlation since 2004 on oil price and dollar value). It is hard to forecast the value of any currency (and of the dollar in particular) in the long term.

But the general robustness of these data, and the reliability of this model in capturing past experience of the production of oil (and also other resources) in basins and regions, suggests that future global 'all-liquids' production is unlikely to be very different from that which the model indicates. The model thus serves as a useful warning of the situation that is likely to lie ahead.

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A Bottom-up Model of Future Global Oil Supply

RICHARD G. MILLER

1. INTRODUCTION

A *bottom-up* model is one which builds up a picture of the whole by summing its smallest practical individual components. When modelling future global oil supply, this usually means estimating the future production of each individual oil field and summing the results. A *top-down* model of oil supply instead forecasts global oil production as a whole, or in just a relatively few large divisions.

Top-down models, for example, may group fields into classes with different behaviours, such as by geological setting, terrain, climate, nationality or political affiliation. Some top-down models require a calculation or estimate of global or regional ultimate recoverable reserves (URR) and/or a rate of production decline after peak production; bottom-up models may derive these parameters from actual field behaviour.

This paper describes in detail one bottom-up model, built and maintained by the author over the past 15 years. It consists of a database of oil production from the world's individual oil-fields since 1992, with production projected out to 2040. Such models are powerful but have both practical and theoretical drawbacks. This paper will be explicit about their failings because they point the way to next-generation models. It also examines this particular model's historical accuracy in a series of annual snapshots over its lifetime.

2. MODEL CONSTRUCTION

2.1 Production and reserve data

The primary data requirement for a bottom-up oil supply model is the past production rate for each oil field or oil project. We define "oil" in this context as mobile crude oil or synthetic crude, excluding condensate and natural gas liquids (NGLs – largely ethane, propane, butane and pentane). For historical reasons we have always included all Venezuelan and Canadian production of extra-heavy oil, bitumen and synthetic crude. These were the only major non-conventional resources in production in 2000 when the model was first created, and their inclusion was both realistic and relatively easy. Light tight oil ("shale oil") is included by default because, in the US, its production rate cannot be easily be deducted from overall US crude production data (which our model records by State rather than by field). Thus this model includes conventional oil, tar sands, Orinoco oil and light tight oil, but excludes NGLs and condensates, oil retorted from kerogen (either above ground or *in-situ*), and also liquids produced from coal or gas, or from biomass (such as biofuel).

In the model the production rate is the annual average of the daily production rate, measured in barrels/day. The data set begins in 1992 which, when the model was first created, allowed for eight years of historical data, sufficient to establish the existing production trend for most fields. Data on remaining reserves are also useful for constraining future production rates, as will be discussed later.

There are various sources for production data but all are neither comprehensive nor entirely accurate. This model was first assembled under the aegis of a major oil company with access to several commercial databases, but none covered every significant oil-field for every year. Even some major fields were entirely omitted, presumably because no data had been released by the field operator. For some other fields the data for certain years were missing. The ultimate source and reliability of the data were usually not indicated, and it was often unclear exactly what liquids were included. These omissions probably reflect reluctance by many national authorities to release what they regard as sensitive or secret data (and also sometimes a lack of awareness or concern for accuracy).

In the model, the minor fields for each country are consolidated into a single group as "others", with net production equal to the difference between total national production and the sum of the major fields. Where field-level data are not obtainable, we use data consolidated by company, geological basin or national state as available.

There are public sources for certain oil production data, all of which are used to compile and update the model:

- The UK Department of Energy and Climate Change (DECC) publishes detailed monthly production data for every UK field[1]. Certain other OECD countries also provide very reliable annual production data by field. The US EIA only provides data consolidated into geographical subdivisions.
- Certain oil companies provide precise field-level production and/ or reserves data in their annual reports for countries where the authorities do not do so, for example Lukoil (albeit the data may be of unknown reliability).
- Some agencies provide occasional nuggets of data but not systematic compilations. Examples include the IEA (in their annual World Energy Outlook) and the EIA (in their country analysis briefs or CABs). The original data sources are sometimes not discussed.
- *Oil and Gas Journal* publishes for its subscribers each December a table of many of the world's producing fields, which at its best includes average daily production rate for the previous year, offshore/onshore location, fluid type, operating company, discovery date, depth, number of wells and API gravity. The table has sometimes been prone to typographical and other errors, and there is a growing tendency for production data to be amalgamated by production company, although this may be outside the journal's control. Its US data are amalgamated by State, its Chinese data largely by basin, and its Russian data by producing company.
- The Alberta Oil Sands Industry provides regular quarterly data on all Canadian oil sands projects, although tending to give capacity rather than actual production data[2].
- Company reports and technical presentations containing hard data can sometimes be found on-line. There are also several on-line oil industry news services that provide a daily news digest.

1 https://www.og.decc.gov.uk/fields/fields_index.htm

2 Most recently, see http://albertacanada.com/files/albertacanada/AOSID_QuarterlyUpdate_Winter2015.pdf

Comprehensive data on reserves are also difficult to acquire. We use the same sources as those above except *Oil and Gas Journal,* which only compiles "estimated proved reserves" data at the country level (these are presumably 1P data, and so suffer problems of under- and over-statement, and non-statement). Problems with reserves data include loose terminology by journalists who do not distinguish between oil originally in place (OOIP), reserves and resources. Some operators and national authorities also do not clearly distinguish between proven, probable and possible reserves; proven, probable and possible, are subjective numbers in any case as different organisations use different definitions and techniques. We always use proved + probable (= 2P, or $\approx P_{50}$) reserves data where available, which from experience are closest to the eventual cumulative production (Bentley *et al*. 2007).

Data are often inconsistent between sources. Differences in field production rates can arise from rounding errors or from the inclusion of condensates or NGLs, but others are not explained. Our model uses data from *Oil and Gas Journal* as the primary but not the sole source for field production data, and as almost the sole source for national total production data, to maximise the model's internal consistency. Once locked into a model, these choices cannot generally be changed without losing its historical insights. The national totals reported by the *Journal* are often significantly lower than those reported by other sources, notably the EIA and the BP Statistical Review, largely because the *Journal* excludes most condensates and NGLs and also because the journal omits numbers for some minor countries.

2.2 Oil Field Production Stages: Growth, Plateau and Decline

Oil fields have a typical production profile comprising a growth phase of several years, a plateau phase of several years, and a long slow decline phase which can last for many decades. The decline is often approximately exponential, i.e. the average production rate each year falls by roughly the same percentage value over the previous year. In general some 60-70% of the initial oil reserves in larger fields are produced during the long decline stage. It follows that, firstly, most of the world's currently operating oil fields are in decline or "post-peak", and secondly, that post-peak fields produce the bulk of global oil supply[3].

3 For this and similar background information used in this paper, the reader is referred throughout to Sorrell et al. (2009).

Our model follows these observations closely. Where a field is in decline, the exponential decline rate is calculated (as the mean of the past three annual rates where the data are available) and is then used to estimate future production rates. Fields on plateau are compared with neighbouring analogues to estimate when decline will commence, and an appropriate decline rate then applied for post-plateau production. Fields still in growth phase usually have a published target plateau rate which can be used.

If reserves data are available, we also compare a field's projected total production out to 2040 with the remaining reserves. Smaller discrepancies can be resolved by adjusting the production decline rate. Larger discrepancies are problematic, and some judgement has to be applied as to whether the estimated decline rate or reported remaining reserve is more likely to be correct.

2.3 Interpolation and Extrapolation of Data

Missing production data have to be interpolated between two known data points or extrapolated into the future from a single datum. Interpolations and extrapolations are clearly distinguished from known data in the data-base, by simple colour coding.

The most unreliable interpolations and extrapolations occur when national production is being depressed for reasons unrelated to simple field operations. For example, most Nigerian individual field data have not been published since 2006, but simple extrapolation since that date is complicated by a wave of increasing sabotage since about 2008, which dramatically reduced total Nigerian output. We do not know which of the hundreds of fields were affected by insurgent activity, or (field by field) by how much. Similar problems have affected Colombia, Libya, Iraq, Kuwait and Iran among others. Production from OPEC states has often been considerably lower than their full capacity, most notably in Saudi Arabia, but in this case for political reasons. Unfortunately we do not know which Saudi fields have been shut-in or are running at reduced output, but we know that current Saudi oil production, which is historically high, may still be significantly less than capacity. The most important field data in bottom-up models are often the least reliable.

2.4 Undeveloped Fields

Discovered but undeveloped fields are incorporated into the model using published or modelled data for dates and rates of future production.

The promoters of fields in development usually announce the expected production rates and anticipated date for coming on-stream, data which can be added very simply to the model. Of more interest are the many discovered but undeveloped fields with no known development plan. Our model assumes that undeveloped fields are always brought on-stream more or less rapidly, according to their location and local practice and regardless of oil demand or price, but some may be undeveloped for good reasons. Recently discovered but currently inactive fields may simply be awaiting their turn for financial sanction, but we have to wonder whether some of those discovered longer ago have deeper underlying problems. For example, some fields may be geologically or technically too complex, or too far from existing infrastructure, to be economic. Some might become economic if the oil price rises, if other adjacent discoveries are made, if technology improves or if new infrastructure is built nearby, but some may prove never to be exploitable. In the worst cases, some fields may have a net energy yield <1 ("EROI", or energy return on energy investment) and never be exploitable at any oil price.

Miller (2012) showed that 173 Gb of 2P global oil reserves listed in a leading proprietary database (13% of the total) were either in appraisal or awaiting sanction, or were simply listed as "discoveries" without further qualification. 58 Gb of these unqualified "discoveries" had been known for more than a decade, with some dating back before 1960, without apparently moving any further along the development chain. Other fields have seemingly been in appraisal or awaiting sanction for decades, without revision of their status. Miller (2012) concluded that perhaps 105 Gb of reserves worldwide are contained in such *fallow fields*, those long-undeveloped fields which will probably always be uneconomic. Since 2012 we have started removing certain older, smaller, remote and/or complex undeveloped fields completely from the model, where we think these are likely to be permanently beyond economic exploitation.

2.5 Conventional Oil in Undiscovered Fields (Yet-to-find, or YTF)

There is no consensus on exactly how much conventional oil (generally taken as mobile oil that has migrated to distinct fields) remains undiscovered, or where it is, but future discoveries must be incorporated into the model in some way. The *ultimate recoverable reserve* or URR is the sum of (1) the cumulative past production, (2) current reserves, (3) future discoveries and (4) "reserves growth", an increase in oil recovery over time that arises from improvements in knowledge and technology. Future discoveries can be modelled by simple extrapolation from past discovery patterns, or else derived from independent estimates of URR and discoveries to date.

Published estimates of reserves, URR and YTF are difficult to compare because different authors include or exclude certain non-conventional oils, condensate and/or NGLs, and use different assessment methodologies for URR. Estimates of conventional oil already produced as of today are largely consistent at about 1350 Gb, but estimates of the ultimate recoverable conventional oil resource have ranged for some years between about 1900 Gb (for Campbell's 'Regular conventional oil) and 3345 Gb (USGS year-2000 estimate, including NGLs) (Sorrell *et al*, 2009). Two current global reserve estimates are 1688 Gb (BP 2014) and 1647 Gb (*Oil and Gas Journal*, 2014) but both estimates include some 360 Gb of undeveloped Canadian oil sands and Venezuelan Orinoco extra heavy oil. Mainstream estimates of the amount of conventional oil remaining to be found therefore range up to 700 Gb.

We currently assume that some 200 Gb of conventional, economically exploitable crude oil remains to be found, which is allocated country by country. For comparison the USGS mean estimate of undiscovered oil resources fifteen years ago was 649 Gb (Ahlbrandt *et al.* 2000) and subsequent rates of discovery suggest that this was an over-estimate (Klett et al., 2005). Our model uses past estimates by the USGS and others, modified according to subsequent discovery volumes, actual discovery rates and professional opinion. We use a simplistic model of discovery whereby 5% of a nation's YTF is discovered annually for the first 6 years, 4% annually for the next 6 years, then 3%, 2% and 1% for subsequent 6 year tranches. Our estimate of YTF was 376 Gb in 2000 and 235 Gb in 2010; it would have fallen to about 203 Gb in 2010, according to the discovery model, if no revisions had been made in that decade. It is now about 200 Gb.

Newly discovered fields are assumed to be brought on-stream rapidly according to national standards, ranging from perhaps five years for remote off-shore or undeveloped mountain areas, to one year for highly developed basins with good existing infrastructure; but we accept that this is perhaps rather optimistic. Each country's future annual discovery tranches are modelled as a single new field each year, with production that peaks and declines according to one of four simple general models which are based on whether the annual tranche is large or small, and whether it is located largely on- or off-shore.

2.6 Technological Improvements to Oil Production

A criticism sometimes levelled at mechanistic, numerical models such as the model presented here is that they cannot or do not take into account improvements in technology, which can range from new exploration technologies to horizontal drilling and reservoir control additives. In the past our model made a very small specific allowance for such change, by increasing each annual forecast production rate by a factor of 0.2% over the raw estimate. The 0.2% factor is based upon unpublished work by Francis Harper (pers. comm.), who some years ago estimated that global production was rising by 0.15% year-on-year for reasons of technical improvement.

However, our model now contains some 20 years of actual historical data. Obviously the technical improvements made during that time are reflected in those data, and we suspect that extrapolating forward in time from those data automatically incorporates further continual, incremental improvement due to better technology and knowledge. Therefore, as of this year, a separate factor for technical improvement in future production rates will not be included in the model.

An exception to this approach would be if the oil price were to be high, ~$100/bbl (or even higher), for long enough for the annual gains in productivity due to the use of enhanced oil recovery (EOR) techniques to be significantly greater than has been the case in the past. While this is conceptually possible, we suspect that such high (or very high) oil prices would instead be more likely to limit the demand for oil.

2.7 Non-conventional oil

As mentioned earlier, the model includes production of some but not all of the non-conventional oils. It includes oil from tar sands, Orinoco oil, and light tight oil currently obtained by fracking of shale and related rock. None of these oils can be modelled in the manner appropriate to production of conventional fields, and in general their production must be forecast by when specific projects for their extraction are likely to be brought on-stream. For these oils, production, reserves and 'yet-to-find' are handled as follows.

Canadian tar sands

The tar sands form reasonably continuous deposits which are divided into numerous project areas. The projects are conceptually relatively simple to model. Project details are declared well in advance of production and published by both company and official sources. Some projects involve strip mining with a constant rate of output until exhaustion. Others are produced *in situ* by various local-scale heating technologies to reduce their viscosity, but because the heating is applied to small blocks within a project area and moved on as each block is exhausted, production levels are likely to prove quite constant until the whole project area has been exploited. Both forms of recovery are thus expected to result in projects which remain on their plateau production levels throughout their life. Reserves data for the smaller projects are not always available.

Venezuelan extra heavy crude

Venezuelan extra heavy crude is quite similar to Canadian tar sand bitumen, but the surface rocks are colder in Canada than in Venezuela because of the climate, so the Venezuelan oil is somewhat less viscous *in situ*. Consequently much extra heavy crude can be produced relatively conventionally, using long horizontal wells, although there is also considerable effort under way to use heating or dilution to improve flow rates and recovery. Project production forecasts are given in public literature.

Although much Venezuelan extra heavy crude will be produced by relatively conventional techniques, the model currently treats the Venezuelan deposits as behaving like tar sands projects, at constant plateau production rates to 2040. There are usually sufficient declared reserves to sustain such a production profile. However, it is likely that these deposits will ultimately decline post-2040 like conventional oil fields with a long slow decline, rather than like tar sand mines with an abrupt end when the deposit is mined out.

Light tight oil

To date, light tight shale oil ('LTO') production is an onshore US phenomenon, occurring within a few large sedimentary basins. LTO production data from the EIA is recorded by basin, but conventional onshore production is generally compiled by State, which are the data used by the model because field-level data are not available. Because the shale basins can extend across several States, it is impossible to know precisely how much production in such States is conventional and how much is not, so LTO production cannot be modelled separately. The problem is compounded because some shale basins also have conventional production from some areas. At present, therefore, the model uses State-level production data which includes both conventional and non-conventional oil. LTO wells are only marginally profitable at current oil prices and have extremely rapid decline rates, typically 50% per year; the future production profile of LTO will therefore be very largely determined by oil price and demand on almost a month-by-month basis, and remains an unresolved modelling problem.

3. MODEL RESULTS

3.1 Current Model

The most recent model for the world as a whole is illustrated by the chart shown in Figure 1, which includes most data to date.[4] Producing countries have been compiled by OPEC or non-OPEC status, and YTF oil has been distinguished. It also shows the factor which reflects future technological improvement on discovery and production (in future this factor will be discontinued as discussed earlier).

The historical data set between 1992 and the first model run in 2000 should of course be identical every year, but it shows a slight increase with time. The two principal reasons are the more recent inclusion of minor oil-producing States for which data was not previously available, and the occasional need to follow subsequent corrections made in the published data.

We have sometimes had to adjust national production data to match field level data. The field level production rates for each country should sum up to the national production rate, but occasionally they apparently exceed the national rates as published by *Oil and Gas Journal*.

The most notable feature in Figure 1 is the forecast decline in the total global production of the classes of oil included in Figure 1 from shortly after about 2020.

A second feature is the 'hump' in future oil production, which commences in 2013 at the start of the projection into the future. This

4 Field level production data from *Oil and Gas Journal* for 2013 were unobtainable until the end of 2014, and are not yet fully incorporated into the model's data.

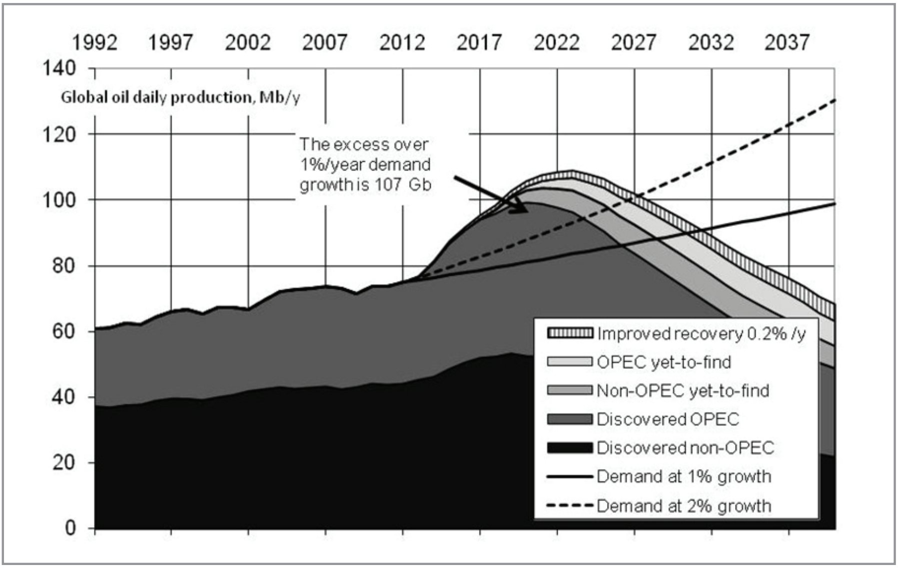

Figure 1: Output of the Global oil forecast model, updated to today. Oil production includes conventional oil (oil in fields), tar sands and Orinoco oil, and 'light-tight' oil from fracking. It excludes production of NGLs and condensate, oil retorted from kerogen, GTLs and CTLS, and oil from biomass (including biofuels).

hump reflects an excess of some 107 Gb over the projected oil demand, should the latter increase at 1% p.a., which is a typical current estimate of demand growth. The hump is primarily generated by known but undeveloped fields which are modelled to come on-stream over the next five years. As discussed earlier, we have some doubts about 105 Gb of oil reserves contained within "fallow fields" ever being commercially exploitable. Other such reserves are certainly real, developed and ready to go on-stream but are simply not required yet, such as some smaller Saudi Arabian fields.

If much of this 105 Gb of oil currently in 'fallow fields' does not come on-stream as shown in Figure 1, total global production of the classes of oil included in the Figure is likely instead to exhibit a 'bumpy production plateau' at around 80 Mb/d or so, from roughly about now. However, if such a plateau occurs, decline after this plateau may be less steep than the rate of decline shown in the Figure of ~3% per year.

3.2 Historical Model Accuracy

Every year since 2000 the author has taken snapshots of the model to be able to examine, analyse and improve its long-term accuracy, and its shortcomings. The summary of future global oil production forecasts is shown in Figure 2. Note the production hump that starts at the end of each model period. This hump has been a feature of the model since its first inception, probably because it contains many of the same group of undeveloped discoveries every year. As the model has been continually updated and improved, the hump gradually achieved a largely consistent size and shape in about 2005. The projected peak of conventional oil production is consistently some eight to nine years ahead of the model date, ever since the first model run in 2000. The last model run in Figure 2 is from end-2012, and its peak is 2021. This behaviour is what might reasonably be expected if the hump represents a block of fields which are either undevelopable or placed on hold for many years for political reasons: each hump will always have the same general size and shape.

4. STRENGTHS AND WEAKNESSES OF BOTTOM-UP MODELS

We do not think our model differs materially in its concepts from most other current bottom-up models, so we may consider the properties of the model type as a whole, based on our experience of this example.

4.1 Strengths of Bottom-Up Models

The first great strength of the bottom-up model is that it makes the fewest assumptions:

(i) Top-down models must assume, explicitly or implicitly, a value for global (or regional) reserves, where bottom-up models use field-by-field reserves. These should be the same but are not, because field data throw up many cases where actual production data do not support the stated reserve data, which can be too low or too high (stated reserves which are far higher than required to support a declining production are not impossible but are often unreasonable). The global reserves data will also probably include certain fallow fields which on balance are unlikely to be developed, and Middle East OPEC official reserves which are often regarded as suspect. These problems can be addressed individually in the bottom-up approach.

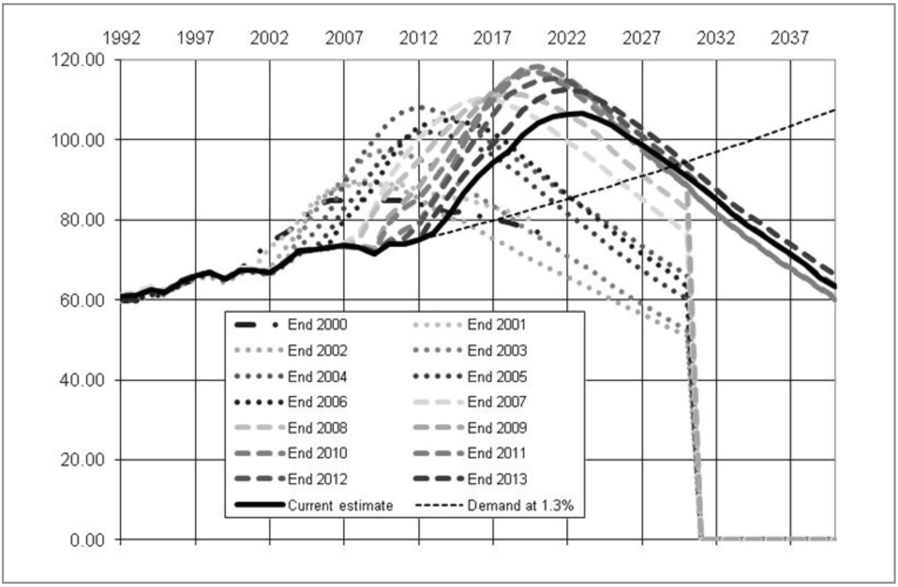

Figure 2: Historical actual global oil production, and forecasts of future production. The forecasts were made annually from end 2000, and extend to the interim forecast for end-2014. (For classes of oil included in the forecasts shown here, see notes for Figure 1.)

(ii) Both model types must make similar assumptions about YTF, although bottom-up models will likely be able to include greater granularity – by basin rather than by country for example.

(iii) Both model types require post-peak decline rates. These are often made explicit in the bottom-up model, which has numerous individual post-peak fields to act as templates, where the top-down has to use a single average for all fields, derived from observed decline rates. When a bottom-up model finds individual field decline rates which do not match expectations from reserves, they can be adjusted or examined further to find any external, above-ground effects biasing the data. Further, when considering a simple historical country production profile, we cannot distinguish between a situation of high field decline rates offset by a high rate of new field development, and a situation of low field decline rates with low rates of new field development. The past profiles will look similar, but their future profiles will differ as new discovery rates and developments fall away. Bottom-up models measure and must honour actual field behaviour.

The second great strength is a greater understanding of actual field behaviour which can be applied when projecting into the future. It has become clear to us, for example, that EOR generally increases the amount of oil recovered, by slightly reducing the field decline rate and extending its productive life; however, in some fields, EOR seems to increase the rate at which the reservoir is drained without greatly increasing the eventual total recovery. We can also see directly in the model how offshore fields are exploited faster than onshore fields, and smaller fields are evidently engineered for faster decline rates than larger fields.

4.2 Weaknesses of Bottom-Up Models

The failings of bottom-up models must be acknowledged, and these are largely the effects of poor data and/or external influences. The greatest of the latter are financial, political and geological.

Bottom-up models suffer from incomplete data. For the more significant fields without production data, estimates must be made. Smaller fields, as noted previously, are conveniently amalgamated into one group with an output fixed by the difference between larger fields and national total production, but this fails when the larger fields alone apparently produce more than the whole country (where different data sources are used for fields and for the country as a whole). By contrast, top-down models frequently use national total production data, which are usually officially published by national authorities and are in that sense complete. Governments have reason to provide reasonably accurate summary data for reasons of taxation, investment attractiveness, national and party political prestige, production quotas etc. Of course different countries include or exclude different liquids such as condensates or NGLs, or liquids consumed as fuels during the production process, causing some inconsistency between different sources for some data. There is also the chance of an approximate crude external audit, because oil exports and imports and refinery runs cannot be realistically hidden, and domestic consumption can be estimated.

The financial weaknesses of simple bottom-up models are clear. Our model assumes by default that all known undeveloped discoveries will be brought on-stream within a few years, for want of a better model. This generates a production hump in the near future in every annual projection, a surge which has never yet materialised. The model takes no account of the external financial environment, the effects of which include (1) the ranking and financial viability and future development (or not) of undeveloped discoveries, (2) the rate of exploration effort and the discovery of new reserves, and (3) the ranking and rate of investment in sanctioned projects, which can be postponed or speeded up. To give an example, in the first half of 2014, with a sustained high oil price, exploration budgets were comparatively high, and a string of postponements made since 2008 in some developing Canadian oil sand projects had been reversed. Such projects should have the effect of ensuring a higher oil supply capacity some years in the future, because they have lead times of a few years to perhaps a decade. Today, with the oil price now halved, exploration budgets have been dramatically cut and new oil sands projects are again being subjected to delays, and this in turn indicates that in the *further* future there may be a dearth of new supply capacity. The oil industry, with its long lead times for new supply capacity, has always displayed a well-known cyclicity in this regard. This cyclicity cannot be accounted for in simple bottom-up models; it requires the imposition of a set of price/cost/demand scenarios.

A second financial effect is that oil production must vary according to demand, and demand in turn is subject to effects such as price, economic growth or recession, efficiency gains in oil use, and regulation requirements as climate change moves up the political action agenda. The size and influence of future demand is missing from the bottom-up model, which treats it as a known and predictable parameter.

Political effects can include for example sanctions, OPEC output quotas and insurgent activity. Bottom-up models cannot easily take quotas into account; we rarely know which fields may be throttled back if quotas are cut, nor with any accuracy how much extra capacity might be brought on-stream if quotas are raised, nor when such a change in quotas may next arise.

Geological influences are another aspect of the financial influence. A recent manifestation has been the development of light tight oil in the US. Although the existence of such oil was well known geologically, few foresaw that a combination of high oil prices, specific US regulatory conditions and improved drilling technology would result in development of this resource, let alone such rapid development. Light tight oil was not a feature foreseen in our model, and is exceedingly difficult to incorporate now.

The financial problems of the old generation of bottom-up models such as this are acute, and it is pleasing to see the development of a new generation capable of adding an economic dimension, such as that by McGlade (McGlade, 2012). These still require a detailed field-by-field and project database, but incorporate scenarios for the investment requirements, the price consequences and the subsequent effect on demand and economic growth.

5. CONCLUSIONS

The simple bottom-up model, in our view, has certain advantages over the top-down model, despite the difficulty of acquiring sufficient and accurate data. It certainly gives the user a deeper understanding of how oil fields behave. Nevertheless we feel that such simple models, which take no account of price and demand implications, have largely run their course, insofar as they cannot materially improve in their current form. The new generation of bottom-up models which include an integrated analysis of financial and economic constraints and considerations should prove more effective and reliable. Such models take a view on likely global economic paths of growth or decline, with their effects on oil price and investment in the production industry. Global demand is modelled, from the likely future price of oil adjusted for investment in new supply, and global economic trends. Because demand, supply and price are all interdependent, the new model iterations and assumptions will be formidable.

In tandem with the broader economic picture, a better model needs considerable granularity in deciding where the available capital should be invested, between countries and between different projects in those countries. The projects will include exploration, primary production and enhanced oil recovery techniques, and will need to be ranked by economic return as well as output capacity. It will be a severe challenge, and one which may perhaps be overtaken by the game-changing effects of the incipient peak in conventional oil supply, the rapid technical improvement of renewable energy generation, and the recognition of the regulatory challenge to all fossil fuel production which may be imposed by climate change.

Author Details

The author writes: "I worked in BP from 1985 to 2008 as a geochemist, geologist and records manager, but also tended to be given exploration problems/projects which fell outside the company's normal business expertise. From 2000 to 2008 I wrote a short internal annual report on future oil supply for the company. Since retirement in 2008 I've still been looking at future global oil supply, with some interests in non-conventional liquids as a consequence. I was a co-author of the UKERC report of 2009 on Global Oil Depletion (Sorrell *et al.*, 2009), and Invited Editor of the recent *Royal Society Phil. Trans.* issue on '*The Future of Oil Supply*' (Miller and Sorrell, 2014)."

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Explaining the Price of Oil 1861–1970: The need to use reliable data on oil discovery and to account for 'mid-point' peak

R.W. BENTLEY[1] AND Y. BENTLEY[2]

Abstract

This paper explains the price of oil, in broad terms, from 1861 to 1970. Over this period the oil price was influenced by many factors, including technological progress, market forces and actions by governments and cartels. But we point to a main factor as being the amount of conventional oil (i.e., oil in fields) that had been discovered. Over most of this period the quantity of oil discovered in fields ran far ahead of demand, and this in turn led to chronic potential over-supply. A variety of methods was used by industry and by governments to try and control the oil supply, and hence to prevent the oil price from falling to ruinous levels.

To understand this potential for over-supply of oil over this period requires reliable knowledge of the rate that conventional oil was being discovered. This information, unfortunately, cannot be derived from the widely-available public-domain *proved* ('1P') oil reserves data, which have been very misleading, and instead must come from the oil-industry backdated proved-plus-probable ('2P') data. Accessing the latter data, however, has generally been difficult or expensive.

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Examining the potential for oil over-supply also requires an understanding of the decline in the production of oil in fields that occurs typically once a region's production 'mid-point' is passed. This 'mid-point' peak results from a region's field-size distribution, its fall-off in discovery, and the physics of field decline.

Lack of understanding these two factors; the quantity of conventional oil discovered, and the 'mid-point' peak, has led in our view to incomplete explanations for the price of oil.

1. Introduction

This paper sets out to explain the price of oil, in broad terms, from 1861, that is, from around the start of significant US drilled commercial oil production, up to the year 1970. A related paper (Bentley & Bentley, 2015) continues this explanation for the period 1971 to the present day.

Figure 1 shows the price of oil between 1861 and 2013, in both money of the day ('nominal', or current-terms), and after adjustment for inflation (real-terms). Data are from the BP *Statistical Review of World Energy,* 2014 edition.

Despite obvious caveats with such long-run data, it is clear that there have been three significant periods of high real-terms oil price (taken here as a real-terms price >$40/bbl): prior to about 1880, from 1973 to 1985, and since 2004. At other times the price has mostly been below this level, with a marked long period of generally declining price from 1920 to 1973.

There have been numerous attempts to explain the price changes shown in Figure 1, often relating to longer or shorter date sequences within the period shown. A brief review of some of the more recent literature in this area is given in Bentley & Bentley (2015). Generally, the explanations for the price of oil seem to have been sought from correlations with economic indicators, examination of the oil available as indicated by proved ('1P') reserves, or from analysis of external factors such as imputed OPEC behaviour, etc.

In our view, the explanation for the price of oil over the period covered by Figure 1 needs, in addition, to include several factors that tend to have been under-recognised in the literature. These are:

- the difference between conventional and non-conventional oil;
- the need to have a reasonably reliable indication of the amount of

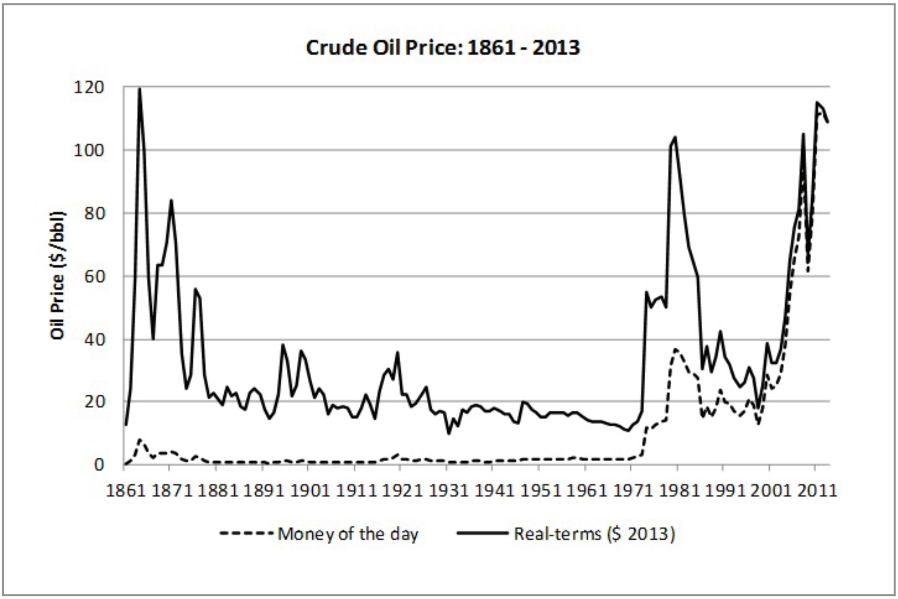


Figure 1. Crude oil prices (in money of the day and in real terms): 1861 to 2013.

Data: 1861-1944: US average; 1945-1983: Arabian Light posted at Ras Tanura; 1984-2013: Brent dated. Source: BP Statistical Review of World Energy, 2014.

Notes:

The chart in the BP Stats. Review annotates significant events effecting oil price.

The oil price at the start point of this chart is somewhat misleading: Prior to the US 1859 Drake well, oil in the region from 'surface springs and salt wells' was selling at a today's real-terms price of from $750 to $2,000/bbl. By the end of the following year, due to the resulting Pennsylvania oil boom, the local price of oil had fallen to $50/bbl in real-terms, and as low as a $2.50/bbl real-terms by the end of 1861. But then a combination of reduced drilling, a tax on alcohol (an alternative illuminant) and the effects of the Civil War caused the oil price to rebound sharply, as shown in the Figure (Hamilton, 2011).

Slightly different data are given in the chart on page 792 of Yergin (1991).

conventional oil discovered at any given date; and

- the need to account for the 'mid-point' production peak of this class of oil.

We recognise that knowing the amount of conventional oil discovered has been difficult for many analysts because of the difficulty in accessing the relevant oil industry data, and we suggest that this has contributed to some of the past historical weakness in the analysis of the price of oil. In addition the 'mid-point' peak in production has often been poorly understood.

The next section looks in more detail at these factors, and also at a number of other factors, that have affected the price of oil.

2. Background Information for Explaining the Oil Price

2.1 Conventional oil vs. non-conventional

(Note that this section, and Section 3.2, is taken from Bentley and Bentley, 2015.)

In this paper we make a critical distinction between conventional and non-conventional oil. This is because it has been the quantities of *conventional* oil discovered at different points in time which, along with technological progress, has been the main driver of the oil price over the last century and a half.

The term 'conventional oil' takes many meanings, but here it is adequate to take it as referring simply to *flowable oil in fields*, i.e., oil within a trap that under a 'standard' drive mechanism (own-pressure, mechanical lift, or gas- or water-drive) is able to able to flow to a production well. The bulk of all oil production currently, and by far the largest part of that historically, has been of conventional oil.

By contrast, 'non-conventional' oils tend to be found in extensive regions (within which there may be 'sweet spots'), and where flow to a production well is not possible without significantly changing the nature of the oil (for example, by heating, or treating with a solvent), or the surrounding rock (for example, by fracking, or sometimes by mining). Such oils include 'light-tight' oil, very heavy oils, oil from tar sands, and the oil pre-cursor kerogen in shales and other rocks.

(Note that oil *production* data often include not only conventional and non-conventional oil, but also 'other liquids', such as natural gas liquids, 'NGLs', coal or gas to liquids, and sometimes biofuels.)

The reasons for making the distinction between conventional and non-conventional oil are twofold: production cost, and energy return:

Production cost

We need to ask why, over the last century and a half, have we used in the main conventional oil (i.e., oil in fields), rather than oil from the many non-conventional sources that exist, and where some of the latter (such as oil from biomass, and from coal and kerogen) were used extensively before conventional oil came to dominate? The answer is simple: Up until now the oil in fields has usually been far cheaper to produce than these other oils. This is because oil in fields flows easily, is concentrated geographically, and often yields large flow rates when produced by relatively simple drive mechanisms, such as its own pressure, gas-drive or water-flood.

For example, in terms of flow rate, while the 1859 Drake well in the US yielded up to about 20 barrels of oil per day (b/d), only two years later the first major US gusher yielded 4,000 b/d, and in 1901 the Spindletop field in Texas flowed at 100,000 b/d. In these early years such flows were often short-lived, but subsequently large fields have typically yielded over 500,000 b/d for considerable periods of time; while the Middle East giants produce 1 million b/d and above, and the world's largest field, Ghawar, averages over 5 million b/d. Thus, once located, oil from large oil fields has generally been intrinsically cheap to produce due to relatively easy production methods and high flow rates.

While it is true that the 'petrol tank does not care' what type of oil (conventional or non-conventional oil) is used, the user certainly does. The user would far prefer pre-1973 conventional oil at its long-term real-terms average price of $15/bbl, or even post-1985 average price (up to the 2004 increase) of $30/bbl, than to have to pay ~$60/bbl for US light-tight oil, or the > $160/bbl for the 'Canada oil sand mine upgraded' oil cost estimated by IHS–CERA, or the full cost - whatever it will be - of retorted kerogen oil plus carbon capture, or of synthetic fuel made from electrolysis of water plus CO_2.

Energy return

A second reason to distinguish conventional oil from non-conventional is that nearly all of the non-conventional oils have lower energy returns than conventional oil. The data are hard to establish unequivocally, but Hall and Day (2009) suggest that the ratio of energy return on energy invested (EROI) for conventional oil was about 30 in the 1930s, rising to 40 in the 1970s as scale increased and technology improved, and subsequently falling, with the more difficult conventional oils, to a ratio of perhaps 14 today. By contrast, nearly all non-conventional oils have lower energy ratios; tar sands, for example, being quoted as having ratios of from 1.5 to 8, and corn ethanol also low. Since Hall *et al.* calculate that modern society will have difficulty in functioning if its fuels have energy ratios of less than perhaps 5 to 10, the current transition from mainly conventional oil to increasing quantities of non-conventionals is likely to be significant.

2.2 1P reserves vs. 2P.

Next we look at the difference between 1P and 2P reserves (see also Bentley *et al.*, 2007). The *reserves* of an oil field give an estimate of the amount of recoverable oil remaining in the field at a given point of time. The *resource* of the field, by contrast, refers to the total amount of oil in-place, and thus includes the oil that is recoverable and unrecoverable. (By volume average, perhaps some 40% of the global oil-in-place in fields is recoverable under reasonable technological and economic assumptions.)

For a region comprising a number of fields, there are also fields yet to find. Here the term 'reserves' refers only to oil that has been discovered. The resource for a region, by contrast, includes the estimated amount of oil yet to be discovered. Thus at a given point in time, a region's ultimately recoverable resource (URR) is given by:

URR = cumulative production to-date + reserves + recoverable oil yet-to-find

but this estimate can be expected to change with the recovery technology used, and the price of oil.

Public-domain proved ('1P') oil reserves data

Annual summary tables of oil reserves data given in the public domain are usually of *proved* (1P) reserves, for example those in the BP *Statistical Review of World Energy*, the annual tables in *World Oil* or the *Oil & Gas Journal*, or on the US Energy Information Administration (EIA) website.

Although such reserves data are used in company reports they have been extraordinarily misleading on the actual quantity of oil discovered, especially in the past, and they generally cannot be used to forecast oil production despite many analysts having done just this. The problems with proved reserves include under-statement, over-statement, and non-statement. Instead, the oil industry *proved-plus-probable* (2P) reserves data must be used. Both categories of reserves are discussed in more detail in Appendix 1.

2.3 The 'mid-point' production peak of conventional oil

Though it has long been known, still too often overlooked is the fact that production of conventional oil in a region typically reaches its '*resource-limited*' maximum and subsequently declines when *only roughly half* of the region's recoverable resource of such oil has been extracted. Three factors taken together provide the basic mechanism for this: the region's field size distribution, its field discovery sequence, and the physics of field decline. A simple model that explains the mechanism of 'mid-point' peak, and also why this peak is counter-intuitive, is given in Appendix 2.

3. Factors Influencing the Price of Oil: Over-supply, & Other Factors

3.1 Over-supply: The discovery of too much conventional oil

So now the question is: What does the above information (conventional vs. non-conventional oil; 1P vs. 2P reserves, and mid-point peaking) tell us about the price of oil?

The answer lies in Figure 2. This gives the cumulative backdated 2P discovery data from 1900 to 2011 from one major industry source (IHS Energy), and compares these with the cumulative production data over the same period.

As Figure 2 shows, from 1920 (and possibly from before, but where clearer pre-1920 2P data would be needed) up until around 1965 (the inflection point of the discovery curve) the discovery of *conventional* oil as measured by backdated 2P data raced far ahead of production, and put large quantities of conventional oil 'in the bank' as 2P reserves.

But the rate of conventional oil discovery peaked around 1965 (some fifty years ago) and from that date forward increases in production were catching up on declining discovery. Even so, up until about 1980, the rate of discovery was still the greater, and hence the volume of oil 'in the bank' as 2P reserves was still increasing. But about 35 years ago, around 1980, global production finally caught up with discovery of oil in new fields, and from that point onwards the reserves of conventional 'in the bank'

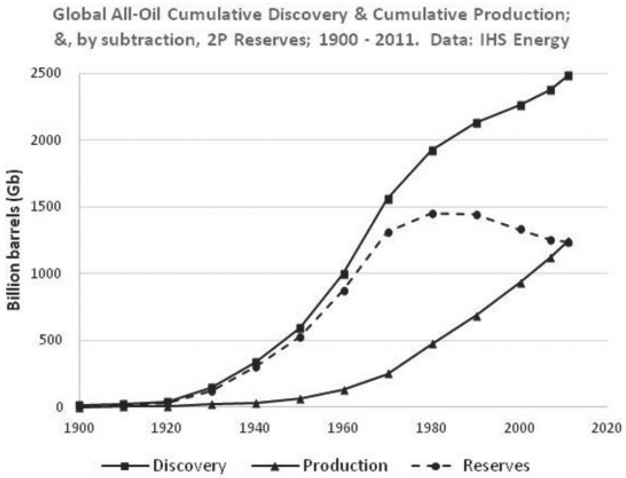


Figure 2: Plot of oil-industry backdated mainly proved-plus-probable ('2P') data for global cumulative 'all-oil' discovery vs. corresponding production, 1900 - 2011.

Notes:

- Data are from IHS Energy, and are 2P except for the US and Canada where the data are proved ('1P') data.
- Both discovery and production are for IHS Energy's 'Liquids' category, and hence comprise: crude oil, condensate, NGLs, light-tight oil, very heavy oils, oil from tar sands, and Orinoco oil. These data exclude liquids from GTLs, CTLs, biomass, and refinery gain.
- The plot is generated by reading data at 10-year intervals from Figure 7 of Miller and Sorrel (2014) for cumulative discovery from 1900 to 2007, and from the corresponding Figure 3 for cumulative production over the same period. Included in this plot are the data for end-2011 as given in the text of Miller and Sorrell.
- IHS Energy data are for oil in fields for conventional oil; and as announced in projects for non-conventional oils. Data are largely for conventional oil up until about the year 2000, after which significant amounts of tar sands and Orinoco oil projects were included, and most recently also data for 'light-tight' oil projects.
- Note that the 2P data are backdated in that they reflect information available to the IHS Energy as of 2007 (for the discovery curve), and to 2011 (for the final discovery data point).
- Reserves data are calculated here (as also by IHS Energy) by simply subtracting cumulative production from cumulative discovery, and therefore are 2P reserves data (except for US & Canada).
- As the plot shows, the global proved-plus-probable (2P) all-oil reserves at end-2011 were ~1250 Gb. This contrasts to the corresponding end-2011 value for global proved only (1P) all-oil reserves (from BP Stats.) of 1652 Gb. The difference, as explained in the paper by Laherrère in this issue of The Oil Age, is likely to be mainly in the probable overstatement of Middle East OPEC proved reserves; plus differences in the non-conventional oil quantities

started to be drawn down, although allowance must also be made for technologically-driven 2P 'reserves growth'.

Today, as Figure 2 shows, this long period of potential global over-supply of *conventional* oil (oil in fields) is drawing to a close. Though there still remains today about 50 years' worth of 2P reserves of conventional oil 'in the bank', the 'mid-point' rule says that production of this oil is close to its decline. This can be seen from the Figure, where a reasonable extrapolation of the 'conventional oil only' discovery curve (i.e. the curve up to about the year 2000) might be seen as some 2500 Gb for the global conventional oil URR, and where production of this oil has reached roughly half of this, at about 1250 Gb. Though the actual details of the global oil peak are complex (see Bentley, 2015b), this simple calculation says that the peak of global conventional oil production must be close.

The final question of this section is then: How have these long-term discovery and production trends affected the price of oil? As Figure 2 shows, the entire period from at least 1920 up to about 2004 has been one of *potential* over-supply of conventional oil, because much more of this class of oil was discovered over this period than was used; and hence it has been this potential for over-supply that has helped keep the price of oil low for most of this period. (Note that the relatively brief period of high oil price from 1973 to 1985, due in part to the US peak, is discussed in Bentley and Bentley, 2015.)

For much of the period of Figure 2, from at least 1920 up to 2004, the potential for over-supply of oil has been at least partly managed, variously, and to a greater or lesser degree, by the following:

- quasi-monopoly of supply in both the US and Russia in some of the very early years;
- subsequently by agreements, often imperfect or short-lived, between oil companies;
- by government encouragement, or government edict; such as in times of war, or the long period of US pro-rationing;
- by the 'Severn Sisters' husbanding production in major oil provinces overseas;
- and mostly recently, up to about 2004, and even today to some extent, by OPEC control.

It is a fascinating story, and Section 4, below, gives greater detail on the period 1861 to 1970.

3.2 Other factors that have influenced the price of oil

Of course other factors, in addition to the quantity of conventional oil discovered and the mid-point peak, are also important for understanding the price of oil. Three of the more general of these are: improvements in knowledge, improvements in technology, and the need to access the more difficult oil. These are described in more detail in Appendix 3.

4. Explaining the price of oil: 1861 to 1970

With the information of Section 3 now in place, we are in a position to address the main aim of this paper: to explain in broad terms the evolution of the oil price between 1861 and 1970. Note that the following is based in large part on Yergin's outstanding book *The Prize* (1991). It would be hard to imagine a better-written or more insightful description of the history of oil, with its dramatic twists and turns, deep political implications, and fascinating cast of characters. In the following, references to Yergin are given simply as: (Y, page x). Mention must also be made of the excellent papers by Hamilton, including Hamilton (2009 and 2011).

4.1 1861 to 1900: Boom & Bust before the Motor Age

Prior to about 1900, oil was used for mainly lighting. In terms of price, in the mid-1800s whale oil in the US typically went for between $500 and $1500/bbl in today's money, depending on catch and demand (Pees, 2015). Poorer lighting oils came from a wide variety of sources, including coal, and were generally somewhat cheaper. The advent of kerosene from 'rock oil' changed the picture dramatically, and gave cheap lighting to the many.

Oil production from 1861 to 1900, especially in the US, was an age of boom and bust, resulting in significant oscillations in the price. A key factor in the US was 'flush production'. Once a new petroliferous province opened up, the 'rule of capture', lack of knowledge of any field's probable lifetime, the presence of multiple independent operators, many mobile workers, and simple greed meant that individuals and companies had every incentive to produce a region as fast as drilling would allow.

Note that while there were plenty of 'busts' in production that applied to individual fields (and to the economic life of towns that relied on these fields) overall production generally (though not always) increased, and large price oscillations generally resulted when supply significantly outpaced demand.

The first US supply boom was that of Pennsylvania. Following Drake's well in 1859, oil production grew rapidly, reaching ~0.45 Mb/y in 1860, and 3 Mb/y just two years later. Not surprisingly, over-supply ensued, and the oil price fell dramatically, from $10/bbl in January 1861 to 10 cents/bbl by the end of that year. But demand for the new wonder lighting oil soon caught up, and the price was back to $7.50/bbl by September of 1863 (Y, p30).

New fields led to serious over-supply in the 1870s, and numerous attempts were made to agree curtailments in production. All came to naught however, primarily because of the large numbers of players involved and their typically independent outlook (Y, p42)

As Figure 1 shows, from 1880 the oil price swings became less severe. This was partly because the price-setting supply/demand balance had begun to become international. The US was shipping kerosene to Russia and Europe as early as the American Civil war (Y, p30); while the other major producer, Russia, saw production expand nearly 20-fold in the decade 1874 to 1884 (from 0.6 Mb/y to 10 Mb/y), with its own exports starting from around 1882 (BP, 2014).

A significant factor in oil's price in these early years, both within the US and internationally, was the growing ownership by Rockefeller's Standard Oil Company. At times this amounted to near-monopoly; initially of oil refining and transport, and later of supply to some degree. The issue was finally partly addressed by the US 'trust-busting' legislation against Standard in 1911 (Y, p110). There is no doubt, however, that though the combine's commercial practices in terms of trying to force reluctant partners to join the Standard camp were often brutal, its willingness to expand rapidly, make large speculative investments, standardise product, and market aggressively allowed it to introduce new technologies and achieve major efficiencies of scale that led in turn to dramatic reductions in product cost, and hence in the price to the consumer.

Crucially around this time, new US provinces began to open up. Ohio and Indiana in the mid-1880s, then Colorado and Kansas, then California and Texas in the 1890s. (Note that California had short-lived discoveries in the 1860s; while production from Texas in the 1890s was only small.) Outside the US, oil was found in Sumatra in 1885; and in Borneo in

1897, with its first gusher in 1898 (Y, p116). By contrast, also in 1897, the Sumatran wells began watering out, and 110 dry holes followed before a big new field was found in 1899 (Y, p118).

No-one should underestimate the immense amounts of capital and effort it took to find and produce oil; with this leading later to the intrinsic tension between the oil companies and concession holders that became a near-permanent feature of the industry. In terms of the price, though supply increased rapidly in the 1890s, so too did demand (including from the Boer War in 1899 (Y, p117)), and the price kept generally high.

Despite the booming production, seeing what could happen to individual fields and to regions, there were many voices of caution; and the fear was always of shortage. In 1885 the State Geologist of Pennsylvania warned that "the amazing exhibition of oil" from Pennsylvania's 'Oil Regions' was only "a temporary and vanishing phenomenon – one which young men will live to see come to its natural end" (Y, p52).

This view (though probably premature in its timing) was substantially correct: Pennsylvania's 'amazing exhibition' did indeed come to an end within a young man's lifetime, when its production of conventional oil peaked in the late-1930s (at ~19Mb/y). Production then steadily declined, falling as low as its 1860 volume (3 Mb/y) by the second 'oil shock' of 1978. Small resurgences in production resulted from the high price then, and post- 2002, but the State Geologist's 1885 view of inevitable decline of oil from fields within 'a young man's lifetime' was essentially correct.

4.2 1900 to 1920: Oil price in the early Motor Age

From 1900 a major change in the oil market took place as result of innovations having roots in the 1880s. In 1882 Edison had demonstrated commercial electrical generating plant and lighting, while in 1886 Karl Benz had patented the petrol-powered car. From 1900 the impact of these inventions was becoming significant: car registrations in the US, for example, rose over 100-fold from 1900 to 1912 (8,000 to 902,000, Y, p80), and globally gasoline sales, mainly for vehicles, first exceeded those of kerosene, mainly for lighting, in 1910 (Y, p112).

Markets had a new reason to grow rapidly - provided supply could keep up.

Supply could indeed increase, on the back of major new discoveries: In January 1901 Spindletop in Texas came in as 75,000 bbl/d gusher, sending the local price of oil down to 3 cents/bbl; oil was discovered in Oklahoma in 1901 (and in its Glenn Pool in 1905), and significant first discoveries occurred also around this time in Louisiana and North Texas.

Outside the US, major finds were made in Persia in 1908, and in the 'Golden Lane' in Mexico in 1910. But overseas demand and supply also had its risks: famine in Russia in 1900 reduced its demand for kerosene, which was then dumped on the world market impacting the global price (Y, p117), while the 1905 revolution in Russia's set her main producing fields, in Baku, ablaze.

Despite such uncertainties, throughout the early part of this period, over-supply became the dominant concern, and to prevent disastrous price cutting many agreements and 'near cartels' between companies were discussed, and some enacted. For example, fears of potential competition on the supply side led Burmah Oil in 1905 to bow to pressure from the UK Admiralty to rescue D'Arcy's concession with the Shah in Persia; while on the marketing side, and partly triggered by rising production in Rumania, Deutsche Bank joined the Nobels and the Rothschilds with their Russian oil to form the European Petroleum Union in 1906, which then cut deals between themselves and with Standard Oil over market share (Y, p132). Over this period, the oil price roughly halved, from about a today's real-terms $35/bbl to under $20/bbl.

However, concerns about over-supply waned dramatically with the First World War, during the course of which the oil price doubled, back to a peak of about $35/bbl. The connection between waging war and the need for a secure supply of oil was becoming apparent. Churchill's decision in 1912 to turn the UK Navy's new capital ships to oil burning is well known; perhaps less so were the many steps by governments around the world, but primarily by Russia, the US, the UK and France, both before and during the First World War, that were aimed at obtaining security of oil supply. Clemenceau had declared that gasoline would be "as vital as blood in the coming battles", and efforts to secure and manage wartime supply included the UK's 1914 decision to invest £2.2 million (in money of the day) in Anglo-Persian to obtain 51% of its stock, the setting up of an Inter-Allied Petroleum Conference during the war, and likewise of the US Fuel Administration (Y, p161, p178).

After the war (when US motorists had to endure 'gasolineless Sundays'), increasing evidence of decline in known basins, coupled with recognition of the growing importance of oil to economic activity, reversed the pre-war concern about oversupply to that of almost-certain shortage.

In 1919, the director of the US Bureau of Mines predicted that "within the next two to five years the oil fields of this country will reach their maximum production, and from that time on we will face ever-increasing decline." The USGS warned of a possible "gasoline famine", and that US known oil reserves would be exhausted in nine years and 3 months. President Wilson noted that: "There seemed to be no method by which we could assure ourselves of the necessary supply [of oil] at home and abroad." The oil price supported these fears: in the US the oil price rose 50% between 1918 and 1920 (from $2 to $3/bbl in money of the day), and the winter of 1919-20 saw a shortfall in oil supply (Y, pp 194-5).

What was to be done? Should the US (then producing two-thirds of the world's oil) fall back on oil from shale, and likewise the UK on oil from coal, as some advised, or should industry explore more overseas? Now strongly backed by their various governments due to lessons from the war, the industry chose the latter.

4.3 1920-1970: The Long Price Decline

Despite these widespread fears of shortage, from 1920 the oil price entered a remarkable fifty-year period of on-average steady decline.

What happened? Firstly the US reserves data quoted by the USGS were *proven* reserves, where these were much less than the known reserves that had actually been discovered. (On *proven* reserves, the US R/P ratio has remained fixed at close to 10 years of supply for well over a century – misleading many analysts to the present day!). Secondly, significant finds were made in the US, including Signal Hill in California, the Greater Seminole field in Oklahoma in 1926 (which yielded 527,000 bbl/d), and the Yates field in Texas which opened up the US Permian Basin (Y, p223). Thirdly, production overseas continued to grow. Russian oil had been constrained, first under the Tsar and then by the 1917 revolution, but in the 1920s it began ramping up again. Elsewhere oil production also flourished, from the East Indies, Persia, Rumania and Mexico, and now also from new finds in Venezuela.

The problem for the producers thus became not one of shortage, but how to manage over-supply. This led to the Achnacarry 'As-Is' agreement of 1928, where participating companies agreed quota in different markets based on existing market share; and later also agreed actual production levels. In the event there 'were too many producers, and too much production, outside the 'As-Is' agreement for it to work' (Y, p265), but nevertheless a variety of marketing deals and understandings enabled the oil majors avert much in the way of major price wars.

The over-supply situation worsened with the discovery of the East Texas field in 1930. With a URR of ~6 Gb, this remains the largest conventional oil field discovered in the US Lower-48, and its discovery helped set the global oil pricing regime for the next forty years.

In East Texas itself the oil price collapsed, falling from an average of $1/bbl in 1930 to 15 cents/bbl by May the following year. This, coupled with a similar price collapse associated with the Seminole field in Oklahoma a little earlier, finally concentrated minds, and between about 1933 and 1935 Harold Ickes with Roosevelt's strong backing was able to formalise 'The Oil Code' that brought about prorationing of much of US production (Y, Chapter 13). Prorationing had been suggested earlier in the US on the back of fears of oil shortage, and hence of the need to manage output to prolong field life, but had always been vociferously defeated, mainly by the independents. The heroic alignment of interests that finally secured the measure is summarised in (Y, pp 258-9).

On its actual mechanism, Wikipedia (accessed 9th Feb. 2015) writes:

> *"Allowable oilfield production was calculated as follows: estimated market demand, minus uncontrolled additions to supply, gave the Texas total; this was then prorated among fields and wells in a manner calculated to preserve equity among producers, and to prevent any well from producing beyond its Maximum Efficient Rate (MER). Scheduled allowables are expressed in numbers of calendar days of permitted production per month at MER."*

Although this related specifically to Texas, under the control of the Railroad Commission the Texas allowable took into account production in other US states; and some of these in turn had their own prorationing mechanisms. The result was near US-wide prorationing of production from the mid-1930s; and for which, to stem a potential flood of imports, a tariff on oil imported into the US was needed, enacted from 1932 (Y, p 258).

After the price fall of 1930/31, Figure 1 would seem to indicate a long period of market stability and calm.

In fact this was very far from the case, and three major new forces began to play out in the oil markets of the world; the surprise being that the oil price reacted so little. These forces were nationalisation, big new finds, and arguments over rent; and there was also the matter of oil disruption in the Second World War to contend with. We discuss these in turn.

(i). Nationalisation

The UK government's 1914 purchase of a stake in oil production was described earlier; and Russia had nationalised much of its oil industry in 1918, though later Lenin had to open this up to outside help. In the years 1920 to 1971 covered in this paper there was a spate of nationalisations: Bolivia in 1937 (and again in 1969), Mexico in 1938, Iran 1951, Brazil 1953, Iraq 1961, Burma and Egypt in 1962, Argentina 1963, Indonesia 1963, and Peru in 1968. (Wikipedia, accessed 12 Feb. 2015).

The motives were various, and the periods before and after each nationalisation were usually extremely fractious and difficult both for companies and governments alike. Part of the motive was undoubtedly transferring rent from the producing companies to government (see below); but simple national pride, and the desire of leaders (particularly despots) to secure support at home by blaming outsiders also weighed heavily. For example, Mexico's struggles concerning nationalisation, and its impact on the oil companies, and on production, were fairly typical, and are described in (Y. pp231-233, and pp271-277).

(ii). Big new finds

A second major factor that one would have thought would have had a dramatic effect on oil price over this period was the very large new finds in the Middle East. Using data from Nehring (1978), which he cautions were often low estimates, Middle East fields with URR's over 10 Gb were discovered in this period as follows: in Persia: Gach Saran, discovered in 1928, URR = 16 Gb, Agha Jari (1938, 14 Gb), Ahwaz (1958, 18 Gb), Marun (1964, 16 Gb) and Fereidoon-Markan (with Saudi. Arabia) (1966, 10 Gb); and in Iraq: Kirkuk (1927, 16 Gb) and Rumaila (1953, 20 Gb).

As for oil in the Arabian peninsular, as late as 1926 some in the industry considered the region "devoid of all prospects" (Y, p281). But a small find in Bahrain in 1932 was critical, as it indicated that oil could also be found on the Western side of the Persian Gulf. Large finds here were: Kuwait: Burgan (1938, 72 Gb); Saudi Arabia and the Neutral Zone: Abqaiq (1940, 13 Gb), Ghawar (1948, 83 Gb), Manifa (1957, 11 Gb), Safaniya (1951, 30 Gb), and Barri (1964, 12 Gb); and Abu Dhabi: Zakum (1964, 12 Gb). By the time DeGolyer, following a mission to appraise the oil potential of the Persian Gulf, reported to Washington in 1944 (i.e., even before the discovery of Ghawar) he suspected total Middle East oil reserves could be up to 300 Gb. Indeed, the State Department was told by a member of the mission that: "The oil in this region is the greatest single prize in all history" (Y, p393).

(iii). Rent

Third in this list of factors that would be expected to impact oil's price during the period of the 'long price decline', we include arguments over rent. Although early nationalisations were partly about rent, it was perhaps only after the start of major finds of the Middle East that the issue of the division of rent between producer companies and governments came to be approached on a consistent basis.

Rent had been moot of course from the beginning. If a government granted exploration and production rights to its land, and a company then brought in expertise and risked very large investments, how should the potential rent be split? In the early days in the Middle East, for example, concession fees were often set simply by how empty were the coffers of the concession giver. Later, once oil was found and being produced, the topic became subject to ever-more fraught negotiation, with each side often deeply suspicious of the other.

Yergin gives a good description of the problem. Eventually, in many cases, both sides came to accept the concept of a 50:50 split; producing companies and owner governments each getting roughly half of the profits from the oil. Venezuela was the first to follow such a formula in 1943, and others followed. However, after a while even this became contentious, with oil-owning governments noting that the *countries* of the oil companies were getting the majority share, via company profit *plus* government taxes, and new formulae were requested.

The stage was set for OPEC. The latter had been set up in 1960, modelled on the Texas Railroad Commission concept of prorationing. Initially not particularly effective, OPEC's resolve was strengthened when global oversupply led first BP, and later Jersey [Exxon], to seek to reduce the *posted* price of oil, and hence undermine the 50:50 formula. But when OPEC tried more than once to raise prices *prior to1973*, the US opened its taps and the global supply balance was restored.

(iv). The Second World War

Finally we look briefly at the impact of the Second World War on the oil price. Readers wanting to understand this war could do a lot worse than look at Yergin's excellent coverage, where access to resources (oil in particular) explains much of the causes of the war, and also some of the major strategies adopted within it. However, despite massive disruptions in supply, this time, unlike in the First World War, there was little impact on the global oil price due to cooperation, planning and controls. In the war itself, oil was to prove crucial. For the Axis powers, despite programmes to produce oil from coal in both Germany and Japan, military activity slowly ground to a halt due shortage of oil; while for the allies' supply was always just adequate, in significant part due to production from the East Texas fields.

5. Discussion

In this Section we look at the information above in rather broader terms.

5.1 Price stability from 1920 to 1970

Given the information above, the question thus remains: How, for 50 years from 1920 to 1970, in the face of nationalisations, super-giant finds in the Middle East, shifts in the distribution of rent, and global war, did the oil price remain on its apparently placid downward path for so long?

The answer during the Second World War (as indeed partly also the case in the First) was almost certainly in large part because of the bodies set up by the allies to allocate oil supply, ration demand, and control price. But in the two long peacetime periods before and after this war, it is harder to identify definite causes.

Among these, however, must be the following: the fundamental global oversupply throughout this whole period as described earlier; the impact of the great depression from 1929 in reducing growth in demand; the major impact a little later of US prorationing, smoothing the price consequences of changes in supply and demand; and, especially in the years after the Second World War, market control by the 'Severn sisters' oligopoly in trying to prevent over-production (often against the wishes of the owners of the oil!) by the main Middle East producers.

5.2 Why was there potential over-supply?

It is a deeper question, and one of economic theory, to ask why was there this potential for over-supply: Why would oil companies spend oil exploration effort and dollars when already too much oil was to hand?

The answer is provided by the details within Yergin's *The Prize*:

- Sometimes the large reserves were held by a company with a small market, and vice versa, so that a company in the latter category needed to look for more.
- Sometimes it was simply the entrepreneurial spirit of 'independents' to look for more; originally the relatively small independents in the US fighting Standard Oil, and then fighting the US majors that appeared (many spawned from Standard). But subsequently the 'independents' were the smaller (but still large) newer oil companies (ENI, for example) that were prepared to take on large exploration risks in order to break the market stranglehold of the very large incumbents.
- Also, as Campbell notes, for commercial companies exploration is fully tax deductible, and hence can be nearly free to these companies.
- But almost certainly the main reason to keep finding ever more oil, even when the global 2P reserves were already large, was that once the reserves were 'overseas' (outside of the US; or both within or outside Russia in the case of the main Russian suppliers), these reserves were not nearly as large as they seemed. Such 'overseas' reserves were always at the risk of higher rent, nationalisation, or complete loss (from the oil company's point of view) from embargo, revolution or war. Yergin has good sections on how CEOs of the oil majors saw these risks. Thus, counter to a pure 'economic' view, there was *always* a strong need for individual companies to find more oil.
- And in this context, in terms of reserves, it is important to differentiate an 'Adelman' view of 'oil reserves being just inventory', to always be replaced as and when needed (a view, it must be admitted, solidly supported by the data on the apparent continual replacement of *proved* (1P) reserves, especially in Canada and the US; but in the UK and many other places also) from the reality of the proved-plus-probable (2P) reserves of conventional oil (oil in fields) being decidedly finite, and in decline since about 1980.

5.3 What should we expect for the future price of oil?

Finally we look briefly at what the information given above tells us about the likely future price of oil.

Since about 2004, proximity to the global peak of conventional oil production (indicated by Figure 2, combined with the 'mid-point' rule) has limited the availability of this class of oil, and required most of today's marginal barrels to come from the non-conventional oils; pushing the real-terms oil price back up to the levels of the 1970s (Figure 1).

As noted earlier, conventional oil is generally *intrinsically* cheaper to produce than the non-conventionals (indeed some which it largely displaced a century-and-a-half ago; those of biomass, and oil from kerogen and coal), because of its general ease of production, at least from large fields once discovered, due high flow rates; and lack of the need to alter either the oil itself, or the surrounding rock or other material, for it to flow to the well.

Once the conventional oil peak is passed, there are indeed many types of non-conventional oil that can be produced, some with potentially large resource bases (see Chart 2 of *The Oil Age*, vol. 1 no. 1). But it is not clear that the generally lower energy returns, high intrinsic costs, large investment requirements, and generally higher CO_2 emissions of these non-conventionals will allow them to compensate for conventional's decline.

As a result, we suggest that it is likely that the price of oil will remain high, on average, unless dramatic change occurs in both the production and cost of the non-conventional oils, or if global oil demand declines substantially for climate change or other reasons.

6. Conclusions

Overall we conclude as follows:

- In the early years of oil supply, from 1861 to perhaps 1900 or so, production was often characterised by 'boom and bust', with production decline in one region being offset by flush production from a new region. As a result, the price of oil fluctuated substantially.
- But from about 1920 (and maybe from before that date) the predominant situation turned to that of potential over-supply of conventional oil (oil in fields), as total discovery of this oil raced ahead of production.
- To see this discovery trend it is necessary to access the oil industry backdated proved-plus-probable (2P) data.

- As to why oil companies would go looking for more oil when plenty was already to hand is an interesting question of resource economics. The answer is discussed in Section 5.2, above, but where the main reason was probably that these apparent large reserves were never secure (at least from the point of view of an individual oil company) being at risk of higher rent, nationalisation, or loss from embargo or war. There was thus always a need to find more oil.
- To counter the resulting potential for over-supply, a wide range of mechanisms were enacted by the oil industry and by governments to prevent the oil price from sinking too low. These included, for example, the Achnacarry agreement of 1928 and US prorationing.
- This period of potential over-supply of conventional oil is now drawing to a close. Though today there still remains large global reserves of such oil, the 'mid-point' rule says that production of this oil is close to its decline. Proximity to this peak has required that most of the recent marginal barrels to meet demand have been of non-conventional oil, pushing the real-terms oil price back to levels last seen in the 1970s.

Caveat

The authors recognise that information provided in this paper is tentative in a number of respects. In part this is because the canvas is large; in part because some of the topics, particularly on the economics of resource supply, are not well known to us; and in part because there are questions that remain unanswered. Feedback to improve future versions of this paper is welcome.

Acknowledgements

This paper could not have been written without immense amounts of time generously given by many practitioners in the field. A partial list is given in Chapter 4 of Campbell (Ed.) 2011. Our thanks go to all of them; and also to the reviewer whose comments significantly helped improve the paper.

Appendix 1: 1P Oil Reserves Data vs. 2P

Proved (1P) oil reserves data

As noted in Section 2.2, analysts should not use the proved oil reserves when considering either past or future oil production. The problems with these data are many:

- In the early years of oil exploration, particularly for large US and Canadian fields, the size of proved reserves reflected limited knowledge of the fields, and also simply the extent that fields had seen production drilling.
- In most cases today proved reserves oil data are *understated*, i.e. they are conservative estimates of the actual reserves. This is part simply because the data are *proved* (notionally 'P90%' values), rather than the more-likely mean or 'P50%' values of the proved-plus-probable reserves. Also aggregation of P90% values significantly underestimates the total at the same level of probability for statistical reasons. And proved reserves can also be low for other reasons, such as fields not yet being sanctioned. In the UK, for example, total proved ('1P') oil reserves have long stood at only *about half* the corresponding value given by industry proved-plus-probable ('2P') reserves.
- In some OPEC Middle East countries the reserves are probably *overstated* (see, for example the article by Laherrère in this issue, and also Figure 2 above).
- For many countries the data are *not stated*, in the sense that the reported data are not changed from year to year.

Oil industry proved-plus-probable (2P) reserves data

Instead the 2P reserves data should be used. Such data can be gathered for individual oil fields from a wide variety of published industry data sources, but with considerable effort. Large commercial *by-field* 2P datasets can instead be purchased from firms such as IHS Energy, Wood Mackenzie and PFC Energy, where the data have been assembled and checked, and where there is also much proprietary information.

Fortunately, simpler 2P datasets are available at moderate cost, for example extremely useful *by-country* 2P data are available from IHS Energy's 'PEPS' database (where researchers should use the version with data back to 1834, and note that the US and Canada data are only 1P).

Some collected 2P data now are in the public domain. For example, 2P data for adjusted 'Regular conventional' oil for a wide range of countries are in Campbell (2013), and excellent plots of past and forecast production (but not of discovery) for all oil-producing countries, based on detailed by-field 2P data are free on the Globalshift website (www.globalshift.co.uk). In addition, Rystad Energy's UCubeFree facility gives past and future production by-country, but again not of discovery, based presumably on their estimates of 2P data. Additional detail on 1P and 2P oil reserves is given in Appendix A of Bentley & Bentley (2015).

Comparing global 1P oil reserves data with 2P data

The main difference between 1P and 2P oil data is simply, as mentioned, that the former cover only 'proved' estimates; and also are subject to the various errors listed above. By contrast, the industry 2P reserves data reflect what are intended to be best estimates of the mean or 'P50' values for the fields or regions concerned (and where, for individual fields, industry practice was often to assume the sum of 1P reserves in full, plus two-thirds of 2P reserves, plus one-third of 3P as the best estimate of a field's size).

A second difference is that the 1P data are generally given on a *current* basis, i.e. are estimates made on the data available in the year for which the reserves are quoted. 2P data, by contrast, are generally *backdated* data, such that a 2P estimate of reserves for some prior year includes *today's* information on the reserves that would have been available at that year.

These two effects, conservative values for the 1P data, and the backdating of the 2P data, lead to very different evolutions of the global reserves data over time, and this, in turn, has led to different analysts drawing very different conclusions about the future availability of oil.

Specifically, for largely conventional oil, the size of global 1P reserves showed a steady ever-upward trend until 2002, and has since increased more sharply still due to inclusion of the proved reserves for tar sands and Orinoco oil. By contrast the industry data for global 2P reserves of conventional oil show that these reserves peaked in about 1980, and have been in steady decline since (see Chart 4 in *The Oil Age*, vol. 1 no. 1), and for the 2P data, Figure 2 above. It is no wonder that different analysts drew such different conclusions.

Appendix 2. The 'mid-point' production peak of conventional oil

This appendix gives a simple model to explain the mechanism of 'mid-point' peak, and also to show why this peak is counter-intuitive.

Assume a sedimentary basin containing conventional oil, where this oil is in many discrete fields of a wide variety of sizes. These fields can be ranked by the size of their initial reserves, based on the basin's field size distribution, as shown schematically in Figure 3. As can be seen, this basin has many fields, each reducing in size by 10%.

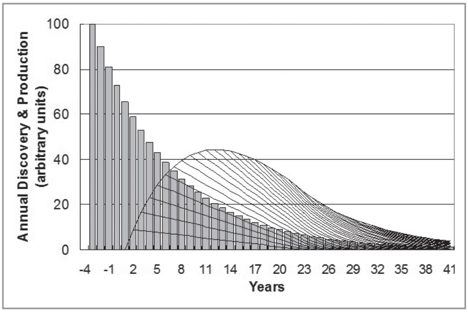
Next we need to look at discovery. At first the petroleum geology of the basin may be little understood, and a few unrelated discoveries made. But pretty quickly a pattern sets in which typically the largest fields are found early because they are (usually) the easiest to find, and are also put into production first as they give the best return on investment.

Now we examine production from an individual field. In practice this can take many profiles, but typically - certainly with newer fields and smaller fields - production tends to ramp up fairly quickly to a peak or short plateau, and then decline away, often approximately exponentially. A true exponential decline would result if the oil flow were driven simply by an expanding gas cap combined with an unchanging production column; and, correspondingly, a steady flow would result from a fixed-pressure water or gas drive in a truly homogenous reservoir. But reservoirs are rarely homogenous, and low-resistance paths in the reservoir, coupled with falling drive pressure and reducing length of the production column, result in most fields entering, quite soon in their lives, a long phase of ever-diminishing production of oil, often accompanied by increasing water-cut if water drive is used.

Figure 3 illustrates production from a *region* that results from such a very simple model.

As can be seen in Figure 3, the total production in the region sums that from successively smaller fields that are assumed to come on-stream annually, and where the production profile of fields takes the form of similar triangles of diminishing sizes: each steeply up, and then with a long decline.

As is clear, from such a model the total production from the region follows a roughly 'whale-back' shape, where the peak of production comes at very roughly the half-way point of production of the region's total recoverable resource. As is also clear, the fundamental drivers of this peak are: the field size distribution in the basin; the fall-off in volume of oil in new fields being discovered (new fields *are* being discovered, but are smaller than those in the past because of the field size distribution); and the production decline in fields due to the physical causes listed earlier.



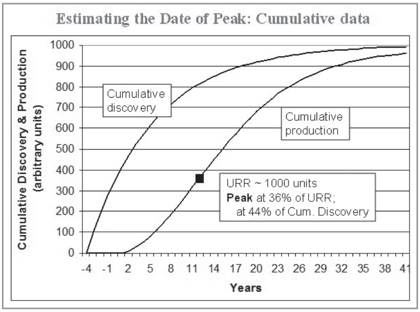


Figure 3: A simple model of oil production in a region.
Left plot: Shows the field size distribution and discovery sequence (grey bars), and each field's subsequent production (triangles), where each field is assumed to take 5 years from discovery to production. The plot is to-scale such that for example the volume of oil shown as discovered for field 1 (leftmost grey bar, 100 units) is the same as indicated for field 1 production (the lowermost production triangle, which starts in year 1, reaches 9.09 units/yr. in year 2, and falls to zero by year 23).
Right plot: The same data for discovery and production, but on a cumulative basis. The resource-limited peak in production (at year 12) is denoted by the small solid square.

The peak is *counter-intuitive* as follows. Imagine a forecast being made at year-10 (two years before the peak). At this date production is still rising steadily; there are plenty of reserves in fields already discovered; new fields of significant size are still being discovered; and, in the real world, advancing technology will be raising recovery factors. Few analysts not well versed in the mechanism of 'mid-point' peak would forecast this region's production as going into decline in the near term.

To-date, some 60 countries are past their peak of conventional oil production, and the majority of these show production profiles generally in line with that of Figure 3.

Appendix 3: Other factors that have influenced the price of oil

This appendix discusses briefly three of the more general factors, in addition to the quantity of conventional oil discovered and the mid-point peak, that are important for understanding the price of oil.

Improvements in knowledge

In the early days of oil, little was known about either its origin or wise extraction, and this, plus the 'rule of capture' (Yergin, 1991, p32), explains some of the early discovery and oil exploitation policies followed by individuals and companies. Proper knowledge of oil's origin and its probable location came only surprisingly recently, once an understanding of plate tectonics was in place in the 1960s, and of the petroleum system (source rock, thermal history, migration, trap and seal) in the 1980s. We now know, for example, that most of the world's conventional oil was produced in two relatively brief epochs, some 90 and 150 million years ago (Aleklett, 2012, p25); and that for example, Western Iraq has relatively poor oil prospectivity because migration from its source rocks has been substantially vertical (Ahlbrandt, 2003).

Improvements in technology

In terms of reducing the cost of oil, the advance of technology clearly had a major role. Better drilling rigs, railways and ever-larger tanker ships, and thermal and then catalytic cracking have all played significant roles; as did photo and magnetometer aerial surveying, and the use of seismic. The latter was especially important: it allowed oil below unconformities to be found, as with some key Middle East fields; and later - in the form of digital seismic - led directly to the vast majority of the world's conventional oil being discovered by about 1990, with the peak of this discovery occurring in the mid-1960s. And better knowledge and technology not only reduced the price of oil directly, but also by generating ever more efficient infrastructures within society reduced the cost of economic activity generally (and some of which, in turn, such as ease of transport, depended in large part on the increasing energy available from oil).

The need to access more difficult oil

Against such cost-reducing processes, it has long been recognised that oil was generally getting harder to access (even if the size of the largest individual fields discovered were still increasing, up until Ghawar in 1948). Exploring for oil in Mexico or Venezuela, for example, was generally more expensive than in the US; while working in the deserts of the Middle East was more expensive still with large concession fees on top. And once the shallow fields in Russia, the US and elsewhere were tapped, progress had to be made to deeper fields, and then, from the 1930s, to offshore oil and to heavy oil with thermal stimulation; then in the 1960s to Arctic and tar sands oil, and most recently to very-deep offshore, light-tight oil, and revisiting kerogen. Once the large Middle East fields were tapped, it has been a clear history of extracting technically ever more difficult oil.

The cost of extraction is one indication of this trend, see Figure 16 of Miller & Sorrell (2014). But the energy needed for the discovery, production, refining and delivery of a barrel of oil may be a better indication as discussed in Section 2.1.

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Charts

As mentioned in Issue-1, it is the intention that each issue of this journal will include a small number of charts - often from already-published sources - chosen as being particularly informative.

In this issue we focus on the production of *conventional* oil, and ask specifically: What has happened to global production of this category of oil in recent years, and what is forecast?

In the two issues of *The Oil Age* to-date, we have presented four forecasts: two top-down forecasts, respectively by Campbell and Laherrère; and two by-field bottom-up forecasts, respectively by Globalshift and Miller. Both of the top-down forecasts predict that the global production of conventional oil (and indeed of 'all-liquids') will go into decline in the near term; whereas by contrast both the bottom-up by-field forecasts see the production of conventional oil as being able to increase (assuming 'above-ground' constraints allow) out to perhaps 2025 or so, before then declining (and 'all-liquids' production also).

Note that the scope for increased conventional oil production in these two bottom-up forecasts is partly based on recent finds, but is largely from the few remaining 'swing' producers, whose production could potentially go quite a bit higher, were they to decide to do this; plus oil currently in 'fallow' fields (though see Miller's caution on this oil in this issue); and also from the increased application of enhanced oil recovery (EOR).

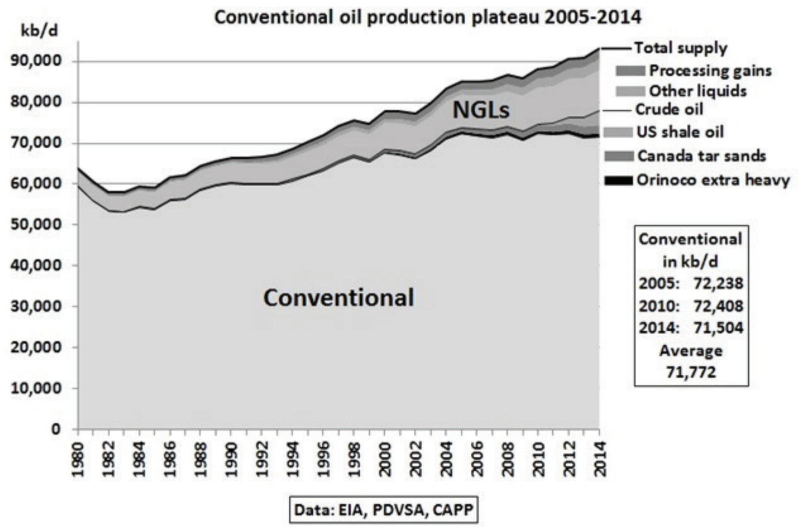
The charts presented below examine two things:

- Global production of conventional oil (taken here as primarily oil in *fields*) from 1980 to the present day, including its components; and also the production costs of some of these to see the impact on the maximum production cost of oil in recent years.
- Three recent 'mainstream' 'all-liquids' forecasts, from the IEA, BP and Exxon. The latter all show global conventional oil production as remaining more-or-less on plateau out to the end of their forecast horizons.

Specifically, the charts presented are:

- Mushalik: Global oil production 1980 to 2014 by oil category. This shows that global production of conventional oil has been on-plateau since 2005.
- Mushalik: A production-cost table from the consultancy: Energy Aspects.
- Mushalik: The resulting global production data categorised by production cost.
- IEA: A 2011 forecast of global 'all-liquids' production to 2035.
- BP: A 2015 forecast of global 'all-liquids' production to 2035.
- Exxon: A 2015 forecast of global 'all-liquids' production to 2040.

Chart 1. Global 'All-liquids' Production by Category of Liquids, 1980 – 2014.



Notes:

- Chart by M. Mushalik of ASPO Australia, see: http://crudeoilpeak.info
- The data are:

  For most categories of liquids, and total, from:

  http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm

  For tar sands oil (in Canada):

  http://www.capp.ca/publications-and-statistics/publications/258990

  For Orinoco oil:

  http://www.menpet.gob.ve/secciones.php?option=view&idS=21

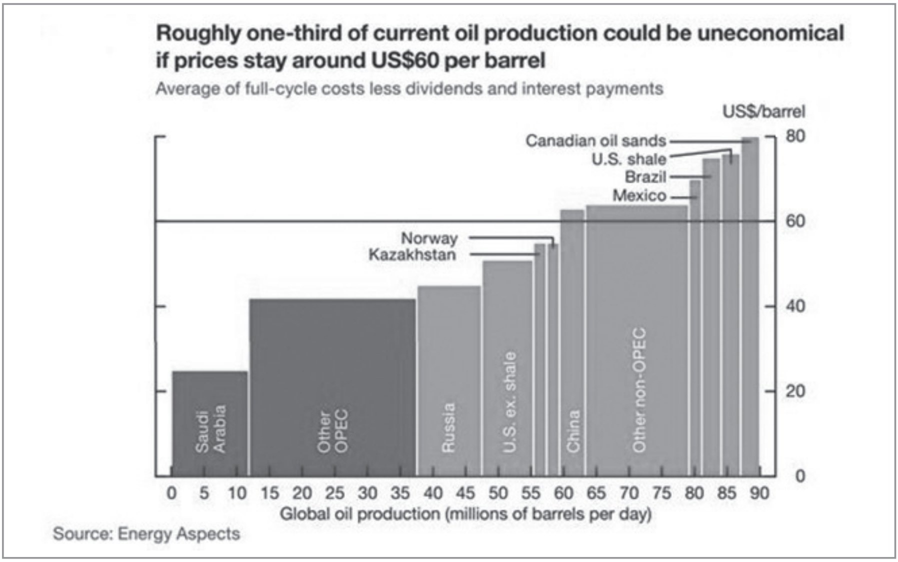
  Note that here Mushalik notes: "I could not get Orinoco production for 2013 and 2014. I just took the 2012 production [for these dates]. If production were a bit different, it would not show up in the graph due to the scale."

- Production of GTLs, CTLs and biofuels are in the ‘other liquids’ category.

Comments:

- The chart shows that global conventional oil production has been on plateau since 2005.
- Except for NGLs, the production so far of the non-conventional oils, and other liquids, has been quite modest; conventional oil has supplied the bulk of global oil for many years.
- What is the implication? Charts 2 and 3 below are provided by Matt Mushalik on his website (accessed 20 May 2015), and look at the implication in terms of the production costs of the other oils that have been produced to meet demand.

Chart 2. Production cost of oil by category



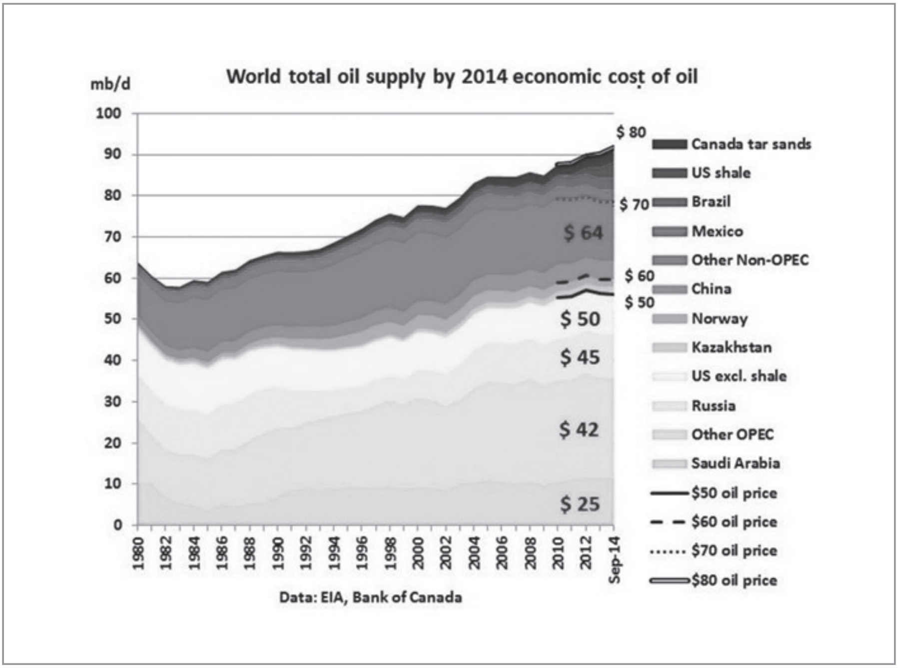
Notes:

- Chart by M. Mushalik, see: http://crudeoilpeak.info, accessed 20 May 2015.
- Data are from Energy Aspects, an independent research consultancy (but the chart is from a Bank of Canada report: http://www.bankofcanada.ca/wp-content/uploads/2014/07/mpr-2015-01-21.pdf).

Comments:

- The message of the chart is clear; various classes of oil have different costs, with the non-conventional oils the most expensive.
- But also compare these data with the higher production costs estimated by the IEA in their 2013 Resources to Reserves report (where the x-axis is total volume of liquids considered recoverable by category, and where a range of other-liquids', in addition to oil, are given), that was reproduced as Chart 2 in The Oil Age, vol. 1, no. 1.
- And also compare to the higher production costs estimated (vs. Mb/d, as here) by IHS-CERA in Figure 16 of: Miller, R.G., Sorrell, S.R., 2014. The future of oil supply. Phil. Trans. R. Soc. Vol. 372: 20130179.
- Mushalik goes on to write: "Let's put these costs into an oil production graph". This is done in Chart 3, below.

Chart 3. Global oil supply split by 2014 estimated economic cost of oil by region of production



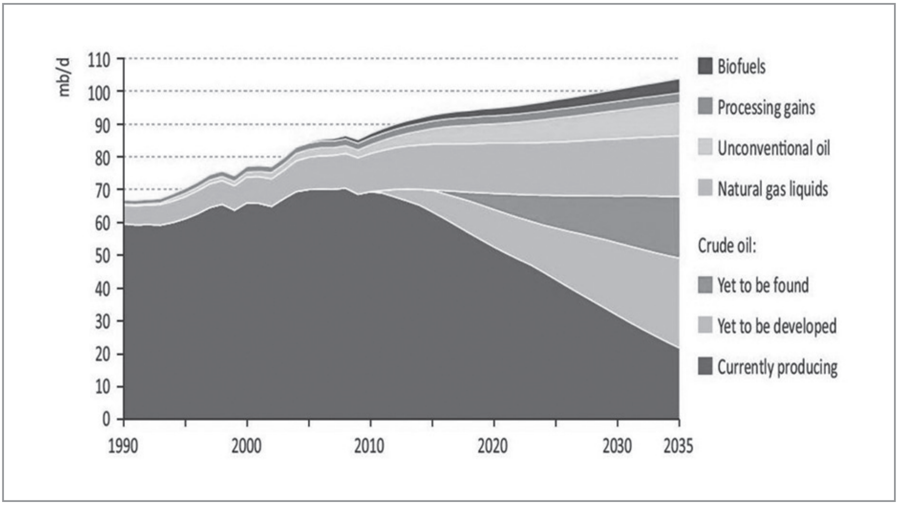
Notes:

- Chart by M. Mushalik, see: http://crudeoilpeak.info, accessed 20 May 2015.
- Data combine US' EIA production data (see Chart 1, above) with Energy Aspects' data quoted by the Bank of Canada, Chart 2.

Comments:

- Mushalik writes: "Figure: Oil supply by country/area and economic cost of oil. [In this figure] oil supplies are stacked by 2014 economic cost of oil, starting with Saudi Arabia ($25/barrel, green) and going up to Canadian tar sands ($80/barrel, dark red). The colours have been extended over the whole period to 1980 so that the production history can be seen. Lines in various styles show 4 different cost levels, whereby their lengths are indicative only to show corresponding production levels for the last years. It seems that oil supplies up to around $75 have peaked (all countries up to Brazil). In other words, if the world is willing (or able) to pay only $75 a barrel, corresponding oil production [has] declined since 2012 – at around 1.6% over 2 years. $50 oil was up and down, but at only 56 Mb/d or 60% of current demand. What is important here is that affordable oil does not appear to increase in volume. That has serious implications for economic and transport planning. [In the figure] supply includes: crude oil, natural gas plant liquids, refinery processing gains and other liquids (including bio fuels). The EIA definitions are here: http://www.eia.gov/cfapps/ipdbproject/docs/IPMNotes.html#p1

Chart 4. IEA 2011 World Energy Outlook Forecast of Global 'All-liquids' Production to 2035



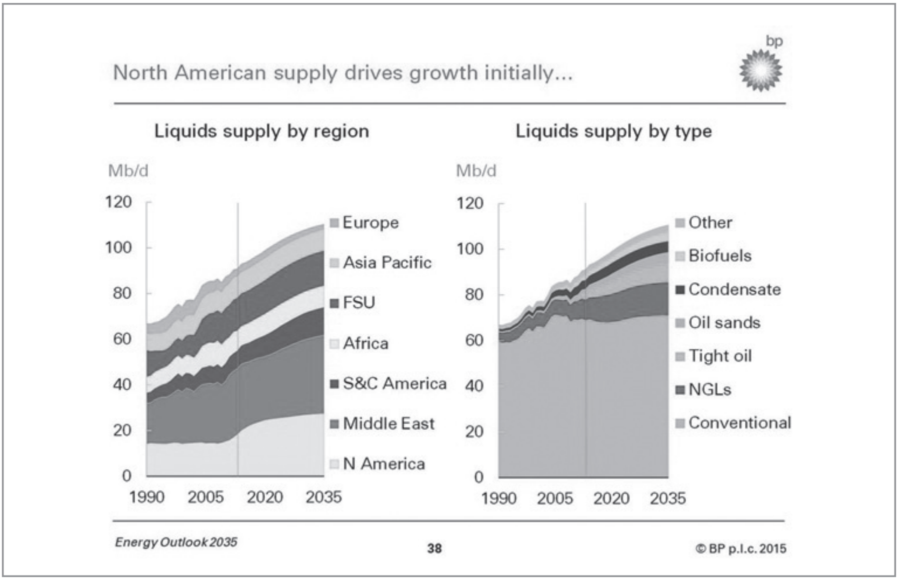
Notes:

- IEA WEO forecast, 2011.

Comment:

- Forecasts that global production of conventional oil (here classed as 'Crude oil) will stay flat to 2035; and all the increase needed to meet demand will be from NGLs, non-conventional oils, refinery gain and biofuels.

Chart 5. BP's 2015 *Energy Outlook* 2035 Forecast of Global 'All-liquids' Production to 2035



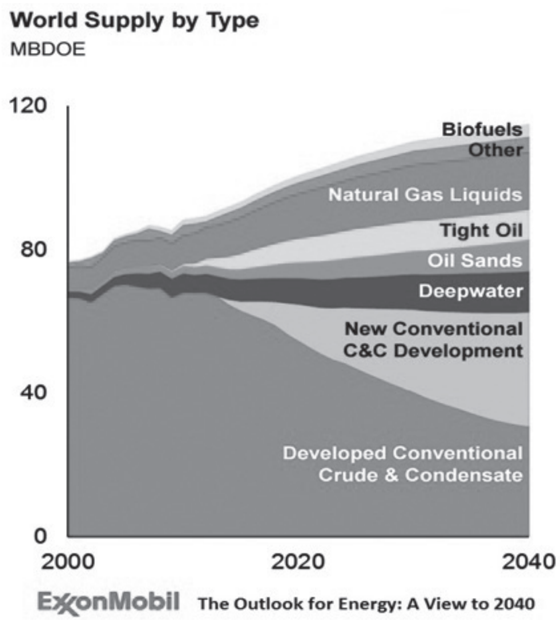
Notes:

- Data from BP website, accessed 20 May 2015, *Energy Outlook* 2035.

Comments:

- Very similar forecast to IEA, above; global conventional oil production remains flat.

Chart 6. ExxonMobil Forecast to 2040 of World Liquids supply, by type of liquid



Notes:

- Data from the ExxonMobil website [http://cdn.exxonmobil.com/~/media/global/reports/outlook-for-energy/2015/2015-energy-outlook-presentation.pdf (accessed 20 May 2015)]

Comments:

- As with Charts 4 & 5, global production of conventional oil is forecast to remain flat to 2040.

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