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.

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Editorial

Welcome to the Summer 2017 issue of this journal.

Thanks for bearing with us while the journal carried the three parts of the long Laherrère et al. paper on 'Data sources and data problems'. If we get sensible feedback on this paper from oil data users and oil forecasters we will update the paper; and also give feedback to readers via our new website (see below) if significant errors have been identified.

The journal now returns to its more normal format of roughly four papers per issue, and this issue covers three key topics: the reporting of oil and gas reserves (Campbell and Gilbert); the amount of oil likely to be available from Saudi Arabia (Zagar); and the global prospect for all-fossil-fuels production, including their CO2 emissions (Wang et al.).

An important bit of news is that the website for *The Oil Age* has now been launched. (I know we announced this in error previously, but this time it is has actually occurred!) It is at: www.theoilage.org

and it can also be accessed via: www.petroleumanalysiscentre.org

Currently the site is mainly populated with a listing of past papers from the journal; with an option to purchase these individually, or as complete issues. But in time we will be populating also the 'Petroleum Analysis Centre' side of the website with useful data and charts.

If readers get a chance to look at the website, and have comments to make (good or bad) we would be very pleased to hear.

- R.W. Bentley, July 3rd, 2017.

Oil Reserve Estimation and the Impact of Oil Price

C. J. Campbell [1] and J. J. Gilbert [2]

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[2] *Retired Petroleum Engineer, formerly BP's Chief Petroleum Engineer, with experience in Iran, Kuwait, Libya, Alaska, California, Venezuela, Colombia, Indonesia and the North Sea.*

(N.B. For details of the above authors' careers, see the relevant chapters in Peak Oil Personalities, Campbell, 2011.)

Abstract

This paper gives observations on oil reserve estimation based on the personal experiences of the authors. One of us was a petroleum exploration geologist, and the other in charge of petroleum production engineering. The paper contrasts the different approaches to oil reserves estimation of these two disciplines. In addition, it discusses of the impacts of changes in oil price, and also a range of often under-recognised commercial and 'political' factors, on such estimates.

1. Introduction

Many think the reported reserves of a new oil field to be a reliable scientific estimate of the volume of oil recoverable from the field, without realising that economics, and especially price predictions, play a dominant role in this calculation. In this paper we examine the different viewpoints on oil reserves estimation of the exploration geologist compared to that of the production engineer, and focus in particular on the impact of oil price on such estimates. The paper also looks at other factors that play a part.

In the context of reserves data, one of us (Campbell) offers a caveat on the oil production forecasts given in *Campbell's Atlas of Oil and Gas Depletion,* which reviewed the status of oil and gas depletion by country as of 2010. The preface to the Atlas recognises that *"probably the only correct numbers in this book are the page numbers"*, but this statement may be particularly true of the reserves data that underpin the detailed by-country oil forecasts in the Atlas. These reserves data may have paid insufficient attention to the critical impact of oil price on oil reserve reporting, and as a result, and given the recent (and expected) on-average high price of oil, the forecasts in the Atlas may predict oil production declines for some countries earlier than will in fact be the case. Time will tell, and it will be fascinating to watch how higher oil prices impact future production in the countries in question.

2. Difference between 'Geological' and 'Engineering' views of an oil field's reserves

Now we examine the differences of view in evaluating the oil reserves of a new field between that of a petroleum exploration geologist and a petroleum production engineer. These differences result from the following:

In the early days of the oil industry, estimates of field reserves were often based on a rule of thumb, such as the US practice of determining reserves on the basis of 200 barrels per acre-foot (acre for the area of the trap, and foot for the average thickness of the reservoir).

But more recently when considering seeking drilling approval for a new oil prospect, the exploration geologist first makes an estimate of the total oil in-place within the indicated trap that comprises the potential field. This is based on a range of factors including an understanding of the general geology of the prospect, analogy with drilling data from adjacent areas, and from the seismic data available.

Then a technically-based preliminary estimate of the recoverable oil from the potential field is generated by assigning from experience a value for the recovery efficiency, the fraction recoverable of the oil in-place. This estimate becomes the basis for proposing the prospect to management for exploration drilling. Generally - at least in the past - no detailed forecasts of cost and revenue streams from a potential discovery and development were made at this point, although the current (and anticipated) price of oil were considered; with many an exploration geologist being disappointed in having a good prospect turned down when the oil price was low, or conversely seeing a less-than-certain prospect approved for exploration when the price was high. The explorers were largely motivated by their quest for more information on the geology of little known new areas. Governments likewise wanted information on the potential of new areas under their control. The Soviet system permitted exploration drilling for information, but countries in the rest of the world were under commercial pressures.

If the project gets the go-ahead from management then exploration drilling takes place.

Importantly, once a prospect has been verified as economically viable by exploration drilling, the petroleum engineers responsible for the field then face a different task. They work in much more detail, and take into account not just the technical parameters defining the discovery, but also the cost of infrastructure to develop it, and the economic conditions which may be expected during its producing life. These calculations are listed in Section 3 below, and typically yield a different (and often significantly lower) estimate of the field's reserves to that previously given by the exploration geologists.

In understanding this difference in approach to estimating a field's reserves, it is crucial to recognise that while the cost of a preliminary exploration well (or wells) may be tens of millions of dollars (and up to perhaps a few hundreds of millions in the case for example of a remote deep offshore well), the cost of production facilities for a field can typically be at least an order of magnitude larger (and up to several tens of billion dollars in the case of a large and difficult new development such as the Kashagan Field). It is thus no wonder that the need for detailed oil-price sensitivity calculations is much greater in the engineering calculations.

3. Steps in an 'Engineering' Assessment of a Field's Oil Reserves

The following briefly outlines some of the steps that petroleum engineers take when estimating the oil reserves of a field.

Note that these apply primarily when making estimates of reserves of conventional oil. The procedures followed when developing estimates of reserves of non-conventional oil, such as tar sands oil, or 'tight' oil in very impermeable reservoirs, have to be somewhat different, as here the flow characteristics of the reservoir fluids are more complex and often poorly understood; and reliable estimates are usually not available until considerable production experience of the particular play under consideration has developed. Note also that there is no standard definition for the boundary between conventional and non-conventional oil deposits, which is a further source of complexity and confusion when considering reported reserves.

Step 1. The engineers re-estimate the hydrocarbon volume in-place in the trap, based on geological and geophysical mapping and on the characteristics of the reservoir rocks, including the porosity, permeability and water saturation, as revealed by the logging and testing of the successful exploration well, known as a *wildcat*.

Step 2. They decide on the well-spacing required to profitably drain the reservoir, and hence the number of producing wells to be drilled. In addition, the number and location of these producing wells determine how many offshore platforms or onshore production centres, both taking huge investments, would be needed. The aim is to maximise the profit from the discovery, drilling the minimum number of necessary wells, based on the company's internal oil price forecast and the cost of field operations. They also have to decide upon the export system to bring the oil and gas to a terminal or refinery. The cost of an offshore development generally greatly exceeds that of an onshore field of the same size.

Step 3. The engineers then have to determine for how long the field is likely to remain on production as reservoir pressure, and hence well off-take rates, declines. The end of the producing life of the field will come when the cashflow from production sales falls below the operating cost of the field; although tax considerations and the advantage of deferring the huge costs associated with field abandonment may sometimes prolong a field's life by some years (see also Section 4, below).

Forecasts of oil price for the entire producing life of the field are therefore essential to these calculations, meaning that the company has to build its own forecast of future oil prices.

In earlier times, when oil supply and demand conditions were fairly stable, forecasting these prices was not a particular challenge, but this has not been the case over recent decades. The following table shows the average price of oil by decade over the past century, based on information from the BP *Statistical Review,* which reports the oil price in real terms to discount the effects of inflation.

Date	Real-terms oil price ($/bbl)
1900-09	22.11
1910-19	27.57
1920-29	17.58
1930-39	17.39
1940-49	17.69
1950-59	16.89
1960-69	11.63
1970-79	103.20
1980-89	61.17
1990-99	29.35
2000-09	68.13
2010 to 2015	96.82

Table. Real-terms oil price vs. date.
Source. BP Statistical Review, 2015.

It is, of course, extremely difficult to forecast oil prices with any confidence.

In the past the supply of oil used to be substantially controlled by US pro-rationing, by the actions of the 'Seven Sisters' in preventing too much oil (especially from the mega fields of the Middle East) from coming to market, and subsequently by OPEC quotas. After a hiatus, today we still have a degree of OPEC control, and now - at least for the present - also agreement with some key non-OPEC players.

But despite this, as recent price fluctuations have shown, over the short term a very small difference between supply and demand can push the oil price significantly up or down; and when averaged over a longer period, other factors affecting the price come into play. These currently include:

- Significant risk of oil supply 'shocks' from short-term restrictions in supply.
- Possible limitations to supply from some exporters due to rising 'resource nationalism'.
- The fact that a high oil price limits demand growth; and too high a price destroys demand.
- The likely more widespread imposition of carbon taxes, and similar measures, to reduce climate change impacts (with this - possibly - leading to the 'peak demand' scenario).
- The fact that as the oil price rises it becomes increasingly viable to tap the generally more costly non-conventional oil sources, for example by those made accessible by hydraulic fracturing.

Despite these large uncertainties, it might be reasonable to think of the oil price as likely to be in the $70 - $90 per barrel (real-terms) range over at least the medium term.

Step 4. Once the number of production wells and the initial well off-take rates have been fixed, then calculations are made of how these production rates will decline with time. Such calculations involve building a numerical model of the reservoir, matching the output of the model to the observed early production performance of the field by altering the input rock and fluid description, and then running the model forwards in time. These well performance estimates, combined with the predicted life of the field, allow the calculation of most-likely field reserves under natural depletion, and hence the recovery efficiency, namely the fraction of oil-in-place that is recoverable. These models are often probabilistic, and range of net-present-value calculations performed to optimise anticipated field production against statistically-weighted possible eventualities.

If the recovery factor seems anomalously low compared with that observed previously in similar reservoirs then the engineers consider whether some form of secondary recovery can be applied to the field. This involves estimating the cost of injecting water or gas into the reservoir, and then calculating the increase in recovery that would result. If this process is seen to be economic, then the additional *Probable Reserves* can be booked, and once the new process is in place, then an increase in *Proved Reserves* can be claimed.

Step 5. If the estimated volume of oil in a trap is large, the engineers might be able to drill on a fairly wide spacing, thereby reducing the number of wells required to achieve adequate drainage, and hence the initial investment. They have to balance the many elements involved to deliver the best possible long-term profit.

Step 6. The management has to review a range of such proposals from their company's discoveries around the world, taking into account many other economic and political factors, and find some combination of projects that would deliver a good annual overall corporate profit. There are often complex tiers of committees in the company and many internal political factors involved. Furthermore, in most cases, the concession holding the discovery is owned by several companies in a joint venture. This adds to the difficulty, as a compromise development plan that is acceptable to all the partners has to be defined.

Step 7. Eventually, the management makes a decision to proceed to develop the oil find or, if the development is insufficiently attractive economically, to defer it in the hope that economic conditions may improve. There is also the likelihood that should development be deferred then technical advances over time, such as chemical methods of increasing water viscosity, changing rock wettability or more efficient thermal stimulation may significantly increase the efficiency of complex secondary recovery techniques. It is reported, for example, that Norway has as much as 3 billion barrels (Gb) of oil in undeveloped discoveries awaiting better economic or technical conditions before their development meets economic criteria.

Step 8. If it is decided to proceed with field development, the first set of development wells will be drilled and placed on production. As indicated above, it is desirable to drill the minimum number of these necessary to deliver a reasonable profit.

The estimated future production from the field can be reported publically under two categories. The *Proved-plus-Probable Reserves* give the expected most-likely value of total production from the field by the time production stops. By contrast, a considerably more conservative figure of *Proved Reserves* is more usually reported, this must follow detailed and strictly-enforced rules on its calculation. In particular, the procedures defined by the US Securities Exchange Commission (SEC) are those most widely followed; and until fairly recently the reserves data given in oil company annual reports had to provide only SEC *Proved Reserves* values. Currently company reports can report both classes of reserves estimates, but must make the distinction clear.

Step 9. Production from the initial wells progressively declines as reservoir pressure falls and the thickness of the remaining oil column in the reservoir reduces. This in turn often prompts the drilling of infill wells, between the existing producers, and also the tapping of any subsidiary traps or reservoirs identified on the flanks of the field in the course of its development. These later developments are often of higher risk, and may deliver lower profits being more vulnerable to falls in oil price.

4. The 'U-shaped' Reserves reporting curve

Given the discussion in Sections 2 and 3 above, it is not surprising that there can occur what might be called the 'U-shaped reserves reporting curve'. This is where the initial estimate of a field's likely reserves (i.e. proved-plus-probable reserves) from the exploration geologist takes a certain value and that of the initial engineering estimate a significantly lower value, driven by the need to fund initial production infrastructure; but where, as the field gets developed over time and subsequent infrastructure and improved recovery methods are employed, this 'engineering' estimate of the field's original reserves climbs back towards the geological estimate. This evolution of reserves estimates is observed, for example, in the case of the Prudhoe Bay field in Alaska.

5. Commercial and 'Political' Realities

The situation set out above would appear fairly straightforward in terms how reserves estimates are made. In the real world however, reserves reporting is often more complex, with a wide variety of commercial, and also what might be termed 'political', realities enter the picture. These include:

(a). Engineering caution on large fields

As explained above, and for good reasons, engineering estimates of reserves often are (or start out) as lower than geology-based estimates. But if a field is large, the engineer can be doubly cautious; the field will see production anyway even if the reserve estimate is low; and if this value climbs over time the engineers can appear in a good light within the company, and the company in a good light to the market. A senior fellow at BP told one of us that he liked to 'keep a little back' in his reserves estimates, both to allow for unforeseen setbacks, but also to give the next person in his post some scope to shine.

(b). Geologist caution on large fields

Perhaps surprisingly, caution on field reserves can apply to the geologists also. As Laherrère reports: *"Sometimes we underestimated a prospect when it was very big in order not to appear too optimistic. This was the case for the reserves estimate of the Cusiana in Colombia; Cusiana is a giant oil field, but we presented the prospect as less to our management."*

(c). Geologist optimism on fields 'difficult-to-sell-to-management'

Conversely however, if a geologist thinks they will find a prospect difficult to sell to management, perhaps because the field is fairly small, or maybe difficult to produce for some reason, or the oil price is low, there is a natural tendancy to put a positive gloss on the various individual factors involved in estimating the field size, and hence derive a particularly optimistic estimate. And as mentioned above in this regards, the geologist is 'in competition' with other exploration groups within the company, and with outside prospects the company may to decide to participate in, if they are to get their prospect adopted.

And in this respect, geologist motivation needs to be properly understood. Campbell writes: *"I remember in my days we tried to get the company to drill exploration wells in new areas, in part to provide the information needed to evaluate it, and in many cases [we] cheated on reserve estimates to get it past the company economists. The Russians had a better system that allowed exploration wells to be drilled just for information."*

(d). 'Small-company' optimism

An import element in recent years has been the growth of many small 'promotional' companies set up in the hope of being able to make a significant discovery on previously unexplored acreage, but whose development costs they would be unable to fund themselves, and need to sell on to a larger company. The seven major international companies, once known as the *Seven Sisters,* are now reduced to four, having found that more profit on the Stock Exchange was to be made by merger than by finding new oilfields from exploration. The small companies have every motive to exaggerate their reserves as they themselves try to raise investment on the Stock Market.

(e). Past flexibility of reporting rules

Companies previously had more freedom in their reserve reporting, the numbers often being the *minimum* needed to deliver a good image to the Stock Market. What rules existed were set to prevent fraudulent exaggeration, but smiled on under-reporting as laudable caution. Any such under-reporting provided the company with a balance that could be used to offset problems with fields, or any unexpected temporary decline that might set in around the world due to accident or political unrest.

(f). Oil price uncertainty

In recent years, with a return to wide price oscillations, the difficulties facing oil companies in forecasting future oil prices, and hence in turn the volumes of economically recoverable reserves, has become very large. Although the expectation is for oil prices going forward to be high *on-average,* wide fluctuations in price are still to be expected, and it may be that new guidance on reserves estimation will be required.

(g). Field abandonment

A topic of increasing recent importance in reserves estimates is that of field abandonment. Management finds itself in the difficult position having to decide on whether to abandon a producing field that is no longer profitable at low prices, while recognising that prices may soon recover. The internal pressures must be enormous as the premature abandonment of a field leads to curtailment of reserves for that field, as well as to job losses and all manner of tensions. This is particularly true if the field is offshore, where the chances of restarting a now-low-reserves field once the infrastructure has been removed are virtually nil.

(As an example of the problem, the *Financial Times,* a UK newspaper, recently reported: *"As many as 50 North Sea oil and gas fields could cease production this year after a collapse in crude prices to 12-year lows industry experts have warned"*; with the consultancy Wood Mackenzie saying: *"Oil companies were likely to halt output at 140 offshore UK fields during the next five years, even if crude rebounded from $35 to $85 a barrel. This compares with just 38 new fields that are expected to be brought on stream during the same period."* In this regard, Paul Charlton, chief executive of engineering consultancy PDL, warned against rapid [North Sea] decommissioning, saying that the industry should co-operate to keep fields producing: *"Once they are gone, they're gone.")*

(h). OPEC 'quota-wars' reserves

In addition to the topics discussed above on reserves reporting there can be very significant wider political factors. This has been especially true in the case of reserves reporting by the OPEC countries. This was discussed at some length in Annex 5 in the paper: *Oil Forecasting: Data Sources and Data Problems – Part 2* (Laherrère et al., 2017). In at least some of these OPEC countries, for example Kuwait, the reported c*urrently remaining* proved reserves would seem to be close to the country's *original* recoverable reserves, i.e. the *proved-plus -probable* reserves before production started.

6. Discussion and conclusions

It is evident from the foregoing that reported reserves for a field may differ significantly from an estimate of the *technically possible* future production from a field. *Economically possible* recovery for a given field may be as little as half the volume of that technically recoverable when economics are ignored. Newly discovered fields have themselves progressively declined in size as the number of remaining giant fields dwindles, adding to the vulnerability of their development to price fluctuations.

In summary, however, there are just two fundamental issues to address, which are simple enough even if calculations are difficult:

(i). How much oil is in the ground (recognising all the different categories of oil). Oil-in-place is a quantity that can be measured by mapping the volume of a trap and the porosity and water saturation of the reservoir rock. The results are naturally subject to a degree of uncertainty as the parameters cannot be accurately determined, but a reasonable approximation can be made.

(ii). How much of this is commercially extractable, which depends on economic factors including:

1) Oil workers' wages
2) Cost of facilities (drilling rigs, platforms etc.)
3) Oil price
4) Forecasts of oil price
5) Rates of extraction
6) Cost of borrowing money
7) Tax on operations
8) Stock exchange movements on oil company shares.
9) Demand for oil (which depends on many factors, including general economic circumstances, population change, legislation, oil price, and changes in demand by sector - such as for transport vs. that for agriculture.)

Calculation of *Proved-plus-probable* (2P, or P50) reserves aims to take these factors into account, but with so many uncertain input parameters, the results are often in reality little more than a 'best guess'.

It is significant that the 2015 issue of the BP *Statistical Review,* a widely-quoted database, shows unchanged *Proved* Reserves for forty countries, although it is utterly implausible that new discovery or valid improved recovery should have exactly matched intervening production. It suggests that the government departments responsible have simply not released the updated data at their disposal, possibly for political reasons.

The challenges of estimating future world production have grown greatly. But that said, it seems evident that the future production of the giant fields, which have dominated world supply, is declining from natural depletion whatever the uncertainties of detail. That itself ushers in the *Second Half* of the Oil Age, when the world, having become very dependent on oil-based energy, faces radical changes. The tensions of the transition are likely to be severe, as perhaps already indicated by riots, revolutions and pressures for migration from people whose home countries can no longer support them.

Governments begin to face the challenges of the *Second Half* when the critical supplies of oil and gas that fuelled past expansion begin to decline due to natural depletion. They are likely to curb immigration, and provide greater devolved power to the regions making up their country, as an oblique recognition that communities will increasingly have to depend more on whatever their region can support.

Better efficiency in the use of oil will be part of the solution. For example, the main road through a typical small village in the West of Ireland is commonly choked by traffic, with many of the cars carrying no more than a single occupant. More efficient vehicles, car-sharing, and the giving of lifts could ease the situation greatly. Since oil is a major source of energy, both government authorities and people at large should have a better understanding of the nature of oil reserve determination and reporting as discussed herein. It is clearly a critically important subject.

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Saudi Arabia – Can It Deliver?

Jack Zagar, Associate, MHA Petroleum Consultants.

Abstract

Note: This paper is based on a presentation given by the author on October 28, 2005 at the Pio Manzu Centre conference, Rimini, Italy. It has been edited for publication, and updated by the addition of an epilogue; and see also the Editor's comments following the paper. (Note that in a few places in the text clarification notes have been added; these are indicated within square brackets.)

OPEC - specifically Saudi Arabia - is often called upon to increase oil exports to cool soaring oil prices and to foster continued growth in global economies. With perhaps as much as a quarter of the World's remaining conventional oil reserves, will or can Saudi Arabia provide the additional oil production? And if so, how much for how long?

With about 90% of the World's reported proved oil reserves unaudited by independent third parties, including all of OPEC's reserves, how much confidence should be placed in Saudi Arabia's reported proved reserves, which have been essentially flat at about 260 Gb since 1990? In a 2004 public forum Saudi Aramco stated the Kingdom's ability to produce at a plateaus of 10 Mb/d and 12 Mb/d beyond 2050. This paper asks if these production forecasts are plausible. It re-examines some of the basic parameters of original oil-in-place, discovery trends and recovery factors and concludes that production of 10 Mb/d to mid-century may be possible, but that sustaining 12 Mb/d beyond 2040 may be difficult without significant new discoveries.

In addition, recent information - including on a recent independent audit of Saudi Arabia's oil reserves, something which has long been needed - is given in the epilogue.

1. Introduction

Increasingly, the world is looking to OPEC, and specifically to Saudi Arabia, to increase oil exports to cool soaring oil prices and to foster continued growth in global economies. With perhaps as much as a quarter of the World's remaining conventional oil proved reserves, will or can Saudi Arabia provide the additional oil production?

In my opinion (admittedly, perhaps a bit of over-simplification) three key factors have to successfully come together before Saudi Arabia can provide the world with significant additional production. These are given in Figure 1.

Figure 1. Three Key Factors for Future Oil Production in Saudi Arabia.

I will discuss the first two of these factors briefly, and then focus on the third where my expertise lies.

The First Key Factor: Does Saudi Arabia have the political will and the economic incentives to increase production? In the late 1970s during the final stages of the nationalization of the Arabian American Oil Company (Aramco), plans were in place by the American parent companies to increase Saudi Arabia's oil production capacity from 10 million barrels per day (Mb/d) to 16 Mb/d.[1] The oil minister at the time, Sheik Yamani, disagreed, stressing *“we are going to need oil for future generations of Saudis”*. Since that time nearly 30 years ago, except for the post-oil-shock cutbacks from about 1982 to 1990, the daily nominal oil production capacity of Saudi Arabia has remained essentially what it is today – about 10 million barrels.

The point here is that it is presumptuous of the World to assume that Saudi Arabia will produce additional oil to meet its needs. To do so it must also meet the needs of the Saudi people and its government. Oil revenues to Saudi Arabia have nearly trebled in the last 18 months [i.e., to October 2005] with little additional effort on the part of the kingdom. Why increase production to lower prices? It is a complex issue, one that balances domestic needs and politics with the Kingdom’s desire to be seen as a reliable member of the global community.

The Second Key Factor is the petroleum infrastructure, security, and access to technical people.

Clearly, in the short term, the most likely scenario that could significantly reduce Saudi Arabia’s ability to provide 10% to 12% of the World’s daily oil production is acts of terrorism or sabotage on the oil producing facilities. Goldman Sachs’ much publicised pronouncement earlier this year [2005] of the potential for oil to reach more than $100/bbl was predicated on such events. Any expansion in production beyond 10 Mb/d capacity will come from producing mature fields even harder, and developing a host of smaller fields scattered within the oil province. Additional drilling rigs, production facilities and transport infrastructure, people, and security will be required for such new developments.

And the final Key Factor of this triad is the publicly reported oil reserves: How valid are they?

Of the nearly 1.2 trillion barrels of remaining proved oil reserves that are quoted in the public domain for the entire world, over 1 trillion barrels, about 90%, are unaudited, including the nearly 900 billion barrels (Gb) for OPEC. Accordingly, Saudi Aramco is not subject to any audits by independent third parties. So, are their reserves conservative? Or optimistic? Are there sufficient remaining reserves to offset ongoing natural decline and to increase capacity significantly beyond the current 10 Mb/d?

These questions are summarised in Figure 2, and are the focus of the remainder of the paper.

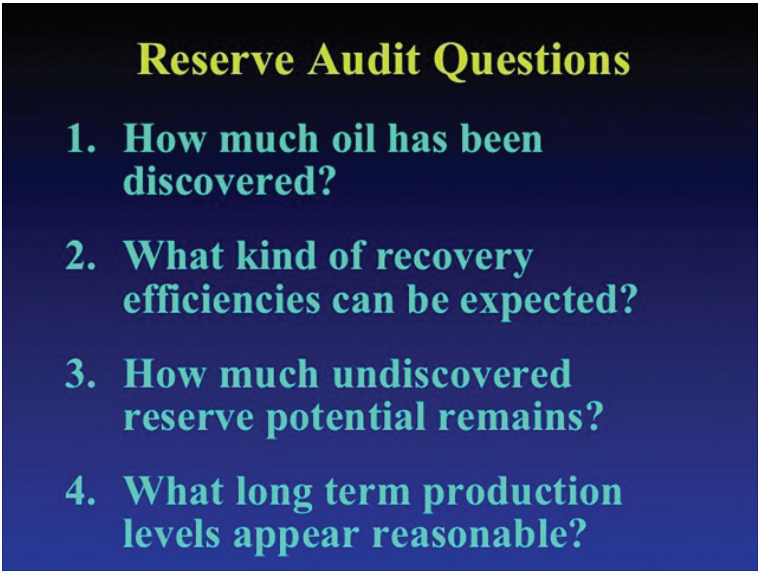

Figure 2. Reserves Audit Questions addressed in this paper.

2. Reserves Audit Questions

2.1 How much oil has been discovered?

To answer the question of how much oil has been discovered in Saudi Arabia, we start with a map of regional Middle East/Persian Gulf oil, Figure 3.

Figure 3 shows the major oil and gas fields, indicated in red, surrounding the Persian Gulf. Perhaps as much as fifty per cent of the World's remaining conventional oil resides in an area extending from Oman and the United Arab Emirates in the south, through the Persian Gulf and along the eastern province of Saudi Arabia, through Kuwait and the western province of Iran, and into Iraq and Turkey. And interestingly, perhaps as a harbinger for political events to come, only about two per cent of the World's population lives in this same area.

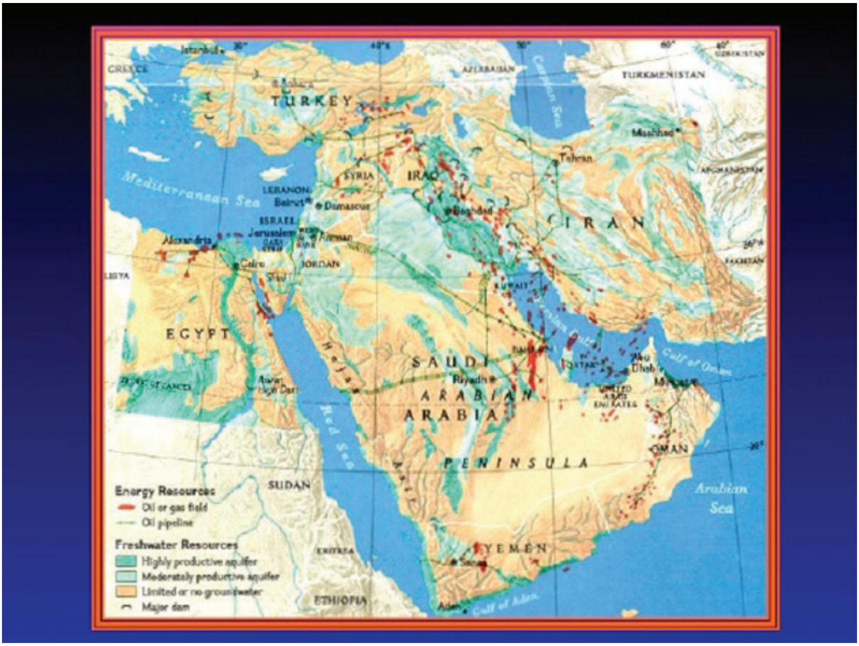

Figure 3. Major Oil and Gas Fields of the Middle East / Persian Gulf Region.

Next we look at the crucial data giving the evolution of oil discoveries in Saudi Arabia, Figure 4, given here in terms of oil initially-in-place (OIIP) in the fields discovered.

In Figure 4 fields with significant ongoing production are shown by red vertical bars; and green vertical bars show 'static' discoveries, i.e., those fields without any significant production [at least to 2005]. The cumulative discoveries for producing and 'static' fields are shown by the purple and green areas respectively, and are scaled on the right axis.

In February 2004 executives from Saudi Aramco publicly stated their perspective on Saudi Arabia's ability to provide crude oil for the next 50 years.[2] One of their charts illustrated OIIP growth of 110 Gb, or about 5 Gb per year, for the 22-year period from 1982 to 2003, yielding their reported current total discovered OIIP of just over 700 Gb. These OOIP growth figures are shown in the upper right hand corner of Figure 4.

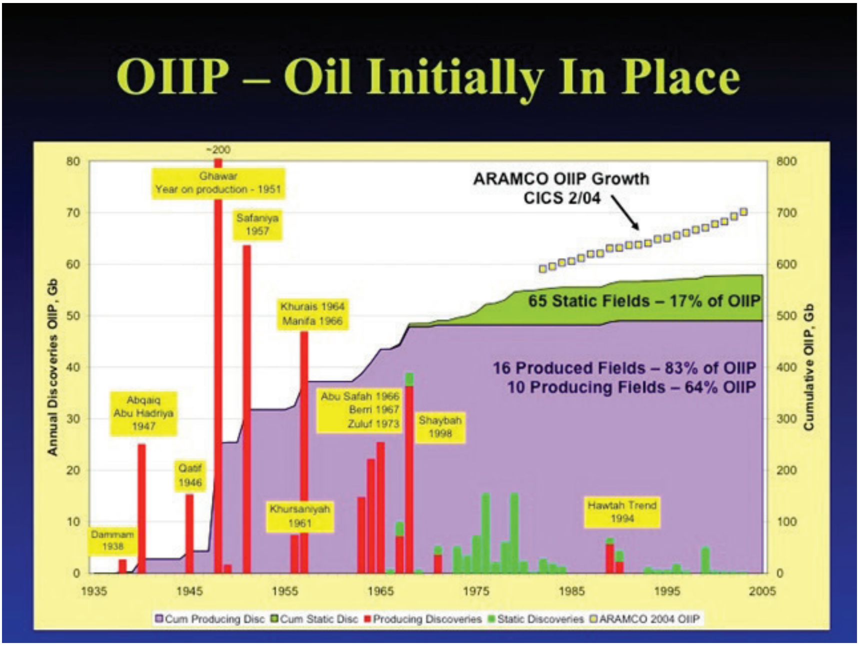

Figure 4. Figure 4. Discovery of oil in Saudi Arabia, given as Oil Initially-in-place (OIIP) on an Annual basis (left scale), and on a Cumulative basis (right scale); Billion barrels (Gb).

Notes:

- Oil initially-in-place is an estimate of the total oil in a field, whether recoverable or not, before the start of production.
- Vertical bars indicate dates of field discovery; text in yellow boxes give dates of start of production.
- 'Aramco OIIP Growth CICS 2/04': See text below.

Source: Oil industry 'scout' data.

The key observations from this Figure are:

- An estimated >80% of Saudi Arabia's oil fields, or nearly 500 Gb in terms of OIIP, are already developed or have a significant level of development; while less than 20% of the remaining OIIP is still to be developed.
- The discovery trend, as can clearly be seen from this Figure, has been declining steadily since the 1950s, despite a very active and ongoing exploration program.[3]

- During the 22-year period that Aramco indicated a 110 Gb growth in OIIP, less than 30 Gb of OIIP in new discoveries were reported to industry. This suggests that the OIIP growth is primarily from remapping (e.g. structure, initial water saturation distribution, and porosity distribution) of known discoveries and developments.

Contacts within Aramco say that the company, like all oil companies, is under pressure to demonstrate replacement of reserves depleted by production. Only time will tell if the additional OIIP shown here will translate into additional 'oil in the tank'.

2.2 Recovery efficiencies

Now we focus on data for specific oil fields within Saudi Arabia's Eastern province, as shown in the map of Figure 5.

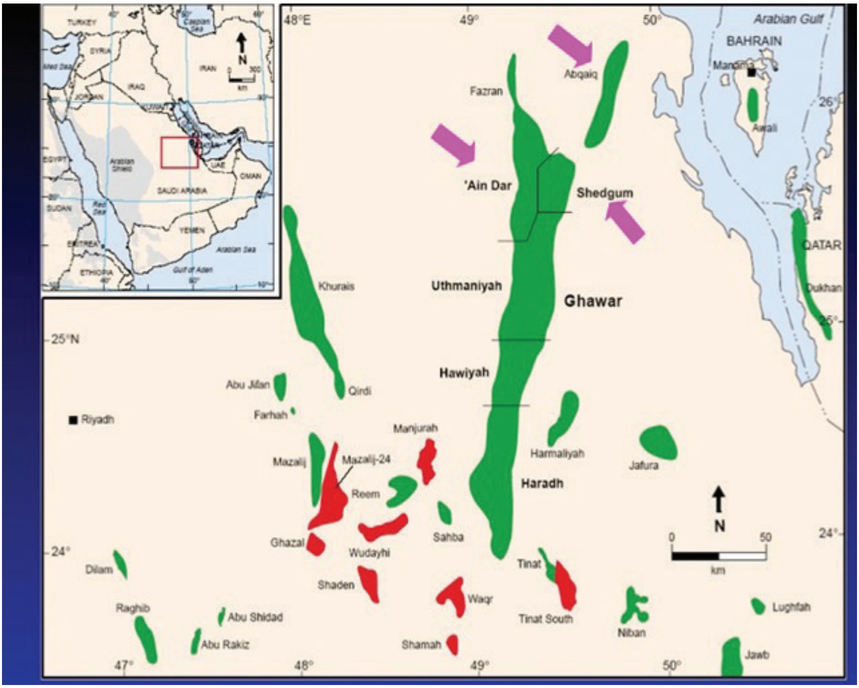

Figure 5. Figure 5. Saudi Arabia's Oil-prolific Eastern province, showing the fields considered.

The map of Figure 5 gives the Saudi Arabian onshore fields of the oil-prolific Eastern province. Oil fields are in green and gas fields in red, and the map points out the location of the two fields I will discuss in terms of oil recovery factors. Specifically these are: the northern areas known as Ain Dar and Shedgum of the super-giant Ghawar field, and the giant Abqaiq field where I worked as a lad of 25 summers.

Figure 6 gives Saudi Aramco data as of 2004 for the 'resources depletion state of the combined Ain Dar/Shedgum area.

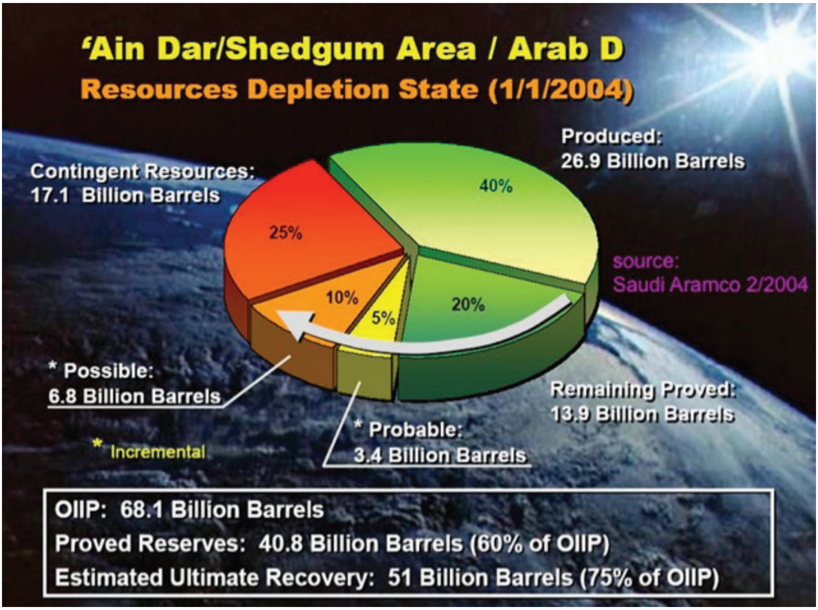

Figure 6. Data on Ain Dar/Shedgum Oil Recovery by Reserves category.
Source: Saudi Aramco, CSIS Washington D.C. meeting, Feb. 2004.

The data in Figure 6 are from a Center for Strategic and International Studies (CSIS) meeting in Washington D.C. in February 2004, and illustrates Saudi Aramco's estimates of recovery factors for the Ain Dar/Shedgum areas of North Ghawar. These two areas of Ghawar have produced over half of Ghawar's production and more than a quarter of Saudi's total production. Aramco says these fields have a proved (i.e., 90%) probability of achieving a 60% recovery of the OIIP; with an additional 5% of probable recovery.

This area of Ghawar has the best reservoir rock and crude oil properties and, together with Abqaiq, probably represents the highest recovery factors to be achieved by any fields of significance in Saudi Arabia.

The 10% additional "possible" recovery could be attributed to such tertiary recovery means as CO2 miscible injection; but such projects are presently not on the radar screen. Given that residual oil saturations are typically in the range of 18% to 25% for rock swept by gas and/or water floods, the 75% "possible" or 3P recovery factor quoted by Aramco for this area of Ghawar implies nearly 100% vertical and areal sweep efficiencies. This, in my opinion, is technically very optimistic.

The "contingent resources" are simply the 25% of the OIIP that are left in the ground after achieving Aramco's "ultimate recovery" of 75% of the 68.1 Gb OIIP. Now we turn to the giant Abqaiq field, see Figure 7.

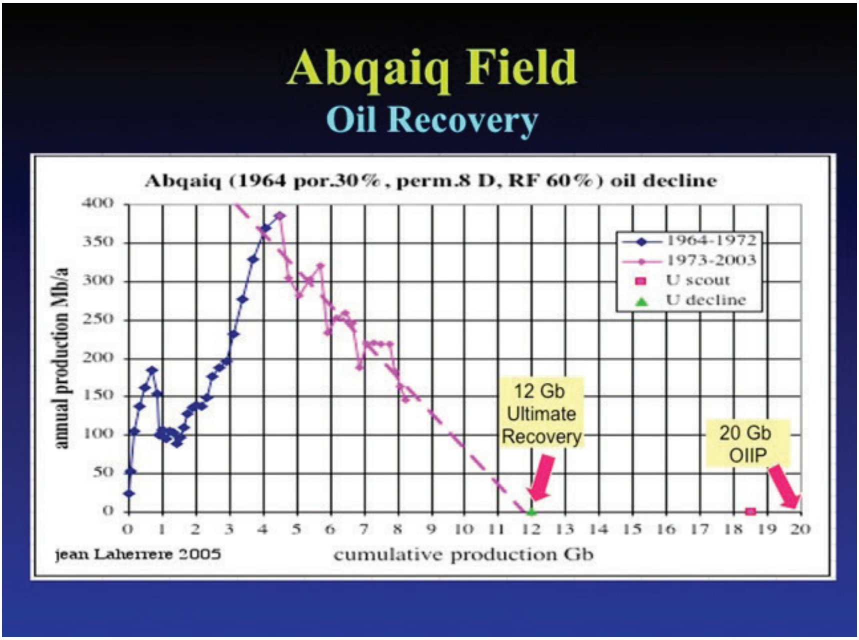

Figure 7. Abqaiq Cumulative Production & Recovery Estimate.
Source: J. Laherrère, from oil industry 'scout' data.

Figure 7 is a plot from a study by Jean Laherrere of ASPO giving Abqaiq annual oil production in million barrels per year versus cumulative oil production in Gb. A plot of this type linearises production decline if the latter is exponential. Here extrapolation of the decline trend suggests an ultimate recovery for the field of about 12 Gb, which is consistent with a 60% recovery factor for a known OIIP of 20 Gb. Numerical simulation studies that I was involved with during the late-1970s, when cumulative oil recovery was about 5 Gb (vs. 2005's 8 Gb), predicted the same ultimate recovery, and recovery factor.

Given that Abqaiq is geologically analogous to the northern area of Ghawar just discussed, this plot supports a 60% 'most-likely' (i.e., proved-plus-probable) recovery factor also for the Ain Dar and Shedgum areas.

Now we put the recovery factors just discussed into a global context. This is done in Figure 8.

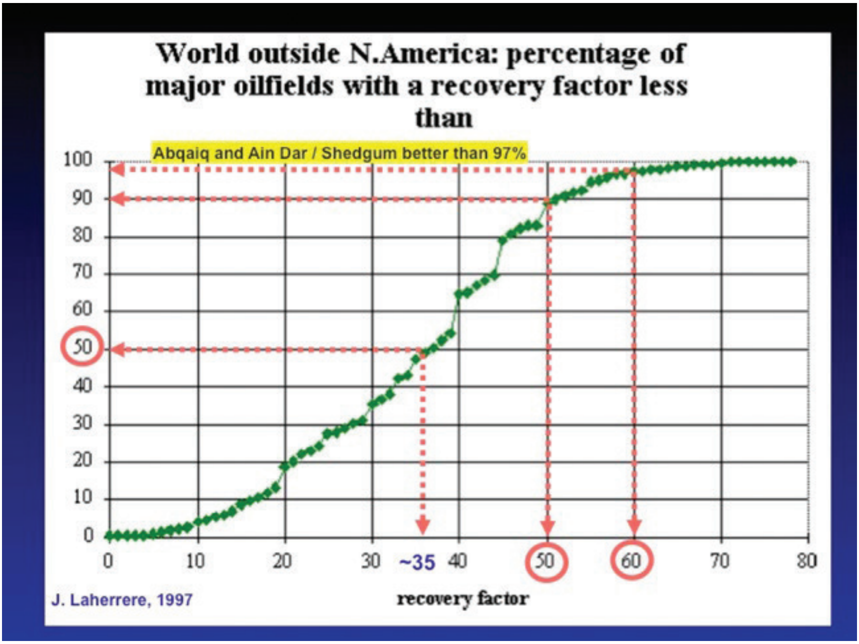

Figure 8. Comparing the Recovery Factor of the Abqaiq field, and Ain Dar / Shedgum regions of the Ghawar field, with the Recovery Factors of Major Oil Fields Globally (ex North America).
Source: J. Laherrère.

Figure 8 is from a study by Jean Laherrère regarding distribution and evolution of field "recovery factors". For 800 major oil fields outside of North America, the curved-line in this plot illustrates the percentage of the fields with an oil recovery factor less than a specific value. The 60% recovery factors for the Abqaiq Field and Ain Dar / Shedgum areas of Ghawar are better than 97% of the fields represented in this study. Ninety per cent of these major fields have recovery factors less than 50% with the median value approaching 35%. For the purpose of this paper in terms of the reserve estimates discussed below, I have assumed what I consider an optimistic proved-plus-probable recovery factor of 50% for all of Saudi's oil fields.

2.3. Potential for undiscovered oil

Now we look at Saudi Arabia's potential for oil yet to be discovered. First we look at the locations of Aramco's exploration ('wildcat') wells drilled as of 2004, Figure 9.

Figure 9. Figure 9. Location of Exploration Wells in Saudi Arabia, as of 2004.

In terms of the potential for future exploration for oil in Saudi Arabia, in February 2004 Mr. Abdul Baqi, head of Aramco's exploration programs stated there are still three main unexplored areas within Saudi Arabia: (1) land adjacent to Iraq's southern border to the north, (2) deep-water Red Sea to the west, and (3) the southern area of the Empty Quarter or Rub al Kahli. It is impossible to tell with any accuracy how many new oil and gas fields are yet to be found in Saudi Arabia, but there are estimates within the industry. One such estimate is shown in Figure 10.

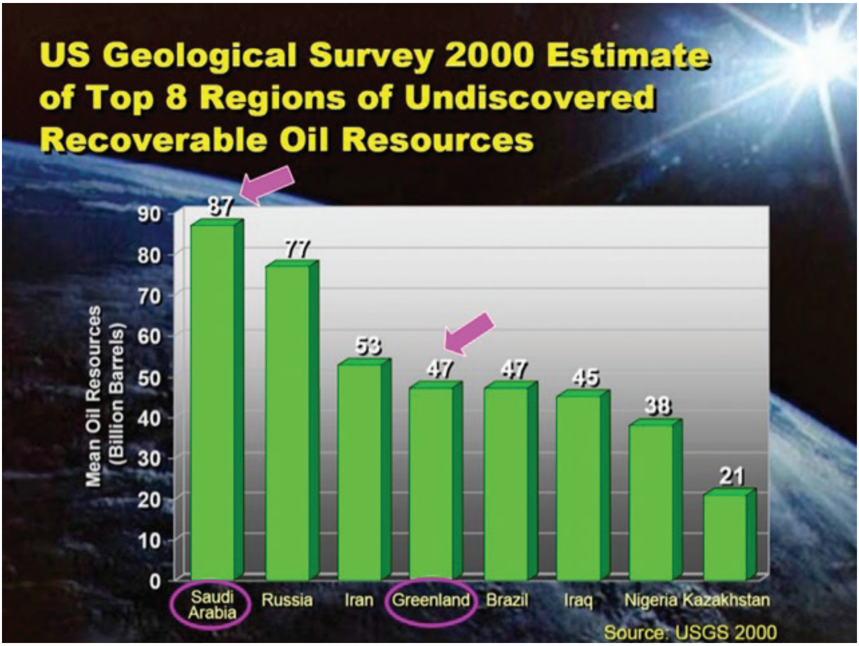

Figure 10. USGS year-2000 Mean Estimates of Undiscovered Conventional Oil, specific countries.

Notes:

- These estimates do not include allowance for 'reserves growth', which in the USGS year-2000 Assessment was added regionally.
- The supporting data for this Assessment included Petroconsultants end-1994 data.

Source: U.S. Geological Survey World Petroleum Assessment 2000 – Description and Results. T. Ahlbrandt et al. USGS Digital Data Series - DDS-60. (Available on CD-ROM at: http://pubs.usgs.gov/dds/dds-060.)

As Figure 10 shows, the United States Geological Survey made an estimate as reported in their 2000 study of 87 Gb for the undiscovered mean conventional oil reserve potential of Saudi Arabia. Aramco's Abdul Baqi cited this USGS estimate as key in supporting his claim that Aramco has about 200 Gb of OIIP undiscovered potential. (It is worthwhile noting, however, that in this same study, the USGS also predicted undiscovered reserves of 47 Gb for Greenland even though not a single well has been drilled in this entire region.)

In February 2004 Aramco publicly stated its own estimate of discovered and potential undiscovered OIIP values, Figure 11.

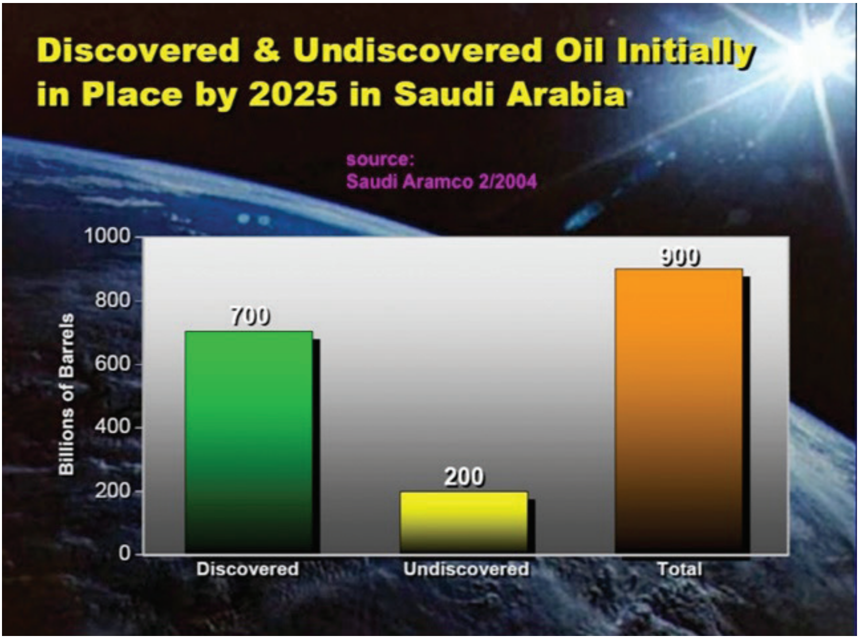

Figure 11. Undiscovered Oil Initially In Place – Aramco Estimate in 2004

As the Figure shows, these estimates for discovered and potential undiscovered OIIP were 700 Gb and 200 Gb, respectively. Furthermore, Aramco predicted the new discoveries to occur within the next 20 years. By comparison 200 Gb of undiscovered OIIP is equivalent to all the new discoveries reported by Saudi Arabia since the late 1950s. Moreover 200 Gb of OIIP discoveries over the next 20 years implies an average of 10 Gb/year new OIIP discoveries, vs. an average new discovery reported to industry of about 1.5 Gb OIIP per year during the last 22 years. Only time will tell if the country can achieve this step-change in discovery rate.

Putting the above information together, we can arrive at two depictions of Saudi Arabia's oil reserves; that stated by the company, and my - admittedly possibly erroneous - assessment of 'most likely'. These are shown in Figure 12.

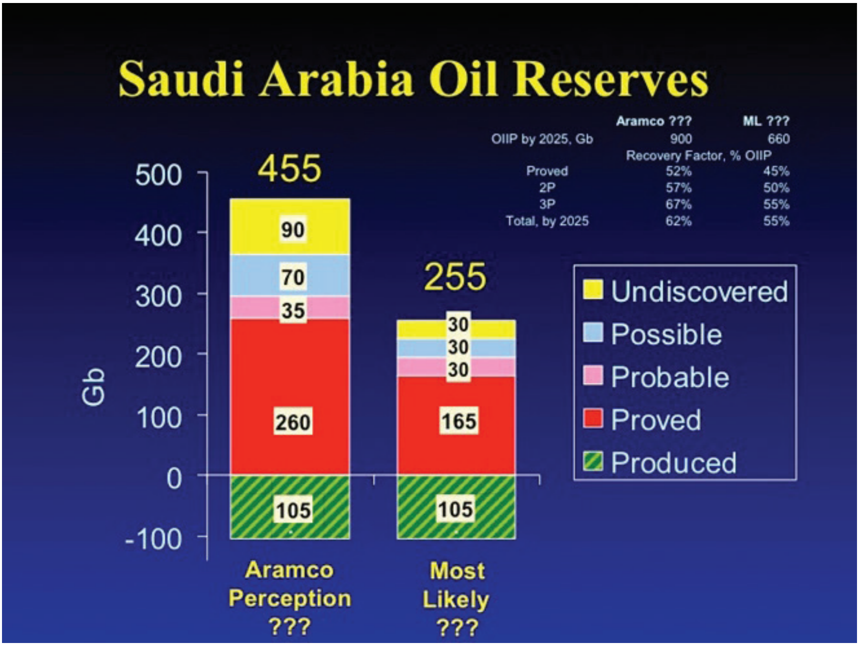

Figure 12. Two depictions of Saudi Arabia Oil Reserves (including Undiscovered).
Note: ML: Author's interpretation of 'most-likely'; see calculation on the Figure and discussion in the text.
Source: See discussion in the text.

Figure 12 gives my interpretation of Saudi Aramco's stated reserves picture including undiscovered oil (shown by the left vertical stacked bar), and my assessment of what may be the 'most likely' values (the right stacked bar).

For generating the Aramco perspective, the bar on the left includes the 105 Gb of historical production (shown by the cross-hatched layer) up to 2004, and the quoted 260 Gb of remaining *proved* ('1P') reserves, shown here in red. If then probable, possible and undiscovered oil are added in, the left bar thus reflects the possibility of a total ultimate *remaining* oil reserves estimate (including undiscovered) in excess of 450 Gb, which agrees with the statement by Saudi Oil Minister Ali Al-Naimi in December 2004.

Aramco's total original *proved plus probable* reserves (i.e., already produced plus remaining) vs. the 700 Gb oil initially in place equates to an average proved recovery factor of 57% - higher than more than 95% of the major oil fields in the world (Figure 8). For the sake of argument, given that we do not have access to reservoir quality data, I have assumed a prudent recovery factor of 45% averaged across all Aramco's fields (Norway, for example, is averaging perhaps ~40% recovery factor, and Malaysia about 35%). Hence, my 45% recovery factor multiplied by my conservative, lower assessment of 600 Gb OIIP (excluding undiscovered), and subtracting off already produced, yields remaining *proved* reserves of 165 Gb, some 95 Gb less than Aramco is quoting.

Probable reserves for Aramco fields are estimated at a reasonable additional 5% of OIIP, i.e., 30 to 35 Gb of incremental recovery for both scenarios.

From what little public information is available, Aramco has stated that another 10% recovery is considered possible with new technology and tertiary recovery methods. If history is anything to go by, insofar as enhanced oil recovery (EOR) is concerned, if it works at all, a 10% increase in recovery is about the most you can hope for assuming the field in question is a good candidate for the application of the specific technology. In 2004, EOR production accounted for less than 1% of the world's total oil production or about 800,000 b/d. For sake of argument, I have assumed that not all Saudi fields will be good EOR candidates, and have therefore assumed what I consider a still optimistic 5% additional recovery on average *for all the fields*. This equates to 30 Gb for my estimate vs. 70 Gb for the Aramco perspective.

For new discoveries, Aramco has adopted the USGS estimate of roughly 90 Gb; i.e., 45% of the 200 Gb of the new discovery OIIP that Aramco predicts over the next 20 years. Again, given Aramco's relatively modest new discovery trend of less than 2 Gb per year during the 20 years (1985-2005), I have optimistically included 30 Gb of new discoveries for the next 20 years (2006-2025).

Based on the above assumptions, we are now in a position to compare the Aramco view with my estimates. As mentioned earlier, from the Aramco perspective the country's total remaining reserves of conventional oil (including that undiscovered) is 455 Gb. This is close to the 461 Gb quoted by oil minister Al-Naimi, and where the above breakdown perhaps helps explain where this apparently high number came from.

Note also that 455 Gb of remaining reserves (including undiscovered), plus the 105 Gb of historical production, gives the country's conventional oil 'ultimate' as ~560 Gb. This corresponds to an average recovery factor of 62% of the stated OIIP total of 900 Gb (including undiscovered), which if it comes to pass will be the best ever recovery factor for a single country with oil reserves of this magnitude.

By contrast, my assessment of the country's remaining reserves (including undiscovered) of conventional oil is 255 Gb, some 200 Gb less than the Aramco value. This represents a recovery factor of 55% of my assessed total OIIP of 660 Gb (including undiscovered), which again if it comes to pass will be the best ever from a single country.

It is important moreover to point out that the difference between these two estimates (of 455 Gb vs. 255 Gb) is equivalent to 55 years of Saudi Arabia's current production level of 10 Mb/d; a difference which has significant implications for the world's economy.

The truth is that we just do not know what the Saudi reserves are. All we have today [2005] is Saudi Arabia's word as to what they might be; and assessments such as I give above. [In this context see the recent information on Saudi Arabia's now-audited reserves, given in the Epilogue below.]

2.4 Long-term production levels

We can now use the above information to evaluate what might be realistic for Saudi Arabia's long-term levels of oil production. We start with Figure 13, which gives a 50-year scenario of Saudi Arabian production if held flat from 2005 at 10 Mb/d.

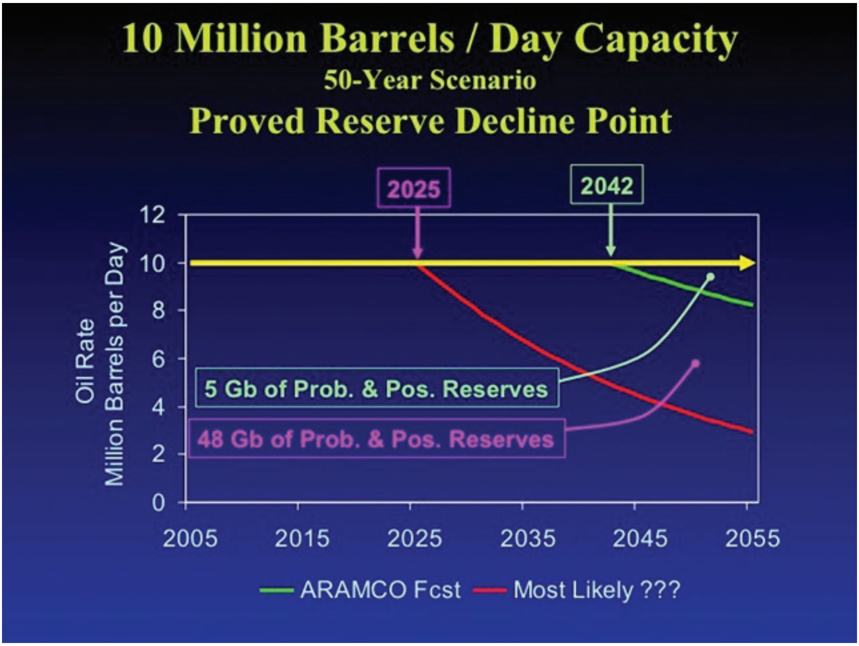

Figure 13. 50-year Scenario of Saudi Arabian Oil Production, if held flat at 10 Mb/d.

Notes:

- Horizontal line: Production at 10 Mb/d.
- Line showing decline of oil production from proved reserves from 2025: This corresponds to the author's 'most likely' estimate of Saudi Arabia's proved reserves of conventional oil of 165 Gb; and on a decline point calculated as given in the text.
- Line showing decline of oil production from proved reserves from 2042: This corresponds to Aramco's stated estimate of Saudi Arabia's proved reserves of conventional oil of 260 Gb; and on a decline point calculated as in the text.
- Also indicated are the additional quantities of oil production from probable and possible reserves required in the two cases if the total production to 2055 at 10 Mb/d is to be met.

Source: Author.

Figure 13 illustrates Saudi Arabia's capacity to sustain 10 Mb/d of oil production for the next 50 years. It also illustrates the decline point of the currently proved reserves base.

Aramco's February 2004 forecast indicated that 10 Mb/d for 50 years was relatively easily achieved, with production from their stated remaining proved (1P) reserves beginning to decline from 2042, and the resulting small shortfall being made up of production from the probable and possible reserves categories.

By contrast, if instead my 'most likely' estimate of the remaining proved reserves (of 165 Gb) is used, and assuming the same decline point at 66% of the total: 'already produced plus remaining *proved* reserves' that Aramco's calculation implies, this suggests that production from current proved reserves will begin decline some 17 years earlier, in 2025; and where now the subsequent shortfall against production of 10 Mb/d out to 2055 has to be made up of 48 Gb of production from the probable and possible reserves, out of my total estimate for these classes of reserves of 60 Gb (see Figure 12).

I therefore conclude that it is *possible* on my 'most likely' estimates of the *total volumes* of reserves for Saudi Arabia to sustain 10 Mb/d for the next 50 years. [But see the caveat in the Epilogue on the difficulty of achieving such production.]

In addition, it may be worth noting that the last time Saudi Arabia produced *annual* averages approaching 10 Mb/d was in 1980 and 1981, when production averaged about 9.6 Mb/d. Over the last ten years (ending 2004) average annual production has been 7.8 Mb/d, with a maximum annual average of 8.1 Mb/d in 1997. Recently [2005], Aramco has been producing about 9.5 Mb/d, but has yet to sustain this high a volume for a year.

Now we look at the case of Saudi Arabia's capacity to sustain a higher production level, of 12 Mb/d, starting in 2005 for the next 50 years. This is because Aramco has announced plans to increase production capacity from 10 Mb/d to 12 Mb/d from 2009. This case is examined in Figure 14.

The analysis here is similar to that of Figure 13. Again, Aramco's February 2004 forecast indicated 12 M/d was easily achieved with their estimate of remaining proved reserves beginning to decline from 2033 (9 years earlier than the 10 Mb/d case), with the shortfall again being easily made up of reserves from the probable and possible categories.

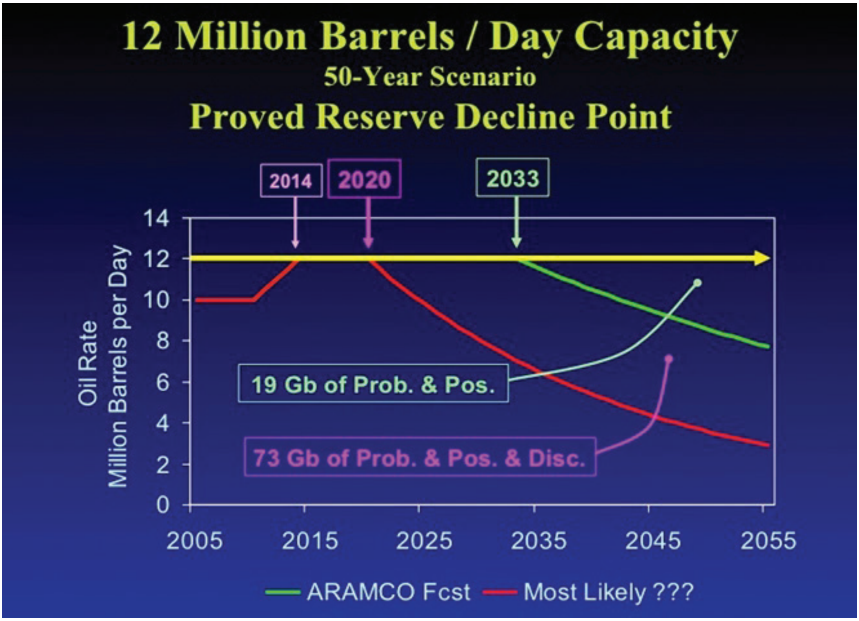

Figure 14. 12 Million Barrels / Day Capacity

If instead my lower 'most likely' estimate of proved reserves is used, and assuming this time the same 63% of proved reserves 'decline point' that the Aramco data implies, this suggests that the country's proved reserves will begin decline in 2020 (i.e., 5 years earlier than the decline point for 10 Mb/d plateau), with the short fall being made up by 73 Gb of reserves from the probable, possible and undiscovered categories. This exhausts my 60 Gb of probable and possible reserves estimate (a volume equivalent to the entire North Sea), and requires 13 Gb of new discoveries. I therefore conclude that Saudi Arabia may have difficulty in sustaining 12 M/d beyond 2040. Also, a significant number of new discoveries will be required to produce at this level through mid-century.

What I have been talking about is the ability for the oil field reservoirs themselves to produce additional oil. An additional two million barrels of oil a day is a lot of oil. Nigeria, one of OPEC's members produces just two million barrels of oil a day. There is the knock-on effect of additional infrastructure required; e.g. more drilling rigs, more well tubulars, more pipelines, more water supply for injection, more pumps, more compressors, more crude stabilizing facilities, more three-phase separation facilities, more offloading jetties for tankers, more tankers themselves, and more refineries built by the importers to handle the type of crude.

These projects are not insignificant and are not accomplished overnight. With the high oil prices of today (2005), steel mills, shipyards, and manufacturing plants serving the oil industry are working at full capacity with long backlogs and a scarcity of technical people.

3. Spare Capacity, and Export Capacity

Now we turn to two topics related to the above discussion; the country's spare production capacity, and its export capacity.

3.1 Spare capacity

Figure 15 lists some of the factors related to Saudi Arabia's ability to maintain spare production capacity.

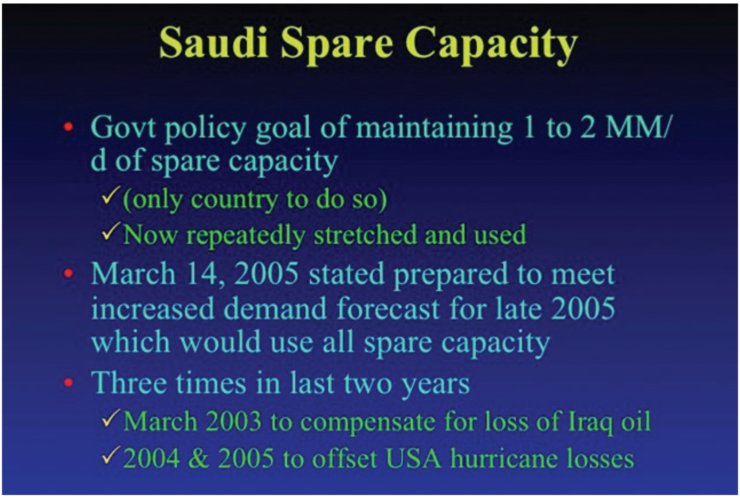

Figure 15. Factors relating to Saudi Arabia's Spare Production Capacity

By government policy, Saudi Arabia is the only country to plan and provide for spare production capacity to help stabilize world oil prices. It is the Saudi government's stated goal to maintain 1.5 to 2 Mb/d of spare capacity. But now this spare capacity is being repeatedly stretched and used.

In March of this year (2005), the Saudi oil minister said that Saudi Arabia is prepared to use its spare capacity to meet the increase in demand, forecast for later this year as we move into the winter season. Three times in the last three years, Saudi Arabia has used its spare capacity to stabilize oil prices and markets: first, in March of 2003 to compensate for loss of Iraq oil and, again, in 2004 and 2005 to offset USA hurricane losses in the Gulf of Mexico.

It now appears that world demand is quickly absorbing this only significant remaining spare capacity into its daily diet. This largely explains why oil prices have increased over the last 24 months and for the moment stabilized in the $60 / bbl range.

The World has changed in the last 18 months. It has gone from an era of oil prices largely controlled by OPEC's ability to provide extra production from its spare capacity to a new era of little spare capacity where demand controls the price level and any disruptions to supply, whether natural or not, send prices up or down. If Saudi Arabia is to maintain their spare capacity to help stabilize oil prices, then they must build additional capacity beyond the 10 and 12 M/d sustained levels that my previous two charts describe. Again, to do so is no small feat.

3.2 Export capacity

Now we look at the country's ability to export oil, given its domestic demand, see Figure 16.

We tend to think of Saudi Arabia solely as an oil exporter, but in recent years its internal oil consumption has grown considerably. When I was with Aramco in 1980, production exceeded at times 10 Mb/d, as indicated in Figure 16. With a population estimated then at 7 million people, and with the industries then in place, oil consumption was about 0.5 Mb/d, with the remaining 9.5 Mb/d exported.

Move forward 25 years to today (2005), and this chart once again shows Saudi Arabia producing about 10 Mb/d of liquids. But this time with a population having increased by a factor of three to about 22 million, oil consumption in the Kingdom has increased by nearly the same factor to about 2 Mb/d, leaving little more than 8 Mb/d for export or about 1.5 Mb/d less export than 25 years ago.

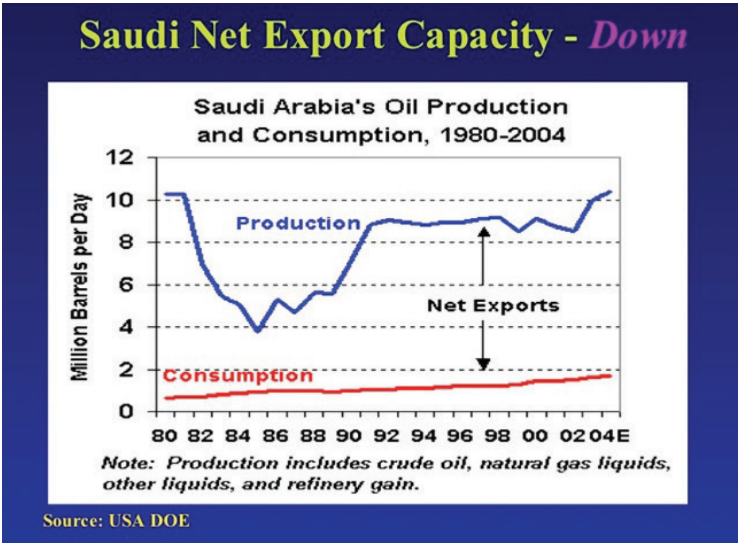

Figure 16. Saudi Export Capacity.

4. Conclusions

The main conclusions of this paper are summarised in Figure 17. These main conclusions are as follows:

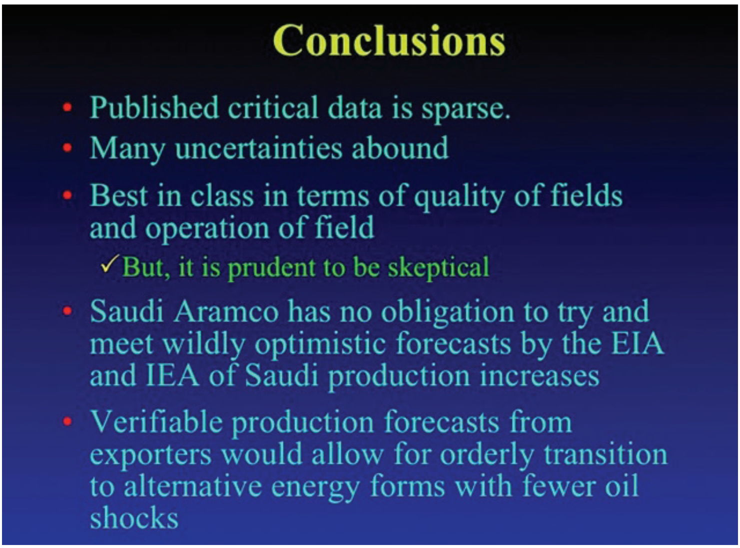

Figure 17. Main Conclusions.

(i). Published critical data on the oil reserves of Saudi Arabia are sparse, giving rise to many uncertainties regarding Saudi Arabia's ability to realistically achieve significant production increases for the long term. I wish to make it clear that I am not "Aramco bashing" today. Saudi Aramco represents the "best in class" in terms of quality of fields and field operations. In my opinion, international oil companies such as ExxonMobil and BP could do no better. However, the mature stage of development and operations into which Aramco is entering require more complex and advanced production techniques, many of them state-of-the-art. And because they are new and cutting edge, the benefits on long-term oil recovery are still unknown.

(ii). In light of what is known, and more importantly, what is not known, I think it prudent to be sceptical of current reserves estimates and production forecasts, and to plan accordingly. As a reminder to us all, Saudi Arabia has no obligation to try and meet wildly optimistic forecasts by the various energy agencies. Saudi Arabia is going to do what is good for its people and the stability of its government, as well being a reliable member of the global community.

Colin Campbell, Matt Simmons and others in the industry have called for some form of verification of reserves and production volumes of oil producers and exporters. Such a process would allow for orderly planning and transition to alternative energy forms with fewer oil-related shocks and the ensuing economic and civil upheavals.

I am reminded of the cartoon in the game of American baseball where the first two batters strike out and they then get upset when the third batter also strikes out, causing their team to lose. Saudi Arabia is the 'third batter' in this story. If the story is to end with a win, the other two batters, i.e. the oil producers and consumers of the rest of the world, have an equal responsibility to efficiently steward production and conserve their resources

5. Epilogue (written March 2017)

[See also the 'Editor's comment' at the end of this paper.]

More than 11 years have passed since this paper was presented in October 2005.

Nearly three years later, in June 2008, oil prices spiked, more than doubling to $140/bbl before collapsing to less than $50/bbl by

December the same year. Coincident with this, new oil from fracking was coming on-stream in North America, building to more than 4 Mb/d (more than 50% of the USA output) today.

Saudi Arabia's oil production in 2016 increased to more than 10.6 Mb/d for a few months (a new record), the highest level since the early 1980s; see Figure 18. The economic standoff between Saudi Arabia's increased production and additional North American production resulted in a precipitous price collapse to below \$30/bbl in January 2016.

At the World Economic Forum at Davos, Switzerland in January 2017, Saudi Aramco's CEO Amin H. Nasser stated that *"The Kingdom has a capacity of 12.5 million bpd, and it continues to build on that capacity."* No significant new discoveries for Saudi Arabia have been announced since 2005 insofar as the author is aware. Cumulative production since October 2005 is more than 40 Gb, bringing the total Saudi oil cumulative production to more than 145 Gb. The population in 2014 in Saudi Arabia has increased to more than 30 million, with indigenous oil consumption increasing to more than 3 Mb/day.

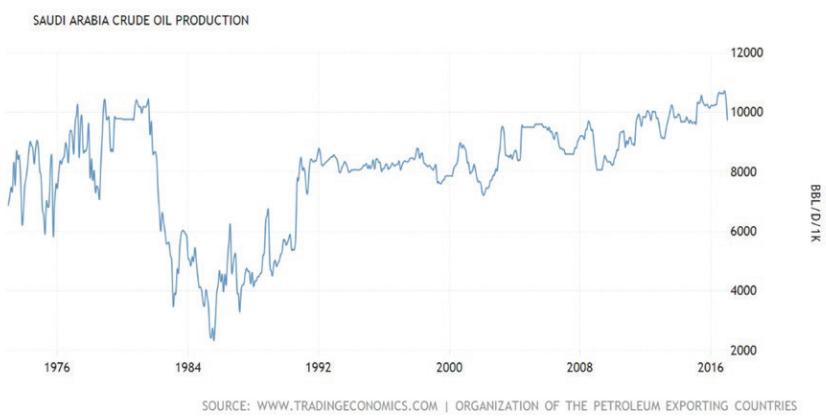

Figure 18. Saudi Arabia Oil Production up to January 2017.

Perhaps the most significant recent news is the Reuters report of January this year (2017) regarding the first independent audit of Saudi Aramco's oil reserves. Two U.S. oil reserve auditing companies (Gaffney, Cline & Associates and DeGolyer & MacNaughton) had been chosen two years ago to make such audits, and under the headline: *"Saudi Aramco's oil reserves confirmed by external audit – sources",* Reuters reported that DeGolyer & MacNaughton had completed its audit in 2016. The report went on to say:

> *"The first independent audit of Saudi Aramco's oil reserves … has confirmed the state oil company's own figures, sources familiar with the situation said, ahead of its planned share market listing next year. … 'The independent audit produced no surprises,' a source familiar with the situation said on Friday. 'Aramco's reserves have always been reported internally in line with international practice.' … Aramco said its crude oil and condensate reserves were 261.1 billion barrels in its 2015 annual report. … The reserves audit produced figures 'definitely not below' those published by Aramco, a second source familiar with the matter said, while a third source said the auditing firm's estimate was higher than Aramco's own." Incidentally, Reuters noted that none of Aramco, DeGolyer, or Gaffney, Cline could be reached for immediate comment.*

What are we to make of this?

If the finding applies to the same class of reserves as reported in the company's Annual Report, this implies that the company has been successful in replacing production with new reserves since 1990. Moreover, if we assume the reported ~260 Gb of reserves as of 2015 are proved reserves (and also, by definition, 'remaining'), this would extend Aramco's ability to produce at a sustained plateau of 10 Mb/d to beyond 2050; or at a sustained plateau of 12 Mb/day to beyond 2040.

But the Reuters report did not formally define whether statements from the sources about the reserves were referring to proved, probable and/or possible reserves. There is thus is still a large measure of uncertainty about the country's reserves, as discussed in the 2005 presentation given above. Fortunately, as the Saudi Aramco IPO progresses, the category of reserves being referred to will become clearer.

References / Endnotes

1. *The World Energy Dilemma,* a book by Louis W. Powers, former Chief Petroleum Engineer for Aramco and my former boss.

2. *Fifty-Year Crude Oil Supply Scenarios: Saudi Aramco's Perspective,* presentation by M. Abdul Baqi and N. Saleri, Saudi Aramco, Center for Strategic and International Studies, Washington D.C. February 24, 2004.
3. Simmons, M. R. (2005). Twilight in the Desert: *The Coming Saudi Oil Shock and the World Economy,* Wiley. See chapter 10: *Coming Up Empty in New Exploration.*

Author's Biography

Jack Zagar is an independent petroleum reservoir engineering consultant, and an Associate of MHA Petroleum Consultants of Denver Colorado. He has more than 40 years petroleum engineering experience, 22 years with Exxon and 18 years of independent consulting. He was on loan from Exxon to Aramco from 1977 to 1980 during which time he was the reservoir engineer on the producing super-giant Abqaiq field, as well as being involved in the early development and appraisal of the giant fields Shaybah and Khurais. His career also has included engineering, project management, economic evaluations of projects, property trades and asset sales and planning assignments in the North Sea, onshore Europe, Gulf of Mexico, onshore U.S.A, and offshore Nigeria. During the period 2006-2008, he was a Co-director of ASPO Ireland.

Editor's comment:

As Editor, I take the opportunity here of adding two perspectives to the above excellent paper that might be useful. These relate Saudi Arabia's potential for future oil production to estimates of the country's likely ultimately recoverable resource ('URR') of conventional oil.

(i). Production decline of all reserves classes, and of yet-to-find

The first perspective concerns the declines expected in the country's production of its *proved* and *probable* reserves, and of its *as-yet-undiscovered oil.* These declines would be expected to mirror in some measure the decline in the production of the oil in proved reserves which was modelled in the author's Figures 13 and 14.

Put another way, production of Saudi Arabia's total reserves, plus that of undiscovered oil, cannot came to an abrupt end sometime after 2055. This is because in any region, as production from the large old fields declines, and that from the newer and smaller fields ramps up, at some point production from the *region as a whole* reaches a peak and then tails away. For most regions this peak of total production occurs at roughly the *mid-point* of the region's ultimately recoverable resource ('URR'), or a bit before. For regions like Saudi Arabia - where generally production from very large fields is long held on plateau - the regional peak of total production is likely to be somewhat later than mid-point.

But this regional peak occurs nevertheless, and hence if the declines of all three classes of reserves and that of the yet-to-find are factored in, then production to 2055 at 10 Mb/d looks technically very difficult (and perhaps impossible) if the lower 'most-likely' reserves estimates given in Zagar's paper above are assumed, even if the country wished to pursue such a course.

(ii). Range of estimates of Saudi Arabia's conventional oil URR

The second perspective relates to URR data for Saudi Arabia published in a recent paper in this journal, Laherrère et al. (2016, 2017). This presented a number of estimates for Saudi Arabia's conventional oil URR, see in particular Section 6.4.1 in Part-1, and Section A5.4.4 in Part-2.

The text to Figure 26 in Part-1 of that paper gives estimates for Saudi Arabia's URR of conventional oil, where these were generated by adding the country's cumulative production (of ~140 Gb to 2015) to various 2P reserves estimates, plus estimated yet-to-find. These resulting URR estimates were:

- 'Hubbert linearisation' of Saudi Arabian production data: ~325 - 350 Gb;
- Rystad Energy data (2016 estimate): ~355 Gb;
- IHS Energy 2004 2P reserves, plus Rystad yet-to-find: ~365 Gb;
- IHS Energy 2011 2P reserves, plus Rystad yet-to-find: ~460 Gb;

These compare to the 2005 conventional oil URR estimates given in Zagar's paper above, in Figure 12, of:

- Saudi Aramco URR: 560 Gb
- the author's estimate of 'most likely' URR: 360 Gb.

In summary, we thus have three distinctly different estimate ranges for Saudi Arabia's URR for conventional oil:

- around 350 Gb: IHS 2004; Rystad 2016; Zagar (i.e., this paper) 2005; Hubbert linearisation of production, 2016;
- about 100 Gb greater, at ~450 Gb: IHS 2011; and
- about 100 Gb greater still, at ~550 Gb: Saudi Aramco data, 2005 estimate; and probably also Saudi Arabia today if the ~261 Gb figure in the company's *Annual Report* is for proved reserves only, to which probable reserves and yet-to-find need to be added.

As Zagar says in his paper, only when external audits are made public will we know Saudi Arabia's true reserves position; but cautious analysis indicates that surprises may well be in store.

Reference

Laherrère, J. H., Miller, R., Campbell C.J., Wang, J. and Bentley, R.W. (2016 & 2017). *Oil Forecasting: Data Sources and Data Problems:* Part 1 (2016): The Oil Age, Vol. 2 No. 3, pp 23-124; Part-2 (2017): The Oil Age, Vol. 2 No. 4, pp 1-88; Part-3 (2017): The Oil Age, Vol. 3 No. 1, pp 1-135.

Production Outlook for Global Fossil Fuel Resources, and Resulting CO2 Emissions

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Note:

The following paper combines, in abbreviated and updated form, two previous papers: Mohr et al. (2015) and Wang et al. (2017). Both papers dealt with global production forecasts of the three main fossil *fuels (oil, gas and coal) based on the likely ultimately recoverable resources ('URRs') of these fuels, including both conventional and non-conventional resources.*

Mohr et al. (2015) assembled extensive oil, gas and coal URR data, and combined judgements on these data with the GeRs-DeMo model to create detailed projections of world fossil fuel production (including non-conventional sources) by country and fuel type. Within this, four critical countries - China, USA, Canada and Australia - were examined in detail, with production projections made at the state/province level. In addition, by converting the fossil fuel projections to greenhouse gas emissions, the projections were compared to IPCC scenarios. This indicated that based on current URR estimates there are insufficient fossil fuels to deliver the higher IPCC A1Fl and RCP8.5 emissions scenarios.

Wang et al. (2017) assembled long-term projections of global fossil fuel production published since 2000 covering 36, 18 and 18 forecasts respectively for conventional oil, conventional gas, and coal production; and 29 and 15 forecasts respectively for non-conventional oil and non-conventional gas. These forecast were combined statistically to yield 'most-likely' mean values under two scenarios. CO2 emission factors for each type of fossil fuel were then used to convert the data to carbon emissions, and these values combined with estimates of CO2 emissions from non-fossil-fuel sources. The reduced-complexity coupled climate model, MAGICC 6.3, was then used to project future climate change under the two scenarios of total CO2 emissions, and the results compared to IPCC projections.

Abstract

This paper uses the Geological Resources Supply-Demand Model (GeRs-DeMo) to present detailed long-term projections of world fossil fuel production, including from non-conventional fossil fuels. The paper first assesses the likely range of the global ultimately recoverable resources (URRs) of the three main fossil fuels: oil, gas and coal. This yields a URR range, in energy terms, for total global fossil fuels combined, including non-conventional sources, of about 50, 75, and 120 ZJ in our 'Low', 'Best guess' (BG) and 'High' scenarios, respectively.

Running the model with these data indicates that the annual global production of all fossil fuels combined (including the non-conventionals) is likely to peak at between 500 and 750 EJ/y, with this peak occurring as early as 2020 in the Low scenario, and as late as 2050 in the High scenario. In our 'Best-guess' scenario, global production of all fossil fuels combined is likely to peak around 2025, at 570 EJ/y. This date of peak is much earlier than many analysts suppose. We compare these forecasts with other published studies, and find that our High scenario forecast represents a probable realistic upper-bound to total fossil fuel production.

Finally, we convert our forecasts into CO2 emissions, and compare these to IPCC projections. The result suggests that the higher emission scenarios modelled by the IPCC are not plausible, at least if driven by CO2 emissions primarily from the combustion of fossil fuels.

1. Introduction

Energy is an important resource for the development of human civilization, and fossil fuels provide by far the largest share of current world commercial energy. According to the BP *Statistical Review of World Energy,* the world's total fossil consumption was 11.3 billion tonnes of oil equivalent (Gtoe) (473 EJ) in 2015, accounting for some 86% of world total commercial energy consumption (BP, 2016).

Many mainstream institutes forecast that the demand for fossil fuels will continue increasing until at least 2050 in their 'medium' cases, although they generally recognise that the growth in demand may be lower than in previous decades. For example, world fossil fuel consumption is forecast by the U.S. Energy Information Administration (EIA) to increase from 461 quadrillion Btu (PBtu) (486 EJ) in 2012 to 638 PBtu (673 EJ) in 2040 (EIA, 2016). Similarly, the International Energy Agency (IEA) forecasts that fossil fuel demand will grow from 11 Gtoe (460 EJ) in 2014 to 13 Gtoe (545 EJ) in 2040 (IEA, 2016).

We contend that these forecasts are generated primarily from a 'demand-side' perspective, where the assumption is made that available resources of fossil fuels are sufficient that there are no significant medium-term constraints on the supply side; hence the usage of fossil fuels will be determined primarily by such factors as economic and population growth, technical progress, gains in energy efficiency, and the development of alternative energy sources (Wang et al., 2017).

This reliance on 'demand-side' analysis also appears to be the case in climate change research. It is widely accepted that anthropogenic greenhouse gas (GHG) emissions, dominated by CO2 from fossil fuel combustion, are the driving cause of global climate change. Predictions of future climate change are therefore strongly tied to predictions of future fossil fuel use and corresponding CO2 emissions. The official emission scenarios adopted by the Intergovernmental Panel on Climate Change (IPCC), such as in the Special Report on Emissions Scenarios (SRES), and in the subsequent use of representative concentration pathways (RCPs), include scenarios of high fossil fuel use that are not supported by contemporary fossil fuel production modelling.

The reason for IPCC reports including such high emissions scenarios is not fully clear to us, but may reflect the view of the SRES authors of there being very large potentially available resources of fossil fuels (including coal, kerogen, and very large volumes of methane hydrates), combined with demand-side analysis, without full consideration of the potential likely constraints on fossil fuel supply due to the practical availability, and (importantly) depletion profiles, of these resources. For discussion of the views of SRES sources on this topic see Aleklett (2012) Chapter 17, and especially pages 241, 247 and 254-257. And in this context, see also Höök and Tang (2013); and Wang et al. (2017).

Long-term fossil fuel scenarios that are outside the bounds of reasonable projections based on resource availability should be avoided, or at least assigned a low probability, to ensure climate change risks can be assessed appropriately. Therefore, the study of reasonable upper-bounds on fossil fuel production remains an important area for research. Moreover, inasmuch as the future availability of energy will affect human wellbeing including ability to withstand and adapt to climate change impacts, it is important to consider projections of future energy from a dual risk perspective (climate change impacts and energy security).

In terms of examining future energy trajectories, M. K. Hubbert (1949) was one of those to describe the long-term production pattern of fossil fuels from the perspective of geological resources, where importantly he maintained that: *'the production curve of any given species of fossil fuel will rise, pass through one or several maxima, and then decline asymptotically to zero.'* Hubbert (1956) then used such a 'bell-shaped' model (originally drawn by hand, without reference to an equation) to forecast the production of US Lower-48 conventional oil based on two estimates of the region's ultimately recoverable resource ('URR') of such oil; a prediction that proved to be correct.

Subsequently there have been numerous studies that have examined the long-term production of one or more fossil fuels from a similar 'geological' perspective. These have included: Campbell (1991), Ivanhoe (1996), Campbell and Laherrère (1998), and Deffeyes (2001); as well as more recently: Mohr and Evans (2007a, 2007b, 2009, 2010, 2011), Maggio and Cacciola (2009); Wang et al. (2011, 2013a, 2013b, 2013c), Höök et al. (2010), Patzek and Croft (2010), Rutledge (2011), and Mohr et al. (2015).

However, there have been some limitations in some of these studies. The first is lack of comprehensive analyses for all types of fossil fuels, since most of these studies only focus on one type of fossil fuel, such as only oil, gas, or coal. The second limitation in our view has been insufficient consideration of non-conventional fossil fuel resources, where many of the studies have focussed on production of only the conventional fossil fuels. A third limitation has been lack of consideration of the potential impacts of stochastic events on production, since the latter can be significantly interrupted by such events. Lastly, but importantly, there has often been a lack of the 'full picture' in presenting such forecasts, by not properly recognising the degree of uncertainty that surrounds estimates of ultimately recoverable resources (URR) of the fossil fuels considered, where reliance on only limited results risks providing insufficient evidence for policy makers.

The purpose of this paper is to present detailed forecasts of world fossil fuel production, while at the same time addressing the issues identified above. In particular, the forecasts presented here consider the resource bases of both conventional and non-conventional fossil fuels.

Note that for the non-conventional fossil fuels, there is no full consensus on the definition of these. In this paper we consider not only those currently believed likely to achieve significant development in the future, such as coalbed methane (CBM), shale gas, other tight gas, extra-heavy oil, natural bitumen and tight oil, but also those fuels that are believed by some as unlikely to achieve large-scale development before 2100 due to their unfavourable economic and technical conditions. These include oil from kerogen, and gas from methane hydrates (Rogner, 1997). Our forecasts use a model that can incorporate the impacts of stochastic events on production. Moreover, an attempt is made later in this paper to show the 'full picture' by including forecasts presented elsewhere in the literature. Finally in this paper we analyse the impacts of such likely 'resource-constrained' fossil fuel production on future GHG emissions and implications for climate change predictions.

2. Resource Availability Analysis

Resource *availability* is a key factor affecting forecast results of fossil fuel production. It should be noted that resource availability is not the same as *total resources*.

Total resources are defined as the total quantities of a fossil fuel resource that are located underground. As many institutes and scholars have indicated, a significant part of a fossil fuel's total resources may never be recovered, where these extra resources are defined as *additional occurrences* by Rogner (1997), *or as unrecoverablwe resources* in the Petroleum Resources Management System (PRMS) proposed by SPE/AAPG/WPC/SPEE (2007).

Available resources (as opposed to total resources) should be a reasonable assessment of the total *recoverable* resources of a fossil fuel, and refer to the resource that can be technically and economically extracted from the deposits. These quantities should not, however, be simply those currently technically, economically and politically extractable, but include – as best as can be estimated – future potentially recoverable resources, to reflect possible long-term improvements in technological and economic conditions, making part of unrecoverable resources extractable. Based on these considerations, the literature generally uses the term of *ultimately recoverable resource* (URR) to reflect total resource availability, including not only past production and present mean (2P) remaining reserves, but also potential future discoveries, as well as reasonably likely future gains in technology or the economics of extraction (such as future higher prices).

It is recognised that it is difficult to present accurate URR assessments of global fossil fuels due to lack of data, quality of data, and inconsistent or inapplicable resource classification systems. Current URR assessments are therefore all rather subjective estimates, based on partial information, to high uncertainties. To reflect these uncertainties, this paper (like many others, for similar reasons) adopts a 'scenario analysis' approach to URR values, and presents three scenarios as follows: a Low scenario (to attempt to define a reasonable lower-bound on the URR values selected); a High scenario (to obtain a realistic upper-bound on the URR); and a 'Best Guess' (BG) scenario that the authors believe to reflect a most-likely estimate of the URR.

The URR estimates of world fossil fuels have been collected from various sources. Specifically, the URR values in the Low scenario are mainly from Laherrère (2009a, 2009b), Campbell (Campbell and Heaps, 2009) and Rutledge (2011), since these authors tend to have URR estimates at the low end of literature range. URR values in the High scenario are mainly from the World Energy Council for coal (WEC, 2013), and Federal Institute for Geosciences and Natural Resources of Germany for oil and gas (BGR, 2012). For URR values in our 'Best Guess' scenario, some are the values of the Low scenario, some are the values of the High scenario, and the remainder are typically estimated either from the literature, or by averaging Low and High scenario values.

In the modelling presented in this paper, the URR of the various fossil fuels were partitioned into over 900 different region/fuel types. Typically a URR was broken down by country, fuel, and fuel subtype (e.g. 'Venezuela, oil, extra heavy oil').

For oil and gas, we estimated URRs of conventional oil and gas, and of various subtypes of what we have classified as non-conventional oil and gas; namely 'light-tight' oil, natural bitumen, extra-heavy oil, and kerogen for non-conventional oil; and coal bed methane, shale gas, other tight gas and hydrates for non-conventional gas.

As there are no standard categories for conventional vs. non-conventional coal resources, in this paper we divide the coal resources into five categories based on their quality, namely: anthracite, bituminous, sub-bituminous, lignite and semi-anthracite. The first four categories are common and fairly well understood (Baruya et al., 2003), while the fifth category (semi-anthracite) is used to describe a small number of resources that are part way between anthracite and bituminous coals. In addition, the term 'black coal' is used in this paper denote anthracite plus bituminous coals, while 'brown coal' denotes sub-bituminous and lignite coals. For modelling of total primary energy supply, all fuels are expressed in units of exajoules (EJ); the conversion factors used are shown in Table 1.

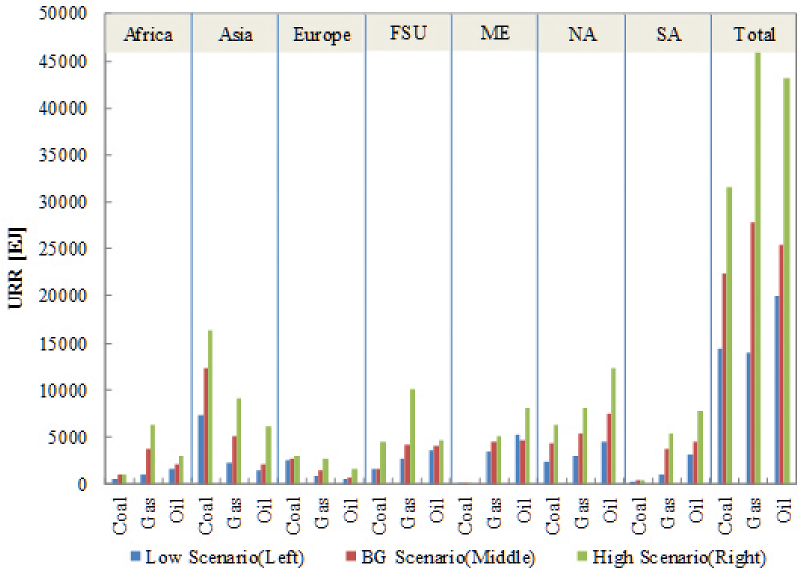
Table 1. Conversion factors used in this paper

1. Coal:

Fuel	Sub-Fuel	Energy content	Units	Mass to CO2 conversion	Units
Coal	Anthracite	30	EJ/Gt	2122	MtCO2/Gt
Coal	Bituminous	24	EJ/Gt	2026	MtCO2/Gt
Coal	Sub-bituminous	16.5	EJ/Gt	1510	MtCO2/Gt
Coal	Lignite	9.5	EJ/Gt	1126	MtCO2/Gt
Coal	Semi Anthracite	29	EJ/Gt	2107	MtCO2/Gt
Coal	Bituminous and Sub-bituminous	20	EJ/Gt	1768	MtCO2/Gt
Coal	Black	26	EJ/Gt	2107	MtCO2/Gt
Coal	Brown	13	EJ/Gt	1318	MtCO2/Gt
Oil	Conventional	5.73	EJ/Gb	434.2	MtCO2/Gb
Oil	Tight	5.73	EJ/Gb	434.2	MtCO2/Gb
Oil	Natural Bitumen	5.73	EJ/Gb	434.2	MtCO2/Gb
Oil	Extra Heavy	5.73	EJ/Gb	434.2	MtCO2/Gb
Oil	Kerogen	5.73	EJ/Gb	610.0	MtCO2/Gb
Gas	Conventional	1.05	EJ/Tcf	54.6	MtCO2/Tcf
Gas	Coal Bed Methane	1.05	EJ/Tcf	54.6	MtCO2/Tcf
Gas	Shale	1.05	EJ/Tcf	54.6	MtCO2/Tcf
Gas	Tight	1.05	EJ/Tcf	54.6	MtCO2/Tcf
Gas	Hydrates	1.05	EJ/Tcf	54.6	MtCO2/Tcf

Data source: Mohr et al. (2015).

The very detailed statistics of each type of URR in each country are not shown here since space is limited; for these refer to Mohr et al. (2015). However, the summarised URR data, by type of fossil fuel and scenario for each geographical region, are given in Figure 1.



Resource	Low (ZJ)	BG (ZJ)	High (ZJ)
Coal	15	22	32
Oil	20	28	43
Gas	14	26	47
Total	48	78	122

Figure 1. URR estimates in different scenarios by regions
Note: BG is Best Guess; FSU is Former Soviet Union; ME is Middle East; NA is North America; SA is South America. Detailed data sources can be found in Mohr et al. (2015).

From Figure 1 we can see that the global URR varies (Low versus High scenario) by a factor of approximately 2 for oil and coal, and approximately 3 for gas. About half of the uncertainty in global coal URR is from Asia, while for oil there are similar magnitudes of uncertainty across Asia, North America and South America. In contrast, there are large differences between high and low estimates of gas URR across all regions, leading to significant uncertainty in the gas URR at the global level.

It should be noted in these estimates that in all three scenarios the global URR of coal is not the largest share of the total global fossil fuel URR. This is in contrast to other literature (e.g. BGR 2012) where coal is the dominant remaining fossil fuel, and points to the importance of considering recoverable, rather than total, resources. We have been deliberately more conservative than some authors on the estimated likely recoverable fraction of total coal resources (see discussion later in this paper). We also note, however, that the URRs of oil and gas assumed here include relatively large quantities of non-conventional recoverable resources of these fuels.

3. Modelling Approach

Many models can be used to forecast the long-term production capacity of fossil fuels, from simple curve-fitting to complex system dynamics models (Brandt, 2010; Wang et al., 2011). Of these, curve-fitting models are probably the most widely used to estimate the maximum production capacity of fossil fuels (Wang et al., 2013a; Wang et al., 2013b; Patzek and Croft, 2010). However, these types of models do not consider the interactions between supply and demand, nor the impacts of potential stochastic events on production.

In this paper, we use the Geologic Resources Supply-Demand Model (GeRS-DeMo). This model uses an algorithm-based approach that allows supply and demand to interact: if demand is higher than supply a signal is sent to place more fields or mines online to try and meet the extra demand, and is able to simulate stochastic events relatively well. The model was originally developed by Mohr (2010), and has been used to develop projections for coal, conventional and non-conventional oil, conventional gas and non-conventional gas, as well as non-energy resources including lithium (Mohr, Mudd and Giurco 2012), phosphorus (Mohr and Evans, 2013), copper (Northey et al. 2014), and various other metallic and mineral resources (Wang et al., 2015).

There are two key modes in the use of GeRS-DeMo: static and dynamic mode. Supply and demand do not interact in static mode, whereas they are influenced by each other in dynamic mode. For this paper, the dynamic mode has been used. The interaction between supply and demand is achieved in the model using a simplified price-supply-demand relationship. While price is not explicitly simulated, a price proxy is calculated based on the percentage difference between supply and demand, providing a signal to stimulate supply and decrease demand or vice versa. Demand is projected based on per capita consumption and future population. Specifically, per capita demand was historically projected to grow exponentially before ideally remaining constant, however the Dynamic version of the model enables the per capita demand to change over time. The projection of population is projected to plateau at 10 billion and can be found in Mohr et al (2015). The model is fitted to historical data (where production data exist) for each of the 900+ nation/fuel combinations.

GeRS-DeMo works by modelling the production of fossils fuels in two distinct ways. For coal and some unconventional oil (natural bitumen, extra heavy oil, and oil from kerogen), production is modelled using the 'mining' model, whereas all other oil production, and also gas production, is modelled by the 'fields' approach.

The mining model works by simulating when a mine is brought online. In the model each new mine in a region is assumed to achieve a higher production level than the one before, where this is due to assumed improvements in technology. (Real-world examples are the use of larger diggers and trucks for open-cast mines, or the introduction of long-wall mining techniques for below-ground mines.)

In the real world also, production from a mine typically remains roughly constant over its life (unless there are significant upgrades or expansions to the mine) due to constraints such as a fixed number of trucks that can operate within the mine or the processing capacity of the mining equipment. The model thus assumes that each mine has a constant output over its life, set to a fixed number of years. Given that mines are assumed to have equal lives, and later mines larger production, later mines are thus also larger in terms of total volume, having higher individual URR values.

Finally the model assumes that mines that are brought on line in a region (when demand is sufficient) must meet a curve of 'current exploitable URR' vs. cumulative production; where 'current exploitable URR' is defined as the total cumulative production to-date in the region plus the remaining recoverable resources of the mines currently online. This curve is assumed to be an exponential, such that it reaches asymptote when the region's cumulative production reaches its total URR.

The outcome of this model is that although the later mines are larger, fewer of these are brought on line vs. the region's cumulative production, and the total production of a region sees a roughly symmetric 'up-and-then-down' production profile. In effect, each mine's constant output, coupled with its decades-long life as assumed in GeRS-DeMo, results in the total production in a region tailing off towards the end because there are then few new mines to add, and the mines already in production continue to close.

The fields model works also by placing successive individual entities on line, but where in this case these are fields, where an individual field's production follows the well-known profile of a long tail of falling production.

Typically moreover, when a new oil or gas region is found, the largest fields are exploited early (e.g. the Forties oil field in the UK North Sea). As cumulative production increases, the size of the fields being brought online in a region tends to progressively be smaller. This results in a profile that resembles the North Sea production: an initial steep growth in production, as a small number of large fields are brought online each with initially a relatively high production rate. Soon the new fields coming online are only medium-sized, but these are sufficient to offset the declining production in the existing fields. Finally, new fields coming online are relatively small and their production is overshadowed by the decline in the fields already producing, resulting in a long steady production decline for the region as a whole.

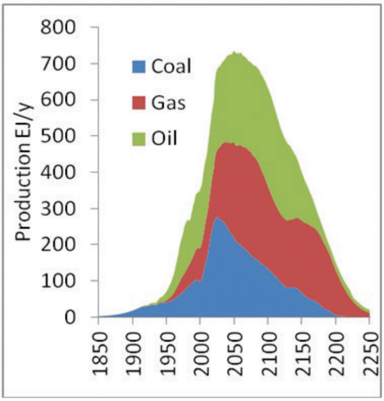
A large country, e.g. the US, typically has many regions of production. In the US example, data exists so that production can be modelled on a state by state basis. For other large countries (e.g. Russia) often this is not possible, but the model does take their multiple regions into account. Specifically here discovery of an individual oil or gas region in such a country follows a different pattern. Initially with limited knowledge, only relatively small oil and/or gas regions are assumed found. As time and knowledge increases, larger regions are found. Eventually knowledge of where the oil or gas is to be found is well known, and all the large fields found; and all that remains are to find the smaller regions that have been ignored or overlooked. For a large country such as the US with multiple regions, the overall roughly 'bell-shaped' total production profile, at least for oil, is well known.

A full description of GeRS-DeMo can be found in Mohr (2010), and in more abbreviated form in Mohr et al. (2015).

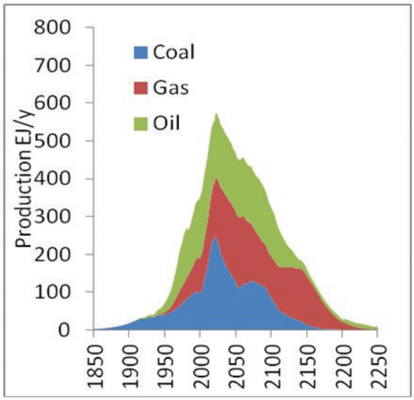
4. Results and Discussion

4.1 Forecast results

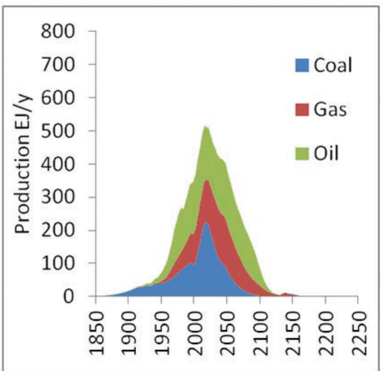
Forecasts of world fossil fuels production by fuel type, using the GeRS-DeMo model combined with the URR values set out above for the different scenarios, are shown in Figure 2.



a) High scenario



b) BG scenario



c) Low Scenario

Figure 2. Forecast World fossil production of fossil fuels by fuel type, under three scenarios.

As can be seen in Figure 2, the results under the different scenarios differ significantly. The predicted trajectories reflect the underlying assumptions in terms of URR for different fuel categories in each scenario:

- The Low scenario is driven primarily by production of bituminous and sub-bituminous coal; conventional oil, extra-heavy and tar sands oil, and light-tight oil; and of mostly conventional gas.
- The BG scenario includes the above quantities, but also significantly greater resources of lignite coal, oil from kerogen and gas from shale and hydrates.
- The High scenario includes the above quantities, but with greater production of lignite and brown coal, as well as larger conventional resources of oil and gas; in this scenario also, considerable quantities of non-conventional oil from kerogen and gas from hydrates are predicted to come on-stream in the distant future, as the large conventional resources are depleted.

In terms of the global production of all fossil fuels combined, these forecasts indicate that this will peak as early as 2020 (at ~500 EJ/y) in the Low scenario, and as late as 2050 (at ~750 EJ/y) in the High scenario. The 'Best-guess' (BG) scenario forecasts that this production of global all fossil fuels combined can increase (if not otherwise constrained) for perhaps six years, reaching peak in 2023 at 571 EJ/y. In the High scenario, although the peak is delayed by some three decades relative to the Low and BG scenarios, the decline in conventional resources offsets growth in non-conventional resources giving an ultimate peak fossil fuel energy production rate only about 40% higher.

A summary of the predicted peak dates for different fuels is given in Table 2.

According to the above analysis, we conclude that the future production of total world fossil fuels will peak probably at the latest by mid-century, with peak production at most likely to be no higher than about 750 EJ/y.

The potential contributions from the non-conventional fossil fuels have been considered in these scenarios; in the high scenario in particular the potential production growth of oil from kerogen-containing rocks, and of gas from methane hydrates. This finding is in contrast to those from a number of 'mainstream' institutes, which

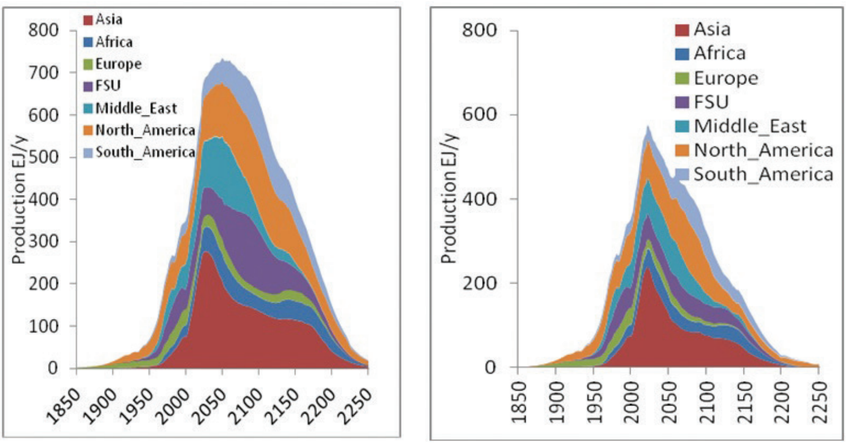
Table 2. World fossil fuel production forecasts under the three URR scenarios

Scenarios	Fuels	Peak year	Peak Production[EJ/y]
High scenario	Coal	2020	270
	Gas	2070	290
	Oil	2100	270
	Total	2050	740
BG scenario	Coal	2020	250
	Gas	2050	190
	Oil	2010	170
	Total	2025	570
Low scenario	Coal	2020	220
	Gas	2040	150
	Oil	2010	170
	Total	2020	520

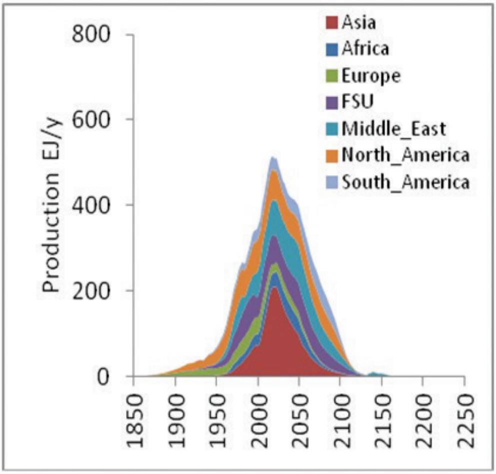
Note: The above data match the results in Figure 2 above, and most numbers here have been rounded.

claim that the resources of the non-conventional fossil fuels are abundant.

The forecasts of Figure 2 are shown in Figure 3, split by geographical region.



a) High scenario b) BG scenario



c) Low Scenario

Figure 3. Forecasts World production of fossil fuels by geographical region, under three scenarios.

4.2 Comparison with other studies

To present a 'full picture' of likely world fossil fuel production as discussed in the introduction, this section investigates the results of some other published studies, and compares these with the results presented here. This part of this paper draws on the analysis presented in Wang et al. (2017).

The comparisons are discussed below by type of fuel: oil, gas and coal. These comparisons suggest that our High scenario gives a reasonable 'upper-bound' of likely total world fossil fuel supply.

(i) Comparison of oil forecasts

A comparison of the world oil production forecasts in this paper against 19 oil forecasts in other studies published since the year 2000 is given in Figure 4.

As can be seen in Figure 4, the global production forecast for oil in our High scenario is the highest of all the forecasts examined except for the result in the *Fast Oil Use scenario* of Kharecha and Hansen (2008).

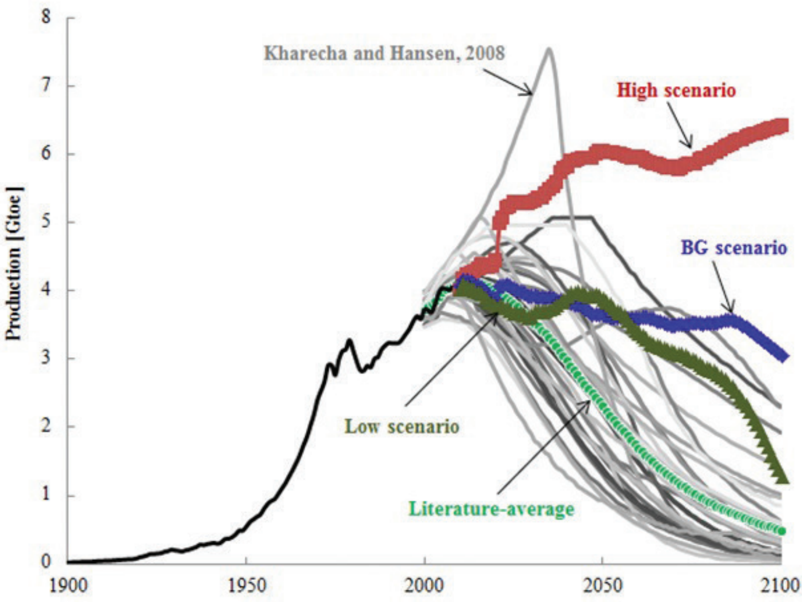


Figure 4. Comparison of world oil production forecasts in this paper to those in some other published studies.
Note: For details of the other studies presented, see Wang et al. (2017).

This scenario from Kharecha and Hansen (2008) is clearly distinct from others in the fossil fuel literature. The reason is possibly that they adopted a model specifically for use in GHG emissions projections, rather than for energy forecasting. This model assumes constant 2% annual growth in global oil production until the ratio of remaining reserves to production decreased to a value of 10 years, declining thereafter to maintain this ratio. This corresponds to US production experience when the reserves used are *proved* ('1P'); it is a very poor model when mean (~ '2P') reserves are used. We note also that total world oil production (including that of non-conventional oil) over the period 2000 to 2015 has averaged an annual growth rate of only 1.2%, and that our model – as with others – assumes a slower growth, followed by a later peak or plateau, than Kharecha and Hansen (2008).

As Figure 4 shows, our High scenario assumes a much greater quantity of oil being ultimately recovered than in any of the literature forecasts. Even the production in our Low scenario assumes larger quantities of oil being available than in the average of the other studies. However, we note that many of the studies shown in Figure 4 considered conventional oil resources only, while neglecting the potential future contribution from non-conventional resources.

(ii) Comparison of gas forecasts

Figure 5 compares, for gas, the production forecasts of this paper with those published in a number of other studies.

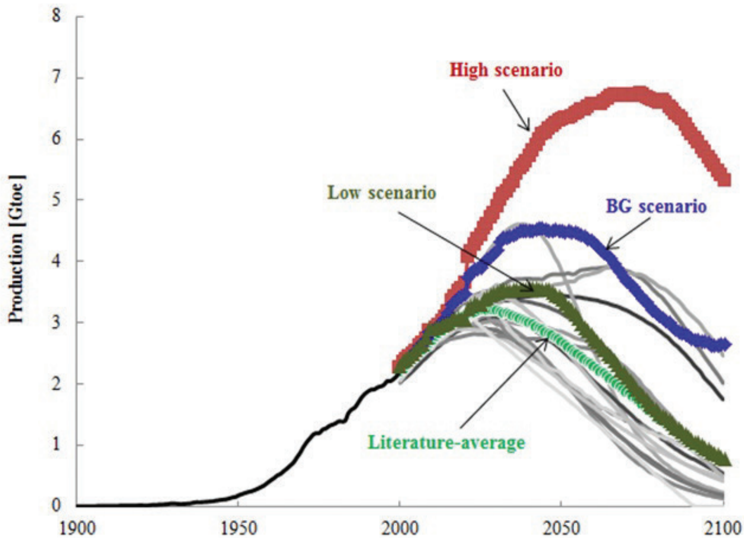


Figure 5. Comparison of world gas production forecast in this paper and those in published studies
Note: For details of the other studies, see Wang et al. (2017).

It can be seen that production of gas in our High scenario by far exceeds those of the other forecasts considered; and even our BG scenario matches effectively the upper-bound of production range in the other published studies. In addition, the average gas production in the literature indicated here is lower than the production in our Low scenario. As with oil, much of the explanation for this lies in our model's inclusion of production from a variety on non-conventional gas sources.

(iii) Comparison of coal forecasts

Finally we compare our forecasts of coal production to those of other published studies; this is shown in Figure 6.

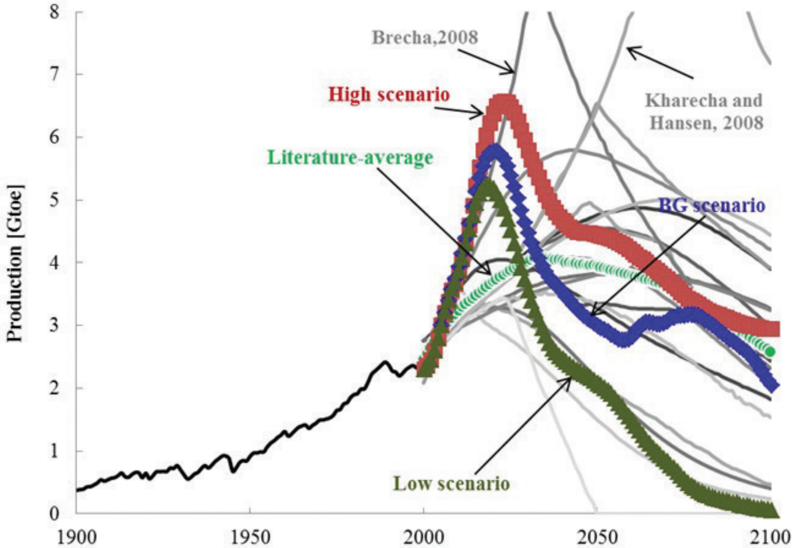


Figure 6. Comparison of world coal production forecast in this paper and those in some other published studies

Note: The results from other studies are taken from Wang et al. (2017).

In contrast to Figures 4 and 5, here our production forecasts for coal tend to be below those of other studies. From Figure 6 we can see that two studies have a higher peak production than our results: the *High Coal Use scenario* in Brecha (2008) and the *Business-As-Usual* scenario in Kharecha and Hansen (2008). There are two reasons for this. Firstly, both studies assume substantially higher URR than ours: about 42 ZJ in Brecha (2008) and nearly 53 ZJ in Kharecha and Hansen (2008), compared with 32 ZJ in our High scenario. Secondly, as both studies were conducted with the purpose of generating plausible, but not necessarily precise, GHG growth trajectories (rather than more precise energy supply forecasts), they employed a simplified modelling framework where global production grows at a fixed rate until an arbitrary decline trigger is reached (such as reaching a reserves-to-production ratio of 10 years).

A number of the other studies also assumed a URR for coal that was higher than our High scenario, albeit with lower and later peaks in production. We contend that the persistent discrepancy in URRs for coal remains the dominant barrier to reliable long-term energy forecasts, as well as reconciliation of fossil fuel energy projections with GHG emissions trajectories. This uncertainty is therefore discussed in more detail below.

4.3 Uncertainty over the global URR for coal

Table 3. Our estimates of coal URR by main six producers

Country	High URR		BG URR		Low URR	
	EJ	%	EJ	%	EJ	%
Australia	5,533	18%	4,567	20%	975	7%
China	6,991	22%	4,958	22%	4,549	31%
FSU	4,445	14%	1,669	7%	1,669	12%
India	1,703	5%	1,703	8%	872	6%
South Africa	955	3%	955	4%	450	3%
USA	6,158	19%	4,191	19%	2,238	15%
Others	5,810	18%	4,364	19%	3,717	26%

World coal production is currently dominated by six countries: China, Australia, India, USA, the FSU (predominately Russia-plus-Ukraine) and South Africa.

According to BP *Statistical Review of World Energy,* in 2015 the coal production from these countries was 130 EJ, which accounted for about 83% of world total coal production; which hence corresponds to our 74% - 82% of the coal URR (BP, 2016). Considering this, and the location of known resources of coal, it is reasonable to expect that future world production will also be determined by these six countries. This is illustrated by our forecasts of coal production by region under the BG scenario; Figure 7.

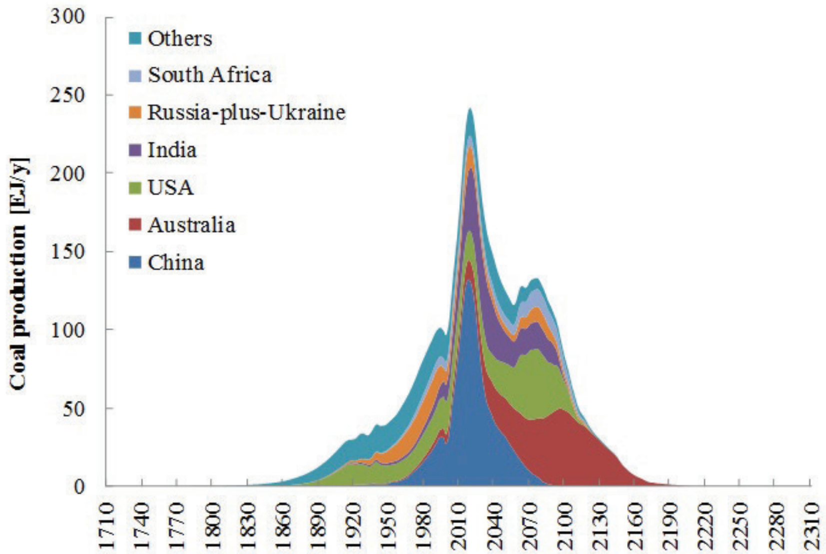


Figure 7. World coal production forecast by region in the BG scenario.

It is our opinion that the size of South African and Australian coal resources are being reported reasonably well (in Australia most of the coal is measured to the Joint Ore Reserves Committee (JORC) specifications and government agencies collate and make public the data). However, the remaining four countries of China, Russia-plus-Ukraine, America and India have substantial issues in terms of data quality and variability.

China is by far the largest coal producer in the world. However, the coal 'reserves' being reported by its authorities are actually the values for 'identified resources' (before 2001) or 'basic reserves' (after 2001), both of which classifications overestimate the likely actual economically extractable coal reserves. For example, in 2003, the identified resources and basic reserves in China were 1020 gigatonnes (Gt) and 330 Gt respectively, while the actual reserves were estimated to be only 190 Gt by Wang et al. (2013c). In light of this problem, Wang et al. (2013c) provided estimates of China's likely coal URR, independent of authorities' estimates. (According to Wang et al. 2013c, the URR of China's coal resources are 223 Gt.)

In India, technical terms such as *geological resources* and reserves are often misused (Chand, 2005). The reserve data reported by Geological Survey of India (GSI) are actually one class of geological resources, since India's classification system of coal resources is primarily based on geological evaluations without assessing the quality or extractability of deposits (Chand, 2005; Chikkatur, 2008). Therefore, using the data reported GSI may overestimate the actual reserves. Considering the data problem of GSI, after 2007, both WEC and BGR report their reserves data by applying a recovery factor to GSI's reserves data (IEA, 2015).

Based on our previous analyses, it is believed that the URR values used in Brecha (2008) and Kharecha and Hansen (2008) may be too high, since they are estimated based on the data reported by authorities or mainstream institutes, and the problems in China and others are not considered in their estimation. Therefore, the results in the High scenario of this paper are presented as a reasonable upper-bound for world coal production.

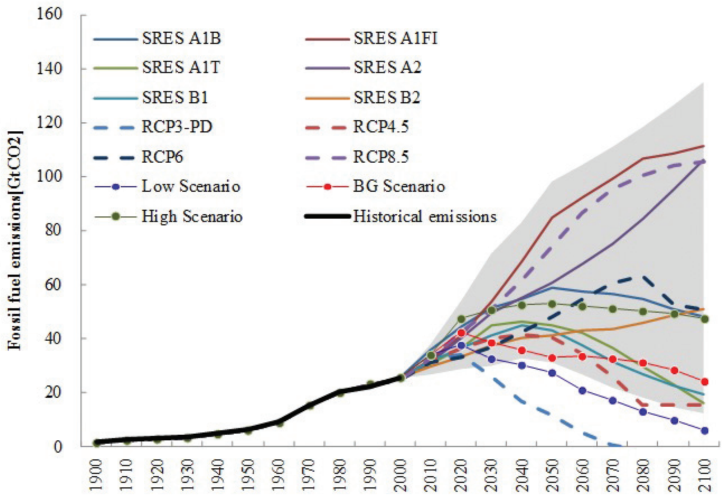
(In this context, see also the remark on coal resources by Mohr in Section A4.2 of Laherrère et al., 2017; and the note in the 'Caveats' section at the end of this paper.)

4.4 Implications for climate change

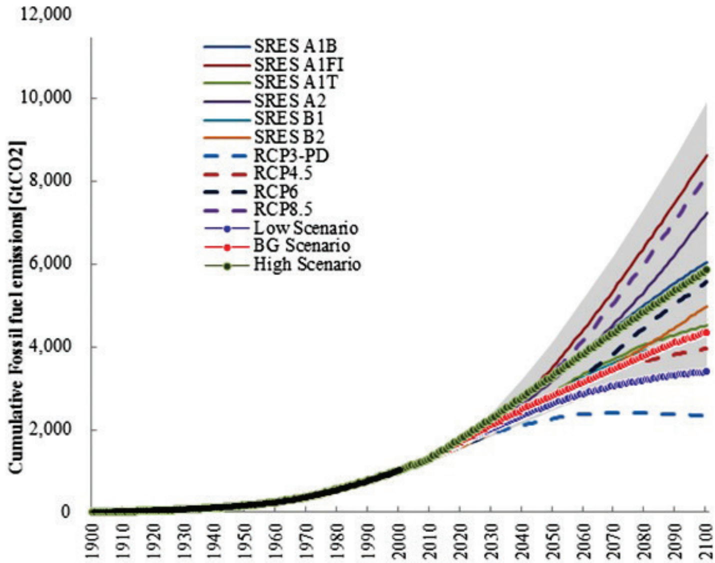
It is widely accepted that future climate change is significantly related to the future usage of fossil fuel resources and corresponding CO_2 emissions. Therefore, this section will focus on the CO_2 emission from fossil fuels. Figure 8 compares the CO_2 emissions from world fossil fuel forecasts of this paper, using the conversion factors given in Table 1, with those in the IPCC's SRES (for six market scenarios, and the range of all SRES scenarios), and with the more recent RCPs (IPCC, 2000, 2013). While they are no longer used to drive new climate model forecasts, the SRES scenarios are included for comparison as they underpin many previously published forecasts of long-term climate change impacts.

From Figure 8 we can see that the result in our BG scenario is broadly consistent with the low emissions scenarios (SRES B1 and RCP4.5) while our Low URR projection shows emissions considerably lower than these scenarios. The SRES B1 and RCP4.5 projections grow slower and peak higher than the results in our Low and BG scenarios by 2070 and the RCP4.5 scenario shows flat production by 2100; but they decline at a similar rate, and in between our Low and BG projections. Only the low emissions scenario (RCP3-PD) is lower than our projections. Our High URR case broadly tracks the medium emissions scenarios (SRES A1B and RCP6.0) used for climate change projections. The SRES A1FI and RCP8.5 scenarios are projected to continue to have strong growth in fossil fuel production, reaching over 100 Gt CO2e by 2100 (when their projection ends).

It should be noted that the emissions in the IPCC's scenarios also include the emissions from cement, vented natural gas emissions, and emissions from land-use change. However, all these emissions only represent around 5% of total fossil fuel emissions. Therefore, these emissions cannot change the conclusion of this paper, i.e., the upper-bound of emissions in IPCC's scenarios are significantly higher than the results in our High scenario. As mentioned earlier in this paper, the main reason for this is that the IPCC studies appear to have implicitly assumed that the fossil fuel resources in total (include large quantities of 'contingent' resources such as oil from kerogen and gas from hydrates) was sufficiently abundant that only 'demand-side' analysis was required, although some studies have suggested that hydrates will never be produced because in most places they are not sufficiently concentrated (Laherrère, 2002).



a) Annual emissions



b) Cumulative emissions

Figure 8. Comparing the World CO2 Emission Forecasts from the combustion of fossil fuels of this paper with those of the IPCC 'all-sources of CO2' forecasts: a) annual emission, b) cumulative emissions

Notes: The grey area indicates the range of values from the Special Report on Emissions Scenarios (SRES).

5. Conclusions from the Modelling, Caveats, and Overall Conclusions

5.1 Conclusions from the above modelling

The future trend of fossil fuel usage is a key factor affecting both the world energy system and climate change. In most projections published and used by government and international institutions, the future usage of fossil fuel has been largely determined by projections of economic and social needs ('demand-side' analyses). However, the maximum available quantities of fossil fuel resources that can be consumed in the future should be determined also by the upper-bound of fossil fuel production ('supply-side' analysis). Both of these two types of analyses should be carried out to provide a reasonable suite of forecasts for future usage of fossil fuels. It has been an aim of this paper to generate a supply-side analysis of the reasonable upper-bound of global fossil fuel production.

The first step in a supply-side analysis is a detailed analysis of ultimate recoverable resources for each type of fossil fuels. Our study shows that the URR for all fossil fuels are likely to be no less than 50 ZJ (in our Low scenario), but no higher than 120 ZJ (in our High scenario). Our 'Best Guess' estimate for this URR value is 75 ZJ. In all scenarios, coal is not the dominant fuel in the total global fossil fuel URR, in contrast to other studies. Two reasons explain this: one is that non-conventional fossil fuels are also included in the our URR estimates, giving high URR values for oil and gas (relative to coal); the other is that the data for coal reserves and resources reported by authorities in a number of key countries are of variable quality and in some cases use misleading category names, causing – in our opinion – a frequent overestimate of recoverable coal resources.

By applying the GeRs-DeMo model, all three of our forecast scenarios show that the consistent strong growth in world fossil fuel production is likely to cease much earlier than many analysts have predicted, with our peak dates between 2020 (Low scenario) and 2050 (High scenario); our 'best-guess' date for this peak of global fossil fuel production is as early as 2023.

By comparing our results with those in other published studies, we can conclude that the projections in our High scenario could be seen as a reasonable upper-bound of fossil fuel production. While there are a small number of studies showing higher peak production, those studies are based on simpler modelling approaches and/or larger URR values. We contend that any forecast of fossil fuel usage that is higher than the results in our High scenario should be avoided for long-term energy planning, unless there is clear justification for the recoverable resource assumptions.

Finally, the forecasts given in this paper have been used to check the reasonability of the fossil fuel CO2 emissions trajectories used in the IPCC's SRES and RCP scenarios. Our results show that medium and low emissions scenarios are plausible, but the fossil fuel components of the high emission scenarios (SRES A1FI and RCP8.5) are implausible and should be discounted in policy setting.

5.2 Caveats

We stand behind the conclusions given above, but it is necessary to point out a number of caveats to these findings. These relate to: the uncertainty over global URR estimates for coal partly touched on earlier; the difficulty of achieving below a 2 °C rise above pre-industrial levels even with the limited fossil fuel URRs suggested in this paper; and the need to be aware of other positive feedback mechanisms for climate change, in addition to CO2 emissions from the combustion of fossil fuels. We discuss these briefly in turn below.

(i). Uncertainty over global URR estimates for coal

We have discussed the large uncertainty over global URR estimates for coal. We suggest that narrowing this uncertainty is an area that needs concerted effort by relevant bodies in the six dominant coal producing countries. In addition, it is recognised that it may become possible in future to access the world's significant quantities of thin and deep coal seams, either by high levels of automation in mining, or by in-situ gasification. If combined with carbon capture and storage, these may make scenarios of higher energy production from coal plausible.

(ii). The difficulty of achieving below a 2 °C rise above pre-industrial levels even with limited fossil fuel URRs

In terms of climate change, it is important to recognise that even under the 'peak fossil fuel' scenarios presented in this paper, detailed climate modelling indicates that the world still exceeds 2 °C above pre-industrial temperature levels; see Capellán-Perez et al. (2016) and Wang et al. (2017).

(iii). The need to be aware of other positive feedback mechanisms for climate change, in addition to CO2 emissions from the combustion of fossil fuels.

Also in terms of climate change, it is necessary to be aware of other drivers for such change, in addition the largest one currently generally modelled, that of combustion of fossil fuels. There are a number of positive feedback mechanisms perhaps not yet fully modelled in the central IPCC projections of temperature change by 2100; including albedo change from loss of the Arctic ice-sheet (see e.g. González-Eguino et al., 2017); the possibility of large methane and CO2 releases from melting of the permafrost (see, e.g. González-Eguino and Neumann, 2016); and methane release from the warming of below-sea methane hydrates. (The last two possibly played a role in the geologically rapid ~6 °C warming thought to have occurred during the Palaeocene/ Eocene thermal maximum.) It is crucial that the climate modelling community apply concerted efforts to understanding the behaviour of such feedback mechanisms in the context of the more likely (i.e. low to medium) GHG emissions scenarios outlined in this paper, in order to generate useful long-term climate change projections for mitigation and adaptation planning.

5.3 Overall conclusions

Based on the above, the overall conclusions of this paper are:

- In terms of modelling future global fossil fuel production, it is not enough to simply say 'there are abundant resources'. Detailed estimates of likely URR values need to be generated for both the conventional and non-conventional resources, and then - most importantly - these must be combined with realistic simulation of production by type of fuel.
- Our modelling indicates that the global resource-constrained peak of total fossil fuel production looks possible within a decade; this is much earlier than most conventional analysis suggests. Such a peak is likely to have significant economic and social consequences.
- Even a 'High URR' scenario generates the corresponding global peak by about 2050.
- Significant uncertainty remains regarding realistic estimates for the recoverable resources (URR) of coal. Given the likelihood of a

near-term peak in global production of all fossil fuels, there is a need for significantly better coal URR data to be assembled.

Regarding the implications for climate change:

- If considering only CO_2 emissions from the global combustion of fossil fuels, the constraints calculated in this paper (and in a number of other studies) suggest that IPCC 'high CO_2' scenarios are implausible.
- However, the forecast of CO_2 emissions presented in this paper are still sufficient that the 2 °C temperature limit above pre-industrial is likely to be exceeded.
- It should not be overlooked that there are potentially other significant drivers for climate change, in addition to CO2 emissions from combustion of fossil fuels. These other drivers, and their positive feedback effects, need also to be taken into account in climate change modelling.

Acknowledgements

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The Background to Our Research on the Future Production of Fossil Fuels by Country

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Abstract

This paper sets out briefly the background that led to my PhD research on forecasting global production of the three main fossil fuels: oil, gas and coal. Also described is the extension of this research, in collaboration with a number of co-investigators, which resulted in the publication of the paper: Mohr et al. (2015), Projection of world fossil fuels by country. This led in turn to the paper by Wang et al. published in this issue of *The Oil Age: Production outlook for global fossil fuel resources*.

The Editor of *The Oil Age* suggested that background information on how these studies came about might be of interest, given that our findings on likely global fossil fuel production differ markedly from that generally assumed. In particular, we suggest that the total global production of all fossil fuels combined, under our 'best-guess' scenario, might reach a *resource-limited* production peak as early as about 2025.

Academic background

I start by noting that I have a somewhat conflicted academic background. Initially I studied a Chemical Engineering degree, hoping - with the idealism of youth - that I could contribute to creating a more sustainable future. I have always had a strong notion of conserving resources since my early degree days. The oft-cited R/P ratio for oil of 40-ish years resonated with me, indicating that within my working life there would need to be an alternative to oil.

When I entered my third year of university I had my first semester without a mathematics subject. I realised I loved mathematics. I therefore changed tack, and enrolled in a Mathematics degree, focusing heavily on pure mathematics and avoiding as best as possible anything practical. During this rebellion, the quote by G. H. Hardy resonated with me: *"No discovery of mine has made, or is likely to make, directly or indirectly, for good or ill, the least difference to the amenity of the world."*

Choice of research topic

With my batteries recharged following the Mathematics degree, I decided to complete the Chemical Engineering degree as closure, so I could move into mathematics without regrets.

One of the subjects that I had to complete was a research component topic. I asked around various professors, and found that Geoff Evans was willing to let me loose. I came up with an idea for, and happily dismissed as completely impractical, a possible engine running off hydrogen peroxide. With research time on my hands, Geoff suggested that I look into oil resources as a justification for the engine. This led me to stumble upon Colin Campbell and Jean Laherrère's seminal work, as well as the hugely impressive work by Robert Hirsch.

While finishing the engineering degree I had enrolled in a maths honours with the intention of undertaking a maths PhD. I faced a dilemma, continue down the pure maths path that my friends were travelling and try to become a maths lecturer, or continue to look at fossil fuel production? I eventually chose to abandon my maths honours and proceed with a chemical engineering PhD under my supervisor Geoff Evans. It was not a topic he was currently researching, but I managed to convince him to let me proceed with this.

With Robert Hirsch's report front and centre in my mind, I started down the track of trying to see how the transition to a sustainable world could occur, and here the key question was timing: what was future fossil fuel production going to look like?

In the first couple of months of the PhD I wanted to create a model of all energy sources, and see if it was possible to go from a predominately fossil fuel based world to a sustainable world smoothly. Sadly, a distinct lack of time resulted in the scope of the work being reduced, to only looking at the fossil fuels.

One of the questions asked early in the PhD was whether a Hubbert curve was realistic or not. In my first couple of approaches I tried to focus on finding more of a theoretical approach to 'how does the production occur'; and hence to try and figure out how to aggregate local production to see what the world production would look like. I accessed the reasonably easy to obtain UK oil and gas production data to look at the production profile of a typical field. And I used the UK's example of the changing size of the fields over time, namely big fields early, then medium sized fields, then all the little fields, coupled with the field profile, as key components for the model.

For coal, I found obtaining data to be very painful. I ultimately settled on getting Australian New South Wales (NSW) coal production by mine to try and determine how to replicate total production in a region. This was far from ideal; data from somewhere like France or the UK would have been better, but I could not source these data. Even for NSW data, I had to plead with the NSW Coal Authority to gain access to folders filled with hand-written coal production data for each of the mines, and to manually translate the data.

In terms of getting data, I probably spent a third of my time collating data, and typically would work to four p.m. on the PhD, and then work the evenings trying to collate the data. The hardest by a long margin were the coal production data. Geoff and I ended up paying the UK Mineral statistics to photocopy the old coal records, then I manually entered the data into Excel. The effort needed to create the datasets is one of the reasons I am passionate about supplying the data in electronic supplements of my articles, to make it easier for subsequent researchers.

In terms of the fossil fuel estimates of their ultimately recoverable resources (URR's), I have always been keen to be as agnostic as possible on these. So the low estimates used in the modelling correspond to URR data from Colin Campbell, Jean Laherrère and Dave Rutledge, while the high estimates generally reflect BGR/WEC/Rogner numbers.

I was keen to use the BGR numbers for all the fossil fuels, but found that their numbers for coal didn't appear reasonable, to the point where I questioned their validity. The coal numbers I finally used do not sit well with me, but were at the time the best I could create, and I stand by them. It saddens me that the WEC is now simply reproducing the BGR estimates for coal, and I think it is important that researchers start to question how much sensibly recoverable coal the world actually possesses. This is difficult, since the bulk of the coal resources exist in a small number of countries, but it feels to me as if coal resources are 'an elephant in the room'.

To give an example here: the UK data have substantially increased estimated coal resources recently and yet this fact goes by mostly unnoticed. Compare this to the OPEC nations increasing their oil reserves, a change which has been heavily critiqued. It beggars belief to me, that when it comes to coal the general statement of `hundreds of years of coal' seems to be an unshakeable belief, which requires no justification. I passionately believe that considerable research is needed in the coal resources space so as to shed some light on what are the plausible recoverable coal resources.

One of the key important components for me was for the model to be as granular as possible, so that the projections generated could be transparent. That said, for each typical country and resource, it might take half an hour or so of work to determine the appropriate parameters to put into the model. As a result, countless evenings and weekends were spent creating the projections.

Collaboration

When I was looking for collaborators to the work, Jianliang Wang at the Chinese University of Petroleum in Beijing was amazing at providing Chinese resource data and production numbers to underpin the Chinese projections. Both James Ward and Gary Ellem where adamant that CO2 emissions needed to be included. I cannot thank James enough for his effort in figuring out the conversion factors to apply. Collaborating with these others was a godsend, not only did it reduce the work load substantially, but it also re-motivated me to finish the work.

Reaction to our work

Since the publication of our results in Mohr et al. (2015), the paper has been cited in a number of journal papers. To-date though, the feedback on the paper has been limited. No other researcher has come back to us to ask about, let alone, question our results; and certainly no-one from the 'mainstream' energy forecasting organisation, such as the IEA, EIA, etc., have done so. We would of course look forward to such conversations.

Longer term, I am hopeful that I can create and ideally maintain projections of all mineral resources into the future, including resources such as iron ore and copper (which I have already written papers about), and lead-zinc (a work in progress).

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