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A New Hope: Iraq Oil's Way Forward

Robin Mills

Al-Bayan Center Publications Series

About the Center

Al-Bayan Center for Planning and Studies is an independent, non-profit centre based in Baghdad. Its main mission, amongst other things, is to provide a credible perspective on public and external policy issues that concern Iraq in particular and the Middle East region in general. The centre seeks to undertake an independent analysis of and to submit practical solutions to complex issues in the academic and political domains.

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Contents

Table of Figures

A New Hope: Iraq Oil's Way Forward

Robin Mills*

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Qamar Energy

Dubai, December 2017

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1. Introduction

This report primarily concentrates on the oil sector in 'federal' Iraq, i.e. that outside the Kurdistan Region of Iraq (KRI). It can be read in conjunction with my earlier study for the Oxford Institute for Energy Studies (OIES) of the petroleum industry in the KRI[1].

The defeat of ISIS (Da'esh) in most of the areas held by it in north-western Iraq and eastern Syria, the referendum on independence held by the KRI on 25th September 2017, and the subsequent reassertion of federal control over large areas of northern Iraq, have fundamentally altered the political situation. This has major implications for the oil industry in those areas, but also at a national level.

Since the award of technical service contracts (TSCs) for Iraq's major fields from 2009 onwards, oil production has risen significantly. However, a great deal remains to be done in boosting oil output further, capturing and using associated gas, developing related infrastructure, meeting national power demand, developing linked industries and restructuring the sector.

At the same time, there have been major shifts in the global energy business and regional politics, including sharp rises and falls in oil and gas prices, advances in renewable energy, reform of Middle East energy sectors and political upheaval and military conflict in Iraq and neighbouring states. Several regional competitors – countries and companies – have been adapting to these changes.

Iraq's energy strategy needs to be updated to cope with these changes. Broadly, a tactical approach which has made some progress in boosting oil output, needs to be subsumed in a strategic approach to meet Iraq's energy and economic needs and develop resilience to new challenges. As the country emerges from war, it has the opportunity to take a longer view, and make fundamental changes in its energy sector.

1. 'Under the Mountains: Kurdish Oil and Regional Politics' (R. Mills), 1st January 2016, Oxford Institute for Energy Studies, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2016/02/Kurdish-Oil-and-Regional-Politics-WPM-63.pdf

2. Iraq and the Evolving Energy World

The global energy sector is undergoing fundamental changes. At the same time, Iraq is at last in a more favourable situation to tackle its energy challenges, short- and long-term.

The tasks of Iraq's energy sector can be listed as follows, starting with the most urgent:

1. Supply the Iraqi population with essential energy services – fuel and electricity;
2. Earn revenues for the national budget;
3. Support Iraq's national security and foreign relations;
4. Develop Iraq's economy and population;
5. Diversify the economy away from reliance on oil exports.

2.1. Iraq in the Region

Iraq is one of the largest countries in the Middle East-North Africa (MENA) region. Here it is compared against its peers, the leading regional energy exporters, plus two of the region's other large countries, Turkey and Egypt. Iraq has the fourth-largest population from this peer group, and the third-largest population of any Arab country (behind Sudan, not shown here, and just ahead of Morocco, also not shown). It has the sixth-largest economy on a purchasing-power parity basis (Figure 1), i.e. accounting for the different cost of living in each country.

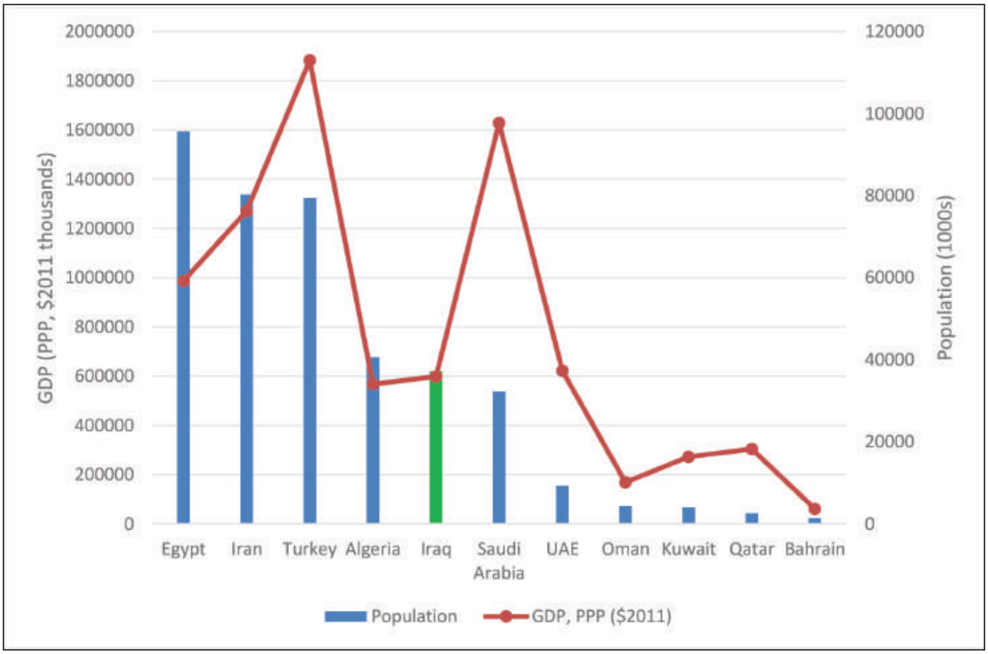

Figure 1 Population and GDP, selected MENA countries[2]

However, Iraq's GDP per capita is only 9th out of these 11 countries (Figure 2), slightly ahead of Iran and some way ahead of Egypt. This indicates that Iraq is not yet transforming its oil resources into wider economic prosperity.

Figure 3 shows the Human Development Index (HDI), a composite of measures of health, security, education, employment, economy and other factors. HDI has improved steadily since 1990 for nearly all the countries in this sample. Iraq's HDI was, of course, badly affected during the 1990s sanctions and then the 2003 invasion and subsequent violence and instability, then the 2014-17 struggle with ISIS. Iraq ranks as one of the lowest of all the selected MENA countries, above only poor and war-affected countries such as Yemen, Syria and Sudan. Still, despite major growth in oil production and the economy during the 2003-17 period, Iraq's HDI fell significantly behind Egypt's and it was equalled by Morocco. Iraq's GDP per capita is about equal to Iran's, but its HDI is significantly behind, 0.649 versus 0.774.

2. Data from World Bank

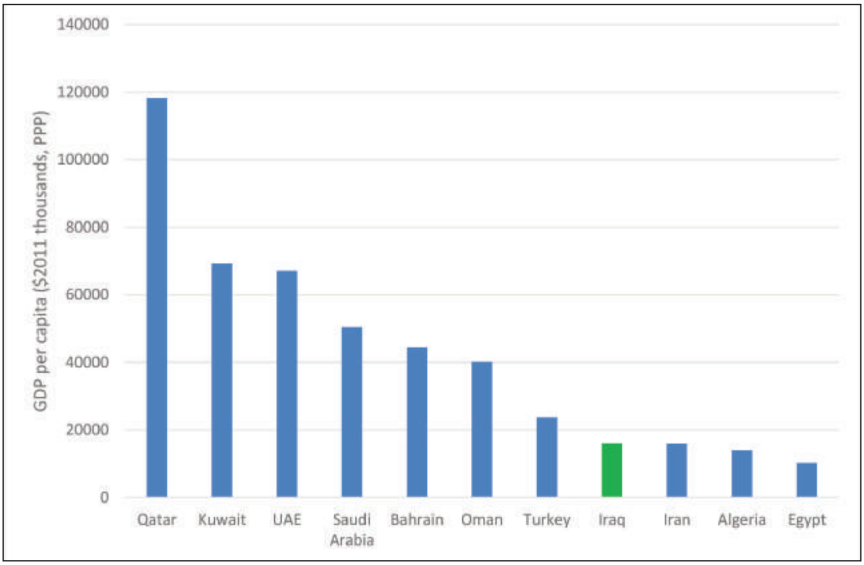

Figure 2 GDP per capita, selected MENA countries (PPP, $2011)[3]

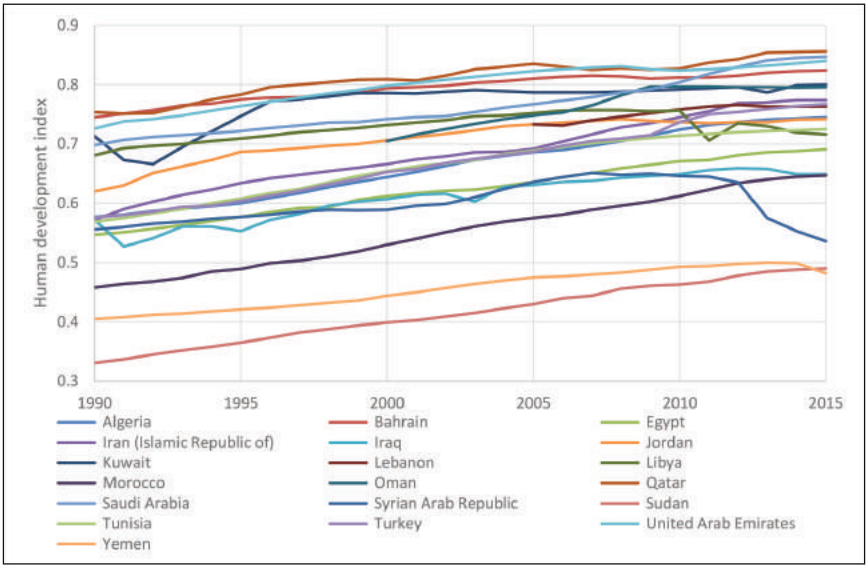

Figure 3 Human Development Index, selected MENA countries[4]

3. Data from World Bank
4. Data from UN Development Programme, http://hdr.undp.org/en/data#

Iraq also lags behind on serving its people's energy needs. Figure 4 shows electricity generation per capita, plotted against GDP per capita. Iraq, with its hot climate, should have rather high electricity generation to meet the need for air-conditioning (like the GCC countries). It also has large oil and gas output for fuel for power plants. But although it has about the same GDP per capita as Iran, it has only half the electricity generation, despite Iran's milder climates. Looked at another way, Iraq generates only a little more electricity per capita than Egypt and Jordan, despite a significantly higher GDP. It generates less than Lebanon, even though Lebanon suffers from severe power shortages.

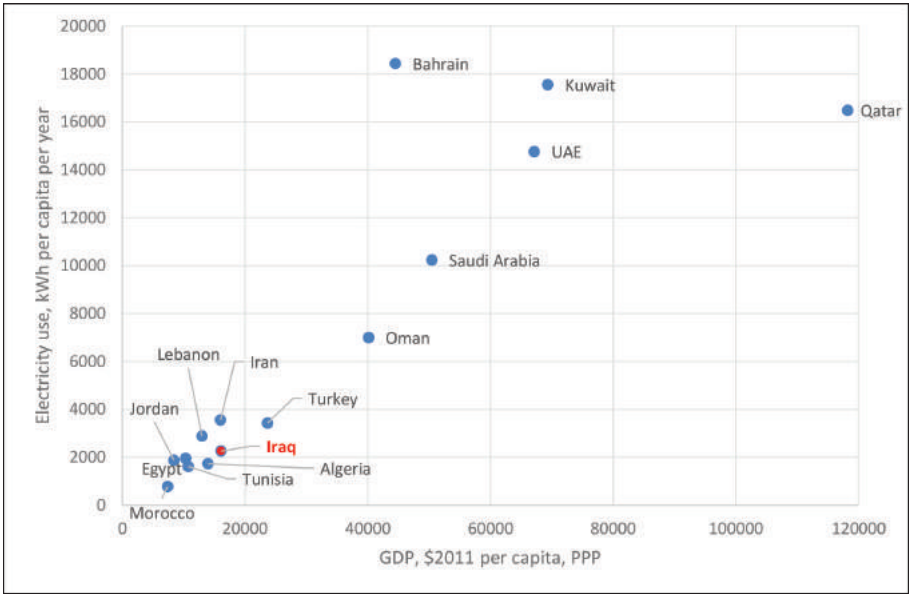

Figure 4 Electricity and GDP per capita[5]

Iraq's economy also remains very undiversified. Figure 5 shows the share of oil and gas revenues in GDP since 2000 (note this does not include the contribution to GDP of other oil and gas activities such as refining and petrochemicals). In all the MENA countries shown, this tended to rise during the mid-2000s due to high oil prices, before then falling sharply in 2015 due to the oil price collapse (most falling to lower levels than the 2009 drop in oil prices). For Kuwait, the least diversified

5. Data from World Bank; BP Statistical Review of World Energy 2017; CIA Factbook. Data for 2016 where available, otherwise 2015

country shown here, the share was 39.1% in 2015. For a more diversified oil exporter, the UAE, it was 11.9%. It should be said that, apart from Qatar and Iraq, no country improved its diversification consistently over this period.

Iraq's position improved considerably from 2004-5 onwards, especially since its oil production was rising significantly during this time whereas for many of the other countries shown, it was rather flat. But it remains the least diversified of this group except for Kuwait (and probably Libya, though recent data is not available).

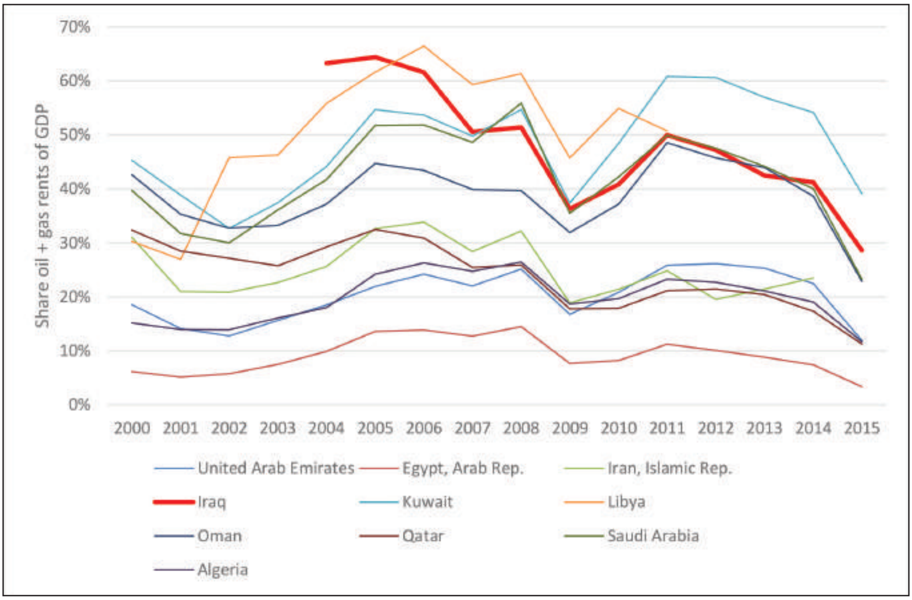

Figure 5 Oil and gas rents as share of GDP, selected MENA countries[6]

Overall, Iraq's position has improved both in absolute terms and relative to its neighbours since 2003, despite all the challenges of violence, insecurity and political turmoil. But other regional oil exporters have a large head-start on Iraq in turning their hydrocarbon resources into economic and human development.

6. Data from World Bank

2.2. World energy situation

Since Iraq launched its first bidding round in 2009, and since the Da'esh offensive of 2014, the world energy situation has evolved in fundamental ways. Some of these are the further development of long-term trends, while others are rather new.

A distinction is made in the following discussion between reserves and resources. Reserves are oil and gas known to be in the ground, and that with reasonable certainty can be extracted with current technology and under current economic conditions (prevailing prices, taxation and so on). Reserves may be proved (known with a high degree of certainty, usually considered to be a 90% chance that true reserves are higher), probable (a 50% chance that true reserves are higher) or possible (a 10% chance that true reserves are higher). By contrast, resources refers to oil and gas that may be discovered or undiscovered. If discovered, it may not be technically or economically feasible to extract. Contingent resources usually refers to discovered oil or gas that appears technically feasible to extract but that requires a commercial decision to go ahead with development, for instance signature of a gas sales contract, at which point it can be transferred to reserves.

2.2.1. Rise of US production

US oil production appeared up to 2008 to be in irreversible decline. Production in that year fell to 6.78 million barrels per day (Mbpd) (crude oil, plus condensate and natural gas liquids), having peaked in 1970 at 11.34 Mbpd. However, since then, it has staged a remarkable revival, reaching a record 12.76 Mbpd in 2015, before falling a little in 2016 to 12.35 Mbpd, due to low oil prices restricting drilling.

This turnaround has been led almost entirely by the advance in 'shale' (or 'tight oil') production. Conventional reservoirs, that dominate production worldwide including in the Middle East, have relatively high permeability – oil and gas in the microscopic spaces between the rock grains can flow easily to producing wells. Hydraulic fracturing has long been used to improve the permeability of reservoir rocks around the wellbore and boost production rates. Horizontal drilling was also widely adopted by the industry from the early 1990s onwards – instead of a traditional well which descends vertically through the reservoir formation, a horizontal well turns to go horizontally and so penetrate more of the target reservoir, improving production rates.

It has also been known since the 1800s that other rock formations, including shales, and low-permeability carbonates (limestones and dolomites) and sandstones, can hold oil and gas in small pores. These 'tight' reservoirs are not always, geologically-speaking, shales (fine-grained compacted mudstones) but 'shale' is a common industry term for them. In most cases, it was not commercially feasible to extract hydrocarbons from such formations as production rates were very low and did not justify the expense of drilling a well. However, from the late 1990s onwards, US oil companies began to experiment with combining horizontal drilling with high-volume hydraulic fracturing, involving injecting large amounts of water and some chemicals to crack open the rock, then 'propping' these cracks open with sand or other materials. The fractures thus allowed the hydrocarbons to flow more easily from the small pores to the wellbore.

Hydraulically fractured wells usually exhibit quite high initial production rates but with a sharp decline thereafter, with most of the production coming in the first one or two years. The decline rate in the Eagle Ford shale, for instance, is 74% in the first year, 47% in the second and 19% in the third. This is in contrast to wells in conventional reservoirs which may decline at 10% or so annually and produce quite steadily for years. Shale reservoirs thus require continual drilling to sustain output.

Shale gas production took off in the US before shale oil, initially with the development of the Barnett Shale in Texas and then with a number of other shales, particularly the Marcellus of Pennsylvania and West Virginia. US gas production was in decline from 2001 to 2005, falling from 53.7 to 49.5 billion cubic feet per day (Bcfd), prices rose significantly, and the country began to plan for large volumes of liquefied natural gas (LNG) imports, particularly from Qatar. But, from 2006 onwards, the development of shales led to a sharp increase in output, to 74.1 Bcfd in 2015 before a slight decline in 2016. This has been achieved despite a crash in prices from $8.85 per MMBtu in 2008 (annual average) to $2.46/MMBtu during 2016. This surplus of gas has been a boost to energy-intensive US manufacturing and petrochemicals, has led to a large-scale replacement of coal by gas in power generation, and to approval of numerous LNG export terminals, as discussed further below.

US crude oil production peaked at 10.044 Mbpd in November 1970 (with another 1.3 Mbpd of condensate and natural gas liquids), and fell thereafter due to depletion of older fields. The development of deepwater offshore in the Gulf of Mexico, and fields in Alaska, reversed the decline temporarily in the 1980s but did not stop it long-term. During 2000-2008, US production continued to fall steadily (Figure 6), slightly interrupted by hurricanes (2005 and 2008).

But, from late 2008 onwards, US production turned around and grew dramatically to about 9.5 Mbpd by 2015. The techniques of long horizontal wells and high-volume hydraulic fracturing that had worked for shale gas were adapted to shale or 'tight' (low-permeability) oil plays. The production gain was almost entirely driven by this development of the Bakken (North Dakota and Montana), then the Eagle Ford (South Texas), and the Permian Basin (West Texas and New Mexico). The Permian has been an important producing area for a long time, but was revived from about 2011 onwards. Finally the Niobrara of Colorado and Wyoming, and a number of smaller tight oil plays, also contributed, while there was a modest positive impact too on conventional oil output.

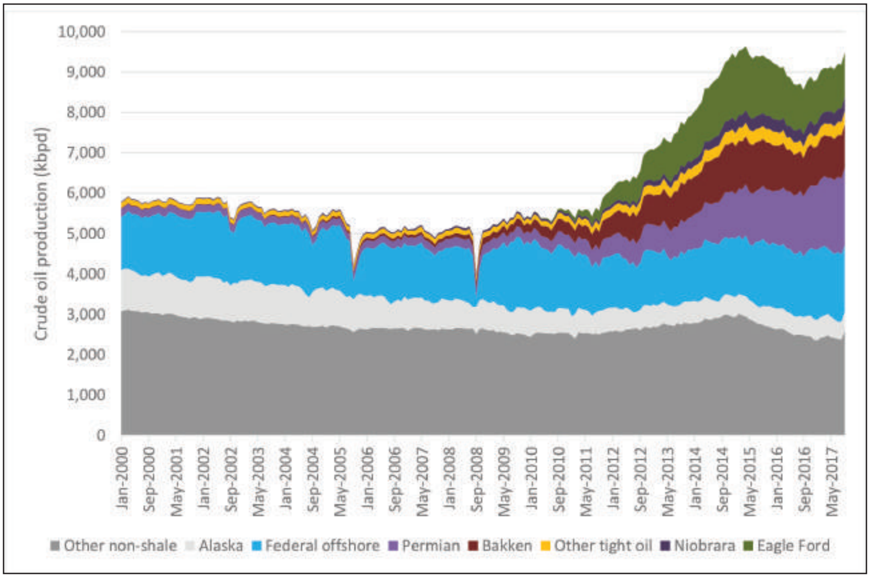

Figure 6 US crude oil production[7]

7. Data from US Energy Information Administration

During the period of lower oil prices from mid-2014 onwards, US oil output did fall, but from about September 2016 it has risen again and is almost back to the 2014 record. The Permian continued to grow throughout, while the Bakken, Eagle Ford and conventional production were more badly affected by the sharp drop in drilling activity.

Shale basins are present all over the world (Figure 7). At present, only those in the US, Canada (which shares part of the Bakken, as well as its own shale gas formations), Argentina and China are producing significant quantities of oil or gas. But there is potential for significant extra production from countries such as Australia and Russia, if legal, regulatory, public opinion and infrastructure issues can be overcome, and particularly if oil and gas prices are strong. In the MENA region, the US EIA did not assess shale resources in Iraq, Iran, Qatar, Kuwait, or Saudi Arabia due to their large conventional reserves. However, the UAE, Jordan, Oman, Turkey, Egypt, and North Africa have potential. Oman is producing about 1 Bcfd of gas from the BP-operated Khazzan field, the largest tight gas development in the Middle East, and Saudi Arabia is developing tight gas resources in its north-west (Turaif unconventional gas project).

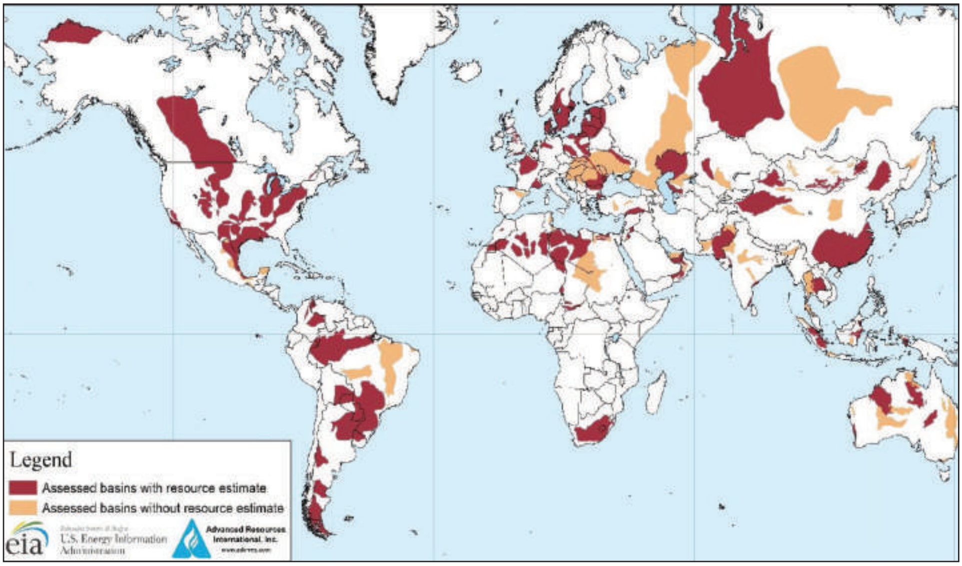

Figure 7 Worldwide shale oil & gas basins[8]

8. US Energy Information Administration

Shale production costs are significantly higher than for conventional onshore or shallow-water fields. However, they have fallen significantly along with the fall in oil prices (Figure 8). This chart shows wellhead break-evens – benchmark oil prices are higher because of transport costs from the fields. It indicates that plays that needed $80-100 per barrel oil prices in 2013 can now produce profitably at $40 per barrel. Transport and corporate costs need to be added to this, and costs will rise again as activity increases, but nevertheless it indicates that US oil production can be expected to grow strongly again if oil prices exceed $50-55 per barrel.

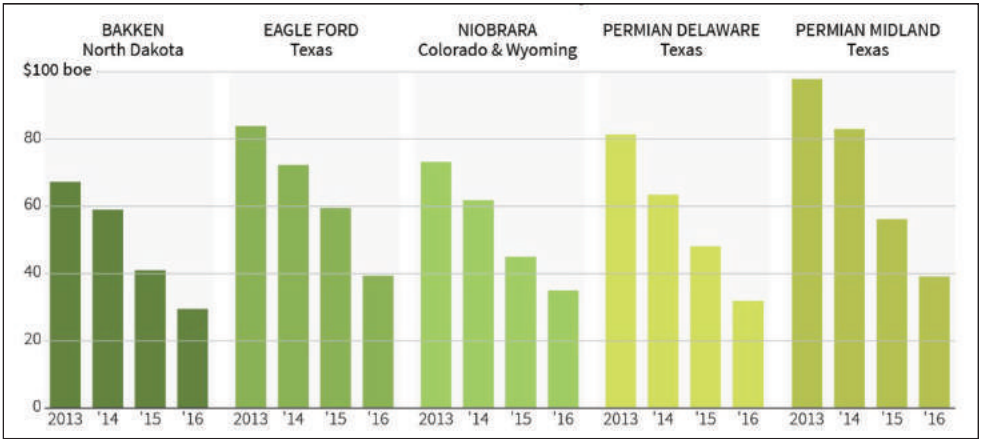

Figure 8 Wellhead breakeven production costs for main US shale plays[9]

As Figure 9 shows, North American shale is relatively more expensive to produce than most sources of oil, but is cheaper than the very high-cost resources such as Canada's oil sands. Onshore Middle East production remains the cheapest in the world, and Iraq (with Saudi Arabia) is likely to be the cheapest. But the availability of shale means that a sharp rise in oil price is likely to trigger strong growth in production, helping to bring prices down again. This makes it difficult for OPEC to achieve prices sustainably above shale production break-evens by cutting its own output.

9. https://www.reuters.com/article/us-opec-meeting-usa-shale/leaner-and-meaner-u-s-shale-greater-threat-to-opec-after-oil-price-war-idUSKBN13P0C8

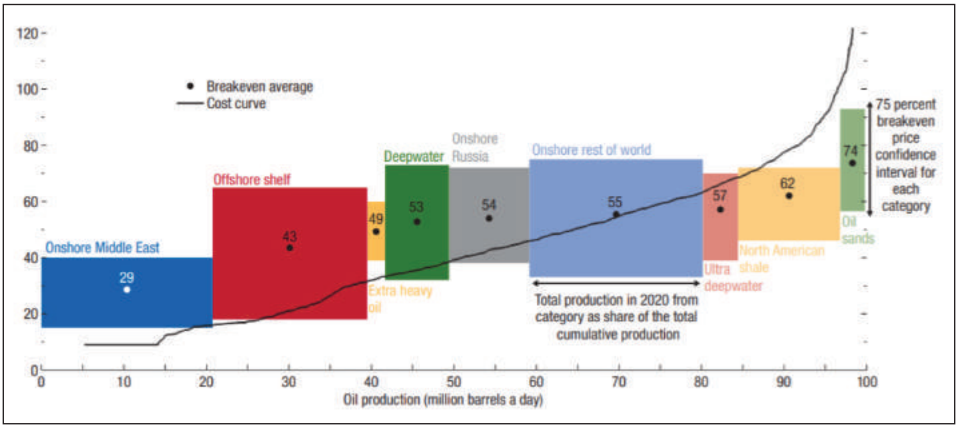

Figure 9 Breakeven oil production costs per area and resource type[10]

The development of shale, along with deepwater (Brazil, Gulf of Mexico, West Africa and elsewhere), oil sands in Canada, enhanced oil recovery and other new areas, has made it clear that there is no danger of a short-term peak in world oil or gas production because of limited resources. In fact, the problem is the opposite: that because of the rise of alternative energy sources, and the need to restrict carbon dioxide emissions to reduce climate change, that a large part of world oil, gas and coal resources will probably never be extracted.

2.2.2. Low oil and gas prices

Oil prices rose strongly from 2009 to early 2011 and were then very stable until mid-2014, at record sustained highs around $110 per barrel. This was the result of lost production, mainly from OPEC (Libya during its revolution and civil war, then Iran under sanctions, and unrest in Nigeria), as well as disruptions from the civil wars in Syria and Yemen, being offset by strong growth in US output. As Figure 10 shows, Saudi Arabia and Iraq increased production during 2009-16, and this helped make up the loss from Iran and Libya, along with the slow decline of Venezuela. But overall OPEC lost market share during this period, from 41.3% in 2009 and 42.9% in 2012, down to 40.9% in 2015[11]). Despite this production restraint, oil prices were slipping gradually in real terms during 2011-13, though

10. http://www.imf.org/en/Publications/WEO/Issues/2017/04/04/world-economic-outlook-april-2017

11. Including crude oil, condensate, NGLs and biofuels

remaining above $110 per barrel, and the US accounted for most global production growth. Oversupply led to a strong accumulation of excess global inventories.

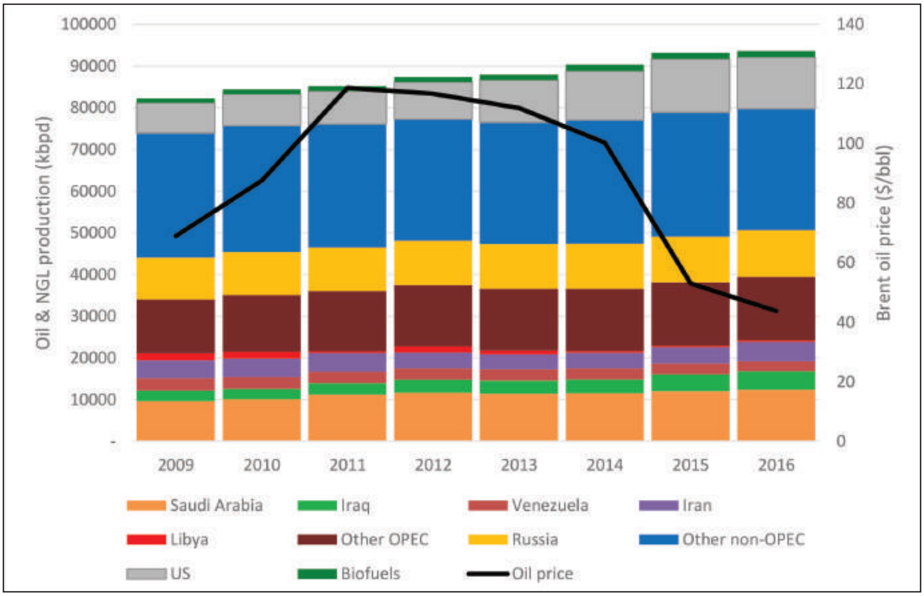

Figure 10 Oil and NGL production by country and price, 2009–16. Oil price is dated Brent in real terms $2016 (inflation-corrected)[12]

This situation was unsustainable. In mid-2014, market sentiment changed in response to a temporary boost in production from Libya and some negative economic news from China, and oil prices fell sharply. In November 2014, OPEC met but did not agree on production cuts, with Saudi Arabia seeking to regain market share. In response, into 2015 and especially 2016, OPEC countries – mainly Iraq, Saudi Arabia and the UAE – ramped up production, causing prices to fall further. US production did fall, but it proved more resilient than OPEC had hoped. Investment was cut sharply across the oil industry, but cost savings and improved efficiency undid some of the impact on output.

Oil-exporting countries had massively expanded their budgets during the period of high oil prices, allowing the break-even oil price (the oil price required to run a balanced budget) to rise sharply. Even for countries whose output was not affected by war, such as Bahrain, Algeria, Iran and Venezuela, break-evens

12. BP Statistical Review of World Energy, 2017

were above $120 per barrel. By 2017, most had cut budgets again, and break-evens for most were in the ranger $60-80 per barrel, still running a deficit but a more manageable one. In the case of countries such as Iran, Russia, Azerbaijan and Kazakhstan, this adjustment was assisted by flexible exchange rates or depreciations that reduced government budgetary commitments in dollar terms. However the GCC countries have so far maintained their currencies' pegs to the US dollar.

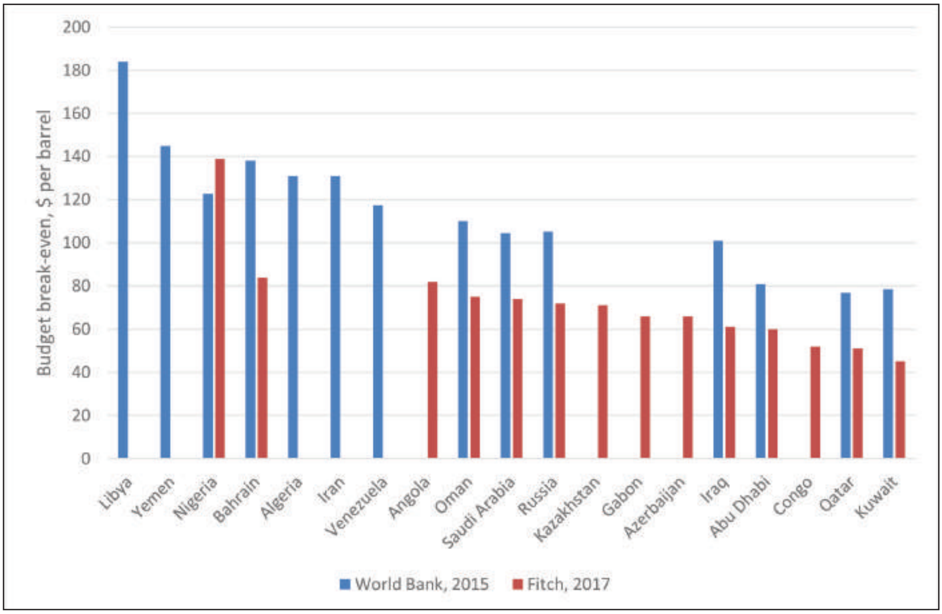

Figure 11 Budget break-evens for major oil producers, **2015 and 2017**[13]

As well as covering the government budget, exports of oil and gas (and any other exports) also have to cover a country's import bill. Otherwise, it will have to adjust by selling assets, drawing down foreign exchange reserves, issuing foreign debt, reducing imports or depreciating its currency. Figure 12 shows this calculation for major oil exporters. Iraq's external breakeven price is calculated around $60 per barrel, somewhat lower than Saudi Arabia's, though Iran, the UAE and Kuwait have much lower break-evens.

13. World Bank; Fitch Ratings

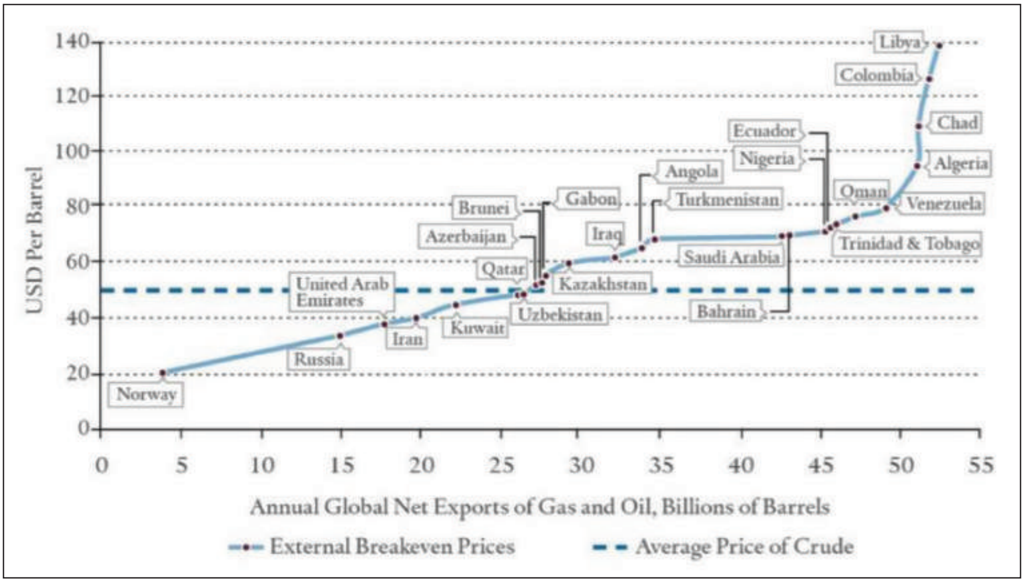

Figure 12 External break-even prices for major oil and gas exporters[14]

Neither budget nor external break-evens guarantee that OPEC will target a certain price or be able to achieve it. Fiscally-strong countries, those with more diversified economies and revenue-raising ability, or with large sovereign wealth funds, can survive extended periods of fiscal and current account deficits.

Middle East and other OPEC countries have responded to the challenge of lower oil and gas prices in various ways. Most have cut government budgets, reduced investment both in the petroleum and non-oil sectors, and reduced headcount (mostly expatriate headcount) in their state oil companies and government departments[15]. There has been significant progress on reforming unsustainable energy subsidies in many of the region's countries, raising transport fuel prices to market levels (as in the UAE), raising electricity and water prices (Saudi Arabia, UAE, Iran, Egypt and others), and increasing natural gas prices to the power and industrial sectors (Saudi Arabia, Oman, Bahrain, UAE, Iran, Egypt). Subsidy cuts can be expected to reduce wasteful consumption and smuggling, and to encourage the use of alternatives and energy-efficient equipment. This will result in lower domestic energy consumption and hence more for export, tending to an extent

14. (Brad W. Setser, 2017)

15. This applies to those countries, primarily the GCC, with large expatriate employment

to depress energy prices. In some cases, taxes and charges for government services have been introduced or increased, mostly consumption-based (for instance the GCC's 5% value-added tax). This has helped in reducing fiscal and external break-evens as discussed above.

However, defence and security spending has tended to remain high given regional political and military problems. Government employment of citizens, the largest provider of formal jobs in most of the region, has also been protected or even expanded, as have various social benefits. Consequently, most regional countries have run large deficits, which they have financed by drawing down sovereign wealth funds and issuing domestic and external debt.

2.2.3. OPEC cooperation

OPEC's output recovered from the cuts made during 2009 as the world economy rebounded. However, during the 2011-14 period, despite significant disruptions to production in important countries, OPEC did not act decisively to boost output and bring down prices which were unsustainably high.

When oil prices began falling sharply in mid-2014, Saudi Arabia, as the de facto leader within OPEC, decided on a strategy of winning market share and trying to drive out high-cost producers (particularly shale). Saudi production and that from some other OPEC states, including Iran's return from sanctions, and Russia ramped up sharply, and this led to prices falling to new lows.

However, the strain became intolerable and political and personnel changes in Saudi Arabia led it to change strategy and explore the possibility of reaching agreement with Iran and Russia. OPEC agreed in November 2016 to reduce its production, with most countries cutting by about 4.5%, Iran agreeing not to increase output further, and Libya and Nigeria exempt due to their problems with instability. A group of non-OPEC states, notably Russia along with Mexico, Kazakhstan, Azerbaijan, Oman and others, committed to cooperate. This deal was of unprecedented scope, as non-OPEC countries had very rarely agreed to cooperate with OPEC before, and usually did not follow through on their commitments. Many of these countries were facing natural declines in their production anyway, so their participation was of largely symbolic importance, but Russia and Oman, in particular, did genuinely reduce output (or restrict production growth).

The production cuts overall, though, were not very deep. They amounted to about 1.8 Mbpd across the participants, while in 2009 OPEC alone had agreed to cut output by 4.2 Mbpd in response to the global financial crisis.

In November 2017, OPEC agreed to extend these cuts from March 2018 to the end of 2018, and they could be extended again (although they could also be wound down if market conditions permitted). This time Libya and Nigeria's production was capped at 1 Mbpd and 1.8 Mbpd respectively. The future of this OPEC cooperation is unclear, with Russia seeking to exit the deal at some point during 2018. On the other hand, some kind of long-term production restraint may be necessary to support prices around current levels, if demand growth slows down and strong shale growth resumes.

2.2.4. Middle East political change

Since 2011 in particular, the political map of the Middle East has undergone great change. This cannot be covered in detail here, but the key developments, many of which affected energy markets, include:

- The fall of long-time leaders in Tunisia, Egypt, Libya and Yemen, leading in particular to endemic instability in Libya, badly affecting its oil production and boosting oil prices in 2011;
- The long-running and destructive civil war in Syria, disrupting that country's oil and gas output, and leading to the growth of ISIS, which itself produced and smuggled oil for financial support, and which was then able to expand into other areas of Iraq;
- The struggle against ISIS in Iraq and its eventual defeat (as discussed below);
- The dispute between the federal government in Baghdad and the authorities in the Kurdistan Region of Iraq (KRI), as discussed below;
- The stringent international sanctions on Iran imposed during 2012-16 over its nuclear programme, which strongly supported oil prices, and their removal under the Joint Comprehensive Plan of Agreement (JCPOA), allowing the country's full-scale oil production to return to world markets;
- The confrontation between Iran, some of its Arab neighbours and the US over Iranian support for the regime of President Assad in Syria, the Houthi opposition in Yemen, Hezbollah in Lebanon and various militias in Iraq;

- The tentative rapprochement between Saudi Arabia and Iraq, with a Saudi ambassador returning to Baghdad, the first visit of a Saudi foreign minister to Iraq for 27 years, and the meeting between Saudi crown prince Mohammed bin Salman and influential Iraqi political leader Muqtada Al Sadr[16];
- The deepening regional involvement of Russia, made more problematic by its current poor relations with the West, including its backing of Assad in Syria in alignment with Iran; confrontation and cooperation with Turkey; political support for the faction of General Haftar in Libya; financial contribution to the Kurdistan Regional Government; OPEC negotiations with Saudi Arabia and Iran; and negotiations for sales of civilian nuclear reactors to Iran, Egypt, Jordan, Saudi Arabia and Turkey;
- The dispute between Qatar and some of its Gulf neighbours (Saudi Arabia, the UAE and Bahrain), over issues including their accusations of Qatari support for terrorism and Islamist movements, leading to a blockade of the country, although so far this has not stopped its oil and gas exports.

The stress of low oil prices may lead to further political instability in weaker countries. However, it is also encouraging different degrees of economic, social and political reform in countries such as Saudi Arabia, the UAE, Oman and Iran.

Wider global political developments are also of importance. China’s Belt and Road Initiative (BRI, previously the One Belt, One Road or OBOR), stresses maritime and land connectivity from China through Central Asia, the Indian Ocean and Middle East to the Mediterranean[17]. It foresees large investments in infrastructure for trade and transport, which includes energy (pipelines, oil storage terminals, electricity transmission, LNG facilities). It is a sign of China’s growing economic and political clout in its wider neighbourhood. Iran and Turkey are key players in BRI because of their geographic links between the Caspian, Gulf and Black Sea, Oman is important for its Indian Ocean coastline, and Pakistan for the route into Central Asia. Iraq could also attract BRI investment.

The election of Donald Trump as US president, and his administration’s policies of ‘America First’ and ‘energy dominance’, also indicate an American approach more inclined to act unpredictably and unilaterally. The US has been more hostile

16. https://www.thenational.ae/world/mena/moqtada-al-sadr-received-by-saudi-crown-prince-mohammed-bin-salman-1.615503
17. http://emerge85.io/wp-content/uploads/2017/10/Chinas-Road-to-the-Gulf.pdf

to Iran than under President Obama, and generally more rhetorically supportive of Saudi Arabia, but the full implications of the new approach are not yet clear. There is a danger they could lead to more regional conflict, negatively affecting Iraq. The administration is strongly pro-fossil fuels, which probably means more production (to a minor extent), and opening up of new areas for exploration in the longer term (the Alaska National Wildlife Refuge and the eastern offshore) but also potentially more consumption of coal which would reduce gas consumption and so leave more for export.

2.2.5. Rise of Asian demand

Growth in Asian oil and gas demand, outpacing all other regions, has been a predominant feature of the world market since the early 2000s and is set to continue. Figure 13 shows an outlook where China and India together account for almost half (46%) of global oil demand growth from 2018-2022. While demand growth overall is set to slow down, due to maturing economies, greater efficiency and the impact of new technologies and somewhat higher prices, in absolute terms Chinese demand growth falls only a little from 2017 onwards, and Indian demand growth increases.

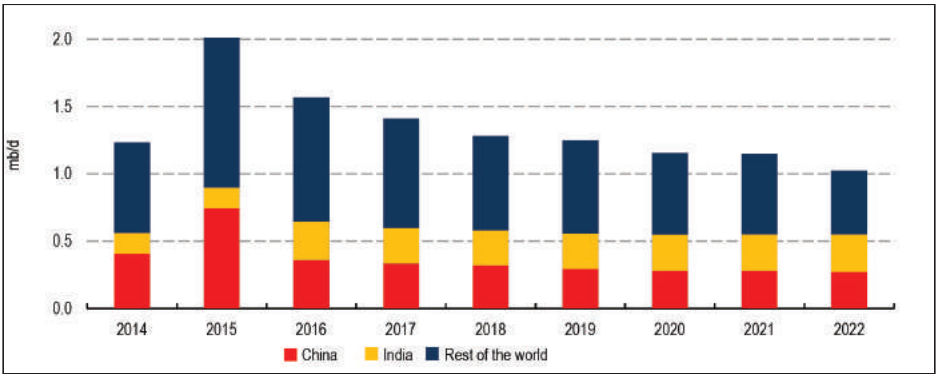

Figure 13 Forecast oil demand growth[18]

While North American oil imports will decrease during 2016-22 (due to increased shale and oil sands output) and European imports will fall slightly (due to falling demand from alternative energy and energy efficiency policies), Asian imports will grow significantly (Figure 14), from 21 Mbpd in 2016 to 24.6 Mbpd

18. International Energy Agency (23rd March 2017), Market Report Series

in 2022. Not only is Asian demand rising, but production is falling in important producers such as China, Indonesia and Malaysia.

At the moment, Middle East exports of 20.8 Mbpd can almost entirely satisfy Asian import demand (with some Former Soviet Union barrels). By 2022, Asia will need significant extra imports beyond what the Middle East can supply, drawing in crude from the FSU, West Africa, Latin America and North America.

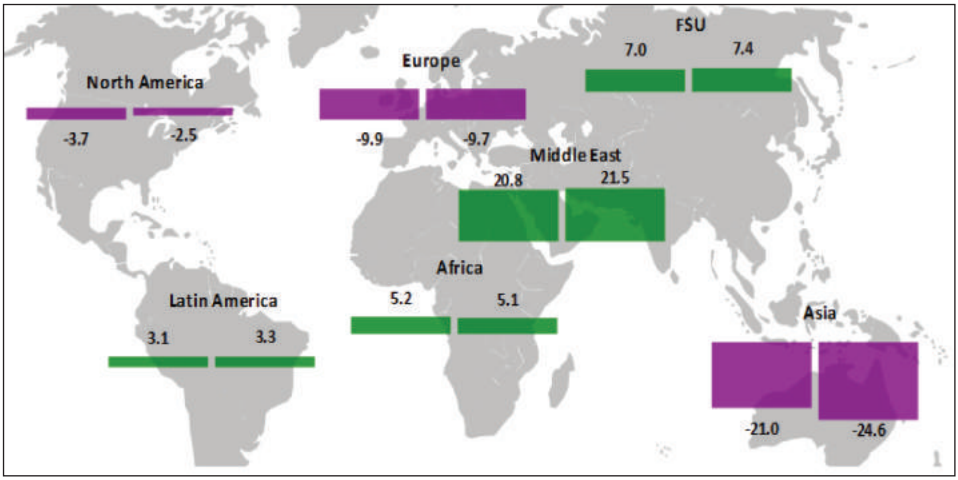

Figure 14 Regional oil exports / imports, 2016–22[19]

This market competition has manifested itself in changes in the official selling prices (OSPs) for the main Middle East producers for their exports to Asia (Figure 15). These are set as a differential to the Oman/Dubai average. During 2015-17, there has been a general trend for the differentials to decrease (smaller discounts) as OPEC cuts have tightened the market for the medium-gravity, sour (high-sulphur) Middle Eastern crudes. From May 2015, Iraq split its Basra exports into Basra Heavy and Basra Light. These have narrowed their differential to other similar Middle East crudes over this period. Strong results from trial auctions of surplus crude have boosted the confidence of SOMO (State Oil Marketing Organisation) in the pricing of its crude, although these limited sales may have made it over-confident in the value it could achieve for all its exports.

19. International Energy Agency (23rd March 2017), Market Report Series

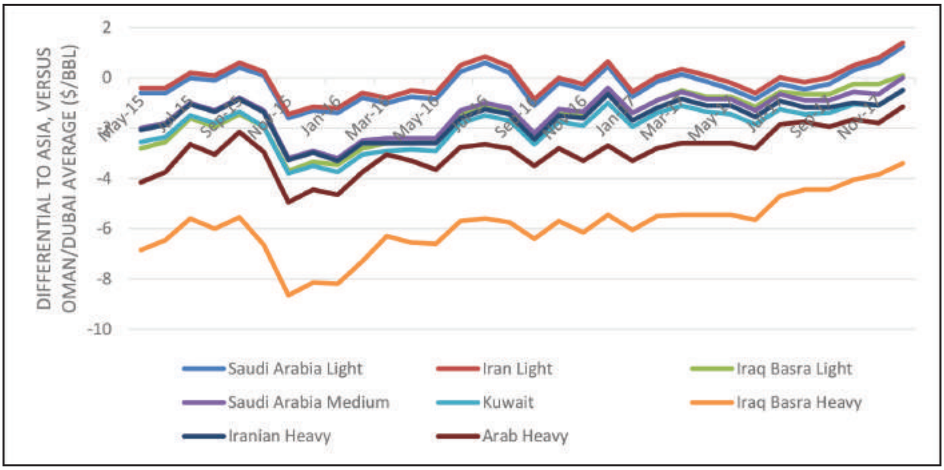

Figure 15 Price differentials for Middle East crudes to Asia[20]

As Table 1 indicates, Basra Light is closest in quality to Kuwait's export blend, though slightly heavier and with higher sulphur. Basra Heavy is much heavier and higher-sulphur than any of the other regular Middle East grades. Kirkuk is similar to Oman.

Table 1 Gulf crude oil quality[21]

Crude	**API °**	**Sulphur** (%)
Saudi Arab Light	32.8	1.97
Saudi Arab Medium	30.2	2.59
Saudi Arab Heavy	27.7	2.87
Iraq Basra Light	29.7	2.85
Iraq Basra Heavy	23.7	4.12
Kirkuk	34.2	2.24
Iran Light	33.1	1.5
Iran Heavy	30.2	1.77
Kuwait	30.2	2.72
Oman	34	2
Dubai	30.4	2.13

20. Middle East Economic Survey, various dates
21. https://www.ijsr.net/archive/v4i5/SUB154465.pdf

In order to capture a share of this rising demand, and potentially an additional share of value, Middle Eastern national oil companies have been investing in refineries, oil storage facilities and petrochemicals in Asia, usually in joint ventures with local state-owned partners (Figure 16). Iraq has also announced interest in investing in refineries and storage in China, Oman, Singapore and Indonesia. This is tricky given the significant capital a refinery requires, and the very competitive global refining industry.

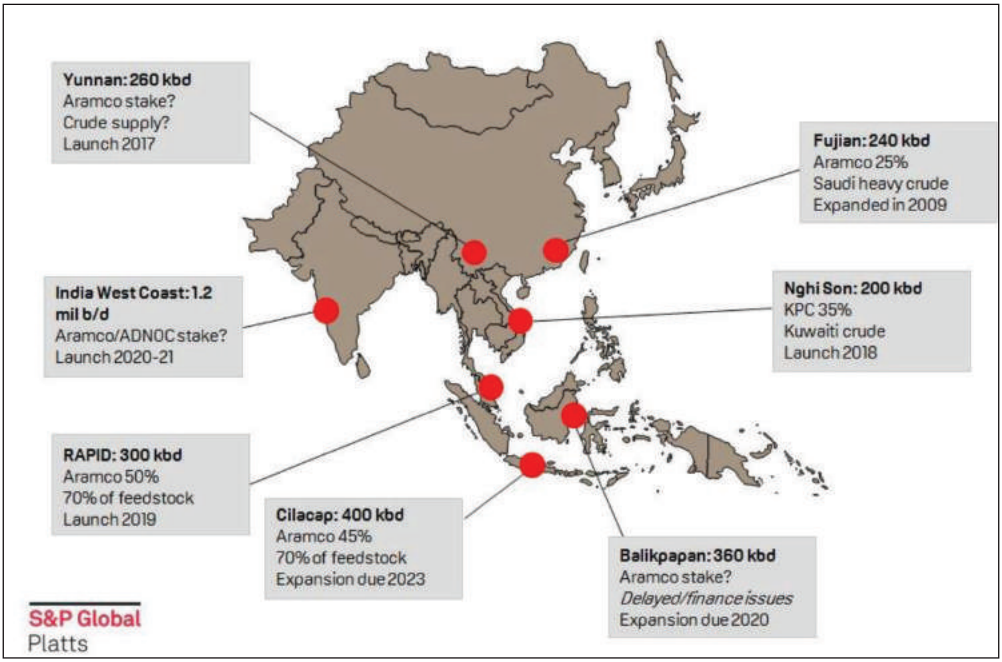

Figure 16 Middle East NOC investments in Asian refineries

Conversely, Asian countries have also been investing in oil and gas projects in the Middle East and other important producing countries. Chinese companies – China National Petroleum Corporation (CNPC), Sinopec, China National Offshore Oil Corporation (CNOOC), China Energy (CEFC) and Sinochem – have been most prominent, entering projects in Iraq (both federal Iraq and the Kurdistan region), Iran, the UAE, Syria (prior to the civil war), Egypt and Saudi Arabia (refining). Pertamina (Indonesia), Petronas (Malaysia), KOGAS (South Korea) and Mitsubishi and Inpex (Japan) are investing in Iraq.

2.2.6. Development of the gas market

The gas market has changed significantly since 2009. Global production rose 19% from 2009 to 2016 (oil was up 13% and coal 5%). The US has virtually disappeared as an importer, and has instead become a net exporter of gas, via liquefied natural gas (LNG) exports and growing pipeline sales to Mexico, permitted by its rising shale gas output. Asian gas demand has grown 41%, and more than half this has come in China. Middle Eastern demand has risen 43%, with all the leading countries showing strong growth. But European demand, which reached its record in 2008, is down 9% since then due to slow economies, pressure for efficiency and growth in renewables.

The global market has become much more diverse and flexible, particularly through the trade in LNG. Floating regasification terminals, introduced in 2005, have quickly become popular as they can be installed much more quickly and cheaply than traditional land-based terminals and are more flexible. This has enabled several new countries to become LNG importers: Kuwait, the UAE (Dubai, Abu Dhabi and soon Sharjah), Jordan, Egypt, Pakistan, Bangladesh, Argentina and more to come, including Morocco and several others in Africa, as well as existing markets in China[22]. World LNG output has expanded through the completion of Qatar's expansion programme in August 2010, and then by large new projects in Australia, the commencement of US LNG exports and smaller projects in Russia (Sakhalin in 2009 and Yamal LNG in 2017), Angola, Malaysia, Papua New Guinea and elsewhere.

However, several countries that looked set to become significant exporters of LNG or pipeline gas have not achieved it. Iran has been held up by sanctions and internal debate. Although it has commenced gas deliveries to Iraq and is a significant supplier to Turkey, its LNG plans have as yet made little progress, and it has not been able to begin supplying Sharjah (UAE), Pakistan and Oman by pipeline. East Africa (Mozambique and Tanzania) and western Canada have not managed to begin LNG exports despite large resources, because of political interference, delays and high costs.

22. https://www.energyinst.org/documents/5092

The consequent oversupply of LNG, along with falling oil prices, has led LNG prices to drop sharply (Figure 17). Japanese LNG import prices can be seen to track oil prices quite closely. They fell to their lowest level in the summer of 2016, rose into the Northern Hemisphere winter of 2016 as is normal seasonally, and have been quite flat since then before rising into winter 2017. US natural gas prices (at Henry Hub) also fell from mid-2014 onwards and have been fairly flat since winter 2016. US gas prices are much lower than in Asia and Europe, which creates the incentive to incur the heavy capital and transportation costs to liquefy US gas into LNG for export.

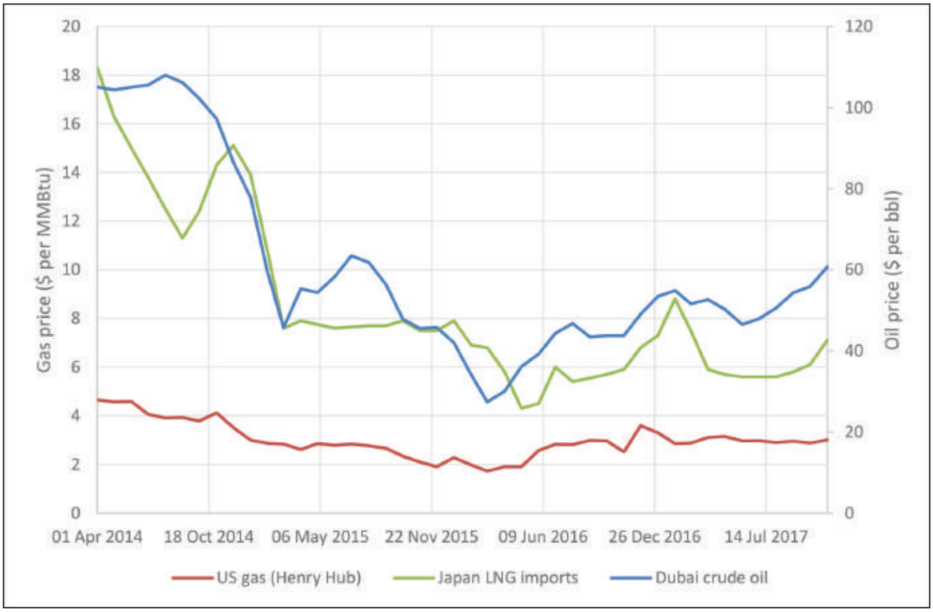

Figure 17 Oil, gas and LNG prices since April 2014[23]

Under the pressure of this oversupply, gas pricing models have also been evolving. Traditionally, gas sold in continental Europe and LNG-importing Asian countries (mostly Japan, South Korea and Taiwan) was indexed to oil-prices under long-term contracts. North America and the UK had developed traded gas hubs where suppliers and buyers of gas do business and compete, and the price of gas is determined by trade and not by reference to oil or any other product. More recently, traded gas hubs have begun to take an increasing share of the continental

23. Middle East Economic Survey; CME; Japan import statistics

European market, and their prices have aligned with each other. Russia's gas export monopolist Gazprom has been forced to take this hub pricing into account in its traditionally oil-linked contracts in order to preserve its market share. In 2016 Algeria fully delinked the LNG contract to ENI (Italy) from oil price indexed terms. New US LNG projects have based their export prices on Henry Hub plus a mark-up for capital and operating costs, introducing a new model. There have also been attempts, such as Singapore's, to launch an LNG pricing hub.

However, gas pricing in the Middle East and some other important markets (Russia, and to a large extent China), remains fixed by governments. Large-scale gas trade in the region has not emerged, except for some bilateral pipelines on long-term deals with fixed prices or indexed to oil (Iran to Turkey, Iran to Iraq, Qatar to the UAE and Oman).

2.2.7. New technologies

The oil and gas industry has been introducing new technologies during 2009. Many of these relate to shale oil and gas: better hydraulic fracturing techniques, more precise targeting of fracs, better selection of proppant types, microseismic monitoring to determine which parts of a shale reservoir are being effectively drained, nano-scale characterisation of shale reservoirs, waterless fracs or those using saline water, and experiments with secondary and tertiary recovery (injecting gas or carbon dioxide to increase the oil and gas extracted from the ~10% achievable by primary recovery).

New technologies in gas include, as noted above, floating LNG liquefaction, floating LNG regasification, and gas-to-liquids (not exactly a new technology, but Pearl in Qatar, the world's largest GTL plant, started operations in 2011).

Exploration has benefited from high-performance computing for processing seismic data, used by ENI in making the giant Zohr find offshore Egypt. In downstream oil, Saudi Aramco and SABIC's planned launch of an oil-to-chemicals plant would transform the economics of petrochemical production from oil, by eliminating the need for the refining step.

Alongside these are a variety of incremental technologies, which for instance improve the economics and environmental impact of oil sands production in Canada; and steadily increase the water depth for viable deepwater discoveries. While in 2006 the deepest producing field was in about 1900 metres of water, this reached 2400 metres in 2008, and jumped to 2900 metres in 2016. The deepest exploration well was drilled in 3400 metres of water in 2016[24].

A cluster of new technologies is also emerging, which centre around the use of information and communications technology (ICT), and fully applying the power of the internet to the oil and gas industry. These include the use of automation and robotics, which can avoid needing to have personnel routinely on-site; drones for monitoring remote, hard-to-reach or dangerous areas, or for example for patrolling pipelines; the Internet of Things (in which facilities and sensors are connected and can be monitored or controlled remotely); 'big data' and advanced analytics, which discover complex relationships in large data sets, for instance for discovering and ranking new exploration prospects or optimising facility operations; and high-performance computing, required to deal with such large data-sets. These approaches can cut costs, improve safety, reduce water and energy use, save on oil spills and air pollutants, and increase oil and gas recovery. Gaining full value from such technologies also requires a transformation in the way petroleum companies work.

In combination, these technological advances have allowed non-OPEC production in particular to keep increasing, and made small, remote, highly mature or technically difficult fields viable. This is likely to continue, or even accelerate due to the incentive of low commodity prices and the greater penetration of ICT. This in turn means that smaller and high-cost producers will nevertheless continue collectively to be a significant competitor to the large Middle Eastern oil-exporting countries.

2.2.8. Advance of renewable and alternative energy and climate policy

2.2.8.1 Renewable and nuclear energy

During the period from 2009 onwards, renewable energy has advanced significantly, particularly in reducing costs. The amount of energy generated has grown rapidly, but remains only a small share of the total (Figure 18). On this chart, 2016 consumption of nuclear and renewable energy was 1922 million tonnes of oil equivalent (Mtoe) worldwide. This compares to 4418 Mtoe from oil. Consumption of non-hydropower renewables was just 420 Mtoe, less than a tenth of the total from oil.

24. http://www.offshore-mag.com/articles/print/volume-76/issue-5/departments/comment/record-well-illustrates-offshore-significance.html

Nuclear energy fell slightly in the period 2009-16, particularly due to the 2011 Fukushima accident in Japan and the consequent shutdown of Japanese and German nuclear power. However, China in particular continues to expand nuclear capacity, while the UAE is to start generation from its large civil nuclear power programme in 2018.

Large hydropower (dams on rivers) continues to be the biggest source of renewable energy worldwide, and grew quite steadily, despite some concerns over impacts on landscapes and historic sites. In the Middle East, Iraq, Iran, Turkey and Egypt make significant use of hydropower.

Solar and wind-power have attracted most attention because of their high growth rates and technological and cost improvements. Recent record-low bids for solar photovoltaic power have included 2.99 USc per kilowatt hour (kWh) for the 800 megawatt (MW) third phase of Dubai's Mohammed bin Rashid solar park in May 2016; 2.42 c per kWh for the 1170 MW Sweihan solar plant in Abu Dhabi in September 2016; and 1.79 c per kWh for the 300 MW Sakaka solar plant in Saudi Arabia in October 2017. In September 2017, Dubai achieved another record with a low bid of 7.3 c per kWh for its 700 MW concentrated solar power (CSP) plant, which can generate through the night-time by storing heat.

Wind power has made most advance in the US, Europe, India and China, with record low prices bid for onshore wind power in Mexico in November 2017[25] and offshore wind in the UK in September 2017 and Germany in April 2017. In the Middle East, Egypt, Jordan, Saudi Arabia, Oman and Iran are also advancing with wind power.

25. https://electrek.co/2017/11/16/cheapest-electricity-on-the-planet-mexican-solar-power/amp/

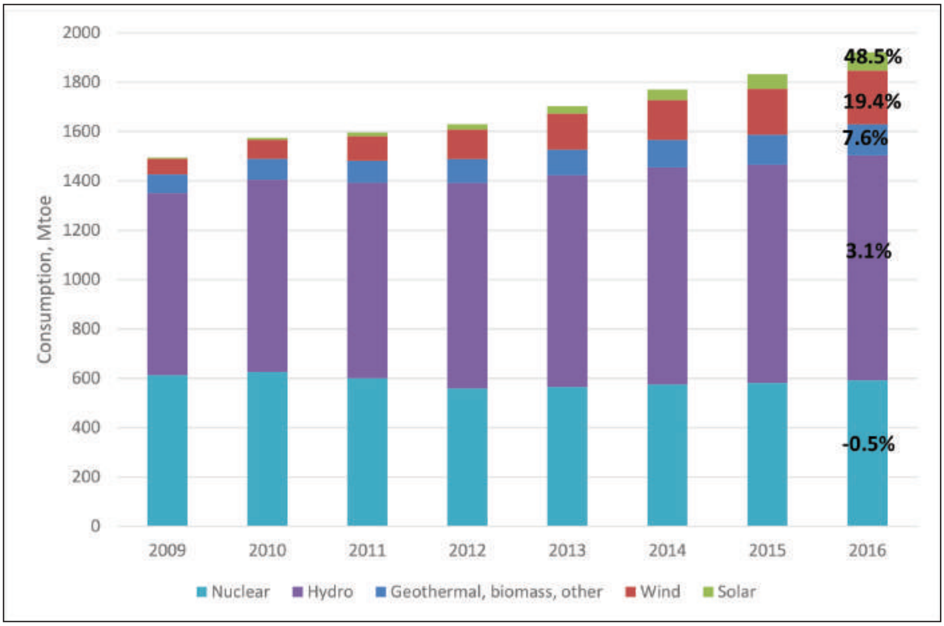

Figure 18 Consumption of nuclear and renewable energy, and compound average growth rates 2009–16[26]

The rise of renewable energy (and a possible rebound in nuclear) does not pose an immediate threat to oil. Most oil worldwide is used in transport (ground, sea and air) and petrochemicals. Renewable and nuclear power generate electricity (and sometimes heat and desalinated water). Oil is still used in power generation on a large scale in the Middle East, particularly in Saudi Arabia and also in Iraq, Iran and Kuwait, though even here efforts are being made to replace it with gas.

Wind and solar PV, the fastest-growing forms of renewable energy, are limited by not being 'dispatchable' – they do not generate as required but are dependent on the sun or wind. To provide reliable day-round and seasonal electricity, they have to be backed up with dispatchable generation (such as gas), electricity storage (via batteries or other methods), import of power from elsewhere, or 'demand response' (being able to turn off large consumers such as industries when power is not available). A combination of these methods is allowing renewable energy to provide reliable power to grids even as its share increases. Some other forms of renewable energy, such as biomass (burning wood or other plant material),

26. Data from BP Statistical Review of World Energy 2017

hydropower, geothermal (from underground heat) and solar thermal (CSP, as noted above) can provide dispatchable power.

Worldwide, renewables do compete against coal and gas. Coal, as a dirty fuel, is likely to be pushed out of use gradually but it remains attractive to some countries, such as India and China, because it is cheap. Gas can be complementary to renewables due to its flexibility, though in the long term it will also suffer from limits on carbon dioxide emissions. Carbon capture and storage can be used to prevent carbon dioxide entered the atmosphere, and so clean up coal- and gas-fired power plants and industry. However so far it is only being used on a limited scale, with the UAE starting up a large carbon capture project on a steel plant in 2016. Captured carbon dioxide can be injected underground to enhance oil recovery.

2.2.8.2. Electric and alternative-fuel vehicles

The big concern for major oil producers is not so much renewable energy, as electric vehicles (and hybrids, which combine a battery and a petrol/gasoline or diesel engine). Petroleum fuels provided 96% of the energy for transportation in 2012[27], giving oil a virtual monopoly in transport.

Electric vehicles have the potential to break this monopoly. The electricity required to run them can be generated by oil, coal, gas, nuclear or renewable means. Battery vehicles have lower fuel and maintenance costs, but still higher up-front costs, long charging times and limited range.

Compressed natural gas (CNG) vehicles have become popular in countries such as Egypt, Pakistan and Iran, being cleaner than oil-powered engines. Trucks and ships can also run on liquefied natural gas (LNG). If gas prices are substantially cheaper than oil, or there is sustained pressure for cleaner fuels, gas may be used more widely.

Figure 19 shows one forecast for worldwide vehicle sales, with electric vehicles overtaking gasoline and diesel sales by 2038. However, since vehicles take a long time to scrap, petroleum vehicles would still be a majority of the fleet for a longer period.

27. US Energy Information Administration, https://www.eia.gov/outlooks/ieo/pdf/transportation.pdf

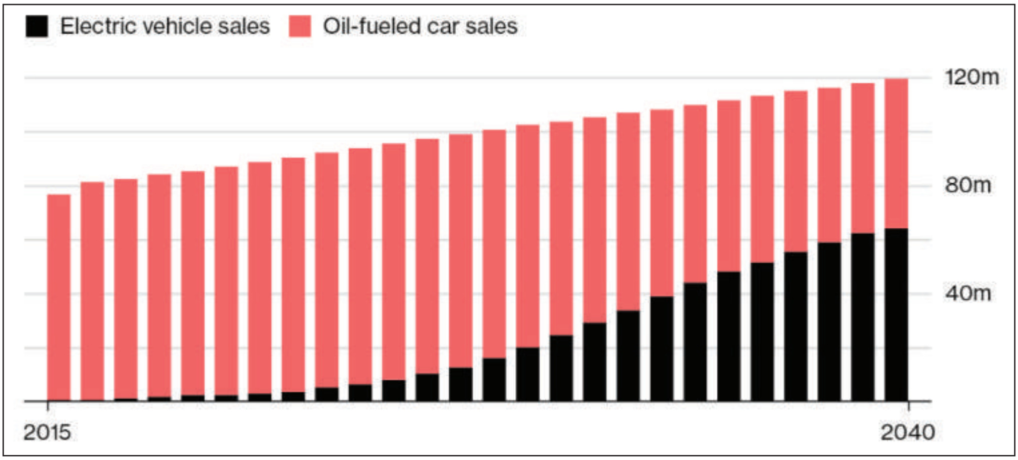

Figure 19 Forecast for electric vehicle sales[28]

Higher oil prices will encourage the adoption of electric vehicles. OPEC and other major oil producers thus have an incentive not to try to raise prices too much in the short term as this would damage their long-term market. The level of electric vehicle adoption shown in Figure 19 would eliminate 0.29 Mbpd of oil demand by 2020, 2.6 Mbpd by 2030 and 8.48 Mbpd by 2040.

2.2.8.3. Climate policy

The combination of electric vehicles, improved efficiency and climate policy could be a substantial reduction in world oil demand in the longer term (Figure 20). The IEA's 'Current policies' lead to oil demand a little below 120 Mbpd by 2040; the IEA base case, which assumes some climate policies, reaches about 102 Mbpd by 2040; while the policies required to limit global warming to no more than 2°C would see a near-term peak in oil demand and a fall to a little above 70 Mbpd by 2040.

28. Bloomberg New Energy Finance, https://www.bloomberg.com/news/articles/2017-09-21/how-electric-cars-can-create-the-biggest-disruption-since-iphone

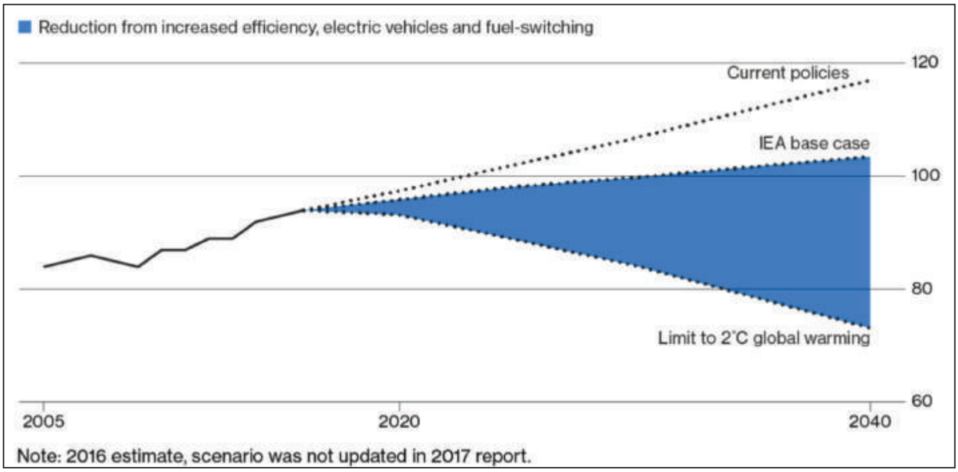

Figure 20 Future oil demand and environmental policy[29]

In a world of flat or falling oil demand, prices would be low, competition for market share intense, and low-cost producers would be inclined to maximise output to produce as much of their reserves as possible while the market remains.

Like other countries party to the Paris Climate Change agreement, Iraq submitted its Intended Nationally Determined Contribution, stating what it intends to do to combat climate change. Iraq's targets were to reduce greenhouse gas emissions 15% below business-as-usual by 2035, a 90 million tonne reduction (total emissions in 2014 were estimated at 155.5 million tonnes).

2.2.9. Middle East and other competitors

2.2.9.1. National competitors

In the last sustained period of low oil and gas prices, in the late 1990s and early 2000s, many Middle East and other OPEC countries opened up their upstream industries and sought to attract investment with new fiscal terms – 'Project Kuwait', the Iranian 'buybacks', the Saudi Natural Gas Initiative, Algeria's oil tax reforms, Libya's new licencing rounds, Venezuela's Apertura Petrolera, and the creation of Qatar's LNG industry. Only Qatar really succeeded. As oil prices rebounded, most of these initiatives withered away.

29. Data from International Energy Agency; graphed by Bloomberg https://www.bloomberg.com/news/articles/2017-12-22/why-the-prospect-of-peak-oil-is-hotly-debated-quicktake-q-a

So far, there has been little similar response. Iran's launch of its new Iran Petroleum Contract (IPC) has been the most notable move, but it faces difficulties in attracting many investors due to continuing concerns over US sanctions. The main change internationally has been the opening-up of Mexico's oil sector, a Pemex monopoly since 1938, which has attracted great interest and already achieved some significant oil discoveries by ENI, Premier Oil and Mexican private companies. Mexico has benefited from the proximity of US expertise and exploration and production (E&P) companies. Brazil has also seen foreign firms such as Shell, Total, Statoil and QP expanding in its deepwater sector, due to the attraction of giant and prolific resources, and the need to cut the burden on state oil firm Petrobras.

Privatisation has been another response. The biggest headline move has been the attempt to launch an Initial Public Offering (IPO) of 5% of Saudi Aramco, now slated for 2018 though it may be delayed further, with questions over the international listing location and valuation. Abu Dhabi National Oil Company (ADNOC) recently listed 10% of its fuel retail arm, ADNOC Distribution, on the Abu Dhabi stock exchange, but this was a relatively small move (raising $851 million) for a minority stake in a non-strategic asset. Egypt, Oman and Kuwait are also considering privatising various non-core oil-related companies. In recent years, Iran has privatised a number of fuel stations and state petrochemical firms, but most petrochemical projects remain closely-held by insiders or quasi-state entities.

During the period of high oil prices, some Middle Eastern sovereign wealth funds and national oil companies (NOCs) expanded internationally. Mubadala of Abu Dhabi acquired producing E&P assets in south-east Asia, Taqa (Abu Dhabi National Energy Company, mainly an electricity generator) bought oil and gas production and gas storage assets in the UK, Netherlands and Canada, and Emirates National Oil Company (ENOC), owned by the Dubai government, bought the minority shares of Dragon Oil, a company active primarily in Turkmenistan and Iraq (Block 9), that it did not already own. Qatar Petroleum entered a joint venture with ExxonMobil to export LNG from the Golden Pass terminal in the US (15.6 million tonnes per year, about 20% of its domestic capacity), and bought oil-producing assets in the Republic of Congo and Brazil. Kuwait Foreign Petroleum Exploration Company (Kufpec), a unit of Kuwait Petroleum Corporation, continued its expansion in Norway and Australia. Egypt General Petroleum Corporation entered Block 9 in Iraq by acquiring a stake from Kuwait Energy.

Saudi Aramco did not follow this pattern, other than its overseas refining assets, but in December 2017, it was said to be looking at investments in US shale, Russian LNG and gas in the Mediterranean and East Africa[30]. Saudi Aramco is respected as a highly-skilled operator at home. ADNOC has been undergoing a major transformation which is designed to make it more efficient, while Petroleum Development Oman (part-owned by Shell and Total) is also known as a good operator with expertise in enhanced oil recovery (EOR). But so far, no Middle Eastern oil company has yet proved itself capable of operating internationally on a similar scale and competence to the Western or Asian majors.

However, if oil prices remain low for an extended period, it is likely that competition between major producing countries to attract investment will become more intense, and fiscal terms will have to improve and become more flexible.

2.2.9.2. Corporate competitors

The Asian oil companies, including the state-owned firms, are competing more successfully with the major international oil companies (Shell, ExxonMobil, BP, Total, Chevron, ENI, ConocoPhillips and others). Some of these, particularly Shell, have been reducing their Middle Eastern presence, while others such as BP and Total have been expanding quite aggressively.

Statoil of Norway, majority state-owned but more like an IOC, has encountered problems in its past investments in Iran and Iraq. One of the most capable NOCs, Petrobras of Brazil, has been consumed by a corruption scandal and financial burdens at home and has scaled back its international aspirations. The Russian firms, state-controlled Rosneft and Gazprom (and its oil subsidiary Gazprom Neft) and investor-owned Lukoil, have gained prominence in the Middle East recently, particularly by taking on projects in Iraq, including the KRI, and showing interest in Iran.

North American E&P companies such as Occidental, Hess, Anadarko, Apache, Suncor and Devon have been under strong shareholder pressure to focus on assets at home, and have exited the Middle East entirely or reduced their presence. In particular, they have sought to exit countries with political and security challenges, such as Iraq, Yemen, Libya and Egypt.

30. https://www.investors.com/news/why-saudi-arabia-is-now-shopping-around-for-u-s-shale-assets/

Medium-scale European E&P firms, such as BG and Maersk have been acquired, while previously-successful smaller companies such as Gulf Keystone, Genel Energy, DNO (all active in the Kurdistan region), Premier Oil (previously present in southern Iraq) and Tullow have run into financial difficulties or at least had to reduce investment. However, remaining mid-sized European E&P firms such as OMV, DNO, MOL, Repsol, Lotos and Wintershall (in talks to merge with DEA) are still interested in growth in the Middle East.

The Asian state oil companies, sometimes referred to as International National Oil Companies (INOCs), are often well-financed and growing in capabilities, but most still lag the major IOCs in applying technology, managing large-scale complex projects (such as frontier exploration, LNG export, Arctic, deep-water), dealing with local stakeholders and transferring skills. Some, such as Petronas and Inpex, have proved their ability to progress major projects in complex environments. Simpler onshore projects, such as those in southern Iraq and Iran, have proved well within the capabilities of the Chinese majors. Ideal partnerships have often involved an IOC and Asian NOC, such as BP and CNPC in Rumaila, BP and Total with CNPC and CEFC in the renewed Abu Dhabi Onshore concession, and Total and CNPC in Iran's South Pars Phase 11.

This is somewhat problematic for countries seeking to attract investment. At least for bigger and more difficult projects, they face a choice between offering more lucrative terms to lure a Western major; taking a chance on a less technically-capable state oil firm; trying to manage projects themselves (at a time of limited finance) with major oil service firms such as Schlumberger; or ending up with an industry dominated by a few of the more aggressive firms – Total, CNPC and the Russians.

2.3. Implications for Iraq

The implications for Iraq of these trends are as follows.

Trend	Implications for Iraq
Rise of US oil production	– Non-OPEC production puts a cap on long-term achievable prices
Low oil and prices	– Oil plans and national budget need to be formulated considering likely long-term relatively low prices; renegotiation of plateau targets with IOCs – More stress for economic diversification
OPEC cooperation	– Iraq needs a clearly-defined strategy for its longer-term role in OPEC
Middle East political change	– Iraq's oil and gas plans, including export routes, need to be robust to such political changes – Need to consider how Iraq's energy resources can support its foreign and security policy – Need to use energy intelligently to reduce chance of conflict within Iraq recurring
Rise of Asian demand	– Iraq needs to develop its oil markets in Asia and continue engagement with Asian NOCs (beyond just Chinese NOCs)
Development of the gas market	– Use Iraq's gas resources and imports suitably for national development – Consider possible gas exports in the light of changing markets

Emergence of new petroleum technologies	– Need for a model of engagement with IOCs that facilitates technology transfer – Requirement to improve the skills of Iraqi petroleum workers and capabilities of state companies – Consider technology gains as another factor tending to increase global oil and gas output and depress prices
Rise of renewable and alternative energy	– Long-term pressure on oil demand and prices intensifies need to diversify economy – Renewable energy becomes attractive for Iraqi use
Middle East competition	– Middle East neighbours (particularly Iran) will compete with Iraq to attract petroleum investment, requiring more favourable terms and better operating conditions
Growing strength of Asian NOCs and declining Middle East engagement of Western IOCs	– Lesser choice for partners – Need to choose technically-capable partners carefully

3. Iraq Energy Situation

As of late 2017, Iraq's energy situation has improved considerably from its status as of mid-2014, despite the slump in oil prices and the destruction caused by the war against Da'esh.

It is worth reviewing the progress of Iraq's energy sector since the 2003 US-led invasion, which can be divided into four phases. In the **first phase**, from 2003-9, the country was in a state of insurgency and suppressed civil war, under US occupation[31]. Infrastructure was in extremely poor condition after three major wars and a decade of severe sanctions, while rebuilding was slow due to the mismanagement of the occupation, corruption, lack of skills and insecurity. Oil production, at 2.5 Mbpd in 2001[32], fell to an average of 1.344 Mbpd in 2003, rose to 2.030 Mbpd in 2004 but then barely grew up to 2007. Marketed gas production (excluding flaring and reinjection), fell from 2.8 billion cubic metres (BCM) in 2001 to 1 BCM in 2004, though it recovered somewhat to 10.4 BCM by 2016[33].

The new constitution was ratified in 2006 and contained provisions relating to the oil sector, particularly governing federal regions (the Kurdistan Region being the only one in existence), but these were interpreted differently by Baghdad and the Kurdish regional government in Erbil. The draft Iraq Hydrocarbon Law[34] was submitted to the Council of Representatives (parliament) in May 2007, which included provisions including the creation of the Iraq National Oil Company. However, this law was not passed and Iraq remains without comprehensive petroleum legislation.

At the end of this period, oil prices fell sharply during the global financial crisis, and it became apparent that international investment was required to develop Iraq's oil potential.

The **second phase** of Iraq's post-2003 oil sector began with the entry of international oil companies as investors and operators. A single field, Ahdab, had already been awarded by direct negotiation in November 2008 with CNPC

31. US troops began being withdrawn in December 2007 and had all left by December 2011.
32. BP Statistical Review of World Energy 2017
33. OPEC Annual Statistical Bulletin 2017
34. English translation at http://cabinet.gov.krd/uploads/documents/Draft%20Iraq%20Oil%20and%20Gas%20Law%20English__2007_03_10_h23m31s47.pdf

and Zhenhua Oil. Four bidding rounds were held, the First Round for existing producing fields (June 2009), the Second Round for discovered but (mostly) undeveloped fields (December 2009), the Third Round for gas fields (October 2010), and the Fourth Round for exploration blocks (May 2012). No further fields have been awarded subsequently, despite some negotiations for the Nassiriya field in particular, and recently negotiations with BP for Kirkuk.

These bidding rounds resulted in the transfer of most of Iraq's largest discovered oil fields to international operating consortia, which included in each case a unit of the Ministry of Oil. Production from most of the fields rose substantially, though it did not reach the plateau levels bid in each case. These were unrealistically high, given the constraints of the reservoirs, export infrastructure, water injection, gas handling, logistics to import required equipment, and skilled personnel. The slow pace of approvals and the delayed payment of companies' costs were further limitations. Fields in the southern part of the country mostly did not experience serious security problems, but those in the north and west suffered such insecurity that development became impossible: Najmah and Qayyarah heavy oil-fields in Ninawa province, operated by Angolan state firm Sonangol[35]; Akkas gas-field in Anbar, operated by KOGAS of South Korea; and Mansuriyah gas-field in Diyala operated by Kuwait Energy and TPAO of Turkey.

Despite these problems, oil production rose from 2.43 Mbpd in 2008 to 2.8 Mbpd in 2011 and 3.29 Mbpd in 2014.

From mid-2014, the **third phase** began. The 'Islamic State of Iraq and Syria' (ISIS), also known as ISIL, IS, or in Arabic, Da'esh, which has been gaining strength in northern and western Iraq, launched an offensive which saw it capture Fallujah in January and Mosul and Tal Afar in June. The federal pipeline from Kirkuk to Turkey via Baiji was made inoperable by repeated attacks and sabotage. Agreement was reached in December 2014 with the KRI to use the Kurds' pipeline to export oil from Kirkuk, but this deal broke down in March 2015 before restarting in August.

35. Sonangol stopped its operations here and at the nearby Najmeh field in February 2014: http://www.jeuneafrique.com/391738/economie/geant-angolais-sonangol-somme-de-revenir-a-mossoul/

In the wake of the fall of Mosul, Kurdish forces secured the city of Kirkuk and the surrounding oilfields of Kirkuk, Bai Hassan, and Jambur.[36] Da'esh forces used oil-fields in Syria and a number of small ones in Iraq, such as Qayyarah, and Alas and Ajeel near Hamrin, to fund its activities. Other fields, such as Khabbaz[37], Bai Hassan[38] and Ain Zalah[39], were attacked and damaged. The large Baiji refinery was captured by Da'esh in June, recaptured in November, with Da'esh forces driven out by Iraqi government troops in March 2015 to October 2015, but it was seriously damaged in the fighting and looting afterwards[40].

The loss and damage to Baiji led to severe shortages of petroleum products across northern Iraq and the KRI, and emergency imports from Turkey had to fill the gap. However the impact on overall national production was limited, as the main fields remained well away from Da'esh's activities, and there was not much effect on the global oil market.

However, Da'esh did use oil produced locally to fund its activities, smuggling it through Syria (including sales to the Assad regime) and Turkey. Most of its production came from the fields around Deir Al Zor in eastern Syria, but it also had control of some fields in Iraq for a time[41].

The US-led anti-ISIS coalition launched Operation Tidal Wave II in 2015, a campaign of bombing tankers and makeshift oil refineries, and later turned to targeting fields in Syria directly. From a peak of $50 million monthly revenues,

36. 'Kurds take 2 vital oil fields near Kirkuk, increasing tensions with Iraqi gov't', 11 July 2014, CBSNews: www.cbsnews.com/news/kurds-take-2-vital-oil-fields-near-kirkuk-increasing-tensions-with-iraqi-government/.
37. https://www.reuters.com/article/us-mideast-crisis-iraq-oil/explosions-hit-two-oil-wells-in-northern-iraqs-kirkuk-sources-idUSKCN0XV1YB
38. http://www.rudaw.net/english/kurdistan/20082016
39. http://www.kurdistan24.net/en/news/2216420c-2e71-463c-8f24-c86c0d21f893/iraq%E2%80%99s-damaged-oil-field-needs--5m-to-restart
40. http://gulfnews.com/business/analysis/the-wanton-dismantling-of-an-iraqi-refinery-1.1662932
41. e.g. 'Inside Islamic State's oil empire: how captured oilfields fuel Isis insurgency', The Guardian, 19 November 2014, www.theguardian.com/world/2014/nov/19/-sp-islamic-state-oil-empire-iraq-isis; 'Isis Inc: how oil fuels the jihadi terrorists', The Financial Times, 14 October 2015, www.ft.com/intl/cms/s/2/b8234932-719b-11e5-ad6d-f4ed76f0900a.html#axzz3s7CJCnXo.

ISIS's oil sales were cut to an estimated $4 million by October 2017[42]. This helped in undermining the group's activities. However, it will leave a legacy of environmental and infrastructure damage, more in Syria than Iraq. In August 2017, ISIS released oil from the Qayyarah field into the Tigris river and, in October 2017, retreating ISIS forces burnt oil-wells in Qayyarah and sulphur from the Mishraq plant, causing severe air pollution[43].

At about the same time as the Da'esh offensive on Mosul, the price of oil in world markets fell sharply, because of increasing oversupply from US shale production, and a strong build-up of inventories. In August 2014, Iraq (excluding independent Kurdish sales) exported 2.375 Mbpd at an average price of $97 per barrel; by December 2014, exports had risen sharply to 2.94 Mbpd but the average price dropped to $57 per barrel. The price dropped further in 2015, and by December of that year, Iraq was earning just $29 per barrel for its exports[44]. This further exacerbated the economic shock of the war against ISIS and the cost of military forces and dealing with refugees.

The **fourth phase** came in late 2017 and was marked by three key events: the defeat of Da'esh in most of northern and western Iraq; the reassertion of federal government control over disputed territories controlled by the Kurdish authorities; and a revival in oil prices from September 2017 onwards, following the OPEC deal implemented from January 2017.

Ramadi was recaptured from Da'esh in March-April 2015, Ramadi from December 2015 to February 2016, Fallujah in June 2016, Mosul in June 2017 and Tal Afar in August 2017. By October 2017, Da'esh was driven out of its Syrian capital, Raqqa, by US-backed largely Kurdish forces. The victory over Da'esh improved investor confidence in Iraq, allowed the government to begin considering the restoration of northern oil infrastructure, and gave it a free hand to move against the Kurds. In October 2017, the Iraq Ministry of Oil was able to announce that it planned to rehabilitate the Qayyarah and Najmah fields and restart production[45], bolstering its influence in this area.

42. https://www.usatoday.com/story/news/world/2017/10/02/u-s-coalition-slashes-isis-oil-revenue-more-than-90/717303001/
43. https://www.vox.com/2016/11/1/13481682/isis-mosul-oil-fires-sulfur
44. https://www.iraqoilreport.com/news/federal-exports-climb-revenues-hit-three-year-high-26403/
45. https://www.reuters.com/article/us-iraq-oil-nineveh/iraq-hopes-to-resume-production-from-nineveh-oil-fields-in-coming-months-idUSKCN1C81BS

On 16th October 2017, on the orders of Prime Minister Haider Al Abadi, apparently by agreement with the Patriotic Union of Kurdistan (PUK), Iraqi army forces and Popular Mobilisation (Hashd Al Shaabi) units entered key locations in Kirkuk, including the airport and the oil-fields. Most of the Peshmerga (Kurdish forces) offered little opposition and withdrew. The federal forces retook control of the city, advancing often to the 2014 lines and in many places beyond them to the 2003 lines. In addition to Kirkuk, they also regained hold of the town of Zumar and the nearby Ain Zalah oil-field. They also moved towards the Khurmala field, the north-west part of Kirkuk, and the Fishkhabour border crossing, near the Syria-Turkey-Iraq trilateral. Control of Fishkhabour would allow the federal forces to control the Kurdistan Regional Government (KRG)'s independent export pipeline where it connects to the Kirkuk-Ceyhan oil pipeline. Khurmala represents the largest remaining field under KRG control, yielding almost half the region's remaining production.

Subsequently, the confrontation between the federal and Kurdish forces has opened the way for a partial return of ISIS, which has mounted attacks and bombings in remote villages. A large area previously patrolled by the Peshmerga is now insufficiently policed[46]. This does create a worry of continuing instability, which would affect reconstruction and petroleum operations.

Before the changeover of Kirkuk control, the Baghdad-run North Oil Company was exporting about 100 kbpd of crude via the Kurdish pipeline to Turkey, splitting the revenues equally with the KRG, and sending 40 kbpd to the Kalak refinery in exchange for products. After the return of Kirkuk to federal control, oil flow through the Kirkuk-Ceyhan pipeline dropped from 550-600 kbpd to around 250 kbpd, as Kirkuk production could not be exported without an agreement with the KRG. Kirkuk's production fell to 80 kbpd, which was being trucked to local refineries and power plants. However, repair of refineries at Haditha (10 kbpd) and Siniya (20 kbpd) and completion of one at Kasak near Mosul (30 kbpd) would allow for some increase in Kirkuk production.

Jabbar Al Luaibi, the oil minister of Iraq, mentioned the possibility that BP, which had previously studied the Kirkuk field, could return to it to boost

46. https://www.iraqoilreport.com/news/insurgency-exploits-baghdad-krg-conflict-26723

production to 700 kbpd[47]. To restore exports, there was discussion of rebuilding the direct Kirkuk-Baiji-Ceyhan pipeline (removing the need to use the Kurdish pipeline), and of exporting 30-60 kbpd of Kirkuk crude by truck to Iran, where it would be delivered to local refineries and swapped against Iranian crude deliveries through the Gulf[48].

Baghdad stated that all Kurdish oil exports should be under its control[49]. The proposed 2018 federal budget contained a 12.6% share of revenues for the KRG's budget (down from 17%, after federal expenses, in earlier budgets).

Finally during this period, in November 2016, OPEC reached a deal, Iraq's part of which was to cut its production from its October 2016 level of 4.55 Mbpd, to no more than 4.351 Mbpd, a cut of about 4.4%, in line with that agreed by other members[50]. This was OPEC's first deal on cuts for eight years. In the two years leading up to the deal, Iraq had been the biggest gainer in production, adding 1.19 Mbpd (Saudi Arabia boosted output by 1.04 Mbpd and Iran, recovering from sanctions, by 0.91 Mbpd[51]). A group of non-OPEC countries, notably Russia, with Kazakhstan, Azerbaijan, Oman, Mexico and others, also agreed to restrict output.

Figure 21 shows the progress in Iraq's oil production and exports since the start of 2007. Output rose steadily from late 2010-14, then rapidly in 2015 due to the resolution of some export bottlenecks. Since the start of 2017, production has been about flat due to the OPEC restrictions, even though they were not fully observed.

47. https://www.al-monitor.com/pulse/originals/2017/11/kirkuk-baghdad-kurdistan-somo-ceyhan.html
48. http://www.reuters.com/article/us-mideast-crisis-iraq-oil-insight/oil-seen-as-real-prize-of-irans-kurdish-adventure-idUSKBN1DE1UY
49. http://www.argusmedia.com/news/article/?id=1557632
50. Iran was allowed to increase production slightly towards its pre-sanctions levels, while Libya and Nigeria were exempt from cuts due to insecurity.
51. https://www.ecb.europa.eu/pub/pdf/other/eb201608_focus01.en.pdf?84e6b1f5356e53c615d6e8e5af195007

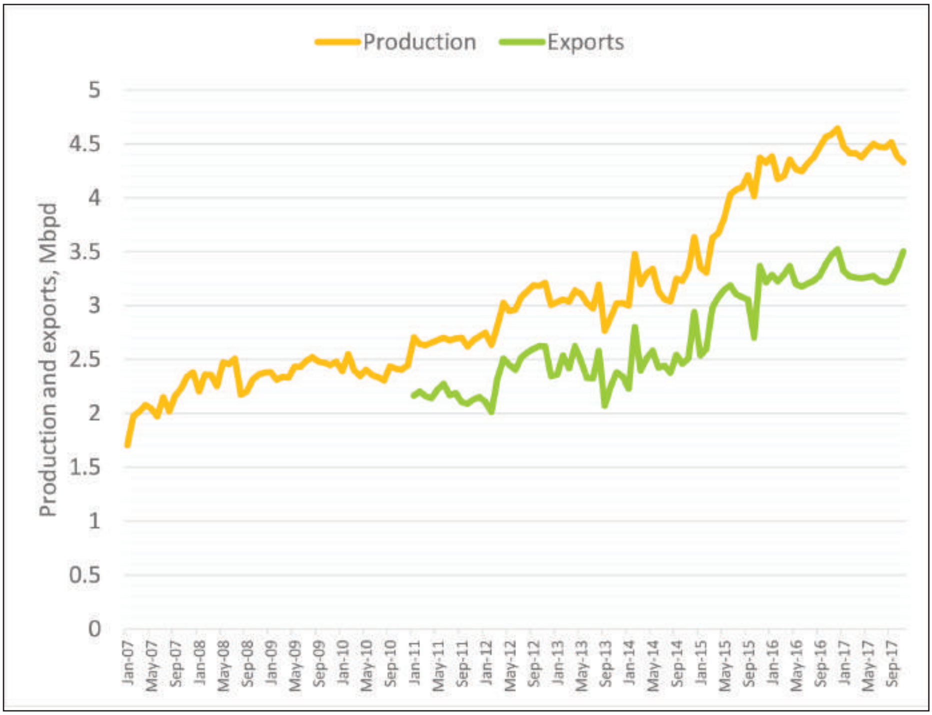

Figure 21 Iraq oil production and exports[52]

Despite rising exports, revenues fell sharply from 2014 to 2015 and remained relatively low through 2016-17 (Figure 22 – note this excludes the Kurdistan region). In late 2017, revenues turned up again due to a significant jump in prices, reaching about $6 billion per month, but remained below the ~$8 billion monthly total in early 2014, despite exports that were 1 Mbpd higher.

52. OPEC monthly oil reports (secondary sources); Middle East Economic Survey, Iraq Oil Report; relevant months

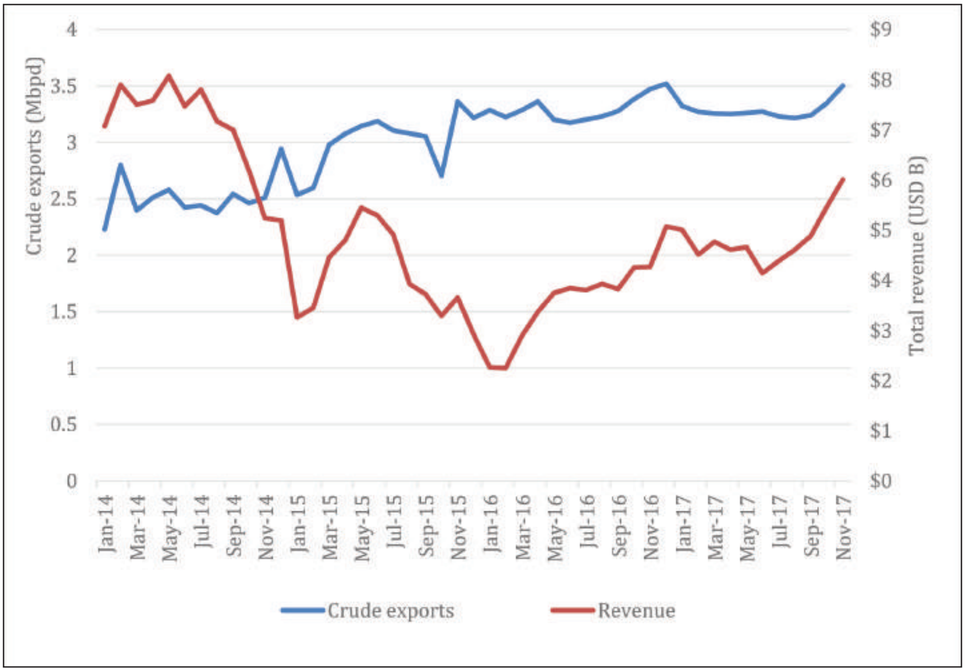

Figure 22 Federal Iraq crude oil exports and revenues[53]

However, international oil companies had continued to be unhappy with the contractual terms they were working under, and in November 2017, Shell announced that it would leave its two oil projects in Iraq, Majnoon (where it was operator), and West Qurna-1 (where it was a non-operating partner to ExxonMobil). It was reported that Total, Chevron and CNPC were interested in taking over Majnoon, under different contractual terms[54]. Petronas, Shell's minority partner, confirmed in December 2017 that it too would leave Majnoon[55].

53. Iraq Oil Report
54. https://in.reuters.com/article/iraq-oil-majnoon/chinas-cnpc-interested-in-iraqs-majnoon-oilfield-oil-officials-idINKBN1DR19J
55. https://www.thenational.ae/business/energy/exclusive-petronas-confirms-exit-from-iraq-s-majnoon-oilfield-1.689876

4. Iraq's Petroleum Sector: Short-Term Priorities

The priorities for the petroleum sector are quite clear, and have been since the IEA's publication of the Iraq Energy Outlook[56] (October 2012) and the creation of the Iraq National Energy Strategy 2010-30[57] (INES, June 2013).

The timeline, of course, has not been achieved. Apart from the conflict with Da'esh, which would have been difficult to foresee, these studies did not adequately consider the delays caused by insufficient skills, institutional weakness, corruption and lack of government coordination, and the shortage of finance resulting from the 2014 oil price crash. The INES had a base case price assumption of $110 per barrel for Brent in real 2011 dollars. The plans presented were still strongly state-led. They paid lip service to increasing the role of the private sector but did not adequately consider the mechanisms and political economy considerations of doing so.

Nevertheless some of the INES goals have been achieved. Table 2 presents a survey of selected achievements.

Table 2 Selected INES targets and actual[58]

Goal	Actual – 2012	Target – 2015	Actual – 2016/17	Target – 2020
Oil production (Mbpd)	3.116	4.5	4.465	9.3
Oil export capacity – south (Mbpd)	2	6.8	4.6	6.8
Oil export capacity – north (Mbpd)	0.7	1.6	0.7	3.8
Export grades	Kirkuk, Basra Light	Kirkuk, Basra Light, Basra Heavy		

56. https://www.iea.org/publications/freepublications/publication/WEO_2012_Iraq_Energy_OutlookFINAL.pdf
57. http://documents.worldbank.org/curated/en/406941467995791680/pdf/105893-WP-PUBLIC-INES-Summary-Final-Report-VF.pdf
58. Iraq National Energy Strategy; BP Statistical Review of World Energy 2017; OPEC Statistical Bulletin, various years; JODI; Middle East Economic Survey

Refining capacity (Mbpd)	0.8	0.8	0.5 + 0.31[1]	1.4
Gas flaring (Bcfd)	1.15	0	1.55[2]	0
Raw non-associated gas production (Bcfd)	~0.3	0.7	0.307[3]	1.4
Domestically marketed gas (Bcfd)	0.36	2.6	1.01	3.1
Power capacity (GW)	7	22	16.91	27
Cement production (million tonnes per year)	7.5	30	21[4]	44
Urea capacity (Mtpa)	0.7	1.4	0.7	2.8

It can be seen that progress on oil production against the 2015 target and on splitting the crude export grades is quite good. Production will, though, fall well short of the 2020 target, and export capacity is also well behind, particularly from the north. Refinery capacity is considerably below the target though this is due to the destruction of Baiji. The new and upgraded refineries planned for 2021 would reach the 1.4 Mbpd target, but they are progressing slowly at best. Gas flaring has actually risen since INES, and there has been little progress on developing non-associated gas, but the supply of marketed gas has increased, mainly due to the Basra Gas Company. Power cuts remain problematic but useable generating capacity has increased substantially. There has been a significant increase in cement output but other downstream industries, such as urea (shown here) and petrochemicals have not advanced.

4.1. Oil production, refining and exports

4.1.1. Exploration and reserves

New exploration should not be a particular priority. Iraq's Fourth Bid Round, in 2012, awarded four of twelve offered blocks. Oil exploration has been continuing at three of these blocks: Block 10 south-west of Nassiriya where Lukoil has discovered the Eridu field; Block 9 on the Iranian border north of Basra, where Kuwait Energy and Dragon Oil (now joined by Egyptian state firm EGPC) have discovered the Faihaa field which is now producing; and Block 12, operated by

Russia's Bashneft (now owned by Rosneft) and where drilling of the Salman-1 well began in February 2017, and was completed on 2nd October at a depth of 4277 metres[59]. Pakistan Petroleum has not been able to progress exploration in Block 8 in the Wasit and Diyala provinces due to insecurity.

Iraq is now moving ahead with tendering 9 exploration blocks along the border for international oil company involvement: 5 along the border with Iran (Naft Khana, Zurbatiya, Shihabi, Huwaiza and Sindbad), 3 along the Kuwaiti border (Fao, Jebel Sanam and Khidr Almaa), and one covering the small offshore area which borders Iranian and Kuwaiti waters[60].

It is a reasonable goal to appraise Iraq's resources in border areas, in order to secure control. Cooperative development of cross-border fields in the Middle East is exceedingly rare and fields are normally developed independently by the countries on each side, although Iraq has held talks with Iran and Kuwait on joint development[61]. Discovering fields close to existing developments which could be easily tied back can also be useful. And there is a benefit in extending geological knowledge of Iraq and bringing development of infrastructure to more remote areas.

However, Iraq's official oil reserves stand currently at 153 billion barrels[62], equivalent to 94 years of production at current rates. For context, this is the third-largest conventional reserves in the world, a little behind Iran (158.4 billion bbl). Since Iran's reserves are probably somewhat overstated, Iraq is probably actually in second place, behind Saudi Arabia with 266.5 billion bbl. The larger reserves in Canada and Venezuela consist mostly of extra-heavy oil which is expensive and slow to recover. Allowing for further appraisal and development of known fields, and improvements in recovery factor[63], Iraq's reserves are likely to rise further. There is no imminent need to discover large new oil resources.

59. http://www.zpec.com/en/news/detail/?id=2405
60. http://www.iraqoilforum.com/?p=3333
61. https://www.platts.com/latest-news/oil/baghdad/iraq-seeks-ioc-investment-in-fields-on-iran-border-26424176; http://en.economiciraq.com/2017/09/06/the-amir-of-kuwait-issues-a-decree-to-exploit-the-border-oil-fields-with-iraq/
62. BP Statistical Review of World Energy 2017
63. The percentage of oil or gas in place in the reservoir rocks that can be commercially extracted, usually in the range 30-40% for oil and 70-80% for gas in the Iraqi context, although it could go considerably higher

Gas reserves are 130.5 trillion cubic feet (about 22.5 billion barrels of oil equivalent), more than 300 years at current production levels[64]. This would put Iraq 12th in the world, so although its gas reserves are significant, they are relatively much smaller than its oil. Of this about 70% is associated (produced as a byproduct of oil), about 10% is dome gas (present as gas-caps in reservoirs above oil, and hard to recover imminently without damaging oil recovery), and about 20% is non-associated (present in separate, non-oil-bearing fields and reservoirs).

There is therefore a need to discover more non-associated gas. As discussed below, Iraq needs gas to back out high-cost imports from Iran, replace oil in domestic power generation and support expanded electricity generation, and potentially for local industry and export. Non-associated gas resources are more flexible as production can ramp up and down to meet summer demand, and is not affected by OPEC quotas. If a surplus of gas becomes available (as discussed below), it could be exported. Iraq should therefore seek to offer gas-prone exploration blocks, which would help meet domestic needs as well as ultimately providing export revenues as some diversification from oil.

Drilling in deeper reservoirs in southern Iraq would be likely to find gas, as has been discovered in north Kuwait. Gas was found in 1980 in Khider Almaa, one of the offered exploration blocks, but most of the offered blocks for now appear to be in oil-prone areas. Gas in Iraq is more likely to be found in the far west, around Akkas on the Syrian border in the Anbar province, and in Diyala where a number of deep, high-pressure gas fields have been discovered but not developed. Blocks 2 and 3 in the 2012 bid round were near Akkas, and Blocks 4, 5 and 6 in largely unexplored parts of the Western Desert which may also be gas-prone – none of these received any bids. Anbar and Diyala suffer from security problems. The Mansuriyah field, near Block 8, awarded to TPAO, Kuwait Energy Company and KOGAS in 2010, and the Akkas field, awarded to KOGAS in 2011, have not proceeded with development due to this insecurity.

64. This refers to sales gas of about 1 Bcf per day; large quantities of gas are also flared

4.1.2. Oil production outlook

As noted, federal Iraqi oil production has risen strongly, particularly from 2011 onwards. Oil minister Jabbar Al Luaibi has stated that Iraq plans to raise capacity to 5 Mbpd by the end of 2017, up from about 4.5 Mbpd currently. This is probably not achievable so soon, but is a realistic objective in the slightly longer term.

The IEA estimated that Iraq would require 1.5 barrels of water injection for every barrel of oil produced. The large-scale Common Seawater Supply Project (CSSP), intended to supply 12 Mbpd of water, has stalled, and operators such as BP are implementing smaller schemes to provide water for reinjection, boosting injection into Rumaila from 60 kbpd in March 2013 to 900 kbpd by October 2016. This is particularly important for the Mishrif reservoir, which holds a large part of Iraq's reserves under development but has weak natural aquifer support. Rather than trying to implement a very large and complex CSSP, it would be better to break it down into pieces, which may be less efficient on paper but at least could be managed more easily and delivered on time. Without it, production at fields such as Rumaila, Zubair and Majnoon will stall as reservoir pressure declines.

During 2017, Iraq's production has been restrained by compliance to the OPEC deal (Figure 23), as well as by reduced output from the Kirkuk area following the changeover of control. However, it has generally been above its 4.351 Mbpd OPEC target, or even the 4.422 Mbpd interpreted by the Iraq Ministry of Oil.

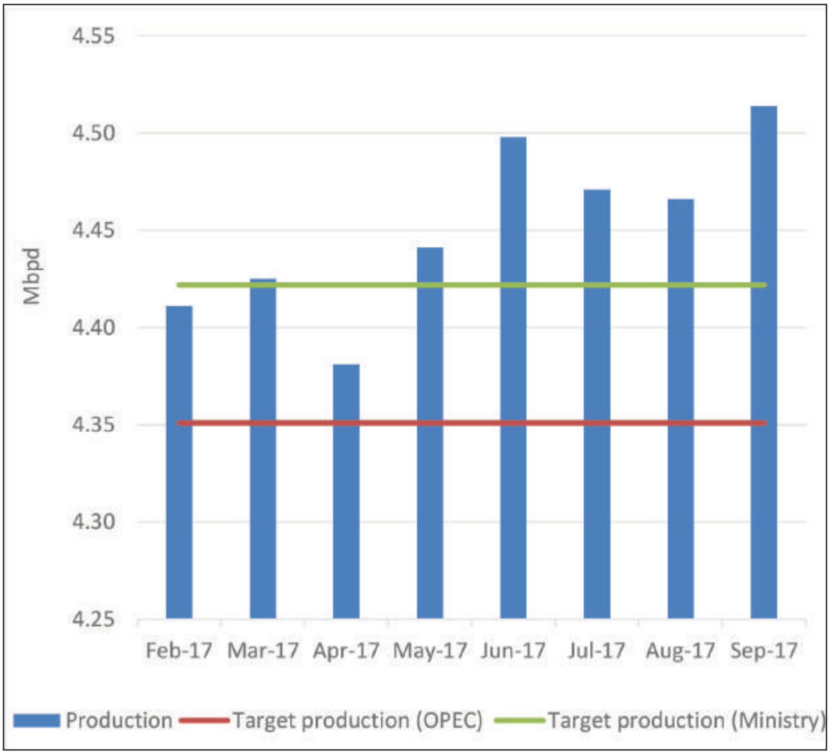

Figure 23 Monthly Iraq oil production during 2017[65]

This growth will rely on the continuing development of the large fields in southern Iraq, and a possible revival of the Kirkuk area. The ambition of returning Kirkuk to 700 kbpd (assuming this refers to the entire area, but excluding Khurmala) would boost capacity from 434 kbpd in September 2016[66], which fell to 80 kbpd after the changeover of control. MoO is seeking to boost Majnoon output from 235 kbpd to 400 kbpd after Shell relinquishes it, though without giving a timeline. In June 2016, Rumaila was producing 1.45 Mbpd, West Qurna-1 450 kbpd, West Qurna-2 405 kbpd, and Zubair 360 kbpd[67].

The expansion of the Faihaa field in Block 9 and the development of Lukoil’s Eridu discovery can add additional volumes.

65. OPEC Monthly Oil Report; Iraq Ministry of Oil
66. http://www.argusmedia.com/pages/NewsBody.aspx?id=1338380&menu=yes
67. https://www.reuters.com/article/us-iraq-oil/iraqs-southern-oil-exports-seen-steady-through-2016-at-3-162-million-bpd-idUSKCN0ZD2JV

In the longer term, Iraq has been considering the development of several other fields. The Nassiriya field has potential for 200 kbpd, and lengthy discussions have been held involving its development in combination with a local refinery of 300 kbpd. The Ministry of Oil has been in talks with ExxonMobil and PetroChina to develop Nassiriya as well as Luhais, Tuba, Nahr Bin Umr (currently 35 kbpd) and Ratawi (currently 17 kbpd), located around the giant southern fields, as a joint project including the common seawater supply facilities, oil pipelines and oil storage[68]. These fields produced 237 kbpd in late 2015 and have a production target of 345 kbpd, though with combined reserves of about 15 billion barrels, they could easily produce 1 Mbpd or more. Other statements suggested a target of 550 kbpd for Nahr Bin Umr and Ratawi combined[69].

As well as the 9 exploration blocks mentioned above, in October 2016 the Ministry of Oil also offered 12 small/medium-sized fields[70], though these discussions have not progressed. These fields are as follows: Sindebad, Umm Qasr, Rachi (Raji) and Abu Khema in Basra province; Kumait, Noor, Amara, Dima (a new discovery made by MoO) and Dujaila in Maysan province; and Marjan, Kifl and West Kifl in Karbala province. The three Karbala fields were listed in the 2009 bid round, with a plateau target of 75 kbpd. The Maysan fields were producing about 30 kbpd in August 2016.

The new exploration and development blocks are mostly in the provinces of Basra, Maysan, Wasit, Diyala and Karbala. Other than the redevelopment of Kirkuk, there does not appear to be provision for the development of resources elsewhere in the country. Other territories recently retaken by the central government from KRG forces, such as Bashiqa, had been undergoing oil exploration. The provinces where ISIS has recently been defeated – primarily Salahuddin, Ninewa and Anbar – also need development. A number of fields have been discovered historically in these areas but there has been little production. The Ajeel oil and gas field, and Hamrin oil-field in Salahuddin are two of the most notable that could be expanded. The Qayyarah and Najmah heavy oil fields in Ninewa, south of Mosul, were being developed by Angolan state oil firm Sonangol but little progress was made due to insecurity.

68. https://www.pressreader.com/uae/gulf-news/20171226/282475709196934

69. https://www.reuters.com/article/us-iraq-oil/iraqs-southern-oil-exports-seen-steady-through-2016-at-3-162-million-bpd-idUSKCN0ZD2JV

70. Middle East Economic Survey (28th October 2016), Volume 59 Number 43, p8

Developing such fields would help in providing a limited amount of local employment and infrastructure development, crude for local refineries and gas for power generation. It would diversify Iraq's geographic development and surplus oil produced could supply the Jordan or Turkey export pipelines.

On the basis of known plans, it is feasible that Iraq could achieve its 5 Mbpd target during 2018, if not restrained by OPEC quotas. This assumes that Kurdish production is steady and that full output can resume at Kirkuk.

In the longer term, more than 9 Mbpd is achievable based on fields in current development, again assuming that Kurdish output is flat, that the expansion plans for Kirkuk, Nassiriya and Nahr Bin Umr go ahead, and that the plateau targets (revised down) for the major fields are eventually achieved. Iraq's production would then rest on Rumaila (2.1 Mbpd), West Qurna-1 (1.6 Mbpd), West Qurna-2 (800 kbpd), Majnoon (1 Mbpd), Zubair (850 kbpd), the Kirkuk area (700-1000 kbpd), and a number of medium-sized fields with output 100-300 kbpd each. However, this refers to wellhead output, and would only be achieved if water injection, gas handling and export capacity can keep up.

The IEA sees Iraq as leading OPEC production growth up to 2022, with a gain of 0.7 Mbpd over 2016 levels, to about 5.1 Mbpd. This appears highly achievable if Iraq can retain reasonable political and fiscal stability, bring the Kirkuk fields fully online and continue a moderate investment programme.

By comparison, growth in Libya is highly uncertain because of political instability, while that in Iran is realistic but could be hampered by US sanctions. The UAE's growth forecast is quite solid, being based on current plans under execution. Kuwait also has the potential for more growth but has repeatedly struggled to award key projects because of political debate. On the other hand, Venezuela's output is likely to collapse more sharply than the IEA forecasts, but it could then grow significantly under better management. Saudi Arabia has the potential to increase output substantially, but does not appear to be planning to do under current market conditions. However, the kingdom does see its output rising to 10.45 Mbpd by 2020 and 11.03 Mbpd by 2023[71], below its current capacity of 12-12.5 Mbpd. This implies an increase of about 0.4 Mbpd on 2016 levels, more than the IEA's forecast of 0.16 Mbpd.

71. https://www.rigzone.com/news/wire/saudis_seen_counting_on_80_surge_in_oil_income_to_balance_books-27-dec-2017-152941-article/

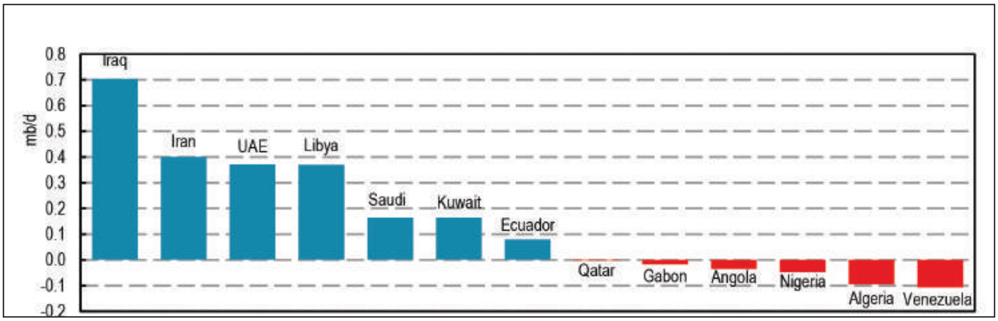

Figure 24 Forecast OPEC capacity growth, **2016–22**[72]

Figure 25 shows a forecast of Iraq's production growth (including the Kurdistan region). Although rising significantly, growth is forecast to slow from the rates achieved during 2010-16, with average growth just 120 kbpd per year up to 2022. This is constrained by export infrastructure, the delayed water injection scheme, lesser investment in the southern fields due to government budget constraints, and disappointing geology and financial problems in the KRI.

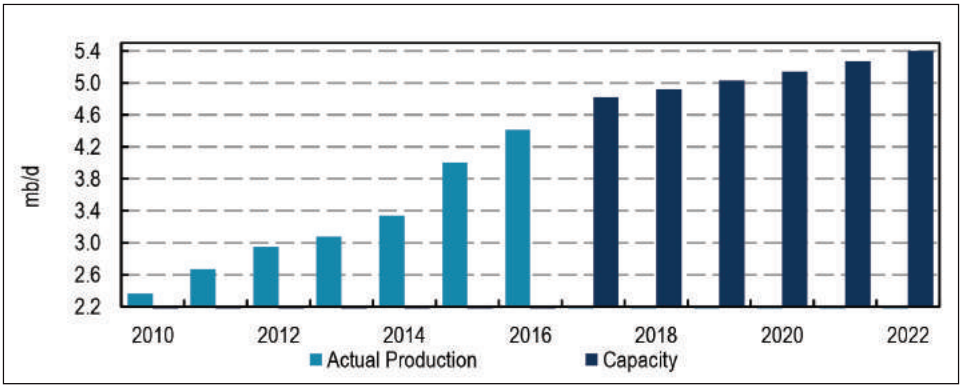

Figure 25 Iraq forecast production growth[73]

Nevertheless, Iraq would on these forecasts strengthen its position as OPEC's second-largest producer, and reduce the gap to Saudi Arabia (with an official 12.5 Mbpd of capacity). These gains would also be larger than those of any non-OPEC producer except the US (forecast to gain 1.6 Mbpd), Brazil (1.1 Mbpd) and Canada (0.8 Mbpd).

72. International Energy Agency (23rd March 2017), Market Report Series
73. International Energy Agency (23rd March 2017), Market Report Series

4.1.3. Exports

Figure 26 shows a snapshot of Iraq's oil export destinations from November 2017. India, the US, China and South Korea were the largest markets. Europe / Turkey and a couple of Asian countries (Japan, Malaysia) account for most of the rest, with the UAE likely representing storage at Fujairah for onward sale. Note that SUMED (Suez bypass pipeline in Egypt) and Suez Canal are not final destinations, but most likely would represent supplies to Europe or the US. 'Armed Guards' refers to ships not reporting their destination for security purposes, likely while crossing pirate-affected waters around Somalia.

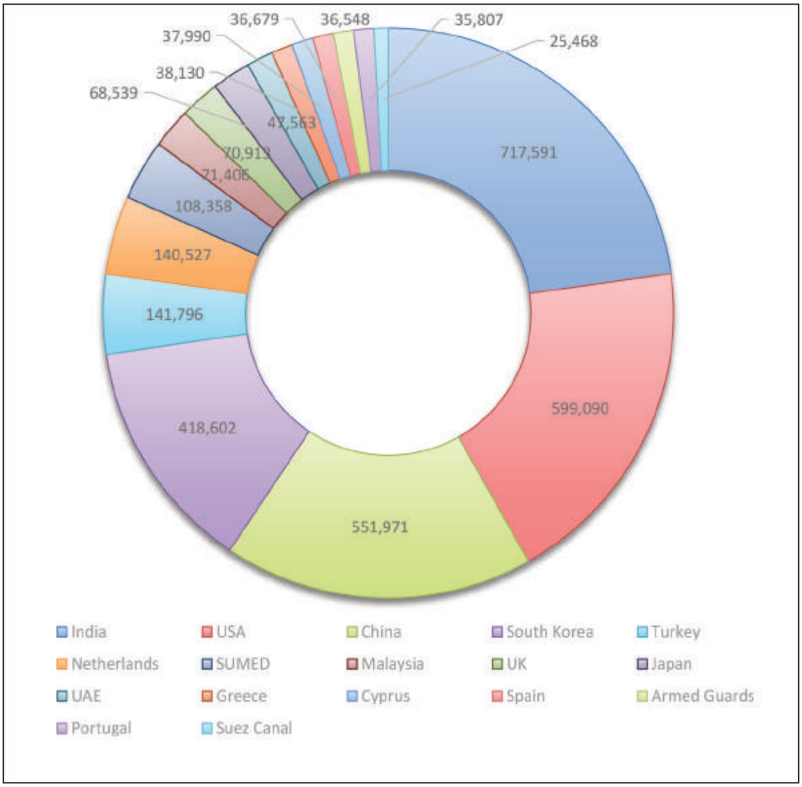

Figure 26 Iraq oil exports by destination, November 2017 (barrels)[74]

74. Tanker Trackers; Qamar research

The dominance of Asian customers is notable. The large role of the US is likely to shrink as shale oil output returns to growth; however, the US still needs significant imports of medium crude oil to balance its refining system with the light crudes typical from shale. Falling exports from Venezuela, and a deliberate Saudi policy for the moment of reducing exports to the US, mean it will have to draw in crude imports from elsewhere.

The evolution of Iraqi oil exports during 2017 can be seen in Figure 27 and Figure 28. Exports from Basra were quite constant in level; most goes to Asia-Pacific. Exports of 'Kirkuk', nearly all KRG-managed crude exported from Ceyhan, dropped sharply in October (and further in November, not shown here) due to the KRG's loss of control over the Kirkuk-area fields. Most was being exported to the Mediterranean, primarily Greece, Croatia (likely for transfer to Hungary), Israel (often being reloaded) and Italy. Only a little went to Asia-Pacific and none to the Americas, due to legal action by Baghdad.

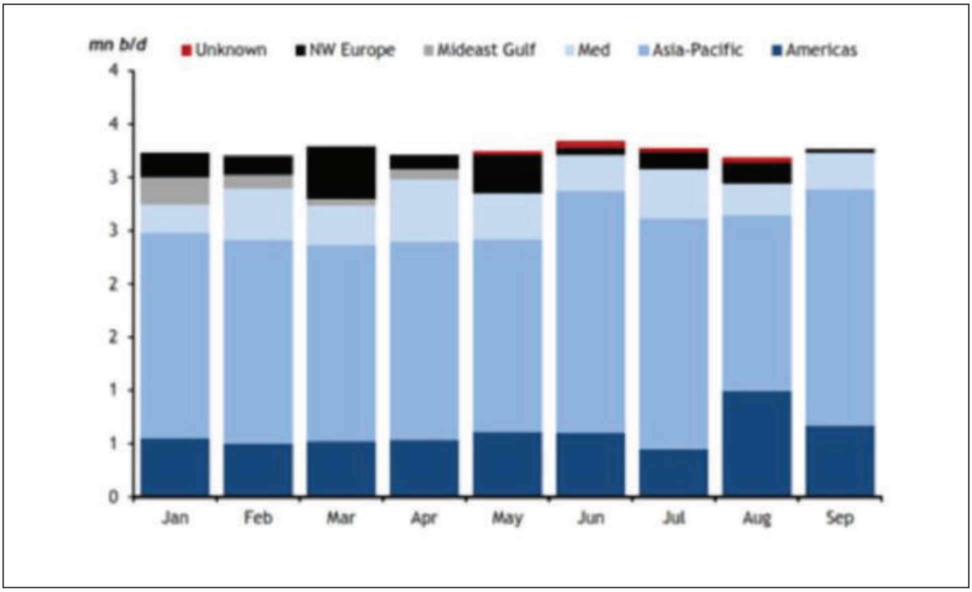

Figure 27 Basra oil exports by destination during 2017[75]

75. Argus

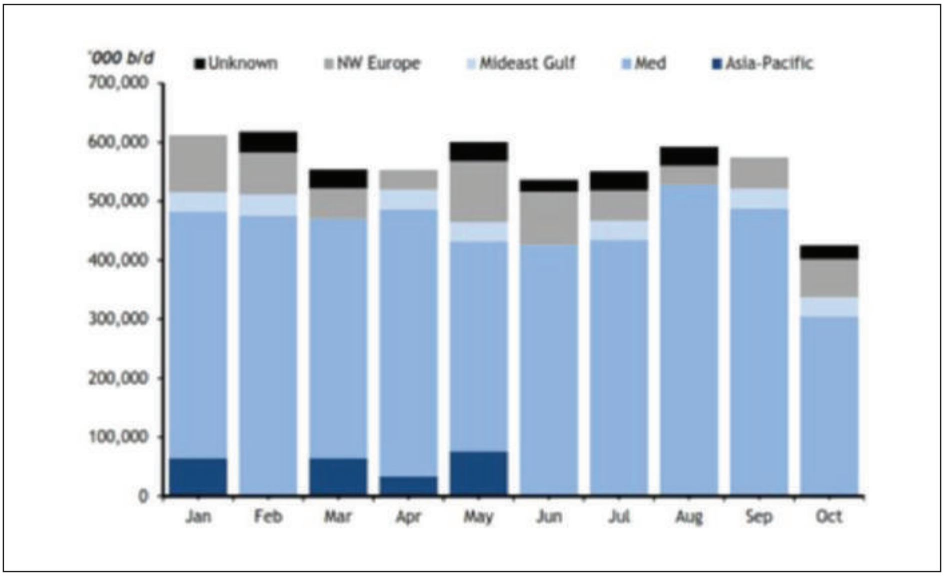

Figure 28 Kirkuk crude exports by destination during 2017[76]

In future, if and when federal Iraq resumes exports from Ceyhan, it would be expected that more Kirkuk crude would head to the Americas, as it is a shorter and cheaper voyage than from Basra.

Iraq has long been constrained on export capacity as its production has risen. Oil minister Al Luaibi announced in October 2017 that the installation of a new 900 kbpd Single Point Mooring (SPM) offshore Basra had raised southern export capacity to 4.6 Mbpd, compared to about 3.3 Mbpd of exports. But pumping capacity, lack of storage and periodic bad weather limit the actual capacity. The Iraq Crude Oil Export Expansion Project is intended to raise capacity to 5.4 Mbpd.

Dependence on the Gulf for exports is also insecure. The small area of offshore Iraqi waters is vulnerable to sabotage, accidents or military action. Exports through Syria to the Mediterranean are impossible for now, but could possibly resume after a political settlement there. Limited exports to northern Iran can be made in return for swapping oil from the Gulf, but this is constrained by trucking capacity to nearby refineries. Iraq has also been discussing with Saudi Arabia the possibility of reopening the 1.6 Mbpd IPSA pipeline to the Red Sea port of Muajjiz, but the Saudis have recommissioned this as a backup line for their own uses. It would be

76. Argus

risky to rely too much on powerful neighbours and oil competitors, whether Iran or Saudi Arabia.

This leaves two other options for exports: Turkey and Jordan. The existing Kirkuk-Ceyhan pipeline consists of two sections in Turkey with a notional capacity of 1.8 Mbpd, but they are in poor repair. Currently the Kurdistan pipeline connects to the Turkish section of this line and is exporting about 225 kbpd, though it has carried up to 600 kbpd and has capacity for about 700 kbpd, while Rosneft's agreement with the KRG involved boosting it to 1 Mbpd. Following the federal reassertion of control over Kirkuk, the plan is to build a new line from Kirkuk to Turkey with capacity of 1 Mbpd[77], though that will take at least two years, and Iraq's northern fields will not be able to export so much for a significant period.

The other project involves constructing a 2.25 Mbpd pipeline to Jordan, with 160 kbpd going to the Zarqa refinery near Amman, and the rest going to Aqaba for export. Aqaba is not an ideal export destination because tankers from here would have to pay to use the Suez Canal to deliver to Europe, or face a longer journey through the Red Sea to Asia than exports from the Gulf. The pipeline will also have to be protected where it passes through parts of western Iraq where ISIS groups may still operate. However, Jordan is at least a stable country with good regional relations, and this pipeline does help to mitigate risk.

If the Basra terminal expansion and Jordan and Turkey pipelines are completed, plus some trucking to Iran, Iraq would have 8.7 Mbpd of nominal export capacity plus 1.5 Mbpd of domestic refining, enough to deal with 10.2 Mbpd of production. This is likely to be more than sufficient for the foreseeable future.

4.1.4. Contract terms

4.1.4.1. Contract terms

Most of Iraq's largest fields are currently under development by international oil companies under Technical Service Contracts (TSCs[78]). These do not give the company in question rights to oil reserves or production. Instead, the contractor invests in developing the field and, starting when a given production target is reached, is reimbursed its costs plus a fee per barrel of oil or thousand cubic feet

77. https://www.dailysabah.com/energy/2017/11/29/iraqi-pipeline-to-send-1m-bpd-of-oil-to-turkey
78. Equivalently, Technical Service Agreements, TSAs.

of gas produced. Operations and budget are determined by joint committees and approved by the Ministry of Oil.

This is an unusual model globally and regionally. The new Iran Petroleum Contract (IPC) is similar though more flexible, while Abu Dhabi's model is comparable economically but not legally. Kuwait has negotiated but never awarded TSAs for field investment.

This fee was determined by competitive bidding in the four bid rounds held, with the Ministry of Oil setting a maximum acceptable fee for each field. The company may chose to be paid its fee in cash or the equivalent quantity of oil. The cost recovery plus fee is payable quarterly and capped at 50% of the incremental revenues generated from the field (70% in the case of exploration blocks). The contractor also pays a signature bonus in the range \$100-500 million (zero for the gas fields, \$15-25 million for the exploration blocks), and has a state partner, a unit of the Ministry of Oil, with a 25% stake.

The remuneration fees bid range from \$1.15-\$2.30 for existing fields, with the exception of Badra (\$5.50) and the heavy oil fields Qayyarah and Najmah (\$5-6). Three gas fields were awarded with bids of \$5.50-7.50 per barrel of oil equivalent (boe), and three exploration blocks for \$5-6.24/bbl.

The remuneration fee is adjusted downwards over time by an 'R-factor', the ratio of aggregate receipts to aggregate costs, to reach ultimately 30% of the original level. The company also has to pay 35% tax on its profits. Ultimately this means that, for instance, Lukoil, which was awarded the West Qurna-2 development for \$1.15/bbl, would receive less than \$0.17 per barrel when considering the R-factor, its state partner and tax.

Under the TSC, the contractor can 'book' (report in its audited financial filings) reserves equivalent to the barrel equivalent of cost and remuneration fees it anticipates. At high oil prices, the barrels required are lower and hence the bookable reserves are lower too. 'Booking' reserves is not the same as having any legal ownership or control over oil reserves in the ground.

These were extremely tight terms for the IOC investors, and disprove any suggestions that Iraq was giving away its crown jewels or that the IOCs were set to make excessive profits.

The question of the level of the remuneration fee is somewhat misleading. A very low $ per barrel bid is not necessarily a good deal for Iraq. In developing an oil-field, the contractor and the Iraqi government are not sharing a fixed cake. Instead, a good contract will add value to the field by attracting the best operator, encouraging efficient and low-cost development and operations, allowing flexibility to changing market conditions or knowledge of the reservoir, and achieving maximal economic recovery of the oil and gas. Put simply, it would be better for Iraq to pay a remuneration fee of $2.50 per barrel than $2 if the extra $0.50 would save $0.51 of costs or add $0.51 of extra production. On a large field with a long producing life, such gains are easily achieved.

As matters turned out, the difficulties of government bureaucracy, severe delays in payment, inadequate infrastructure such as export capacity and water injection, skills shortages, logistical constraints and insecurity meant that progress was much slower than the companies had anticipated. The initially-bid targets added up to 12 Mbpd by 2020. It became apparent this was not achievable, and would anyway overwhelm the oil market and the Iraqi government's ability to repay costs. The targets were negotiated down on a field-by-field basis, usually including extension of the contract period, reductions in the state partner share, and elimination of the R-factor mechanism. This led to a revised target of 8.5-9 Mbpd by 2020. As noted above, the IEA now sees capacity at 5.13 Mbpd by 2020, and this includes some 0.25 Mbpd from the Kurdistan region.

The TSCs have several problems, which have contributed to Iraq's slow progress towards its production goals:

- By allowing the companies immediate recovery of all their costs, they encourage exaggeration of costs (particularly by steering subcontracts towards related entities) and so-called 'gold-plating' (lack of cost control). Iraqi oil minister Jabbar Al Luaibi has rightly complained about the high costs and targeted cutting costs by 30%[79]. But though high costs are partly the fault of the contractors, they are also the fault of a flawed contract model;
- The immediate cost recovery imposes a heavy burden on the Iraqi government, which was faced with a large cost recovery bill potentially approaching 50% of oil revenues, at a time that it was already struggling with the fall in oil prices and the war against Da'esh;

79. https://aawsat.com/english/home/article/1120766/iraq-starts-taking-over-majnoon-oilfield-operations-shell?amp

- The large cost recovery bill, inadequacies in financial controls, bureaucratic delays in approving investments, and low remuneration fee per barrel led to late payments, causing IOCs to scale back their development plans, depriving the government of needed revenues;
- The individual development plans were not sufficiently coordinated with the construction of required common infrastructure, notably oil export, gas handling and water injection;
- The bidding structure encouraged the companies to bid unrealistically high production targets to win, with the hope of negotiating them down later;
- The low remuneration fees give no incentive to the operators to employ more advanced technologies or to develop more difficult areas or reservoirs of the fields;
- The differing fees between fields run the risk that operators with higher remuneration fees are able to prioritise developments over those with lower fees, regardless of the profitability of those investments for the government of Iraq;
- The signature bonuses are effectively loans from the company to the government (they are either cost-recoverable, or at least the company will factor them in to its required economic returns). This is a much more expensive way for the Iraqi government to borrow money than issuing conventional bonds. Its bond in August yielded 6.75%[80] whereas an oil company will typically seek at least a 10% return on capital;
- Rumaila, West Qurna-1 and Zubair are required to provide surplus gas to the Basra Gas Company at zero cost, which provides no incentive to them to optimise gas production or use it efficiently;
- Exploration contracts are unattractive because the limited remuneration fee does not cover the explorer adequately for their risks. This explains why only four out of the twelve exploration blocks offered in federal Iraq's 4th bidding round were awarded (or even attracted any bids at all), even though Iraq is one of the world's most prospective areas for new discoveries. By contrast, the higher-risk and smaller Kurdistan Region was able to sign 52 production sharing contracts by January 2015.

80. https://www.ft.com/content/1a90e608-7792-11e7-90c0-90a9d1bc9691

Because of these drawbacks, some leading IOCs such as Chevron and ConocoPhillips did not acquire fields in the bid rounds, while others such as Statoil, Occidental and now Shell (and partly Petronas) have withdrawn. This leaves Iraq dependent on a shrinking circle of investors, weakening its negotiating position in future.

4.1.4.2. Comparison to PSCs

The TSCs have been unfavourably compared with the production-sharing contracts offered by the KRG. The KRI, as a new exploration area with significant technical risk and a high degree of political risk, and smaller fields than federal Iraq, had to offer more attractive terms. Opinion in federal Iraq was that PSC terms would have been against the constitution, and given too much control and profits to the foreign investors.

Many other leading oil producers, globally and regionally, have adopted the PSC, including Indonesia (its originator), Nigeria, Azerbaijan, Kazakhstan, Brazil, Qatar, Algeria, Libya, Syria, Egypt, Oman and others.

Under a Production Sharing Contract, the contractor invests to explore and develop a field and in return, is entitled to a share of the oil and gas produced to compensate for costs and provide a profit. If the exploration is unsuccessful, no costs are recoverable.

The structure of the KRG's PSCs is fairly simple and typical. A royalty (10%) of gross revenues is due directly to the government. 40-50% of the revenues after royalty is available as Cost Oil. If it is insufficient to recover costs in the current accounting period, unrecovered costs are carried forward to the next period. Unused cost oil is added to the profit oil pool. The revenues after royalty and cost recovery are entitled Profit Oil, and split 30% to the IOC, reducing to 15% as the 'R-factor' (ratio of cumulative revenues to cumulative costs, a rough measure of profitability, and very similar to the R-factor in the federal Iraq TSCs) increases. In some cases, an up-front cash bonus was paid to the government, also a normal and legal feature of many PSCs and TSCs worldwide. Subsequently, the KRG has introduced 'capability-building payments', intended, at least officially, to be used to develop infrastructure. These were typically around 30% of profit oil, which was reclaimed by the government instead of being paid to the contractor. However, as part of the settlement of overdue payments to the IOCs, some of these capacity-building payments (such as that due from DNO) were cancelled.

The KRG initially held a 20-25% carried interest in most of the PSCs – it did not pay its share of exploration costs, but it was entitled to take a share in any commercial discovery. A 20% stake was also often reserved for new entrants, to allow larger companies to come in later. Most of these carried and open stakes have now been assigned, or sold by the KRG to cover its financial needs.

Although these PSC terms appeared fairly attractive, their profitability was reduced by the introduction of the 'capacity-building' payments, the high costs for exporting oil, amounting in many cases to $12-15 per barrel (including quality discounts), and the lengthy delays and incompleteness of payment.

If a PSC or similar contract were to be used by federal Iraq, the terms would of course be tougher due to the lower geological and political risk. Most likely this would be achieved by reducing the profit oil share (and possibly the cost oil allocation).

It is important to distinguish between the legal and the economic mechanisms of these contracts. A PSC is legally different from a TSC because it allows the contractor to take ownership of a share of the oil and gas produced at the wellhead. But a TSC could be written to be economically identical to a PSC in the financial returns to the contractor.

4.1.4.3. Possible new terms

The Iraq Ministry of Oil has invited proposals on new terms for the fields and exploration blocks offered in 2016-2017.

Eventually, if a new contract model is agreed and tested for smaller fields, it could be applied by negotiation to the existing fields in development under the TSCs. A quid pro quo of improved terms (and profitability) could be reached in return for higher investment and production levels.

The discussion here applies primarily to the fiscal terms of these contracts – the division of cashflows between company and government. The other features of these contracts, such as approvals, regulations, dispute resolution and so on, will not be covered here.

Some key features of a new contract model are as follows:

- Is in accordance with the Iraqi constitution
- Achieves high level of government take in accordance with Iraq's large, low-cost resources
- Does not put a large fiscal burden of cost recovery on the Iraqi state at times of low oil prices (with a trade-off of higher profits to the contractor when prices are higher)
- Ensures prompt payment of the contractor for amounts due, or at least provides compensation for overdue payments
- Can be quite readily understood by civil society and non-specialist politicians and journalists
- Is simple to calculate and administer
- Allows the Iraqi state to exercise reasonable control without a heavy bureaucratic burden
- Ideally, has a basic form which can be applied to all projects (exploration, green-fields, brown-fields) with modification of parameters but with the underlying contract structure remaining the same
- Allows for production to be reduced in line with OPEC requirements;
- Incentivises the contractor to transfer skills and technology to Iraqi staff and partner companies
- Allows reasonable profits to the contractor
- Allows the contractor upside (increased profits) for performing well, e.g. increasing production and reserves, while penalising the contractor if targets are not met for reasons within its control
- Encourages cost-efficiency from the contractor, on a full life-cycle basis (i.e. not just lowest up-front cost)
- Reimburses the contractor appropriately when costs rise unavoidably (e.g. due to global rises in industry costs)

- Limits the contractor's ability to reduce government take or inflate recoverable costs via methods such as transfer pricing, offsetting head office or R&D costs, or awarding contracts to related parties
- Responds flexibly to changes in markets (e.g. oil price), technology and reservoir behaviour without renegotiation
- Encourages the efficient development and use of gas (associated or non-associated)

There is a tension between some of these objectives, such as reimbursing the contractor appropriately while encouraging them to cut costs and not practice tax avoidance; or having appropriate control over the project while allowing the contractor to perform to their best. A number of countries' fiscal systems achieve these objectives in different ways, though they may not be perfectly adaptable to Iraq's situation.

Norway has a high oil tax level at 78%. Investments are depreciated over 6 years, so spreading the tax burden to the Norwegian treasury. Investments are allowed an additional 'uplift' on depreciation to compensate for this delay in recovering costs. The Norwegian state take is further raised by the State Direct Financial Interest (SDFI), a direct holding by the state in many licences where it pays its share of costs and receives its share of profits after tax; and by its 67% share in state oil company Statoil, which is the main operator in Norway and from which it receives dividends. The role of Statoil also allows Norway to build up its skills in the industry and to use and export them worldwide.

In addition to ordinary corporate taxation and royalty, **Australia** applies a 'resource rent tax'. This is charged at a rate of 40% on after-tax profits above a certain annual rate of return (which is the Australian government's long-term bond rate +5% for development expenditures and +15% for exploration expenditures).

Mexico's oil tax system was passed into law in August 2014 as part of opening its upstream oil industry to international investors. Some key features include:

- Minimum in-country content in contracting of 13% during exploration, 25% in the first year of field development, rising to 35% by 2025[81]

81. https://www2.deloitte.com/content/dam/Deloitte/mx/Documents/tax/2_Oil_Gas_Fiscal_Regime.pdf

- Royalty based on oil and gas prices, starting at 7.5% for oil, with the level increasing when prices are higher
- Additional royalty, a percentage of operating profits, which is bid by the contractor for each area and used to determine the winning bidder, with the minimum level set at 8.5-24.8% depending on the block in the June 2017 shallow-water auction;
- Cost recovery by the contractor from a maximum of 60% of monthly revenues, and costs depreciated over a period of 1-10 years depending on the category;
- Profit sharing based on the pre-tax rate of return of the project to the contractor, with the share falling to 20% of the previously-agreed amount when the rate of return exceeds 30%;
- Corporate income tax of 30%

The new **Iran** Petroleum Contract is quite similar to the Iraq TSCs but with greater flexibility. Companies are reimbursed their costs from a share of production, but depreciated over several years (so costs are not all due at once). They then receive a fee (a biddable element) per barrel of oil or thousand cubic feet of gas, in the same way as the TSCs. However, this fee is adjusted up or down in line with oil prices and project risk. It can also be increased if the company increases production above the baseline (or, correspondingly, decreased in the event of underperformance).

A new contract model can be applied to new contract awards, whether for exploration or development, and to re-awards of TSC fields relinquished by the operator (such as Majnoon). However, migrating existing TSCs to a new model would be tricky, to ensure that the contract balance is respected (including proper compensation for past investments and risks taken by the contractor), and that operations and investment are not interrupted. The same would apply if it is eventually desired to migrate the Kurdish PSCs to a common Iraqi model.

Full design of a contract model would require stakeholder consultation, discussion with potential investors, and economic modelling of a variety of fields and situations under different oil and gas price assumptions. However, a possible contract model could be as follows:

1. Contract continues to follow the TSC principle, where the contractor does not

have a right to oil reserves or a share of production, but is rewarded as a share of the cashflows of the project.

2. Capital costs are depreciated over a period, say 10 years, to avoid the government facing an excessive burden of cost recovery.

3. The reimbursement to the contractor is calculated as a percentage of project profits, with profits defined as: (oil production x oil price) + (gas production x gas price) – operating costs – depreciation – financing costs. For the purpose of this calculation, the oil price would be the official selling price for the oil produced by the field (which might be Kirkuk Light, Basra Light, Basra Heavy, a mix or any other new grades introduced), and the gas price would be a reasonable benchmark price (see the discussion on gas imports and exports for suggestions on a price benchmark). Financing costs would be calculated based on the contractor's cumulative negative cashflows (outlays) to that point, with an annual return which could be calculated similarly to Australia's system – a suitable bond rate + 5% for development expenditures and 15% for exploration expenditures. As Iraq does not have an established yield curve for government bonds, the US Fed rate or LIBOR (London Interbank Offered Rate) could be used.

4. The percentage of such profits used to calculate the contractor remuneration would be a biddable parameter, and would decrease smoothly in line with a set formula based on the contractor's rate of return to that point, to a fixed minimum (say 5%). For example, a contractor could bid an initial share of 30% which would decrease to 5% as profitability increases.

5. An Iraq-nominated state company would have a share of the contract to facilitate learning and monitoring. However this company's budget should be run on a corporate and not a government basis, to ensure long-term rational commercial decisions are made (as discussed below). Ideally the contractor partnership would feature at least two IOCs, to give a diversity of technical opinions and minimise self-dealing (e.g. award of subcontracts to affiliates).

4.1.5. Refining

In 2012, Iraq planned to reach 760 kbpd of refining capacity by the start of 2013. Current capacity is around 500 kbpd (excluding the Kurdistan region), with the main refineries being Baiji (310 kbpd, but inoperable), Daura near Baghdad (210 kbpd) and Basra (210 kbpd). In the Kurdistan region, Kalak and Ninewa near Erbil have 140 kbpd capacity between them and Bazian near Sulaimaniyah 34 kbpd. Deputy Oil Minister Fayyad Al Nima said in June 2017 that federal capacity would rise to 1.5 Mbpd, excluding the Kurdistan region, by 2021[82]. This would include a new 300 kbpd refinery in Basra, a 70 kbpd refinery in Kirkuk, a 150 kbpd refinery in Nassiriya, upgrades of the existing Daura and Basra refineries, and completion of the 140 kbpd refinery in Karbala, currently delayed due to a lack of funding. This amounts to 660 kbpd of capacity in new refineries, excluding the upgrades, which implies that a repair of Baiji would have to be included to reach the 1.5 Mbpd target.

Iraq's domestic demand varies significantly on a monthly basis. But excluding direct use crude oil in power plants (which does not require refining), it hovers around 500 kbpd (Figure 29). It was rising strongly up to 600 kbpd from 2007 to 2013, but then fell sharply due to the impact of the conflict against Da'esh. The main product categories used are LPG (home heating and cooking), gasoline / petrol (road transport), diesel / gasoil (heavy road transport, local generators and power plants), kerosene (heating and cooking), fuel oil (power generation and industry) and crude oil (power generation). The direct use of crude oil has recently fallen to zero due to greater gas availability.

82. https://inspectioneering.com/news/2017-06-12/6579/iraq-hopes-to-triple-refining-capacity-by-2021

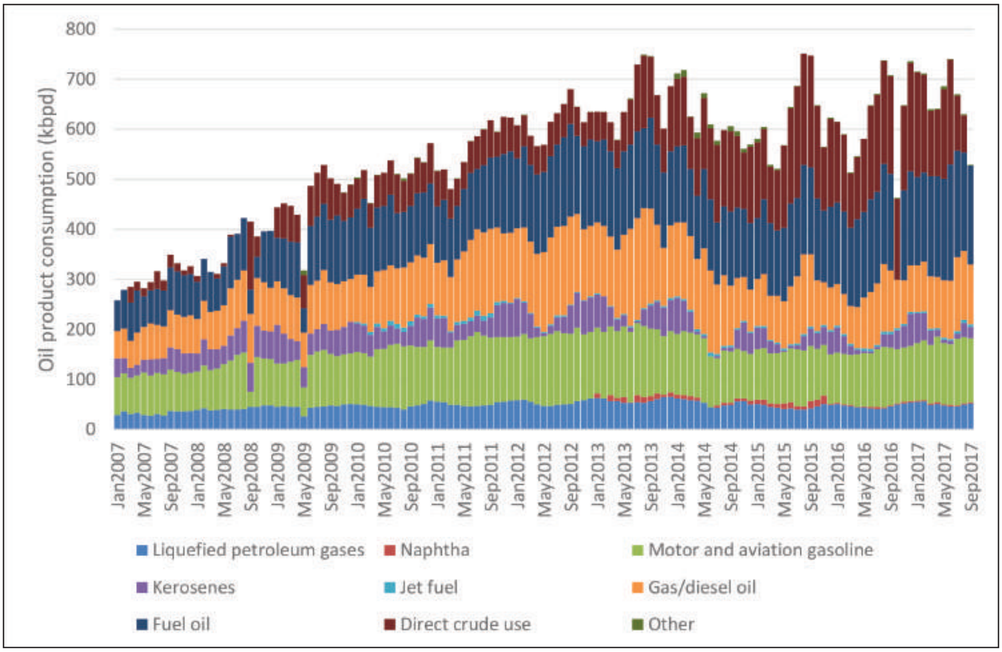

Figure 29 Iraq refined oil product consumption[83]

After that war, it is likely it will again grow strongly. However, on an aggregate basis, some 600-700 kbpd of demand can be supplied by domestic refining capacity with some upgrades. The main issue is the mismatch of product types, with current refineries producing too much fuel oil and too little diesel and gasoline (Figure 30). Iraq exports the surplus fuel oil (this rose significantly during 2017 due to increased gas supplies reducing the need for fuel oil in power stations). Gasoline and diesel imports have been significant and quite steady at about 90-100 kbpd total since 2011. However LPG imports have mostly ceased because of supplies from Basra Gas Company, and indeed Iraq has begun to export LPG. New refining capacity therefore needs to concentrate on providing diesel and gasoline for domestic use, and reducing output of low-valued fuel oil.

83. JODI

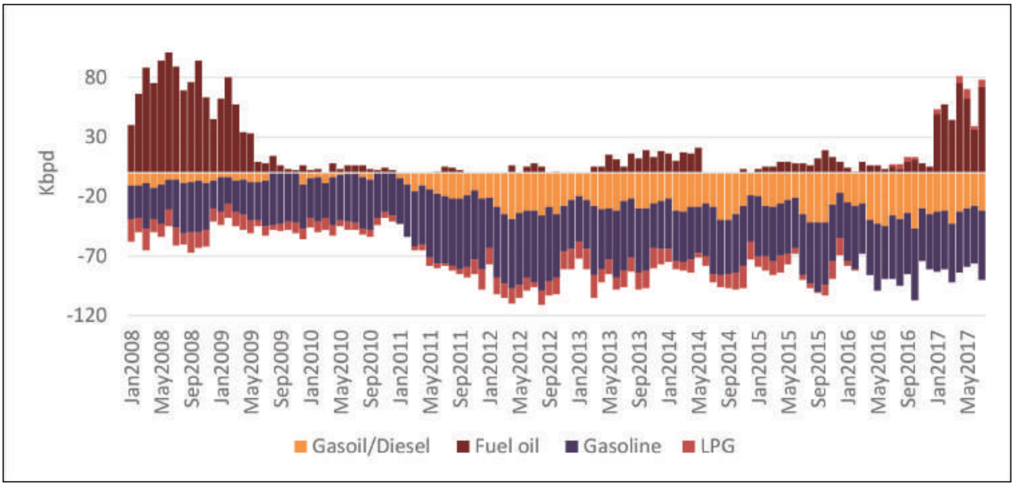

Figure 30 Iraq oil product imports and exports[84]

Meanwhile, the pattern of global oil product demand is shifting (Figure 31). The predominant growth is for transport fuels and petrochemical feedstocks: LPG, naphtha, gasoline and gasoil/diesel. Fuel oil use will decline due to restrictions on high sulphur fuel oil in shipping from 2020 onwards, and replacement in power generation by gas and renewable energy.

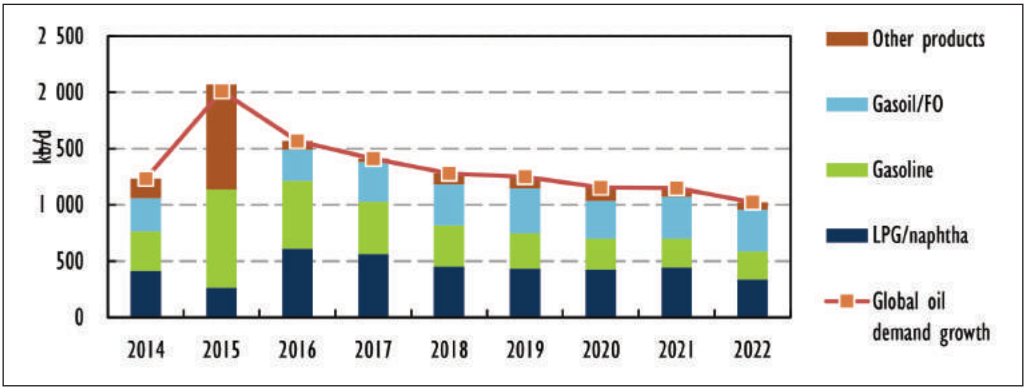

Figure 31 Forecast oil demand growth per product[85]

84. Data from JODI
85. International Energy Agency (23rd March 2017), Market Report Series

If Iraq completes its refining plans, it will be a significant net exporter of products. However, apart from Basra, its refineries are inland serving domestic demand, and poorly-sited to access export markets. Marine export infrastructure is already crowded and constrained in exporting crude oil. Neighbouring countries, particularly Iran, Saudi Arabia, Kuwait, the UAE and Oman, are all expanding their own refining capacity to become self-sufficient and target export markets. Integration with petrochemical facilities has been a favoured route to improve refinery economics, but this does not appear to be under consideration for Iraq.

Globally, refining capacity is forecast to gain about 7 Mbpd while oil product demand grows 6 Mbpd, meaning that excess refining capacity will grow. The Middle East and China will lead most of the gains (Figure 32), so new export-oriented refineries in Iraq would face a competitive situation. Local exports to Jordan, a post-war Syria and southern Turkey would be more viable but only in relatively small volumes.

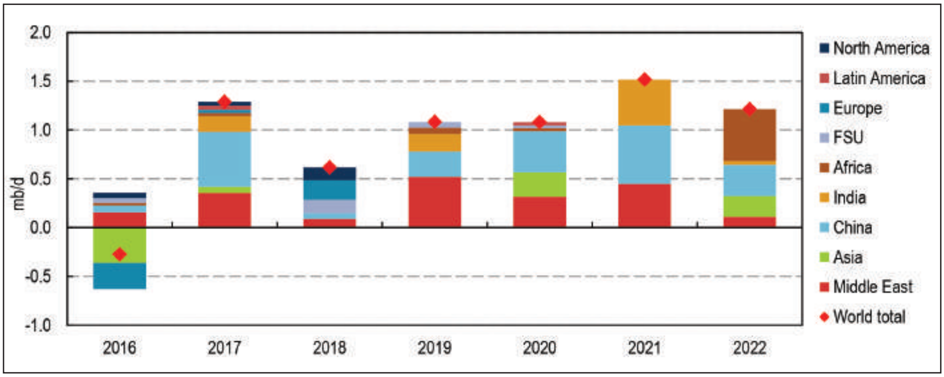

Figure 32 Global refining capacity additions[86]

When awarding refinery projects, Iraq should resist the temptation to link them to upstream projects (as was the plan with Nassiriya). This is over-complicated, obscures the economics of the separate parts of the project, and risks choosing partners who are not the best for either upstream or refining. The KRG has been more successful in allowing private-sector refineries. But as there is no free market for either crude inputs or refined product outputs, any form of private-sector involvement in domestic-oriented Iraqi refineries for now requires a guarantee on crude and product prices, with a sufficient margin to allow profitable operations.

86. International Energy Agency (23rd March 2017), Market Report Series

4.2. Gas production and utilisation

4.2.1. Production and domestic use

Gas production has risen substantially in Iraq since 2009, mostly because of associated gas production – the byproduct of growing oil output (Figure 1). There is only one large producing non-associated gas field in the country, the Khor Mor field in the Kurdistan region (which also produces condensate and LPG). Siba near Basra is due to come onstream in 2018 while, as noted, insecurity has held up the development of Mansuriyah in Diyala and Akkas in Anbar. Other large non-associated gas fields in the KRI, Chemchemal, Miran and Bina Bawi, have not yet been developed due to a lack of government approvals, financing and export markets.

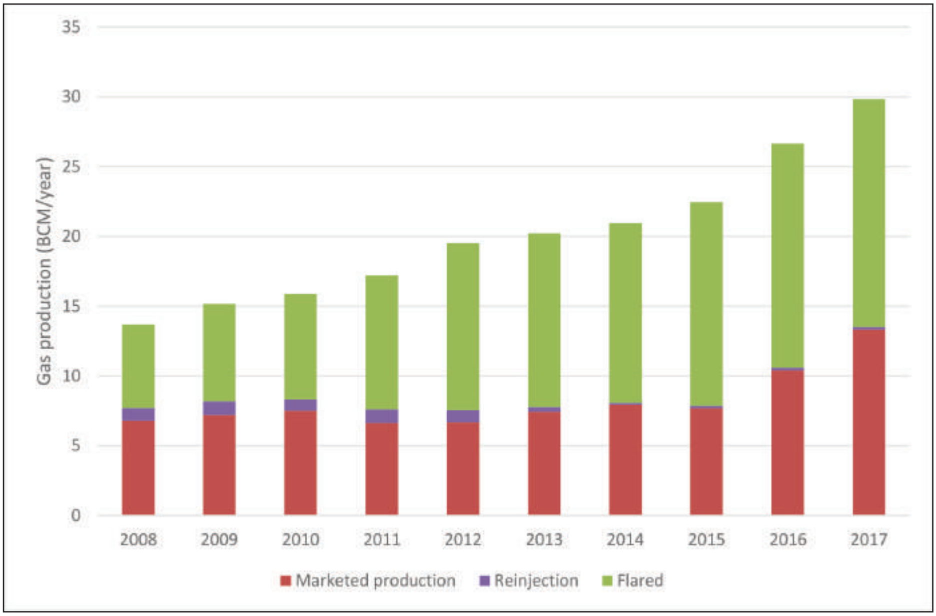

Figure 33 Iraq gas production[87]

The increased supplies of gas in 2016 and 2017 have helped cut crude oil

87. JODI, OPEC Annual Statistical Bulletin (various years), Middle East Economic Survey. 2017 is average of January-October. 2016 and 2017 reinjection figures are assumed to be the same as 2015.

burning in power plants and also free up fuel oil for export. This is in addition to its environmental benefits. Gas availability has been helped by imports of Iranian gas, as discussed below.

However, flaring remains very high and has even increased due to greater associated gas output as oil production has grown. As well as being a waste of resources, flaring is environmentally damaging. For now, flaring should be progressively restricted over a period of time until routine flaring of gas is banned. Any surplus that cannot be sold or used by the company appropriately in its operations should be reinjected.

Most of Iraq's central electricity generation currently comes from gas. A large part of installed capacity is not available due to breakdowns, lack of fuel, transmission constraints and security problems. Table 3 shows that most currently installed capacity is gas turbines (which can run on gas or diesel) and steam turbines (which can run on gas, diesel, fuel oil or crude oil). These are inefficient. Most of the new capacity being installed is of the much more efficient combined cycle type (including conversions of existing plants), but it requires gas or diesel fuel.

Table 3 Federal Iraq electricity generation capacity by type[88]

Type of plant & capacity (GW)	Installed, end–2016	Available, end–2016	Under construction	Planned
Gas turbine	14.97	10.85	0.32	
Steam turbine	7.31	4.79		1.4
Combined cycle			9.89	
Diesel	2.03	0.68		
Hydro	1.84	0.59		
Solar	0	0		0.06
Imports and power barges	2	2		
Total	28.15	18.91	10.21	1.46

88. Middle East Economic Survey (8th December 2017), Volume 60, Number 49, p11. Excludes the Kurdistan region

In addition, there is widespread use of small diesel generators to serve neighbourhoods when mains electricity is unavailable. These are expensive (consuming substantial amounts of subsidised diesel), low-power, noisy and polluting.

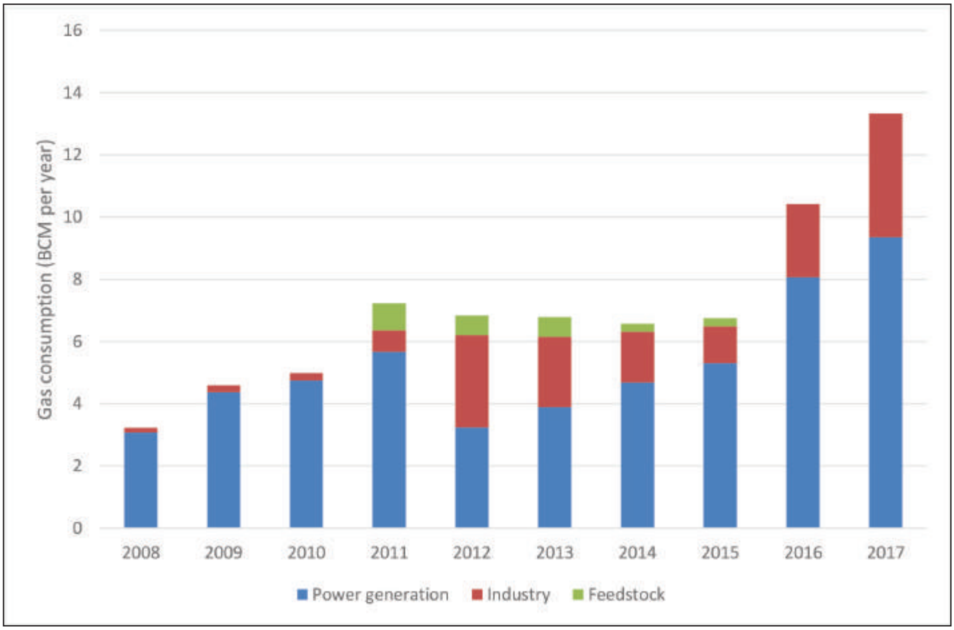

Figure 34 Iraq gas consumption by use 2008–17[89]

Most marketed gas in Iraq is used for power (Figure 34). The data is somewhat unreliable and data on feedstock is not available before 2011 or after 2015. The change in industrial gas use in 2012 is probably a reclassification while the apparent increased industrial gas use in 2016 and 2017 is probably mostly going into power. Nevertheless, it can be seen that the power sector consumed about 9.4 BCM in 2017.

The current programme of power plant expansion will require another 1.48 Bcfd of gas (15.3 BCM). Running this would therefore require more gas imports and/or capturing and using nearly all of the 2017 total of flared gas. Otherwise, plants will have to run on expensive diesel.

89. JODI; IEA; 2017 is annualised based on January–October figures

In the longer term, demand is expected by the Ministry of Electricity to reach 35 GW by 2030[90]. Assuming full rehabilitation of existing hydropower, and installation of reasonably efficient modern generation, this will require about 32-40 BCM of gas in total. However, other studies suggest this is a serious underestimate and that demand will reach 50-60 GW by 2030[91], which would require 47-70 BCM.

Iraq's associated gas production is at a ratio of about 550-620 standard cubic feet per barrel. Oil production of 5 Mbpd would therefore yield about 28-32 BCM per year and 9 Mbpd would yield 51-58 BCM. For comparison, INES forecasts 32 BCM of marketed production in 2020, 53 BCM in 2025 and 69 BCM in 2030, which includes non-associated gas. To this could be added 18 BCM of Iranian gas imports under the current deals (see 4.2.2 below), and 11 BCM of non-associated gas from current plans (Siba, Akkas and Mansuriyah).

Table 4 Iraq gas demand, 2030[92]

2030 figures	**Low gas production**		**High gas production**	
Gas, BCM	**Low electricity demand**	**High electricity demand**	**Low electricity demand**	**High electricity demand**
Gas production	39	39	69	69
Shrinkage	3.9	3.9	6.9	6.9
Imports	18	18	18	18
Power demand	47	70	47	70
Surplus / deficit	6.1	-16.9	33.1	10.1

Table 4 shows the outcome of different levels of gas production and demand. There is obviously a wide range of uncertainty. Future gas demand could be reduced by efficiency measures and by more use of renewable energy (solar, wind and hydropower). Renewable energy can be highly competitive in suitable conditions

90. http://www.bayancenter.org/en/wp-content/uploads/2017/09/909865676600.pdf
91. https://www.brookings.edu/wp-content/uploads/2016/06/Alkhatteeb-Istepanian-English-PDF.pdf
92. Assumes all associated gas is captured and used. Low electricity case assumes 50 GW produced with high efficiency; high electricity case assumes 60 GW with lower efficiency. Shrinkage assumes 10% of produced gas marketed as ethane and LPG. Cases assume no electricity imports and no use of renewable energy except for rehabilitation of existing hydropower.

in Iraq, as long as gas is priced appropriately at its opportunity cost. Renewable energy can also supply remote areas where it is expensive and/or insecure to run power lines and gas pipelines. These figures do not include gas used in industry, currently around 2-3 BCM but which should grow substantially to support the Iraqi economy. Gas could also be supplied to households for winter heating in colder parts of the country.

In the cases of gas deficit, gas and/or electricity imports would have to be increased, or more oil used for power generation, or power supply curtailed causing economic and social damage. In the cases of gas surplus, more gas could be supplied to industry, gas imports could be reduced, and ultimately gas could be exported. However, even if gas is sufficient to meet demand on an annual basis, it may be in short supply in summer when demand reaches its peak.

Development of more non-associated gas would cover for seasonal fluctuations in demand, allow for delays or cuts in oil production (with reductions in associated gas), and allow for exports. As part of a resolution of outstanding issues with the KRG, federal Iraq could import non-associated gas from the KRI's large fields, which are well-sited to serve demand around Mosul, Kirkuk and Baghdad.

4.2.2. Imports and Exports

In 2013, Iraq signed a deal with Iran to import gas, 25 million cubic metres per day to Baghdad and 25 million m^3 per day to Basra (each equivalent to 9.1 BCM per year). Exports to Baghdad were held up by insecurity in Diyala and attacks on the crew constructing the pipeline, but began in June 2017 and totalled 1.2 BCM by November[93].

The price of this gas is relatively expensive, being linked to oil, and is much higher than the domestic Iraqi price. At current oil prices, it is about $6.6-7.2 per MMBtu[94]. At current prices, the Iraqi government pays the Basra Gas Company (BGC) about $2.50 for gas and resells it at $1.2 per MMBtu. The Iraqi government therefore bears a substantial subsidy burden for both the imported Iranian gas and the BGC gas, though BGC gas (from capturing and treating associated gas) is still far cheaper. Note that the price to BGC, along with the sales of LPG and condensate extracted, is intended to compensate the BGC partners for the estimated $17 billion cost of the required infrastructure.

93. https://financialtribune.com/articles/energy/76443/iran-gas-export-to-iraq-at-12-bcm
94. Formula from https://www.icis.com/press-releases/time-to-reconsider-irans-lng-future/

As discussed above, Iraq may eventually have a surplus of gas for export, depending on its progress in developing associated and non-associated gas, on relations with the Kurdistan region, and on demand in the power and industrial sectors.

Iraq's gas demand pattern is quite favourable for exports. Peak demand is in summer to run power plants for air-conditioning (this is similar to the GCC countries, which have even more peaked seasonal demand because of more use of air-conditioning). Neighbouring Turkey and Iran, by contrast, have higher demand in winter for heating.

In November 2017, it was also announced that Iraq was planning to rebuild its gas pipeline to Kuwait, which operated in 1990 with capacity of 400 MMcf per day (4.1 BCM per year)[95]. Exports could start at 50 MMcfd and rise to 200 MMcfd. Proceeds from the gas export could be used to pay off Iraq's remaining $4.6 billion of war reparations to Kuwait. Kuwait is seeking a price of less than $3 per MMBtu, linked to the US's Henry Hub, while it pays about $6.6 per MMBtu for new LNG imports (at a Brent price of $60 per barrel).

The Kurdistan region has been negotiating on gas exports to Turkey for a significant period, and part of Rosneft's entry into the region was intended to support this, with exports of an initial 20 BCM. The Turkish market is competitive, and its recent energy policy, announced in early April 2017, emphasises the use of domestic resources (coal, renewables and, if more domestic resources can be discovered, oil and gas), building nuclear power, and diversifying gas supplies including LNG[96]. This is likely to reduce or stop gas demand growth[97].

In 2016, Turkish gas imports were 54% from Russia and 17% from Iran, and the country has been seeking to diversify this. However, construction of the Trans-Anatolian Pipeline (TANAP) from Azerbaijan and Turkish Stream from Russia will bring a large amount of extra capacity. Iraqi gas entering Turkey would have to be competitively priced and/or transit on to Europe to find a market.

95. https://www.reuters.com/article/us-iraq-kuwait-gas-exclusive/exclusive-iraq-looks-to-kuwait-gas-pipeline-to-pay-off-reparations-idUSKBN1DM1LU
96. https://www.dailysabah.com/energy/2017/09/30/turkey-set-to-implement-national-energy-policy-with-diverse-resources
97. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/04/Turkeys-gas-demand-decline-reasons-and-consequences-OIES-Energy-Insight.pdf

Other regional markets could include the other GCC countries (depending on political relations), Jordan and Syria. Supplies to Syria (and through Syria to Lebanon) obviously depend on the restoration of security and reconstruction from the war. Jordan is only a small market and is negotiating for supplies of gas from Israel, which are likely to be cheap though politically unpopular. Egypt (via Jordan) is another possible market for Iraqi gas, depending on its gas import demand after development of the giant Zohr field.

BGC was also planning to export LNG, via a small project of 4 million tonnes per year (5.4 BCM). However, given the availability of neighbouring markets, it will probably be more economic and technically simpler to export by pipeline, if a gas surplus is available.

As well as generating revenues, exports of gas would help tie Iraq to its neighbours economically and politically, and improve relations.

Rational use of gas within Iraq depends on setting the price correctly. The aim should be to have a price that reflects the opportunity cost of gas, i.e. the price that could be obtained for the gas when selling it for its optimal uses (including exports), equalised with the cost of obtaining that gas (whether from production or imports).

For instance, if there is demand in Iraq for 30 BCM per year of gas at a price up to $5 per MMBtu, and 20 BCM can be obtained from domestic production at a cost of $2.50, and 10 BCM from imports at a price of $5 per MMBtu, then the opportunity cost is $5 per MMBtu. If at a later time, demand has increased to 40 BCM, of which 30 BCM is willing to pay $5 per MMBtu while 10 BCM can only afford to pay $3 per MMBtu, and domestic production has increased to 50 BCM at a cost of $2.50 per MMBtu while an export market is willing to pay $4 per MMBtu for 10 BCM, then the opportunity cost would be $3 per MMBtu. If the export market is only willing to pay $2.40 per MMBtu, this is below the cost of production and no gas would be exported.

This gas price should also be that charged to the oil companies for their internal use, and to the power and petrochemical industries. If it is desired to support new industries, the gas price in Iraq under a market system is already likely to be competitive given Iraq's large, low-cost resources. The current low price could be steadily phased into a market-based price on a 5-10 year timescale, so giving an initial incentive to companies while still encouraging them to plan for longer-term efficiency. If further support is required, this can be done in the form of investment credits, R&D subsidies or other forms of support that do not rely on artificially cheap energy. Other regional countries that have tried to encourage industry via low energy prices have found they have created energy-inefficient sectors that consume large volumes of oil, gas and electricity that could be used to generate more value elsewhere in the economy. Some regional countries, such as Kuwait, Egypt and the UAE, have become net importers of gas, thus eliminating their supposed cost advantage. Similarly, electricity and water prices should be gradually raised to their full cost, with protection for low-income consumers via direct cash transfers and/or a 'lifeline' rate for a limited amount of consumption.

4.3. Budget

The proposed 2018 national budget sets spending at $88 billion; revenues are anticipated at $77 billion, of which $65 billion comes from oil sales (3.9 Mbpd of exports at $46 per barrel).

In November 2017, Iraq's federal exports were 3.5 Mbpd, the second-highest monthly level ever (surpassed only by December 2016). The average price received was $57.19, and the exports comprised 22% Basra Heavy and 78% Basra Light. KRG sales were about 281 kbpd[98]. The official selling prices to Asia were set at -$0.25 to the Oman/Dubai average for Basra Light, and -$3.85 to Oman/Dubai for Basra Heavy. For sales to Europe, they were -$3.05 to Brent for Basra Light and -$6.30 to Brent for Basra Heavy. Brent averaged $62.88/bbl in November and Dubai $61, implying that Basra Light would have earned $60.75/bbl sold to Asia and $59.83/bbl sold to Europe; Basra Heavy would have earned $57.15/bbl to Asia and $56.58/bbl to Europe.

If similar discounts and split in exports persist in 2018, the $46 per barrel export price would equate to about $47/bbl for Dubai and $49/bbl for Brent. This is a fairly conservative oil price assumption. 3.9 Mbbl of exports should also be achievable if included the KRG's exports, as it is only about 100 kbpd above the November figure, although it would mean exceeding the OPEC target. If the average Iraqi export price were instead to be around $57/bbl (~$60 for Brent), oil revenues would be $81 billion and the budget would be in surplus – if spending levels were adhered to.

98. https://www.iraqoilreport.com/news/iraqi-exports-shoot-near-record-levels-26792/

The budget moves away from the previous allocation of 17% to the Kurdistan Region, and instead allocates specific amounts to each province: $5.6 billion, or 12.67% of total spending minus sovereign expenses, divided with 40% to Sulaymaniyah, 36% to Erbil and 24% to Dohuk[99].

The draft budget includes a real-terms cut in spending (a 1% rise in nominal terms) but this is achieved by cutting investment, a damaging path given Iraq's need for improved infrastructure and the repair of war damage. International investment could help close the gap, but only if given much more favourable business conditions. Budgeted revenues are still 85% provided by oil, indicating only a slight improvement on 2017.

Avoiding the massive budgetary and economic swings that come with changing oil prices is a problem most oil-exporters suffer. In Iraq it is particularly acute given the lack of other government revenues, the dependence of much of the population on government salaries and benefits, the need for heavy spending on reconstruction, and the high level of corruption and patronage politics.

Ideally, Iraq would stabilise its budget by developing new revenue sources, and reforming and reducing subsidies. Low-income citizens could be compensated by cash transfers (as in Iran and Saudi Arabia), and the country could even move to a direct distribution of some oil earnings to the entire population (as in Alaska) combined with establishment of an effective income tax system. Developing new exports, even if energy-related such as gas and petrochemicals, would help reduce price volatility to some extent. A well-administered stabilisation fund, combined with a conservative oil price for annual budgeting, would allow for smoothing over the oil price cycle. A large sovereign wealth fund to save oil wealth for future generations is probably not politically realistic now, and Iraq can realise higher returns by investing in domestic public infrastructure and human development, but the administrative and fiscal framework could be put in place.

However, it is recognised that in the Iraqi context, corruption, lack of government capacity and the political pressure to retain the power of patronage, implementing such improvements is very difficult and would probably require a reform-minded government supported by sustained international pressure.

99. http://1001iraqithoughts.com/2017/12/11/baghdad-proposes-new-approach-to-revenue-sharing-with-erbil/

5. Iraq's Oil Sector: Long-Term Challenges

5.1. Internal organisation

In order to deliver on the ambitious (and much-delayed) targets of the INES, or more recent targets announced by the Ministry of Oil and other government bodies, the energy sector will have to be organised to be capable to deliver.

A full description of the scope of such reorganisation is outside the scope of this report. But some general observations can be made.

Currently the Ministry of Oil combines the functions of ministry, state oil company and regulator. Its various subsidiaries cover upstream (Basra Oil Company, North Oil Company, Maysan Oil Company, Dhi Qar Oil Company and Midland Oil Company), gas (South Gas and North Gas companies), infrastructure (State Company for Oil Projects, SCOP), oil marketing (State Oil Marketing Organisation, SOMO), exploration (Oil Exploration Company, OEC), refining and fuel distribution and retail. The Petroleum Contracts and Licensing Directorate (PCLD) acts as a licensing body.

Best international practice would be to separate clearly the functions of the ministry, which sets policy and strategy, leads Iraq's role within OPEC, and interacts with parliament and other ministries; the regulator, which regulates conformity with licence conditions, laws and regulations, including environmental protection; and the state oil company, which operates assets and partners with IOCs.

The removal of operating responsibilities from the Ministry would free up its attention to concentrate on Iraq's longer-term strategic issues, on energy market reform (such as reducing and restructuring subsidies), and on coordinating with other ministries to deliver wider economic gains, particularly with the Ministry of Electricity (on fuel supply), the Ministry of Water Resources, the Ministry of Environment, the Ministry of Finance (on planning the short- and long-term national budget and ensuring sufficient funds for investment), the Ministry of Planning, the Ministry of Foreign Affairs (for using Iraq's energy role strategically in its international relations) and the National Investment Commission (in ensuring private and international investment in energy-related industries).

The state oil company could be purely an upstream entity or it could be vertically-integrated to include refining and fuel retail. But, however organised, it should include within in the core functions of exploration, production and crude oil and gas sales. It can have different geographic divisions, but these should not duplicate key skills, and there should be one unified corporate strategy and budget. It is understood that the division of the Ministry's subsidiaries between different regional oil companies is to demonstrate decentralisation to provincial authorities and spread investment and employment more evenly. But this should be achieved by other methods than spreading the available skills too thinly over different operating entities, potentially working at cross-purposes or at least not in coordination.

The provision of key infrastructure (export and major internal pipelines, oil storage, export terminals and water injection) should be done on a commercial basis, with operators (including Iraq state oil company entities) paying a market-based or at least cost-reflective fee for their use. This would be cost-recoverable to avoid conflict with the existing TSC provisions, but would at least ensure that new infrastructure is built with a commercial rationale and that its users pay appropriately for it, and properly consider other alternatives.

As noted, other regional national oil companies are moving towards part-privatisation, such as the sale of a 5% stake in Saudi Aramco, ADNOC's IPO of a 10% stake in its fuel distribution business, and sales of non-core parts of the state companies by Oman, Kuwait and Egypt. Some countries eventually sold their state oil companies entirely (the British government sold the British National Oil Company and its 51% stake in BP; France has divested from Total, Canada from PetroCanada (now Suncor) and Italy mostly from ENI) while Brazil (Petrobras), Norway (Statoil), China (Sinopec, CNOOC and PetroChina) and India (ONGC and others) have sold minority stakes in their NOCs. Sales of minority stakes can raise cash and introduce commercial rigour, without giving up much in the way of control or future revenue flows to the government. In order for this ultimately to be an option for Iraq, the state oil company would have to be organised as a commercial company, suitably transparent and well-managed. It would need suitable budgetary and operational autonomy from the ministry and parliament, to ensure it could execute multi-year projects.

If major projects raised the required capital on a project finance basis, this eases the burden on the Iraqi treasury, as well as improving the control of corruption, and ensuring that the projects are commercially feasible.

Iraq should also consider the encouragement of local private E&P companies. This could be achieved by reserving a minority stake in the new fields and exploration licences for local companies, on the condition of meeting financial and technical qualification procedures. These companies would mobilise local capital, build local skills and Iraqi buy-in to resources, and could ultimately develop into companies capable of operating their own projects, both within Iraq and internationally. Examples of such firms from the region include Kuwait Energy (which operates in Iraq), KAR Group in the Kurdistan region of Iraq, and several small Egyptian and Omani companies. Alternatively, such a local company could be formed by privatising a unit of the state oil company which could be awarded some smaller or marginal fields.

Iraq achieved validation by the Extractive Industries Transparency Initiative in 2012. However, it has now been suspended due to inadequate progress on a range of issues of disclosure and transparency[100]. Improved transparency would boost public confidence in the administration of contracts with IOCs and the use of oil revenues, and reduce corruption.

5.2. Federal government relations with the KRG

Relations with the KRG, and the legal status of its petroleum sector, post its referendum and the changeover of control of Kirkuk and other areas to the federal government, are complicated and still unclear. But an appropriate relationship between Baghdad and the KRG is important for reviving the northern oil and gas sector. The most immediate area for cooperation is the restart of full production and oil exports from Kirkuk, which could recommence through the Kurdish pipeline to Turkey. This requires proper agreement on metering and marketing that oil from Ceyhan, and paying the revenues to the Iraqi treasury (minus a possible transit fee). An arrangement would be required for the traders who have advanced large sums to the KRG[101], and for payment of the costs of the IOCs active in the region.

Other key areas that require a sustainable long-term agreement include the possible export of gas from the KRI to federal Iraq; the eventual arrangement for marketing the KRG's exports (whether under SOMO or continuing independent marketing); and the legal position of its PSCs and possible migration to a new contract model.

100. https://eiti.org/validation/iraq/2017

101. See discussion at https://twitter.com/PatrickOsgood/status/934144980838506496

5.3. OPEC and production policy

Iraq, with its rising production and large resources, is, as noted, likely to be the largest contributor to OPEC production growth in the medium and longer term. The country needs to define a clear strategy for its production expansion in the context of OPEC. The current deal, which runs to the end of 2018 and may well be extended beyond that, constrains Iraq's production for now.

As discussed, some OPEC countries have the plans and potential for growth – notably Iran and also the UAE and Saudi Arabia. Venezuelan production is likely to drop but could increase significantly under a new government. Libyan and Nigerian output is volatile, while production in Algeria and Qatar is set to decline. With its large, low-cost reserves, Iraq should aim to expand production considerably. However, it has to do this without provoking a price war with other OPEC states, particularly Saudi Arabia.

5.4. National economic development

As noted, Iraq's recent energy industry progress has involved significant growth in oil production and associated infrastructure; some growth in gas capture, processing and use; the start of gas imports; and growth in electricity output, though not yet enough to satisfy demand. Very little has been achieved in oil refining or in wider economic development related to the energy industry.

INES laid out areas of linked industry, relying on energy-intensive inputs, following a similar path to that attempted by Saudi Arabia and other petroleum-producing neighbours: petrochemicals, fertilisers, bricks, cement, steel and aluminium. Another similar product, not mentioned in the INES, is glass.

Of these, bricks and cement can be made with gas or heavy fuel oil, are relatively unsophisticated materials, have high transport costs, have locally-available material in Iraq, and are in great demand for reconstruction. There is therefore a strong rationale for developing capacity. Domestic fertiliser demand can also be satisfied by local production, helping to support agriculture.

Petrochemicals, steel and aluminium, to be competitive, require world-scale facilities with access to imported inputs (iron ore and alumina) and export. Petrochemicals can make use of ethane, LPG and naphtha from gas processing and oil refining. Iraq is competing in these against Iran and its GCC neighbours

(SABIC, Qchem, Borouge, Equate and others), all of which have a significant head start and better logistics. Some existing facilities at Al Qaim, Baiji and Khor Zubair need extensive rehabilitation and upgrading.

INES proposed establishing a large petrochemical/industrial park near Basra. Other countries have done the same, for instance Iran (the Pars Special Economic Zone at Assaluyeh, and others), Oman (Sohar and Duqm), Qatar (Ras Laffan) and Saudi Arabia (the complexes at Jubail and Yanbu', including the PlasChem Park at Jubail). Saudi Arabia's PlasChem Park is designed to encourage the establishment of downstream businesses that will produce more sophisticated products from the bulk basic chemicals. Such parks can achieve cost savings by sharing infrastructure (port, utilities) and developing a local skilled work-force.

The INES makes almost no mention of oil services. The development of a competitive private Iraqi oil services industry, and the localisation of operations of international firms such as Schlumberger, Halliburton and Baker Hughes, is important for reducing industry costs, developing national skills and employment, and creating companies that are able to add value and expand into other sectors. Oman, Saudi Arabia and Iran, to mention three regional examples, have in-country value-add programmes or local content requirements. These have to be structured carefully to ensure they develop genuine capabilities rather than subsidising uncompetitive firms or enriching intermediaries who simply outsource the work. The Ministry of Oil has a number of service-related subsidiaries, such as the Iraqi Drilling Company, and these should be developed into commercial entities, prior to a decision on (part)-privatisation or development via a joint venture with a leading international partner.

5.5. External relations

Energy is an important part of Iraq's external relations. At the simplest level, it shares fields with Iran, Kuwait and Syria, and possibly Jordan, and may wish to cooperate on development. At least, it has to delineate those fields where this is not clear, and ensure that it receives its fair share. It exports some oil via Turkey, a small amount to Iran (via a swap) and will export oil both to and via Jordan in future. It might reach agreement with Saudi Arabia to restart oil exports across its territory to the Red Sea. Its offshore area, responsible for the bulk of its exports today, is small and vulnerable. Diversifying export routes reduces the threat of disputes with any one neighbour.

Iraq imports gas from Iran and may export gas to Kuwait, Turkey and perhaps Jordan, Syria and even Saudi Arabia in future. Such exports require at least reasonable political relations with neighbours. They also give Iraq some leverage over its neighbours.

Iraq's relations with its neighbours and with other petroleum exporters are also mediated through OPEC. As noted above, Iraq's production growth policies pose a future challenge to OPEC, particularly to those countries not able to increase production. Iraq is also a member of the Organisation of Arab Petroleum Exporting Countries (OAPEC), which is not very active, and the Gas Exporting Countries Forum (GECF). As its economy and political situation stabilises and matures, Iraq will have to play a larger role in such international organisations, including a more active part in climate change negotiations.

In the wider sphere, Iraq has attracted large investments in its upstream petroleum sector from China in particular, and also from Korean, Japanese, Malaysian, European and US companies. It is an increasingly important supplier of oil, particularly to Asia. Lenders to major projects in Iraq, such as refineries and petrochemical plants, also have an incentive to monitor and support its financial state. These lenders can include multilateral agencies, including those linked to China's Belt and Road Initiative. Sited between Iran, Turkey, the Gulf, the Red Sea and the Mediterranean, Iraq is well-sited to play a part in this initiative. This gives its customers a stake in its stability and success.

6. Conclusions and Recommendations

Iraq's energy goals were summarised in Section 2 as:

1. Supply the Iraqi population with essential energy services – fuel and electricity;
2. Earn revenues for the national budget;
3. Support Iraq's national security and foreign relations;
4. Develop Iraq's economy and population;
5. Diversify the economy away from reliance on oil exports.

From these objectives, (1) has improved but electricity provision remains short of demand, significant quantities of gas, electricity and refined products are imported, and both fuel and electricity attract unsustainable subsidies. (2) has improved significantly via the increase in oil production, more effective marketing given the split of crude grades, and the replacement of oil b gas in power plants. The fall in oil prices is outside Iraq's control but it has cooperated with OPEC to raise prices, at least in the short-term. (3) is still dependent on the wider political context, including relations between the federal authorities and Kurdistan region. (4) has made some progress but the energy development is still primarily in oil production and concentrated around Basra. (5) has made little progress in the energy sector due to slow advances on gas and refining, and no advance in petrochemicals or other energy-related industries.

At the same time, most regional countries have made significant steps forward and their energy sectors are more competitive and effective, and better-placed to cope with the huge long-term shifts in the global industry. This is particularly true of the UAE, Saudi Arabia, Oman and (from a lower starting point) Iraq and Egypt.

This study has surveyed Iraq's energy sector in this changing national and global context. These points require further detailing, but key high-level recommendations are as follows.

1. Oil production expansion should continue (within possible OPEC constraints), and can be supported by the development of smaller fields in less-developed and border areas.

2. Development of new export capacity is required to support this production expansion, and routes need to be diversified, including ideally restarting federal exports through the KRG's pipeline to Turkey; and constructing the Jordan export pipeline.

3. The common seawater supply project, urgently required to support improved oil recovery and sustain plateau production, should be progressed. It should be a standalone project (not combined with contracts for field development or other infrastructure) and it may be more viable to split it into smaller pieces.

4. The upstream oil sector has become too dependent on a shrinking group of IOCs, and efforts should be made to attract a more diverse group, including smaller companies. New licences can also make a provision to include a suitably-qualified local private Iraqi partner.

5. The new field offerings should be under a more flexible contract model that better-aligns the interests of Iraq and the IOC contractor. Existing TSCs can be consensually migrated to this model as it becomes tested and proves attractive.

6. There is no near- or medium-term need to discover new oil reserves, but exploration can be targeted in under-developed regions, border areas, and gas-prone areas.

7. Iraq needs to develop a long-term OPEC strategy which allows it significant room to expand production but without provoking a price war with Saudi Arabia or other members. It should argue within OPEC for relatively higher output and lower prices, and particularly avoid price spikes, as this would encourage shale oil and other competing supply, reduce demand and encourage deployment of electric vehicles. $65 per barrel may already be too high a price to target in the long term.

8. Non-associated gas should be explored for and developed, to meet domestic demand, back out imports and potentially provide for exports. Gas resources in the Kurdistan region can also be developed to supply federal Iraq.

9. A gas pricing scheme should be developed to more towards pricing domestic gas appropriately.

10. As more gas and derivatives become available, suitable energy-intensive industries should be developed, with a preference for private-sector investment, and a balance between industries primarily serving local needs, and those targeted at exports. Export industries such as petrochemicals will most viably be based near Basra and can be co-located to achieve economies of scale and shared infrastructure.

11. Fuel, gas and electricity subsidies should be restructured and reduced over time, being replaced where required with direct cash payments to low-income or otherwise vulnerable Iraqis.

12. Iraq's refinery plans need to be reconsidered in the light of domestic demand and export viability given global over-capacity and strong regional competition.

13. The oil sector should be reorganised to split the Ministry of Oil into a ministry, responsible for strategy and political coordination; a regulator responsible

for legal, regulatory and environmental compliance; and a state-owned oil company responsible for field operations.

14. Non-core businesses of the Ministry of Oil should be converted into commercial entities, and ultimately they could be (part-)privatised or launched into joint ventures with leading international partners.
15. Efforts should be made to restore full compliance with the Extractive Industries Transparency Initiative.
16. Much greater stress should be given to encouraging the private sector (local and international) to develop energy-linked businesses.
17. The oil services sector should be encouraged, including domestic companies and the localisation of international companies.
18. The national budget should be made less volatile and dependent on oil by methods such as a stabilisation fund; conservative budgeting assumptions; subsidy reform; development of alternative revenue sources and exports.