Department for
Business, Energy
& Industrial Strategy

FOSSIL FUEL PRICE PROJECTIONS EXPERT PANEL

Final Report

June 2017

This document is available in large print, audio and braille on request. Please email enquiries@beis.gov.uk with the version you require.

FOSSIL FUEL PRICE PROJECTIONS EXPERT PANEL

Final Report

Any enquiries regarding this publication should be sent to us at [insert contact for department].

This publication is available for download at www.gov.uk/government/publications.

Contents

Executive summary

Each year the Department for Business, Energy and Industrial Strategy (BEIS) updates its long-term price assumptions for oil, gas and coal. These assumptions are required for long-term economic appraisal and therefore reflect a range of potential long-term trends. They are not forecasts of future energy prices. Forecasting fossil fuel prices into the future is extremely challenging at the best of times and, at present, the levels of uncertainty are particularly high. This year, we had the added complication of the fall in the value of the pound to factor in. The oil and coal price assumptions are valued in US$, but the gas price is in pence/therm and is sensitive to exchange rate fluctuations. However, the process by which BEIS generates its price assumptions focuses on estimates of fundamentals and other available evidence to arrive at a range of future prices. These assumptions then feed into work across Government on appraising the economic impacts of policies.

This year, as last, the Fossil Fuel Price Projections Expert Panel (FFPPEP) was convened to work alongside the BEIS team responsible for this work. Last year Wood Mackenzie supplied a series of fossil fuel supply curves, these are still considered fit for purpose and have been used in the 2017 price assumptions. This year, the Panel's deliberations and our report have focused on four tasks: first, reviewing the methodology and data used for both the short-term and the long-term price assumptions; second, reviewing the current context, sources of uncertainty and longer-terms drivers and fundamentals relating to each fossil fuel; third, assessing the 'reasonableness' of the initial fossil fuel price assumptions; and fourth, scrutinising the position of the demand assumptions, taken from the IEA, relative to other demand forecasts and scenarios. The Panel also assessed the quality assurance procedures employed by BEIS.

For each fossil fuel, an approach was adopted that reflected the key influences on the price for that fuel in UK markets. For oil, the short run (2017-18), price assumptions are based on the Brent futures curve, the data for which is available from Bloomberg. The high and low assumption are derived as a range around this central starting price using data from the Bank of England on options implied distributions, as used by BEIS. The reason for not using futures prices beyond two years is that they do not accurately reflect expectations of market participants about oil supply and demand, as there have been some fundamental changes to the oil market recently that can distort the price discovery mechanism using the futures curve. For gas, BEIS's central case short-term gas price assumption (2017-18) is based on forward prices over this period, as these price levels reflect the current price view based on gas supply and demand over this two-year time period. The liquidity of the UK National Balancing Point (NBP) forward market is viewed sufficiently high over this period to support this approach, but beyond two years there is a question as to whether the market is sufficiently liquid for the prices to inform the view on future gas prices. The short-term coal price assumptions (2017-18) are based on spot and forward prices for ARA CIF[1]. Forward prices represent well the current context of the European and global coal markets. They implicitly account for the arbitrage potential between the Asian and European coal markets. For similar reasons, as in the oil and gas markets, the use of forward prices is limited to 2 years.

For the long run supply assumptions, The Wood Mackenzie supply curves for each fuel from last year were used. It is only 7 months between the completion of the 2016 analysis and the start of the 2017 analysis. An explanation of their approach and underlying assumptions and their final outcomes are available in their report for the 2016 exercise [2]. The view of the Panel is that the specific sources of uncertainty that Wood Mackenzie used to construct the variations in their supply curves for the three fuels still gives a reasonable sense of the overall scale of uncertainty and that the supporting narratives provide a sound basis for their high and low supply cases.

The long run demand assumptions were obtained from the IEA's *World Energy Outlook 2016,* which the panel believes is an appropriate source for this purpose. This year we paid particular attention to the future demand outcomes of these scenarios relative other forecasts and scenarios. With the exception of their EU high gas demand projection, which is lower than most, the IEA's scenarios fall within the range of future demand projections produced by other organisations. For the long run price assumptions, the preferred method is the marginal cost curve. This is because long run price assumptions should be anchored at the expected cost of marginal supplies at projected levels of global demand. For instance, for oil: the assumption is long term oil supply is responsive to price and that any large rents in the market could incentivise increased exploration activity and production.

The Panel considers this to be a reasonable approach to generating long run price assumptions for long-term economic appraisal. However, as with last year, some additional adjustments were made: for the 2017 Assumptions the panel has recommended constraining Iran's long-run production capacity at 5 mb/d, due to the country's inability to raise production beyond 3.8 mb/d. Further, given the upside surprise shown by the Permian, the panel proposed a 57% further increase for Permian production versus what Wood Mackenzie have previously assumed for 2030. This assumption will increase the US LTO production assumptions compared to the 2016 price assumptions. To arrive at a range of future fossil fuel price assumptions, BEIS has used the IEA's three scenarios: a '450 scenario' in which the average global temperature increase due to climate change is limited to 2°C; a 'current policies scenario' in which the energy system continues to develop on a business as usual trajectory, shaped by policies that are currently implemented; and a 'new policies scenario' that assumes future planned policies to reduce emissions are implemented. This year the 'new policies scenario' includes the commitments made under COP 21, the Paris Agreement. The 'current policies' scenario supports the high price assumption, the '450 scenario' the low-price assumption and the 'new policies' scenario

[1] ARA CIF is a coal price notation for coal delivered to the ports of Amsterdam, Rotterdam and Antwerp, Europe's major coal ports. The coal price comprises cost, insurance and freight and refers to a metric tonne of coal at 6000 kcal/kg net as received.

[2] At https://www.gov.uk/government/publications/fossil-fuel-price-assumptions-2016

the central case. A ‘straight lining approach’ is used to link the short-term price assumptions to the long-term price assumptions. The Panel discussed the outcomes with the BEIS team, carried out its own comparative analysis of the IEA scenarios, and agreed that this was the most sensible approach. The resulting price assumptions are broadly in line with other external price projections. Overall, the Panel considers the approach used to generate the fossil price assumptions to be reasonable, straightforward and transparent.

The Panel explored the current context for each fossil fuel and the potential interaction between the three fuels in UK and European markets. In the case of oil, the key uncertainties relate to OPEC’s (and Russia’s) reaction to the current period of oversupply and the emerging role of US light tight oil as the marginal source of supply. In the case of natural gas in Europe, the key uncertainties relate to the consequences of a coming period of over-supply on the global LNG market and Gazprom’s likely response to increased LNG imports into Europe. The importance of Europe in the global coal market is likely to decrease. Because of that and the fact that European and Asian coal markets are interrelated because of arbitrage opportunities, European coal prices are likely to be more and more driven by international uncertainties such as the development of the Chinese coal sector, decarbonisation targets around the globe or US energy policy. When compared to former BEIS 2016 fossil price assumptions, the new set of assumptions reflect the fact that the fundamentals are different for each fuel, with varying degrees of uncertainty. For oil, the short range upward adjustments reflect the impact of the OPEC-non-OPEC agreement, but the long run fundamentals remain unchanged. The gas price assumptions are complicated by the exchange rate issue raised above. The higher short-term prices also reflect market conditions in early 2017. The elevated long-term high price assumptions reflect uncertainty around the global LNG market should the market balance and then tighten. In the case of coal, the short-term price assumptions reflect the sharp increase is spot and forward prices in the second half of 2016. The long-assumption show a higher range between low and high and an elevated central assumption.

The Panel reviewed BEIS’s quality assurance procedures in relation to the production of its fossil fuel price assumptions. BEIS has developed a detailed and well-documented Quality Assurance (QA) process for their models. This has been applied to the models that have been used to develop the fossil fuel price assumptions, with a separate Assumptions Log and QA Log for each fuel. Overall, the QA process is rigorous, and provides significant evidence that BEIS has critically reviewed its processes and the input assumptions that have been used. BEIS has made the judgement that assumptions taken from the *World Energy Outlook 2016* are ‘based on high-quality analysis performed by specialist teams within IEA’. Given that the model is documented in some detail, and the *World Energy Outlook* is subject to significant external scrutiny and peer review, this is a reasonable and well-founded assumption to make. As we noted last year, Wood Mackenzie used their own models to derive the fossil fuel supply curves that have been used by BEIS. Wood Mackenzie did provide some basic information about the structure of their oil and gas models (but not for their coal model), but commercial considerations meant that they were not willing to publish this information. This limited the panel’s ability to assess the quality of these models and these quality assurance concerns should be considered in any future tender.

The Panel’s overall conclusion is that the process adopted by BEIS to provide external scrutiny of the process by which it generates its fossil fuel price assumptions has worked well and has resulted in a reasonable set of price assumptions that have been arrived at using a straightforward and transparent set of data sources and methods.

The Panel would like to thank the members of the BEIS fossil price assumption team for their efficiency in responding to our requests and their hospitality during our various meetings at BEIS

1. Purpose and work of the Panel

Each year the Department for Business, Energy and Industrial Strategy (BEIS) updates its long-term price assumptions for oil, gas and coal. These assumptions are required for long-term economic appraisal and therefore reflect a range of potential long-terms trends. They are not forecasts of future energy prices. Forecasting fossil fuels prices into the future is extremely challenging at the best of times and at present the levels of uncertainty are particularly high. The unknowns include the prospects for future economic growth across the world, but especially in emerging markets that are the key drivers of future energy demand; the development of new technologies that might make available new reserves and/or constrain carbon emissions; global climate change policies—especially in the aftermath of COP-21; and the strategies of major resource holders—in particular the OPEC states. The process by which BEIS generates its price assumptions focuses on estimates of fundamentals and other available evidence to arrive at a range of future prices. These assumptions then feed into work across Government on appraising the economic impacts of policies.

In 2015, former DECC published a set of comments by external reviewers alongside the *DECC 2015 Fossil Fuel Price Assumptions*.[3] In late 2015 former DECC announced an Invitation to Tender for appoint to the FFPPEP (Tender Reference Number: 1106/11/2016) and in January 2016 the members of the Panel were appointed. The panel is comprised: Michael Bradshaw (Chair), Harald Hecking, David Ledesma, Amrita Sen and Jim Watson (short biographies can be found in Annex A of this report). The Fossil Fuel Price Projections Expert Panel (FFPPEP) re-convened in November 2016 to work alongside the BEIS team responsible for this work. The FFPPEP has followed the same procedures as last year and this report can be considered as an update of the detailed report that was published in November of 2016.[4] When the Panel was first convened, then DECC published price projections, it then changed their description to price assumptions, which is the term used throughout this report, but the result is a mismatch between the Panel's name and the title of the report now produced by BEIS.

---

[3] The 2015 report and the reviewers' comment are available at: https://www.gov.uk/government/publications/fossil-fuel-price-projections-2015

[4] The 2016 report by the FFPPEP is available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/567251/BEIS_FFPA_2016_-_Final_Expert_Panel_Report.pdf

1.1 Terms of Reference

The tasks of the Panel include (but are not limited to):

- Attend all Panel meetings (no delegation is possible);
- Report to Government through formal written reports and informal reports (for example, presentations or written minutes of meetings);
- Review the fossil fuel price assumptions modelling methodology and techniques used and proposed;
- Review the analysis produced by any contractors BEIS uses for the fossil fuel price assumptions;
- Submit informal reports to BEIS on the modelling methodology; contractors' analysis and outputs; and other evidence and data sources used; and
- Submit a formal report for publication in advance of finalisation of each year's fossil fuel price assumptions.

1.2 Work of the Panel

To aid in fulfilling these duties a number of meetings have taken place at BEIS between the Panel and the BEIS team responsible for the price assumptions. This year, the initial meeting took place in 21st November 2016 and the BEIS team explained the purpose of the price assumptions and methods used to generate them. Initial documentation was provided to the Panel ahead of the meeting and Summary of Actions was prepared after the meeting, which included additional written feedback by members of the Panel. A second meeting took place 7th February 2017 when members of the team discussed methodological issues and the approach that would be adopted for the 2017 work. A draft of their initial report was submitted to the Panel on 28th March 2017. The Panel then undertook to produce an initial draft of its formal publication by 13th April 2017. A third, and final, meeting took place 5th May 2017 to discuss the Panel's draft and hear the responses of the BEIS team. Following the third meeting, this final version of the formal report was produced for consideration by the BEIS Chief Economist. This final report also reflected on BEIS' quality assurance processes and includes the Panel's final conclusions and recommendations.

The Panel's deliberations and this report have focused on two tasks.

Reviewing the methodology and data used for both the short-term and the long-term price assumptions.

The central case for the short-term assumptions is based on forward/futures curves with the high and low ranges for oil and gas being derived from distributions around the central case using methodologies and data provided by the Bank of England and the EIA. The range for coal is based on errors of historic forward prices. However, it remains the case that this is only reliable for two years into the future, after that there are insufficient transactions to discover reliable price information.

The long-term assumptions are generated using supply and demand fundamentals. The future fossil fuel supply curves are those provided by Wood Mackenzie for the 2016 report, which we consider still fit for purpose. The demand assumptions are based on the various scenarios produce by the International Energy Agency (IEA) in its *World Energy Outlook 2016.* This year we asked BEIS to pay particular attention to the 'representativeness' of the IEA's various demand scenarios.

Reviewing the current context and longer-terms drivers and fundamentals relating to each fossil fuel and then assessing the ‘reasonableness’ of the initial fossil fuel price assumptions. In the case of the oil price the analysis is global in scope, while the natural gas and coal assumptions are based on factors influencing the price of natural gas in Europe and the price of seaborne steam coal imports into Europe.

2. BEIS's Methodology and Data Sources

This section considers the data sources used and describes and assesses the methodologies that have been employed to arrive at both short-term and long-term price assumptions.

2.1 Data Sources and Short Term Price Assumptions

Oil

As with the 2016 Fossil Fuel Assumptions, for the short run, the 2017-2018 price assumptions are based on the Brent futures curve. The high and low assumption are derived as a range around this central starting price using data from the Bank of England on options implied distributions, as used by BEIS. The Bank of England is able to generate probability density functions (PDFs) using options prices and extracting information from them under certain assumptions while the futures curve data is reported by Bloomberg, both of which are credible and robust sources of data and methodology. These probabilities can be derived under the assumption that investors are “risk neutral”. For these implied distributions, a confidence level of 75% has been chosen which means that that the market attaches a 75% likelihood that the oil price will fall within a certain outcome.

The futures curve is used for two years. The reason for not using futures prices beyond two years is that whilst they reflect expectations of market participants about oil supply and demand, there have been some fundamental changes to the oil market recently that can distort the price discovery mechanism using the futures curve. So, using the futures curve in the current form can underestimate BEIS’s long term price assumptions.

The rapid growth of US shale has brought about increased volumes of hedging (locking in future prices). Too much producer selling automatically pushes the forward curve into backwardation (a situation in which the cash or spot price of a commodity is higher than the forward price). Producer selling has been at record highs in recent months.

At the same time, buying further out has dried up and has resulted in lower liquidity at the back of the curve. The key players who used to be long on the futures contract were airlines, hedge funds and banks. Following the 2008/09 financial crisis, banks have been heavily regulated, which has had a negative impact on their ability to trade in the derivatives market and therefore their ability to warehouse risk for counterparties further out in the futures curve. This has reduced the open interest in the forward curve.

The other option for forecasting is via supply-demand analysis and the most crucial element in this is forecasting OPEC productive capacity. In theory, output related to OPEC is, or should be, the primary driver of prices, with some combination of the trend in demand for OPEC oil, OPEC market share, and/or surplus capacity in OPEC. Predicting OPEC output, while crucial, is based on political decisions by governments, and thus is difficult to model. Similarly, forecasting demand a few years out is challenging given the lack of knowledge on technological advances and government policies. Overall, given the range of uncertainties and challenges for forecasting future oil prices, the panel believes the BEIS approach is reasonable as it uses the most liquid part of the futures curve as guidance for short term prices and a detailed marginal cost curve analysis for the long term (discussed in more detail later). Given these distinctive approaches and the panel's view that the market is currently out of long term equilibrium, interpolating between the short and long term estimates is appropriate.

Gas

BEIS's central case short-term gas projection (2017-2018) is based on the forward curve, while the low and high cases have been derived using an implied volatility analysis. The liquidity of the UK National Balancing Point (NBP) forward market is viewed as sufficiently high over the initial two-year period to support this approach, but beyond two years there is a question as to whether the market will be sufficiently liquid to support the forward curve prices being used for future gas prices assumptions. The central and low price assumptions have, therefore, been "flat-lined" for the two years to 2020. This approach is viewed as reasonable. In the high gas price case the gas price has not been "flat-lined" as it is assumed that demand in the European market will rise faster than expected which would tighten the market and absorb any surplus LNG. As such, prices rise on a linear basis from 2018.

The NBP price used for the gas price forecasts is the average NBP price for the 30 trading days prior to the end of March when the forecasts and this report were developed. In its discussions, the panel addressed what historical period should be used as the NBP price for the 30 trading days prior to the end of March was $5.8/MMBtu (44 p/therm), compared to a higher price of $7.25/MMBtu (month+1) for the earlier period mid-January to mid-February 2017. It was viewed that this lower price as a starting point for price forecasts over the period to 2020, with a correspondingly lower price in the low gas price assumption case, would be more realistic as there are some fundamental changes taking place in the LNG and gas market over the next four years that are likely to drive weaker prices in Europe (see section 3.2). Price weakness is expected during this period due to additional LNG supply into North-West Europe competing with Russian pipeline gas. Post 2020 it is assumed that the market will start to adjust to long-term supply/demand equilibrium. As such, in the period 2018-2020, the flat line in the low gas price case should be consistent with a price floor equal to the lowest US LNG export cash cost price, which represents the lowest price at which US exports will be exported[5]. At a US Henry Hub price of $3.00/MMBtu[6] this should equate to an NBP price of ~ $4.15/MMBtu (32 p/therm). BEIS have tested their low gas pricing assumptions price assumption against this and have found them to be consistent.

As with the 2016 Fossil Fuel Price Assumptions, the Low and High pricing cases have been developed using options volatility calculations that determine the likelihood that the market attaches to future price levels using a 75% confidence level[7]. This assumption is reasonable.

The linkage to US LNG supply, together with competition from Russia and Norway pipeline gas, as well as uncertainty over gas demand in Asian and the newly developing LNG importing countries, means that gas price volatility is expected to rise in the short to medium term. This price volatility should be contained in the forecasts as the BEIS forecast is based on annual averages.

Coal

BEIS's short term coal price assumptions (2017-18) are based on spot and forward prices for ARA CIF[8]. Forward prices aggregate the available information and expectations of market participants and, hence, represent well the current context of the European and global coal markets. They implicitly account for the arbitrage potential between the Asian and European coal market. Thus, the use of spot and forward prices is the most suited approach to derive the short-term price assumptions.

For similar reasons, as discussed in the BEIS 2016 Fossil Fuel Price Assumptions and as applied in the oil and gas price assumptions, the use of forward prices is limited to 2 years. Thus, for the central scenario, the year 2017 is derived by a 30-days average of the Q1 outturn prices and of the Q2 to Q4 forward prices. The 2018 price is modelled from year

[5] This "Floor Price" is assumed to be Henry Hub gas price x 1.15 + $0.30 (shipping) + $0.40 (regasification) /MMBtu. This price is deemed a "Floor Price" as US LNG will set the marginal gas import price as Russian gas is expected to follow/match the floor price not set it in order to for it to maximise profits without having to sacrifice sales volumes.

[6] $3.00/MMBtu short-run price assumption is in line with other independent views (as advised by BEIS)

[7] At a 75% confidence level the market attaches a 75% likelihood that the gas price will rise or fall within a certain outcome.

[8] ARA CIF is a coal price notation for coal delivered to the ports of Amsterdam, Rotterdam and Antwerp, Europe's major coal ports. The coal price comprises cost, insurance and freight and refers to a metric tonne of coal at 6000 kcal/kg net as received.

ahead forward prices for 2018 averaged over the same 30-days trading period. Unlike for oil and gas, the option price approach is not applied for coal due to limited data availability. Instead, low and high scenarios are modelled by accounting for historic deviations of forward and realized coal prices between 2007 and 2016.

In last year's BEIS 2016 Fossil Fuel Price Assumptions, the high scenario added 1 standard deviation to the base case whereas in the low scenario only 0.5 standard deviation was subtracted to account for the fact that coal prices were exceptionally low last year. Whereas, in retrospective and given today's higher coal prices, the approach was sound, it is for the same reason appropriate to add and subtract 1 standard deviation in the high and low scenario in this year's price assumptions.

2.2 Data Sources and Long Run Supply Assumptions

For the long run supply assumptions, last year, Wood Mackenzie was commissioned to produce supply curves for each fuel[9]. Given that the final version of the Wood Mackenzie report was submitted to then DECC in May 2016 and work on this year's price assumptions started in November 2016, only 7 months later, it is reasonable to assume that the Wood Mackenzie report is still fit for purpose; although additional work has been done around supply assumptions for future Iranian production and US light tight oil (LTO). The long run demand assumptions were obtained from the IEA's *World Energy Outlook 2016*. For the long run price assumptions, the preferred method is the marginal cost curve. This is because long run price assumptions should be anchored at the expected cost of marginal supplies at projected levels of global demand. For instance, for oil: the assumption is long term oil supply is responsive to price and that any large rents in the market could incentivise increased exploration activity and production. The Panel considers this to be a reasonable approach to generating long run price assumptions for long-term economic appraisal.

Oil

For each fuel, Wood Mackenzie has drawn on the data it has available (see below) and in-house expertise to develop plausible 'unconstrained' curves for different time periods (2020, 2025, 2030 and 2035). The overall scope of the cost curves is different for each fuel: global supply for oil; European supply for gas; and seaborne imports into Europe for coal. This is appropriate since it reflects the fundamental differences between the markets for each fuel – and the way in which international availability is likely to influence prices in the UK.

Clearly this is a simple framework and is designed to capture the condition that in the long run the price will equal marginal cost of extraction for a given supply curve. To capture the uncertainty over the long run and a plausible range of alternative supply cases Wood Mackenzie[10], following discussions with former DECC, derive sensitivities around their

[9] At https://www.gov.uk/government/publications/fossil-fuel-price-assumptions-2016

[10] Wood Mackenzie responded to the Panel's question about the high-cost elements of the curves as follows: "Each of the fuel cost curves represents a view of the cost at a particular point in time and a degree

central supply curve to establish a 'low supply' and a 'high supply' case. The Panel's view is that the sensitivities illustrate a reasonable range of uncertainty and the underlying narratives were established through detailed discussions involving Wood Mackenzie and the Panel. Meanwhile the long run demand assumptions were obtained from the IEA's *World Energy Outlook 2016* using all three of IEA's scenarios: a '450 scenario', a 'current policies scenario' and a 'new policies scenario' details of which are described in the next section.

For oil, a few adjustments have been made to the Wood Mackenzie's central supply curve. In 2016's Fossil Fuel Assumption, the panel believed the unconstrained oil curve—as requested by former DECC—did not take into account of above-ground constraints in certain OPEC nations such as Libya, Venezuela and Nigeria. As a result, based on the panel's recommendation, BEIS adjusted the central supply curve to reflect the loss of future productive capacity in 2030 across the three countries by around 1 mb/d each, or cumulatively by 3 mb/d. Similar concerns were raised about a few other smaller producing nations such as Colombia, China but with the Wood Mackenzie curve not reflecting the upside surprise potential from Norway's fields beyond 2020, these balance each other out. Further enhancing this, for the 2017 Assumptions the panel has recommended constraining Iran's production capacity at 5 mb/d in the central and high price scenario, due to the country's inability to raise production beyond 3.8 mb/d even after the lifting of sanctions and the return of foreign companies delayed by the Trump Administration's hostile demeanour towards the country. Companies such as Total have put their investments on hold for now and without IOC capital, Iran will be unable to grow. Finally, given the upside surprise shown by the Permian, the panel proposed a 57% further increase for Permian production versus what Wood Mackenzie have previously assumed

of caution must be taken in interpreting prices from the curves. This is particularly true for higher cost supply to the right of each of the curves. There are two principal points that have to be taken into consideration that would tend to soften any price estimates drawn from this portion of the curves."

- In each curve, there are volumes that are not called upon that will roll over to the next supply curve that are not taken into account in our methodology, which assumes a static model due to the limitation of not matching supply and demand.
- As you move towards the right of the curve the price increases and this price increase will have the tendency to introduce further additional investment above the Wood Mackenzie base view which could increase lower cost supply beyond that modelled.
- Moreover – the shape of the supply curve at the extreme is largely a function of expectations. In a world of higher expected prices, over the long run we would expect the supply curve to extend and to continue to be responsive to price.

in 2030. This assumption increases the US LTO production assumptions compared to the 2016 price assumptions .

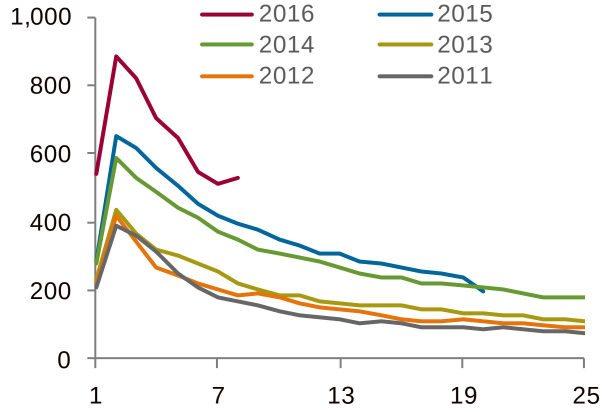
- For the central assumption, assume production reaches 10 mb/d, compared to 8 mb/d in 2016's report as the US keeps its cost efficiencies and the market price allows to hedge significant volumes of production
- For the Low Supply-High Price Scenario: assume a production volume of about 7.5 mb/d as LTO becomes costlier to produce and new supplies struggle to match demand levels
- For the High Supply-Low Price assumptions: US LTO production reaches about 5.3 mb/d, as competitive supplies from OPEC have significant market share and low market prices limit the LTO production that can be hedged.

From 2030-2040 oil prices are flat-lined due to the uncertainty around geopolitics, technological innovation, and energy efficiency.

Note on the Permian

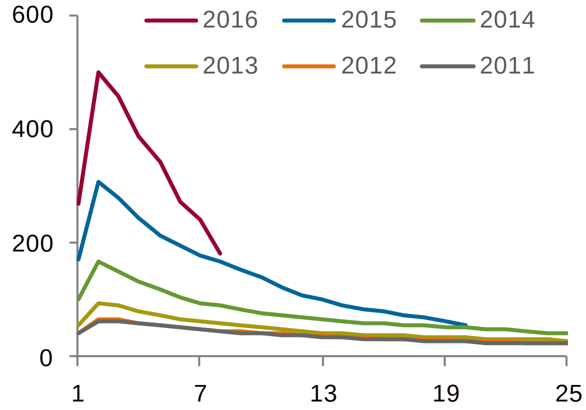
In 2016, when US crude production fell sharply, by over 0.4 mb/d, Permian production continued to edge higher. The entire decline curve for wells completed in 2016 has shifted upwards. So, the combination of a moderate increase in activity alongside huge gains in initial production (IP) rates for wells drilled in 2016 is ultimately what is driving production growth—not just a higher rig count. Thus, the impact on production of one additional Permian rig today is far more pronounced than it was last year. Ultimately, these impressive 2016 IP rates will mean that fewer rigs, and fewer completions, are required to grow production. A well level model for the Permian currently predicts 0.44 mb/d of production growth in the basin in 2017, with an exit rate in December 2017 of 2.7 mb/d. In 2018, further growth is expected, of over 0.50 mb/d y/y, with possible upside risks depending on the price of oil and pace of growth once the initial ramp up phase is behind us. This would take the exit rate in 2018 to 3.2 mb/d.

Fig 1: Delaware Basin type curves, boe/d



Source: DrillingInfo, Energy Aspects

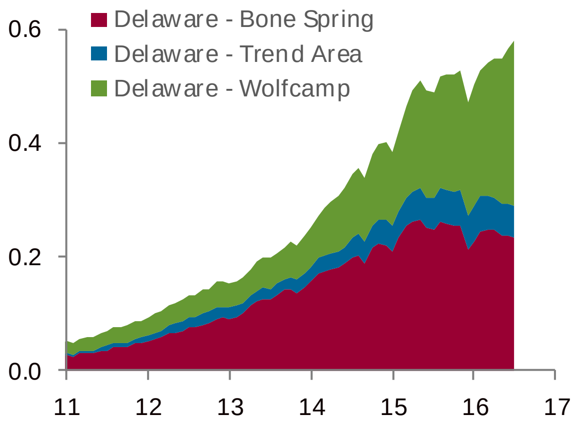
Fig 2: Midland basin type curves, boe/d



Source: DrillingInfo, Energy Aspects

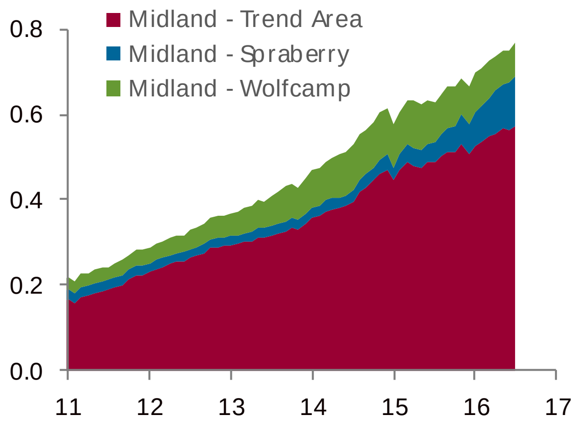
The Permian is home to some of the stalwarts of the US E&P industry—companies that have been at the cutting edge of the shale boom from the beginning, pioneering hydraulic fracturing and enhanced recovery techniques that others saw as too risky a few years ago. At these firms, best practices are quickly adopted and rolled out across production portfolios, resulting in year on year improvements in IP rates, better estimated ultimate recoveries (EURs) and lower costs per barrel of oil produced. With multiple stacked payzones in the basin, operators are constantly learning new techniques and leveraging past experiences to maximise output and reduce cost. This level of improvement is impossible to mimic in a basin with one payzone.

Fig 3: Delaware output by reservoir, mb/d



Source: DrillingInfo, Energy Aspects

Fig 4: Midland output by reservoir, mb/d



Source: DrillingInfo, Energy Aspects

This high grading in the Delaware and Midland has pushed Permian IP rates higher y/y. The average well in the Permian now yields peak IP rate of almost 600 boe per day compared to 308 boe per day in 2015. In the Delaware, Wolfcamp wells yield a huge 950 boe per day peak IP versus 648 boe per day in 2015, and Midland Trend Area wells give 500 boe per day versus 308 boe per day a year ago. Put simply; each well is producing more oil as producers drill better rocks and improve drilling techniques. Better quality rock ultimately means higher production and more profitable wells, if costs are kept in check. Thus, it is no surprise to see acreage valuations in the Permian skyrocket as firms look to cash in on these assets at a time of depressed oil prices. Indeed, the average acre is changing hands for $27,000. The highest transaction this year occurred at $58,000 per acre, with QEP Resources spending $600 million to acquire Martin county acreage from RK Petroleum Corp (the deal metrics imply a dollar per proved boe of $7.89 per barrel). EOG acquired 324 thousand acres of Yates Petroleum's Permian acreage, and other assets, for $2.5 billion. Private equity firms also began to pull the trigger on Permian acquisitions in late 2016. Blackstone have committed $1 billion to Jetta Permian—which aim to target assets in the Delaware basin—and also invested a further $500 million in Guidon Energy, which controls 16 thousand acres in the Midland basin. Finally, Exxon Mobil has doubled its oil and gas holdings in the Permian for $5.6 billion.

Permian based producers have also actively hedged their production, with Apache hedging 0.18 mb/d using a put contract at $50.47 per barrel. Other Permian focused producers such as Pioneer (88%), WPX Energy (81%), Encana (77%) Concho (75%) and Diamondback (60%) all have large and active hedging portfolios. Furthermore, many producers are hedging the Midland differential to protect from a blow-out in the Midland-WTI differential. For example, Encana, hedged an average 35 thousand b/d of Midland differential at WTI less $0.61 per barrel and extended its programme out to the 2018 to 2020 period. The company has hedged an average 17 thousand b/d at WTI less $0.83 per barrel over that time period.

Gas

BEIS's longer-term gas assumptions (anchored around 2030) assume that the gas market is moving towards a long-term equilibrium and are based on the expected cost of marginal gas supplied to Europe, at projected levels of European gas demand. This is the same methodology, using long run marginal cost curves, as has been used for coal and oil. These curves were developed by Wood Mackenzie for BEIS (formally DECC) as part of the 2016 Fossil Fuel Price Assumptions which are viewed as still valid for the 2017 Fossil Fuel Price Assumptions exercise[11]. In this review, this time last year, it was noted that it is the lowest cost gas and LNG supplier that will set the marginal supply price in Europe and, as the gas price is for the North-Western Europe market, based on gas supply/demand[12].

The behaviour of the Russian gas supplier Gazprom, which has historically been the largest gas supplier to Europe, is a major factor influencing the level of gas prices in North-West Europe. Specifically, with rising LNG supplies, the question is; will it sell its gas to maintain market share (that would result in lower gas prices until US LNG hits a price floor) or seek to maintain higher prices through reducing gas pipeline supply, allowing US LNG to be imported until LNG export plants hit a maximum export capacity?[13] In March 2017, the European Commission said that Gazprom had committed to a raft of changes to its supply contracts, including abandoning destination clauses and increasing the use of hub-

[11] The only adjustment, made in December 2016, was to Wood Mackenzie's long-term Henry Hub gas price assumption for 2030

[12] In 2015, the IGU estimate that 92% gas sold in North-West Europe was market priced based (gas on gas competition). For the whole of Europe this figure reduces to 64%. 2016 data are not available until May 2017.

[13] Reference footnote 3.

based pricing in long-term contracts[14]. At that time, EU competition commissioner Margrethe Vestager said “We believe that Gazprom’s commitments will enable the free flow of gas in Central and Eastern Europe at competitive prices” which will: “better integrate gas markets in the region”. These commitments are consistent with increasing competition between Russian gas pipeline supply and LNG in setting the gas market price on European hubs. If Gazprom was to seek to maintain market share, which it is expected to do, (34% European gas supply came from Russia in 2016[15] vs. 31% in 2015) and gas prices were to fall, then this could discourage the development of new LNG capacity which, in the long-term, could enable Gazprom to increase its prices. If, however, new LNG supply FIDs were to take place, even in a low gas price world, then this could mean that Gazprom’s competitive strategy may have to change in the longer term when it needs to develop new, higher priced, gas supply and infrastructure to meet its European buyer’s demand. In April 2017 Qatar lifted its self-imposed moratorium on the development of further gas projects using North Field gas[16]. This additional source of low cost associated gas is likely to be used to supply the existing Qatari LNG trains that have spare capacity and could additionally be de-bottlenecked[17] to produce an additional 12-15 mtpa low cost LNG[18]. Qatar already has available import infrastructure into the GB market through its South Hook regasification terminal at Milford Haven, Wales. The timing of this additional LNG supply is not clear, so it has not been factored into this review but should be included in the 2018 Fossil Fuel Price Assumptions Review. Additional LNG supply will result in additional competition to other LNG suppliers and a source of additional low cost gas to the GB gas market.

Norway is also a critical supplier to GB and, due its proximity to the market, will always seek to supply GB and North-Western Europe markets in priority to others. Its pipeline

[14] Heren Global LNG 16th March 2017 Heren Global LNG 16th March 2017 and Oxford Institute for Energy Studies (OIES) “The EU Competition Investigation into Gazprom’s Sales to Central and Eastern Europe: a comment on commitments”, Jonathan Stern and Katja Yafimava, April 2017

[15] Gazprom Investors day 2017 presentation “Strong Foothold in Changing Times” March 2017

[16] Qatar’s moratorium was announced in 2005 to allow an analysis to be made of the North Field’s performance but this has been extended on a rolling basis. In 2014, it was stated that a comprehensive evaluation of all the reservoir, well data and models was continuing in order to develop the optimum strategy for the long-term future of the field (Source: “Qatar Lifts its LNG Moratorium”, Oxford Institute for Energy Studies, April 2017)

[17] Debottlenecking an LNG plant is about identifying the parts of the plant that are constraining production and removing the constraint. It might involve increase the size of some of the pipework, increasing the power of the compressors and or increasing the capacity of the gas treatment units. The modifications will vary from plant to plant and will be specific to that plant. The work is typically carried out during a maintenance shutdown and can often realise an additional 10% of LNG production (Source: MEES).

[18] In September 2009, Faisal al-Suwaidi, Qatargas's chief executive, has said that each of Qatar's 7.8 mtpa LNG mega-trains could see their production capacity increase to 10 mtpa after debottlenecking, meaning that Qatar's targeted 77mtpa peak LNG output capacity could be increased to 89 mtpa with relatively short notice (Source: https://www.ihs.com/country-industry-forecasting.html?ID=106594999)

exports are, however, expected to fall, especially post 2020, but if new gas reserves were found this would result in additional supply, though the geography of future production will likely be different, requiring GB to access Norwegian gas via the North-West European market.

From 2030-2040 gas prices are flat-lined due to the uncertainty over gas supply conditions post 2030. During this period energy efficiency and enhanced use of technology should mitigate the potential use of new expensive sources of gas supply.

Coal

Concerning BEIS's medium term coal price assumptions (2019-30), the approach assumes a flat-lining of the 2018 price assumptions for the years 2019 and 2020 for the low and central scenario. After 2020, prices are interpolated to the long-term equilibrium prices of 2030. It is sound to assume that, first, given today's downward trending forward prices price assumptions do not rise in the low and central scenario until 2020 and that, second, after 2020 the coal market moves again towards a long-term equilibrium. In the high scenario, 2018 price assumptions are interpolated to 2030 to account for the possible development that in a high price world, European coal prices start to move more rapidly towards the long-term equilibrium.

Long-term equilibrium prices of 2030 are derived by the same approach as in BEIS Fossil Fuel Price Assumptions 2016. A low/central/high demand case has been coupled with a high/central/low supply case to derive 3 long-term coal market equilibria for the base, low and high price assumptions. The supply cost curves have been derived by Wood Mackenzie for last year's BEIS Fossil Fuel Price Assumptions 2016. These curves cover main uncertainties of the global coal market and remain useful to be used in this year's analysis since there have not been any substantial changes in the cost structure of global mining companies.

In the high price scenario, EU import demand has been reduced compared to the initial demand assumptions. This reflects the fact that at higher coal prices, European domestic coal production, in particular Polish coal production, would become more competitive and therefore increases, lowering EU import demand at the same time.

2.3 Long-term demand data sources and assumptions

As was the case for the 2016 assumptions, future demand projections have been taken from the latest International Energy Agency *World Energy Outlook*. This was published in November 2016. This publication is an established and respected annual source of global analysis, which uses the IEA's own World Energy Model to explore scenarios for the global energy system. Whilst the IEA has sometimes been considered to be relatively conservative in the past, especially with respect to its assumptions about the potential for non-fossil energy sources, this conservatism has been addressed to some extent in recent years.

The IEA develops and publishes three scenarios for energy supply and demand each year. These include a '450 scenario' in which the average global temperature increase due to climate change is limited to 2°C; a 'current policies scenario' in which the energy system continues to develop on a business as usual trajectory, shaped by policies that are currently implemented; and a 'new policies scenario' that assumes future planned policies to reduce emissions are implemented. The new policies scenario includes the IEA's assessment of policies within intended nationally determined contributions (INDCs) that were submitted for the Paris Agreement. However, these policies fall far short of limiting emissions to meet the 2°C target.

BEIS have compared the IEA scenarios for demand for fossil fuels with other global scenarios or projections, including:

- analysis by other public sector bodies such as the US Energy Information Administration (EIA) *International Energy Outlook 2016*[19];
- scenarios from the World Energy Council, a membership organisation with members from public, private and third sector organisations; and
- analysis produced by the oil companies such as BP's Energy Outlook[20] and Exxon-Mobil's The Outlook for Energy: the view to 2040[21], or a producer organisation (OPEC).

[19] US EIA (2016) *International Energy Outlook 2014*. Washington DC: US Energy Information Agency. Available at: http://www.eia.gov/forecasts/ieo/
[20] BP (2017) *Energy Outlook 2017 Edition*. London: BP.
[21] ExxonMobil (2017) *The Outlook for Energy: the view to 2040*. Irving, Texas: ExxonMobil.

The BEIS report also uses a number of other projections to test whether the IEA scenarios include a sufficiently robust range of growth rates for electric vehicles – and the consequent impact on oil demand. As the BEIS report shows in figure 2, some of these other projections displace significantly more crude oil in 2030 than the IEA 450 or new policies scenarios.

As the differences of view about electric vehicle demand illustrate, it is important to bear in mind that many long-term scenarios are produced by organisations that have specific commercial interests – and these interests are very likely to influence their views on the outlook for particular fuels or technologies[22]. For example, it is not surprising that oil company 'business as usual' scenarios are more optimistic on oil and gas demand, and more pessimistic on electric vehicle uptake, than scenarios that are designed to explore how to meet ambitious climate change goals.

Figure 5 compares the global demand scenarios for the three fossil fuels from the IEA World Energy Outlook with scenarios from some of these other sources. It includes some of the same sources as the BEIS report, with the addition of scenarios produced by the Institute of Energy Economics, Japan's *Asia/World Energy Outlook 2016*[23]*.* The rationale for including this additional source is that it might provide a perspective that is different those from organisations based in Europe and North America. Some caution should be exercised when comparing scenarios since they use different methodologies and assumptions. In each case, a standard unit has been used (million tonnes of oil equivalent) to facilitate comparison between fuels as well as between individual scenarios. Note that the first set of figures refer to liquids demand rather than oil demand. Liquids demand is usually higher due to the inclusion of biofuels, for example.

[22] For example, a critique of oil company scenarios by Greenpeace and Oil Change International highlights some potential sources of bias within these scenarios. However, this critique should also be viewed with caution, given that it comes from a leading environmental NGO. Greenpeace and Oil Change International (2017) Forecasting Failure; https://secure.greenpeace.org.uk/page/-/ForecastingFailureMarch2017.pdf

[23] IEEJ (2015) *Asia/World Energy Outlook 2015*. Tokyo: The Institute of Energy Economics, Japan.

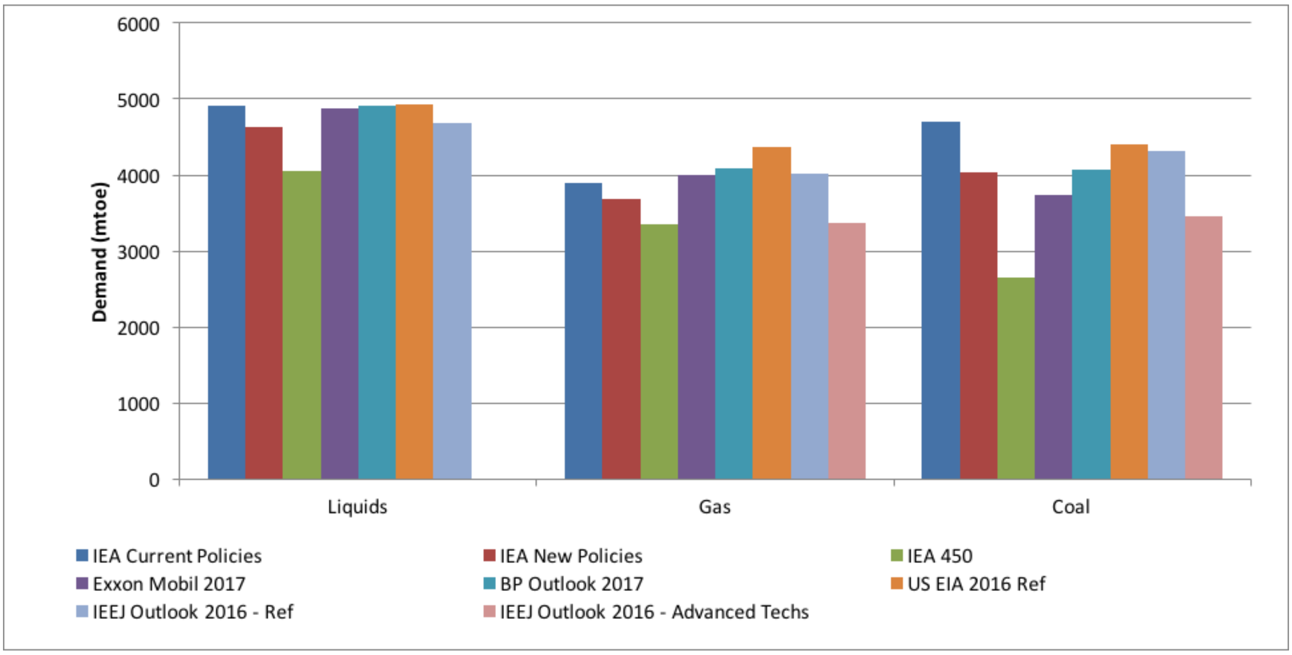


Figure 5: Comparison of scenarios for global fossil fuel demand in 2030

Notes:

Exxon Mobil provides figures for 2025 and 2040. 2030 demand has therefore been estimated via interpolation from these figures.

Exxon-Mobil and US EIA figures were originally quoted in Quadrillion BTUs, and have been converted to mtoe using a conversion factor of 1 Quad BTU = 25.21 mtoe.

Three points are particularly important to note:

First, as was the case in 2016, the IEA's '450 scenario' generates the lowest projections of future fossil fuel demand. This is understandable since most of the others result in a level of greenhouse gas emissions that would result in global warming above 2^{o}C. The BP Outlook includes an 'even faster transition' scenario, which is broadly in line with the IEA 450 scenario, but there is insufficient detail in the Outlook to accurately assess the impact on oil demand in 2030. According to the summary presentation from BP, oil demand declines between 2015 and 2035 within this scenario by roughly 15 mtoe per year. Therefore, it is likely that 2030 oil demand in this BP scenario that is a bit higher than the level in the IEA 450 scenario.

Second, there are other scenarios for gas demand for 2030 that are higher than the figures in the highest demand IEA scenario (current policies). This applies to scenarios from BP, Exxon Mobil, the US EIA and the Institute for Energy Economics Japan. The US EIA demand figure for 2030 is over 10% higher than that in the IEA current policies scenario. One factor that could explain these differences is assumptions about economic growth –

both globally and in different regions. However, the economic growth assumptions from the IEA, US EIA and Exxon Mobil are similar[24].

What matters for the BEIS fossil fuel price assumptions is gas demand in Europe, not global demand. If the figures for European gas demand are compared, it is clear that demand figures from most other organisations are within the range of the IEA scenarios. The exception is the US EIA outlook, which has gas demand for OECD Europe in 2030 that is almost 20% higher than gas demand for this region within the IEA current policies scenario. If demand were higher in 2030, it may not necessarily lead to a higher long-term gas price. This is because the supply curve that is used to generate the BEIS high gas price assumption is flat at the point where it crosses the level of European demand in the IEA current policies scenario.

Third, the additional analysis of projections for the growth of electric vehicles in figure 2 of the BEIS report shows that both McKinsey and Bloomberg New Energy Finance expect significantly more crude oil demand to be displaced by 2030 than the IEA – around 4mb/d rather than approximately 1mb/d for the IEA 450 scenario. If this additional 3mb/d of displacement were to occur, it would not necessarily lead to lower prices. This is because the supply curve that is used to generate the BEIS low oil price assumption is flat between approximately 85mb/d and 90mb/d (see figure 3 of the BEIS report).

Overall, the IEA scenarios cover a fair range of demand for oil, gas and coal. It is possible that global energy trends could fall outside this range in future, and there may be an element of ‘group think’ in the demand projections that are available. The existence of higher gas demand scenarios and higher electric vehicle demand growth projections from other bodies means that these two areas should receive particular scrutiny in future revisions to the BEIS assumptions.

[24] The global average growth rates assumed are 3.4% (IEA); 3.3% (US EIA); and around 3% (Exxon-Mobil).

3. Fossil Fuel Price Assumptions

This section examines each fossil fuel price assumption. It follows a common format that starts with a discussion of the current context; it then identified the common uncertainties; and it concludes by assessing the ‘reasonableness’ of BEIS’s fossil fuel price assumptions.

3.1 Oil Price Assumptions

Figure 6: Front-month Brent crude prices, 2007-May 2016, $ per barrel

Source: Reuters, Energy Aspects

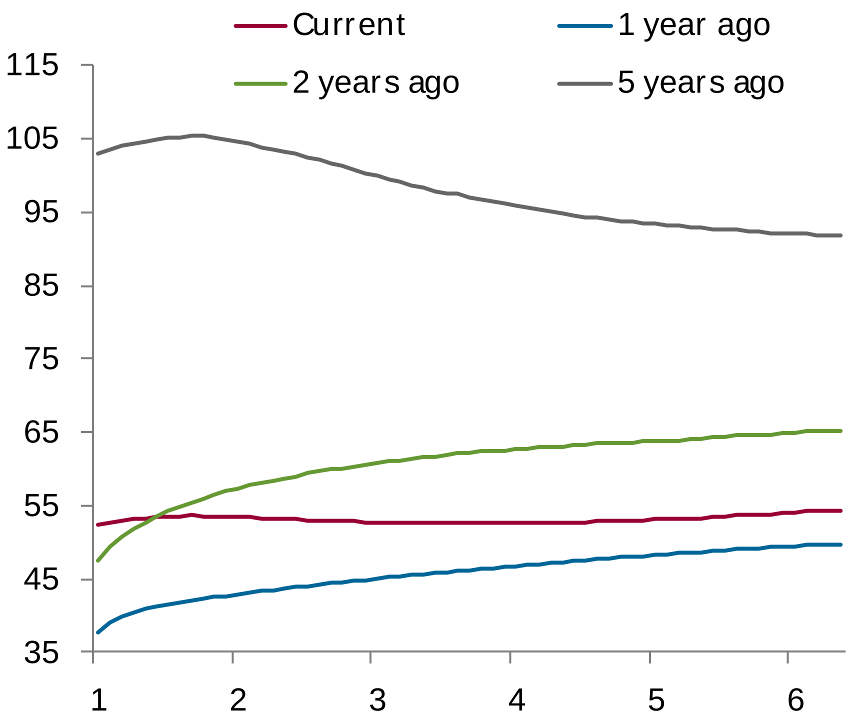


Figure 7: WTI forward curve, April 2017, $ per barrel

Source: Reuters, Energy Aspects

Context

Following a few years of high, but stable, oil prices between $90-$110 per barrel, a strong supply response in reaction to those very high prices triggered a sharp downturn in prices in mid-2014 (see Figure 6). At that time, all eyes were on OPEC to balance the market as usual, but the group, namely Saudi Arabia, decided to roll over the 30 mb/d collective quota on 27 November 2014 as they failed to bridge the gap between GCC members and others. Instead, OPEC went on to increase production by over 1 mb/d y/y during 2015 to levels only seen three times since 1995, and broadly at par with 2012's record levels.

Yet, by mid-February 2016, prices and sentiment had both turned. The effects of over $250 billion of capital that has been taken out of the system since 2014 were starting to be felt. Project cancellations and deferrals have risen to above 6.3 mb/d and costs have been cut to the bone, which is starting to push up underlying decline rates in mature fields. December 2015 marked the first month of y/y declines in non-OPEC supplies since 2011 and 2016 saw non-OPEC supply decline by 0.8-0.9 mb/d y/y, according to the IEA. The decline was broad based, but particularly steep in Latin America and Asia. Separately, with public finances dwindling, many Middle Eastern, African, and Latin American OPEC nations struggled to make ends meet. For instance, Angola's national oil company Sonagol had to be bailed out by China, while Venezuela is on the edge of bankruptcy. This led to a rise in the forward curve (see Fig 7) and also forced OPEC to come up with a historic deal in November 2016, pledging to reduce 1.16 mb/d of output and non-OPEC countries such as Russia also joining, pledging another 0.6 mb/d in cuts. In Q1 17, compliance from OPEC has been at historically high levels, well above 95%, which has helped start the rebalancing process.

Key uncertainties

Supply: The biggest uncertainty in the oil market today is the divergence between short and medium term outlooks. While OPEC cuts have helped reduce the inventory overhang significantly, there is probably around 300 mb (extrapolated from the IEA) of inventory still remaining. That will continue to cap prices, although with OPEC extending the production cut deal in May through to early 2018, the inventory overhang should disappear by the end of 2017/early 2018. Still with billions of dollars of investment cutback, a scenario can be constructed where prices surge in the coming years as a supply gap forms, as the number of new projects being added dwindles to a 15-year low in 2019/2020.

The ability of producers to hedge (lock in future prices using the forward curve, which is in contango, i.e. futures prices are higher than spot prices) also adds to the uncertainty. This may mean the supply response to lower prices is delayed or even muted as producers may have locked in prices above their cost of production.

Another uncertainty pertains to costs, which have fallen sharply in the recent downturn. But one of the reasons why tight oil costs have come down so sharply is due to high grading and producing closer to the amenities such as cement plants, water facilities and so on. Once producers start to move out of the core in response to higher prices, they will be producing from less attractive acreage, which means a higher cost base.

Finally, there are plenty of concerns about attracting back human capital, with many producers and service companies seeing high attrition rates (over and above redundancies) especially in the context of the global jobs market faring better today compared to 2008/09. So, labour costs are also set to rise and the risk of losing experienced workers is higher still.

Demand: The other uncertainty pertains to the outlook for demand. Following multi-year highs of over 1.8 mb/d of y/y growth in 2015 and 1.6 mb/d in 2016, oil demand growth is set to grow at 1.5 mb/d or higher. Demand has surged in some of the key big Asian net oil-importing economies, e.g. India, Korea, Thailand and the Philippines. India in particular is a bright spot despite demonetisation and even China is starting to look better. Global PMIs have hit their highest since 2011, which is supporting diesel demand in both the OECD and non-OECD. Longer term, while electrification of the car fleet is expected to weigh on gasoline and diesel demand growth, continuing urbanisation will help support petrochemical demand, offsetting a large part of the transportation weakness.

The impact of the changing value of the US dollar on oil markets is also thought, by some, to be a major driving force in oil price determination. Where this factor leads us in the next few months depends on: how well commodity-dependent economies and net oil-importing economies have adjusted to lower prices; whether commodities prices have truly bottomed out as some believe; and, on changes to interest rates.

Geopolitics: The current situation in the Middle East is hardly benign. Saudi Arabia, Iran, Russia, and the West, are all embroiled in the ongoing proxy war in Syria with significant ramifications across the region. The risk of a resumption of sanctions on Iran are also non-trivial, following the victory of Donald Trump in US Presidential elections. Meanwhile, lower oil revenues are forcing producer nations to make difficult financial choices. Even Saudi Arabia and its Gulf neighbours are reforming subsidies and cutting spending as they face record budget deficits. But these steps carry political risks despite the fiscal buffers that some have to deploy to help them through the downturn. Thus, there is always the possibility that geopolitical events will impact on the oil price, but by their very nature these are difficult to predict. However, it is noteworthy that the oil price has fallen significantly, and remains low at present, despite these geopolitical uncertainties.

Assessment

In general, just as persistent high oil prices can dampen oil demand growth and induce more investment on the supply side, so low prices can induce feedback mechanism that can act to maintain a floor on prices as demand responds and investment in future supply is discouraged. The oil market has been through two such cycles in the last 10 years, with the 2008/09 global economic recession and now the 2014/16 cycle leading to sharply lower oil prices but ending up curbing supplies

The set of BEIS assumptions aims to capture a range of these plausible oil market dynamics through periods of relative looseness/tightness though intentionally does not attempt to model price cycles or uncertainties around intangibles such as geopolitics. Where reservoir damage to productive capacity is likely, this has been captured by adjusting the marginal cost curve as discussed above. So, overall, the basis and factors behind the calculation of BEIS's 2016 Oil Price Assumptions are plausible and sound. In the short and medium terms (2016-2018) the use of the Brent futures curve, interpolated to long run 2030 price derived through the use of Wood Mackenzie's marginal cost curve, along with some adjustments, before flat lining over 2030-2040 seems reasonable given the constraints on data and uncertainties on geopolitics, while the statistical filters used in the analysis are robust.

The central long run assumption is that the supply side is more flexible and responsive to any periods of relatively high real oil prices, which is reasonable. The high oil price assumption is based on a state of the world in which global oil supply does not respond as strongly to persistently large rents in the market and where US tight oil growth is lower than the central case. Altering these assumptions shifts the supply curve inwards and there are less infra-marginal barrels produced. The overall price profile reflects a market that is steadily tightening over a prolonged period as demand growth outstrips supply growth. While this may seem far-fetched in the current market, the sharp reduction in capital expenditure is leading to significant cutbacks in investment and has already resulted in the delay or cancellation of 6.5 mb/d of projects scheduled to come online between 2017 and 2021. The possibility of a supply crunch in the coming years is rising. The low-price assumption is illustrative of a world where there is substantial demand reduction due to for example aggressive policy action to mitigate climate change, a sound assumption. Slower rates of economic growth and reduced energy intensity are also a factor. The level of global oil demand in 2030 under the IEA 450 scenario (as explained in more detail above) is used to capture the impact of these policies and demand changes and is combined with the Wood Mackenzie ‘high supply’ curve. The entire approach is reasonable, according to the panel.

3.2 Natural Gas Price Assumptions

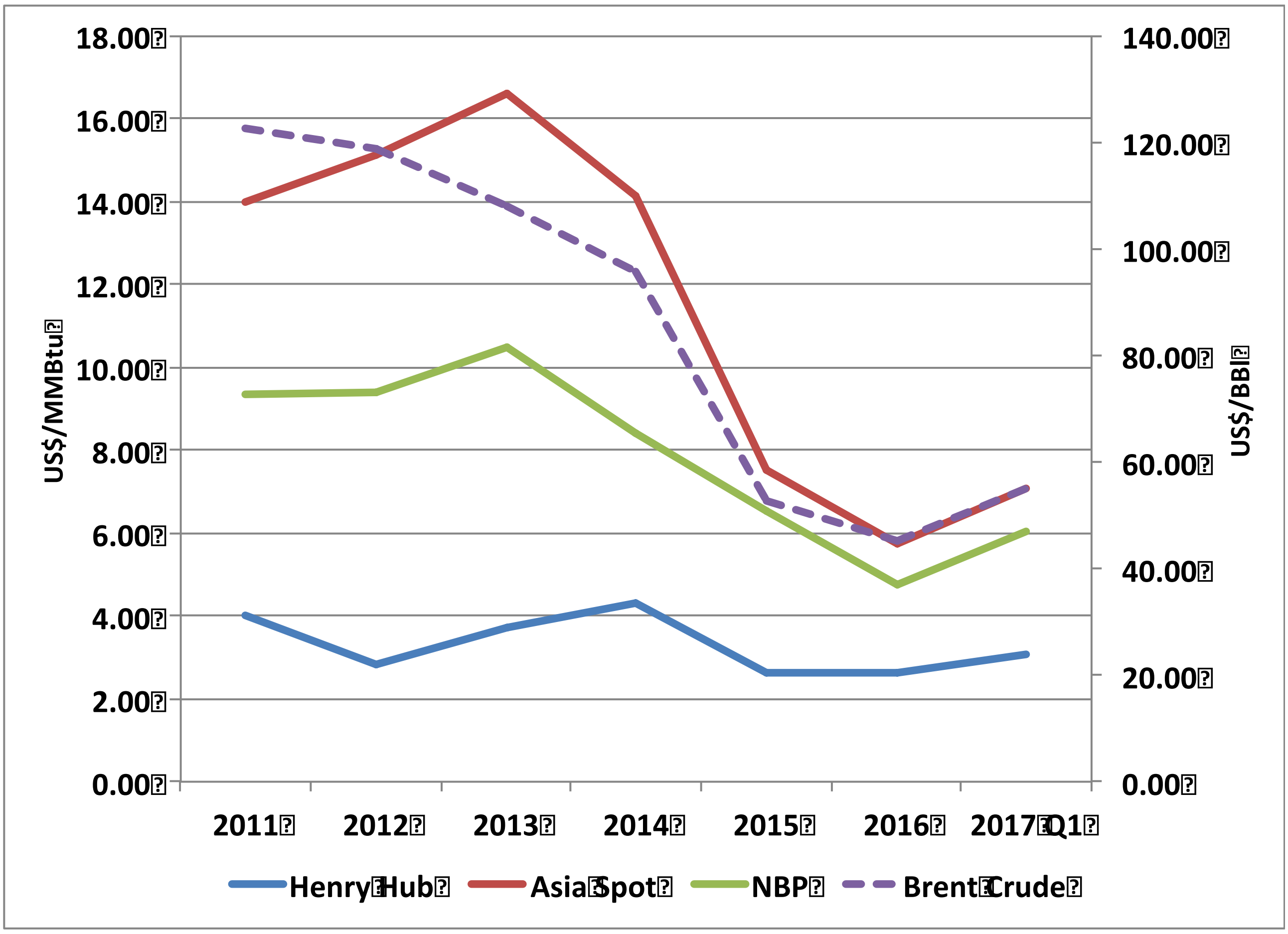


Figure 8: Trends in natural gas prices 2011 to end March 2017

Source: Heren

Context

With no global price for gas and LNG, gas price formation is based on regional markets that in recent years have seen price convergence as shown in Figure 8: the US Henry-Hub price is based on gas to gas competition in a largely closed and self-sufficient North American market; similarly, the UK's National Balancing Point (NBP) is formed by gas-to-gas competition, but it is also influenced by LNG spot prices and continental European gas prices, and the Asia-Japan/Korea spot is for short-term LNG cargoes. The 2016 Fossil Fuel Price Assumptions set out the history of how Asian and European LNG gas and LNG prices have moved. The conclusion was that, as additional LNG supply enters the market at a time of weakening gas demand (Japan's nuclear fleet is starting to come back on line), LNG prices would be weak in Asia, but that what happens in the future is far from certain. And price volatility is expected. The market saw this in the winter of 2016/17, when higher than expected demand in Asia, together with slower than expected new supply starting up, meant that prices rose to $8.20/MMBtu November 2017-January 2017 vs. $7.00 the year before or $5.00/MMBtu in the 2016 summer[25]. Global LNG is priced in US Dollars while GB gas prices are in Pence per therm[26]. Following the EU referendum on 23rd June 2016; Sterling's value has fallen considerably against the US Dollar. The 2016 long-term price assumptions assumed an exchange rate of £1 = US$1.529 while the 2017 report uses the OBR's exchange rate of £1 = US$1.313 (a 14.1% depreciation). At the time of writing this report, May 2017, the market exchange rate is slightly lower. The impact of this exchange rate change is to increase the price of domestic gas in Sterling terms. Further exchange rate weakness would correspondingly increase the cost of gas in GB, in local currency, further.

Global gas supply and demand is facing considerable uncertainty. In 2016, global output of LNG was 362 Bcm (264 million tonnes)[27] and by 2020 the industry is expected to producing 520 Bcm (380 million tonnes) LNG, plus additional LNG production of 158 Bcm (116 million tonnes)[28] (~ 1,800 cargoes pa). Half of this new supply will come from North American LNG supply projects that also bring more contractual flexibility than traditional LNG contracts. This increased flexibility will drive more liquidity and shorter-term LNG cargo trading.

This increase in LNG supply is happening at a time of global energy demand uncertainty. Reduced energy demand by China has resulted in a short-medium term surplus of committed LNG. The position in Japan, the world's largest LNG market, is increasingly uncertain due to the lack of clarity over the pace of nuclear restarts, deregulation in its energy market, the pace of renewables penetration and impact of energy saving measures. Korea, Taiwan and South-East Asian countries are also seeing gas demand uncertainty and the potential growth market of India is very price sensitive. The newer markets of Egypt, Pakistan and Jordan have provided some support. The implications of this reduced growth in LNG demand is that Asian LNG will supply Asian buyers and Atlantic Basin produced LNG will stay within that region with reduced cross-basin arbitrage. Middle East LNG will move to the highest value market.

[25] Source: Heren EAX Asia Spot Assessments; Month+1
[26] Global LNG is priced is US$/MMBtu and domestic gas prices priced in local currency, for the UK gas market in pence per therm, so the Sterling/US Dollar exchange rate is important in developing price assumptions for UK gas prices.
[27] GIIGNL "The LNG Industry 2017"
[28] Assumes 90% plant utilization.

The implications for GB is that LNG not taken by the established and new LNG buyers will seek to find a market in North West Europe where it will compete with pipeline gas. As prices fall, because of higher gas supply, sellers will be forced to marginal cost[29] their gas and LNG supply until prices are too low to support marginal costs. Gazprom's strategy is to let the market absorb the higher LNG import volumes from current LNG projects, and those currently under construction, until around 2020 and to discourage future projects from being sanctioned by maintaining its gas export volumes to keep prices below the long-run marginal cost of LNG.

Post 2020/22, the current surplus of LNG is expected to turn into a shortfall unless new LNG production capacity is constructed. To be online in time companies must take FID[30] by 2018/19, in a potential period of low prices. If FIDs do not take place then the market may face a tightening of LNG supply, and potential rise in gas prices.

Key uncertainties

The 2016 Fossil Fuel Price Assumptions set out a full list of uncertainties, this report updates the points made in that report:

Global Gas as Demand: Natural gas is expected to grow faster than oil and coal, growing by 1.6% p.a. between 2015 and 2035 with China, Middle East and the US being the primary growth regions in both the industrial and power sectors. If there was faster than expected global gas demand growth would result in an increase in demand for LNG globally which could remove the surplus of LNG available to Europe over the next five years and support prices in the short, medium and long-term.

Japan Nuclear: LNG imports into Japan fell by 2% 2016 vs. 2015 as nuclear power starts again following the Fukushima earthquake and subsequent tsunami in March 2011. This trend is expected to continue and energy saving measures, together with a move to renewables, is further expected to reduce Japanese LNG demand by 2025. This would increase global LNG availability, some of which would target the European and GB markets.

Gazprom's strategy: The Gazprom strategy is to absorb the additional LNG import volumes from current and LNG projects under construction, and to discourage future

[29] Investment in liquefaction and shipping are sunk costs. LNG sellers could therefore price LNG on a marginal/operational cost basis only. For US LNG this could equate to Henry Hub price x 1.15 + $0.30/MMBtu.

[30] Final Investment Decision - the date on which the project sponsors decide to make a binding financial decision to proceed with the project. Also known as FID date.

projects from being sanctioned by keeping European gas prices below the long-run marginal cost of LNG. If this strategy was to succeed, then, post 2020/22, gas prices may rise in Europe as LNG supply available to Europe would reduce and gas prices rise.

US LNG production: Downward pressure on European gas prices will mean that US LNG capacity holders will be forced to marginal cost their gas and LNG supply to maintain production. Should prices fall so low that they do not support marginal costs then, if US LNG is not economic, it may not be produced.

European gas supplier disruptions: Minor earthquakes related to the Groningen gas field have resulted in the Dutch government reducing gas production from the field by 60%. This has resulted in greater imports of pipeline gas from Russia and LNG into Europe. If there were further supply disruptions from the Netherlands, or other European gas suppliers, then this could mean that European domestic gas supply would reduce further and additional imports would be required by pipeline gas or LNG.

Coal prices: If coal prices were to rise globally, or an effective carbon tax is introduced in Europe such that gas is again economic in power production, then demand for imported gas and LNG will rise.

Legislative support: As Europe seeks to diversify gas supply sources away from its traditional suppliers, if the European Commission encourages the greater use of LNG to achieve greater European security of energy supply, then it could lead to an increased demand for LNG into Europe.

Rising oil prices: Should oil prices rise above $60/bbl (and Henry Hub gas prices remain below $3/MMBtu), then oil priced LNG in Asia would rise to a level higher than the fully built up cost of US LNG. This would pull short-term cargoes of LNG away from the North-West European market as Asian buyers seek to reduce term LNG and replace with lower priced spot/short-term cargoes. This would, therefore, reduce LNG supply to the European and GB markets.

Sterling / US Dollar exchange rate: Further weakness of Sterling would result in higher imported gas costs in Sterling terms. Volatile exchange rates create price uncertainty.

Disruptions to the market: Short-term disruptions in the market due to political and market restructuring events could also impact on global gas and LNG supply/demand.

LNG supply 2025+: If significant new investment decisions are not taken on additional LNG export capacity by 2018/19, taking into account increased LNG production from Qatar, then new plants will not be constructed for LNG supply post 2022/23. This could result in a supply shortfall.

Assessment

The basis and factors behind the calculation of BEIS's 2017 Gas Price Assumptions are viewed as sound. In the short and medium terms (2017-2018), the use of the NBP forward curve, extended or "flat lined" to 2020; in the medium-term (2021-2030) the use of linear interpolation to the long-term equilibrium price based on the marginal cost of gas pipeline supply (for the central and low price cases); and in the later longer-term (2030-2040) flat line seems reasonable. For the period 2018-2020, the low price case is consistent with the lowest US LNG export cash cost price, which represents the lowest price at which US exports will be exported. The high gas price case has not been "flat-lined" (2018-2020) and for the period post 2020 has a faster adjustment to long-term equilibrium, which is also reasonable.

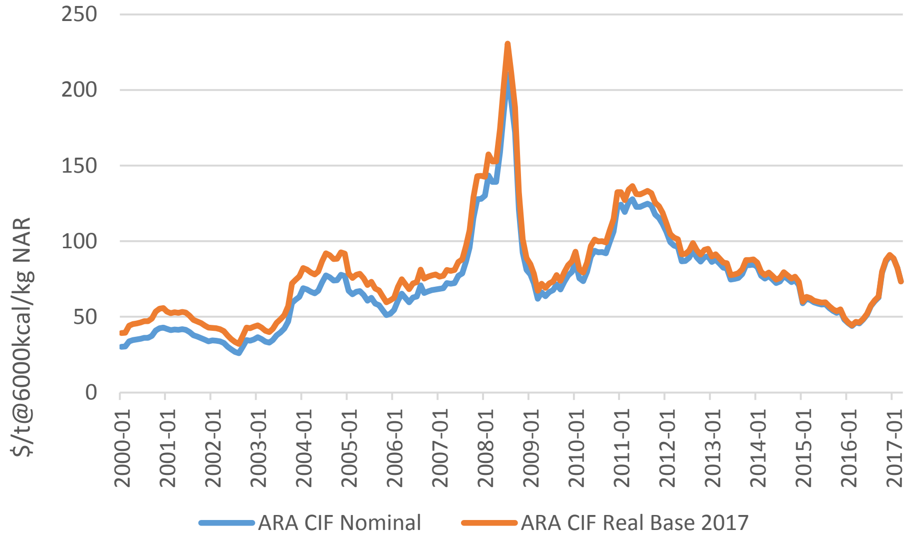
The additional LNG production of 158 Bcm (116 million tonnes)[31], ~ 1,800 cargoes pa, from LNG projects under construction in Australia and USA will enter the LNG trade over the next 2-3 years. This will bring weakness to European gas prices that will only be countered by reduced gas pipeline supply from Norway/Russia or higher gas demand. During this period, there is likely to be price volatility, but this should average out over each year (the prices in the forecast are annual averages). During this period, some LNG sellers (and maybe pipeline gas sellers) will be forced to sell below full cost. As noted in the 2016 report, gas price formulation in Europe, especially Northern Europe, is expected to continue to move from a relationship with oil to solely a hub price basis where the price of gas is determined by supply-demand of natural gas. This trend is supported by the statements made by Gazprom in March 2017 (see section 2.2)

In the long-term, the market will have to pay the full cost of marginal LNG supply otherwise investment in new supply capacity will not be made. The BEIS Central gas price scenario is 67 pence/therm, 2017 prices in 2030 ($8.80/MMBtu). This NBP price level should support new LNG capacity FIDs.

The uncertainties discussed in this section will test the UK gas market over the period of the BEIS forecast. The impact of these factors on UK gas prices should be contained within the high and low gas price scenarios set out in the price forecasts which are viewed as reasonable price forecasts. If new LNG capacity is not constructed before 2025, and pipeline gas supply from Russia and Norway does not increase to fill market demand, then gas prices could expect to rise towards the high price case level.

[31] Assumes 90% plant utilization.

3.3 Coal Price Assumptions



Source: IHS Markit – McCloskey Coal Report

Figure 9: European Steam coal price trends 2000-2017

Context

Since 2011, global coal prices have declined almost continuously, but 2016 witnessed a price spike with thermal coal prices doubling between February and December. As a result, the ARA CIF price marker for European steam coal imports, which stood at roughly $42 /t in the beginning of 2016 reached more than $90 /t in December 2016 (Figure 9).

This abrupt change in the price dynamics is remarkable given the rather bearish long-term trends the coal market has been exposed to during the last years, many of which may still prevail in the future. First, after 15 years of soaring coal demand in China with some double-digit growth rates, mining capacities grew worldwide especially in major coal exporting countries such as Australia and Indonesia, but also in China itself. However, demand growth, foremost in China, but also worldwide, has stalled during the last three years. Second, many planned projects for new coal-fired power plants, especially in Asia, have been abandoned implying less than expected coal consumption in the future. Third, low US shale gas prices prevail to displace coal fired generation, driving US coal to international markets. Miner-friendly policies by the new US administration could reinforce the latter. Fourth, low prices during the last few years have triggered a substantial decrease in mining costs and improvements in the productivity of coal mines.

There are at least two reasons to explain the contrary price trends in 2016. First and foremost, the Chinese Government reduced the working days for coal miners by 16% in Spring 2016. Reduced Chinese coal production meant that Chinese coal imports from the seaborne market increase sharply. These restrictions were relaxed in late 2016, and Chinese domestic output has recovered and prices have fallen again. However, the latest relaxations do not compensate for the fact that China has closed mine capacity of about 100 million tonnes in 2016. Second, reduced Chinese production was amplified by unfavorable weather conditions, hence less coal supply, in Australia and Indonesia, both key exporting countries on the global seaborne market for thermal coal.

Since coal is simple to transport at rather low costs compared to the price of the good, developments in Asia immediately affect European coal prices because of arbitrage opportunities. The latest development underlines that European coal prices must be seen in the context of global developments. Hence many of the following key uncertainties for the European coal price address global trends.

Key Uncertainties

Chinese coal market: Chinese steam coal demand is more than three times higher than the global steam coal seaborne market volume. Hence, several uncertain market developments in China (restructuring of the mining sector, de-bottlenecking of inland transport infrastructure, energy policy limiting coal demand) have a strong impact on global and therefore European coal prices. This uncertainty did in fact materialise last year, when, mainly driven by China, global and hence European coal prices increased tremendously.

US coal market: Uncertain market developments in the US will impact coal export volumes and hence European coal prices. Two important uncertainties in this context are future US gas prices, as well as Federal Government policy on air quality and decarbonisation that may increase or decrease coal use in the power sector and therefore affect coal exports. At least over the next years, governmental support of the US coal mining sector might conceivably affect US coal exports and hence European prices.

Global coal demand: On the one hand, global decarbonisation targets after COP 21 imply a decline of global coal demand. On the other hand, coal is the cheapest primary energy for many emerging countries e.g. in Southeast Asia, where a strong increase of GDP growth and, hence, electricity demand growth is expected. This uncertainty is, however, crucial for European coal prices since Asian and European coal market are strongly interrelated amongst others because of arbitrage opportunities for Russian or South African coal exports, for example.

European coal demand: In several European countries (UK, Netherlands, Germany), national measures against coal in the power sector have been realised or are currently discussed such as phasing-out coal by policy intervention and/or by CO_2 floor prices. However, since the European power sector is part of the EU-ETS, national measures in one country may enhance coal fired generation in another one. The EU-ETS may also impact coal demand negatively, if the resulting CO_2 price will be sufficiently high to make gas and renewables competitive with coal. Certain reforming measures currently discussed (e.g. market stabilization reserve, minimum prices) may change the dynamics of the EU-ETS, hence CO_2 and coal prices.

Mining costs and capacities: As seen in recent years, further productivity gains through cost cuts may decrease mining costs, hence European and global coal prices. In contrast, coal quality is expected to decline on global average implying higher costs. Additionally, the uncertain development of important production factors such as labour, oil, machinery or dynamite as well as the development of foreign exchange rates will affect mining costs.

Assessment

The approach to use and update last year's methodology is sound and, moreover, makes last year's and this year's price assumptions comparable.

The BEIS team's approach to model short term coal price assumptions (2017-18) for a base, with a high and a low scenario are sound as discussed in Section 2.1.

Coal price assumptions for the medium term (2019-2030), i.e. the flat-lining of the low and central case (2019-20) and the interpolation to 2030 are sound as discussed in Section 2.1.

The long-term coal price assumptions (2030-40) are based on last year's analysis of supply cost curves (see Section 2.2) from Wood Mackenzie for the year 2030 and scenarios of future European coal demand based on the three scenarios CPS, NPS and 450 from IEA's *World Energy Outlook 2016*. WEO 2016 covers most of the uncertainty of European coal demand since IEA's scenarios cope for different policy developments. Also, a reasonable range of uncertain developments regarding mining costs and capacities (as discussed above) is accounted for in three different supply cost curves provided by Wood Mackenzie. Even though, Wood Mackenzie's analysis is from last year, there have not been any substantial changes in the coal industry implying similar long-run costs for the year 2030. Hence, it is useful to use last year's coal supply curves for this year's report. Furthermore, BEIS's approach of correcting European coal demand for domestic

European coal production as well as European lignite and metallurgical coal demand is precise and robust. In particular, it is very reasonable to model a higher European coal production in the high price scenario, since at higher prices, coal production will rise, in particular in Poland implying lower imports.

The BEIS’s coal price assumptions lie close to those of the external price projections. For the central case, 2020 price assumptions are similar to external ones, whereas in 2030 and 2040 BEIS’s price assumptions are ca. 10$/t higher because of the supply cost curves used. For the low-price scenario, 2030 and 2040 prices are similar, whereas 2020 BEIS’ price assumptions are ca. 15$/t lower resulting from subtracting one standard deviation from current prices. In the high price scenario BEIS’s price assumptions are slightly higher than all the external projections considered. However, summing up, all deviations from external price projections seem plausible and justifiable and result from different methodologies applied.

4. BEIS's Quality Assurance Process

In last year's panel report, we discussed the Quality Assurance (QA) process for the models BEIS uses to generate the fossil fuel price assumptions. Overall, we concluded that the QA process is rigorous, and provides significant evidence that BEIS has critically reviewed its processes and the input assumptions that have been used in these models. In the scoring system that is used for the process, all of the fuel-specific models reached the required threshold score of 90%.

The QA Logs that were shared with the panel by BEIS from last year's exercise showed that there was room for improvement with respect to the formal documentation of the three fuel-specific models. This documentation has recently been updated and shared with the panel. It explains how each of the models work, and includes a step by step guide to using the model, the sources of data and how to change the input assumptions. Whilst this documentation provides very clear guidance, the panel's experience of working with BEIS shows that some of the knowledge required to generate plausible price assumptions resides with particular analysts – and can be difficult to codify. It is therefore important to ensure that this knowledge is retained within BEIS team, and is passed on effectively when there are changes in personnel.

A second limitation of the QA Log process was highlighted in our 2016 report: the long-term demand and supply assumptions that are used to calculate BEIS's fossil fuel price assumptions are provided by external organisations (the IEA and Wood Mackenzie respectively). In each case, models are used by these organisations. It is therefore important for BEIS to ensure that sufficient attention has been paid to QA of those models.

The IEA *World Energy Outlook*, which is the source of the energy demand assumptions used by BEIS, is produced using the IEA World Energy Model[32]. This model is large and complex, and depends on a number of more specific models. It is a partial equilibrium simulation model, for which the documentation is available, the structure has a number of standard elements that link energy supply through to energy service demands. It calculates energy supply, demand, prices, investment and emissions on an annual basis. Exogenous input assumptions include GDP, CO_2 prices, policies, demographics and

[32] IEA (2016) World Energy Model Documentation 2016. Paris: OECD/IEA. Available with more detailed explanations of specific aspects of the World Energy Model here: http://www.worldenergyoutlook.org/weomodel/documentation/

technological change. In some other models, some of these inputs assumptions are endogenous. Demand is mediated through stock models for end use sectors (e.g. vehicles or housing). The *World Energy Outlook* is subject to significant external scrutiny and peer review. It is therefore reasonable to conclude that the demand assumptions have been derived through a rigorous process – though with the caveat that these assumptions should be compared with other scenarios and projections to ensure they cover a reasonable range of possible outcomes.

Wood Mackenzie used their own models to derive the fossil fuel supply curves were supplied to former DECC last year. As we noted in our 2016 report, QA on these models is more difficult than for the IEA model. Whilst Wood Mackenzie provided some basic information to former DECC and the panel about the structure of their models, commercial considerations mean that they are not willing to publish this information. They also provided a brief overview of their internal QA process. Whilst the panel has extensively scrutinised the supply curves that have been produced by Wood Mackenzie's models, the panel were not able to assess these models in any detail.

5. Conclusions and Recommendations

5.1 Conclusions

The Panel believes that there is great value in having external experts review the process by which BEIS arrives at its fossil fuel price assumptions. There is currently a large amount of uncertainty on global energy markets. In such an environment, testing the reasoning and methodologies behind the fossil price assumptions is particularly important.

The Panel considers the approaches used to generate the fossil price assumptions to be a reasonable, straightforward and transparent.

The panel supports the methodologies that have been used to make both the short-term price assumptions based on the futures/forward curve and long-term price assumptions based on marginal costs, as well as the use of 'flat lining' and/or interpolating to link the two. The resulting price assumptions are generally in line with other external price projections and we support the cap on the long-run high oil price assumption at $120.

The Panel is satisfied with the quality of the data that has been used to conduct the short-term analysis and supports the use of the IEA's *World Energy Outlook 2016* and its three scenarios to generate future demand scenarios.

The Panel is of the view that that the specific sources of uncertainty that Wood Mackenzie have used to construct the variations in their supply curves for the three fuels gives a reasonable sense of the overall scale of uncertainty and that the supporting narratives provide a sound basis for their high and low supply cases. While we made further minor adjustments this year, we consider the supply curves supplied for the 2016 exercise to still be 'fit for purpose,' but it will be necessary to consider whether new analysis is required for the 2018 exercise.

Overall, when compared to the BEIS 2016 fossil price assumptions, the new set of assumptions have resulted in higher short-term price estimates for all three fuels, but it is only in gas where there is an upward movement of the central and high long-term price assumption. These changes have been justified by supporting analysis and reflect current market conditions and the impact of exchange rate changes.

5.2 Recommendations

Here we reflect on the recommendations that we made last year and suggest some issues to consider for the 2018 price assumptions exercise.

First, last year the appointment of Wood Mackenzie took place in parallel with the Expert Panel and this made it difficult for us to understand what they had been asked to do. BEIS needs to determine if they want to appoint external contractor to update the 2016 cost supply curves; if they do, next year it would be good to involve the Panel at the beginning of the process so that they understand fully the underlying assumptions behind the production of curves. In addition, the quality assurance expectations should be made clear in any future tender.

Second, last year the Panel noted that its work is compressed into a relatively short period of time and that it would be good if internal deadlines could be set by BEIS, when the schedule for the Panel meetings is agreed, to enable a bit more time to read the material ahead of the meetings. This year we did received draft documents in good time and there were fewer instances of last minute changes, although the late delivery of the first draft and final draft reports has pushed the timetable back.

Third, this year volatility in the gas market and the issue of exchange rate changes has complicated assumptions about short-term gas prices. In particular, the start point of the analysis raised concerns and it is suggested that BEIS agree the anchor date and subsequent average price data period for all three fuels at the onset of the exercise; and revise the timetable so that the first draft presented to the panel is not subject to the temptation to make revisions as new data subsequently become available.

Fourth, although we are satisfied with the quality assurance procedures used during the production of the price assumptions, BIES also needs to pay attention to the issue of ensuring the integrity of the price assumption procedure year-on-year. Given the inevitability of staff turnover, it is important to keep detailed records of the data sources used and procedures followed so that incoming staff can easily replicate the methodologies.

Finally, this is the end of the term of the current Expert Panel, we share the belief of the BEIS team that there is great value in involving external expertise in the fossil fuel price assumptions exercise and we hope that the practice will continue. However, we would recommend that the title of the Panel be changed to ‘Price Assumptions’, rather than ‘Price Projections,’ to reflect the current nomenclature.

Annex A: Biographies of Panel Members

Professor Michael Bradshaw is Professor of Global Energy at Warwick Business School at the University of Warwick. His research focuses on the interface between economic and political geography, energy studies, and international relations. He is a Fellow of the Royal Geographical Society, where he formerly served as Vice President, and a Fellow of the Academy of Social Sciences. He is an Honorary Senior Research Fellow at the Centre for Russian, European and European Energy Studies at the University of Birmingham, a Senior Visiting Research Fellow at the Oxford Institute of Energy Studies and a Visiting Professor in the Department of Geography at the University of Leicester. His recent outputs include: *Global Energy Dilemmas* (2014) published by Polity Press and the co-edited book *Global Energy: Issues, Potentials and Policy Implications* (Oxford University Press, 2015; with Paul Ekins and Jim Watson). He is currently involved in UKERC and Horizon 2020 projects examining the development of unconventional oil and gas.

Dr Harald Hecking is Managing Director of EWI Energy Research and Scenarios, a leading energy economic think tank in Germany. EWI seconded him twice to the IEA for co-authoring 2013 and 2014's Medium-Term Coal Market Reports. In his PhD research, he developed economic models for global and European coal, gas and power markets. These models were applied in several consultancy projects for the energy industry and political institutions as well as in peer-reviewed economic journals. With EWI, Harald Hecking is frequently publishing reports on security of supply and infrastructure developments on the European gas market as well as reports on developments around the German "Energiewende".

David Ledesma is an independent gas and LNG consultant focusing on gas and LNG strategy along the value chain including the structuring of commercial arrangements, financing and markets for pipeline gas and LNG projects. He is an experienced commercial manager with hands-on experience of developing and closing commercial gas transactions as well as developing business strategy. During thirty years in the energy and utility sector David worked on the development of complex integrated energy projects, negotiations at government level, and in the management of joint ventures. From 2000 to 2005, as Director of Consulting then Managing Director of the Gas Strategies Group (formally EconoMatters Ltd), David worked on and managed LNG and gas consulting assignments in around the world. David is a Senior Research Fellow of the Oxford Institute Energy Studies and has co-authored several gas and LNG books, and research papers. In May 2013 David was appointed as a Non-Executive Director of Pavilion Energy, a subsidiary of the Singapore investment firm Temasek Holdings. David gives numerous commercial training courses on gas and LNG in the UK and overseas, writes on gas and LNG and presents regularly at conferences.

Amrita Sen is the founding Partner and Chief Oil Analyst at Energy Aspects. Amrita leads Energy Aspects' analysis and forecasting of crude and products markets. Her specialism is in energy commodities, particularly oil and oil products. Amrita's deep understanding of the complex relationships within the global energy sector, her wealth of industry contacts and 10 years of experience, allow for a unique perspective on market outlook. She holds an MPhil in Economics from Cambridge University, a BSc in Economics from the University of Warwick, and is pursuing a PhD in Economics at the School of Oriental and African Studies, University of London. She is a Non-resident Senior Fellow at the Atlantic Council, a Research Associate at the Oxford Institute of Energy Studies and was formerly Chief Oil Analyst for Barclays Capital. She is frequently featured in leading media outlets, including the Financial Times, BBC News, Reuters, Bloomberg, CNBC, Wall Street Journal, and Sky News, and at leading industry events as a speaker, and is regarded as a leading authority on oil markets.

Professor Jim Watson is Director of the UK Energy Research Centre and Professor of Energy Policy at the University of Sussex. He has 20 years' research experience on climate change, energy and innovation policy. His recent outputs include co-edited books: *New Challenges in Energy Security: The UK in a multipolar world* (Palgrave, 2013; with Catherine Mitchell) and *Global Energy: Issues, Potentials and Policy Implications* (Oxford University Press, 2015; with Paul Ekins and Mike Bradshaw). He was an advisor to the Government Office for Science for a Foresight project on energy (2007-08), a member of the DECC and Defra social science expert panel (2012-16), and has been a Specialist Adviser with three Parliamentary committees. His international experience includes over ten years working on energy scenarios and energy innovation policies in China and India, and a period as a Visiting Scholar at the Kennedy School of Government, Harvard University. He is a member of the Strategic Advisory Group for the Global Challenges Research Fund and a judge for the Queens Awards (sustainable development).

Department for Business, Energy & Industrial Strategy
3 Whitehall Place, London SW1A 2AW
www.gov.uk/beis