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FOSSIL FUEL PRICE ASSUMPTIONS EXPERT PANEL

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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, as last, we had the added complication of currency fluctuations to deal with. 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 in the last two, the Fossil Fuel Price Projections Expert Panel (FFPPEP) was convened to work alongside the BEIS team responsible for this work. Two years ago Wood Mackenzie supplied a series of fossil fuel supply curves, this year the BEIS team presented evidence to support the view that these are still fit for purpose and they have been used again in the 2018 price assumptions. Again, 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 is adopted that reflected the key influences on the price for that fuel in UK markets. For oil, the short run (2018-19), 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. In previous years the BEIS central case short-term gas price assumptions were based on forward prices for a two-year time period. However, when the short and medium-term prices were re-calculated it resulted in a set of prices that are at odds with market sentiment. In consultation with the Panel, it was decided to extend the futures curve to 2020. The reasons for this are explained in both the BEIS report and this report. The short-term coal price assumptions (2018-19) 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, and 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, as explained above, the Wood Mackenzie supply curves for each fuel are used. 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 at the time was 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 2017,* which the panel believes is an appropriate source for this purpose. Following on from our report last year, this year the BEIS team has paid particular attention to the future demand outcomes of these scenarios relative to other forecasts and scenarios. 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. To arrive at a range of future fossil fuel price assumptions, BEIS has used the IEA's three scenarios: the new 'sustainable development scenario' that outlines an integrated approach to achieving internationally agreed objectives on climate change, air quality and universal access to modern energy; the '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 the 'new policies scenario' that assumes future planned policies to reduce emissions are implemented. The 'current policies' scenario supports the high price assumption, the ' sustainable development scenario' the low-price assumption and the 'new policies' scenario 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 and agreed that this remains 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.

[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

Furthermore, as this is the third year the current approach has been used a broadly consistent methodology has now been developed.

The Panel explored the current context for each fossil fuel and the potential interaction between the three fuels in UK, European markets and global markets. In the case of oil, the key uncertainties still 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. The situation in Venezuela remains uncertain and this year the central long run supply scenario has been reduced by 0.5 mb/d. The past year has seen a significant drawdown on storage and demand growth remains strong, thus the price has rebounded and the market is more exposed to unplanned outages and geopolitical risk. 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 expected over-supply of LNG in 2017/18 failed to materialise due to unexpected demand growth in China. However, the LNG market is still unlikely to re-balance before the early 2020s, though the size of "over supply' before this date is likely to be less than previously expected with strong gas demand from Asia, but could tighten thereafter unless there are significant new FIDs for LNG capacity soon. 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 2017 fossil price assumptions, the new set of assumptions reflect the fact that the fundamentals are different for each fuel, with varying degrees of uncertainty. In Annex A of their report, BEIS compare the results of the 2018 price assumption exercise with those of 2017. Overall, differences are modest, which reflects the fact that there has been little change to the fundamentals. In the case of oil, a slight increase in the short- to medium-term price reflects the longevity of OPEC production cuts, optimism surrounding economic growth and perceptions of geopolitical risk. The reduction of Venezuelan output has slightly increased the long run price in the central and low scenarios (by $5 in each case). In the short-to-medium-run the gas market is well supplied and this may lead to some additional price weakness during the period 2019-2020. Increased volatility is expected in the short-term with the potential rise in Asian LNG demand and there is some uncertainty over both supply and demand in the longer term. Initial analysis using the forward curve out to the end of 2019 (for the central and low prices) resulted in a range of prices that were at odds with other industry forecasts. As a result, this year BEIS have used to the forward curve to the end of 2020. This has resulted in a set of prices that are in line with wider market sentiment. Over the coming 12 months as new LNG projects move into production and the situation with China's gas demands becomes clearer, the level of uncertainty should be clearer, and, as noted above, thereafter the price may weaken. That said, China's announced 25% import tariffs will likely cause a rebalancing of the LNG market as non-US sourced LNG supplies China. It is not clear at this time what short and long-term impact there will be on the price and volume of LNG supply to Europe of this potential industry rebalancing. Finally, because the gas price assumption is in pence per therm, changes in exchange rates also impact on the price assumptions. In the case of coal, the short-term upward adjustments reflect an increase in coal spot and forward prices in late 2017, which sustained in the first half of 2018. The price increase can be reasoned amongst others with higher coal import demand from Asia, and especially China. In the longer term prices are slightly lower due to lower demand projections.

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 2017* 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 has 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 is now well established 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 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; and the strategies of major resource holders—in particular the OPEC states and Russia. 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 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 was reappointed in Autumn 2017 for a further two years. 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 January 2018 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 to the reports that were previously published in November of 2016 and 2017.[3] When the Panel was first convened, then DECC published price projections, they 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.

1.1 Terms of Reference

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

- Attend all Panel meetings (no delegation is possible);

[3] 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 and the 2017 report can be found at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/663102/2017_Expert_Panel_Final_Report.pdf

- 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 17th January 2018 and the BEIS team explained the purpose of the price assumptions and reviewed the methods used to generate them in light of the previous year's experience. Initial documentation was provided to the Panel ahead of the meeting and Summary of Actions was prepared after the meeting, which included additional input from members of the Panel. A second meeting took place 15th March February 2018 when members of the team discussed the initial price assumptions. A draft of the BEIS report was submitted to the Panel on 13th April 2018. The Panel then produced an initial draft of its formal publication for 20th April 2018. A third, and final, meeting took place 27th April to discuss the Panel's draft and hear the responses of the BEIS team. Following the third meeting, a final version of the formal report was produced for consideration by the BEIS Chief Economic Adviser for Energy and Market Frameworks. This final report also reflected on BEIS' quality assurance processes and includes the Panel's final conclusions and recommendations.

Given that the price assumptions are not actually published until November each year, at our final meeting we agree that if there are significant market changes and/or changes to the underlying data used by BEIS that result in a need to revisit the price assumption, then the Panel is available to comment on any revised set of assumptions. This year this has been necessary due to short-term market changes for all three fuels and a change in the exchange rate used to calculated the gas price in pence per therm. During July and early August a new set of price assumptions was produced by BEIS and made available to the Panel for comment. The report published by BEIS is based on those new calculations and this report reflects on the overall process and comments in detail on the revised price assumptions, not those that were initially calculated in April 2018.

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

First, 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 market, 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 2017.* This year BEIS has paid particular attention to the 'representativeness' of the IEA's various demand scenarios.

Second, reviewing the current context and longer-term 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—although these are increasingly global in scope—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 Assumption

Oil

As with the 2017 Fossil Fuel Assumptions, for the short run, the 2018-2019 price assumptions are based on the Brent futures curve. The futures curve is used for two years for the same reasons highlighted last year. 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 far outpaced consumer buying over the last few years. 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.

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 even though the short term oil assumptions have been raised compared to last year's assumptions driven by the extension of the OPEC-led production cut until the end of 2018. The panel also notes that as fundamentals have tightened materially over the course of the last 18 months, the backwardation in the oil curve has steepened (a sign of a tight market), which somewhat distorts the price calculations. Given the lack of inventory buffer and rising geopolitical tensions, in particular the decision by the Trump Administration to impose new sanctions on Iran—it is more likely that 2018 and 2019 prices may come in closer to the high case scenarios rather than the base case.

Gas

As with the previous two years, initially the BEIS's central case short-term gas assumption (2018-2019) was based on the forward curve with the low and high cases being derived using an implied volatility analysis. The liquidity of the UK National Balancing Point (NBP) forward market has in previous FFPA reports been viewed as sufficiently high over the initial two-year period to support this approach. The Panel's view has been that beyond two years liquidity drops such that it is considered that there may be insufficient liquidity to support the use of forward curve prices for future gas prices assumptions. However, when the central case was recalculated in July it produced a set of short-term prices that were at odds with market sentiment. The use of the forward curve was extended to 2020, rather than flat lining, as it was viewed that the liquidity of the NBP had increased over the past few years. This has resulted in a set of price assumptions that are more in line with the market. The high gas price case has not been "flat-lined", representing a case where demand in the European gas market rises faster than expected. Under this case, the market would tighten, absorb any surplus LNG, and gas prices would rise to attract additional gas and LNG supplies to meet the additional demand. These approaches are viewed as reasonable.

The NBP price used as the basis for the gas price assumptions is the average NBP price for the 30 trading days prior to the end of June when the forecasts and this report were finalised. The Panel discussed the applicability of using this 30 day pricing period, and were of the view that even though the period used is slightly later than the period used in 2017, due to changes in Asian spring gas demand (especially from China) and low European gas storage levels the period of lower priced European summer gas trading was delayed. It was viewed therefore that putting back the period for the basis of the gas price assumption would be prudent. The average (month+1) price for the 30 trading days prior to the end of the end June 57 pptherm ($7.7/MMBtu)[4]. This price, as a starting point for price forecasts over the period to 2020, was in line with the market at that time, but is higher than the 2017 FFFPA price for 2018 of 45 pptherm ($5.9/MMBtu). At this starting point, the forward curve may not reflect the weakness of additional LNG coming onstream of North America over the coming 18 months and assumes that the Asian market remains bullish to absorb these additional volumes. If this is not the case, and supply increases while demand does not increase as fast, then prices could be weaker and NBP could fall towards the floor price of US LNG into Europe[5].

There is considerable uncertainty in the market as to whether there will be an additional price weakness in the short to medium term due to additional LNG supply arriving in North West Europe from newly started-up North American LNG export projects. With increased Asian demand for LNG in 2017/18, and delays in start-up of the new LNG export projects, the market fundamentals have changed and are less bearish than they were in quarter two 2017 (when last year's FFPA report was drafted). Should the supplies arrive they would compete directly with Russian pipeline gas. In the case of this LNG arriving, some could be priced based on US LNG export cash cost price as US sellers seek to secure a market for its LNG and recover at least some of their costs. This price would represent the lowest price at which US exports would be exported[5] and could be a floor price for NBP gas. It was viewed that this floor would be broadly in line with the low price case. BEIS have tested their low gas pricing assumptions agains this and have found them to be consistent. Post 2021/2 it is assumed that the market will start to adjust to long-term supply/demand equilibrium.

As with the 2017 Fossil Fuel Price Assumptions, the low and high pricing cases have been developed using options volatility calculations that determine the likelihood that the market

[4] Converted to pence/therm using the market based exchange rate assumption of 1.35 US$/£ for 2018.

[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 in order to maximise profits without having to sacrifice sales volumes. At a US Henry Hub price of $3.00/MMBtu this should equate to an NBP price of ~ $4.15/MMBtu (30 pptherm at 2020 US$/£ exchange rate).

attaches to future price levels using a 75% confidence level[6]. This assumption is viewed as reasonable.

The linkage to US LNG supply, together with competition from Russia, Norwegian pipeline gas and the uncertainty over Dutch gas supply from the Groningen gas field, as well as uncertainty over gas demand in Asia and the newly developing LNG importing countries, means that gas price volatility is expected to be high in the short to medium term. That said, the gas price volatility should be contained in the annual average BEIS assumptions and within the low and high assumption cases.

Coal

BEIS bases its coal price assumptions for the short term, hence, the years 2018 and 2019 on spot and forward prices for ARA CIF[7]. Using these market prices is the best available approach to derive the short-term price assumptions for two main reasons: First, forward prices aggregate the market participants' available information and expectations. Second, they implicitly account for all arbitrage opportunities between the Asian and the European coal market. Therefore, spot and forward prices represent well the current context of recent market developments not only for the ARA market but also the interdependencies with the global market.

Similar to the approach applied in the oil and gas price assumptions and for the same reasons, as discussed in the BEIS 2017 Fossil Fuel Price Assumptions, only the next two years (2018 and 2019) are modelled using spot and forward prices. In coal markets, liquidity for forward products, especially for those beyond a 2 years horizon, is even lower than in gas and oil.

Thus, to derive the short-term coal price projections in the central scenario, the year 2018 is derived from an average of the Q1 and Q2 outturn prices and from the Q3 to Q4 forward prices. Forward prices have been derived from averaging forward prices for a 30-day trading period until 29 June 2018. Notably, the methodology has slightly changed in BEIS 2018 Fossil Fuel Price Assumptions compared to last year's approach, which used a 30-day trading period until the end of March and not until the end of June. Averaging year ahead forward prices for 2019 averaged over the same 30-days trading period yields the 2019 price.

Due to limited data availability and unlike for oil and gas, it is reasonable not to apply the option price approach for coal. Instead, historic deviations of forward and realized coal prices for a 10-year period between 2008 and 2017 are derived and used for modelling the low and

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

[7] 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.

high scenarios. For that purpose, the low scenario subtracts 1 standard deviation from the central scenario, whereas the high scenario adds 1 standard deviation.

Overall, the choice and use of both, methodology and data, is a plausible and most suited way to model price assumptions for the years 2018 and 2019.

2.2 Data sources and Long Run Supply Assumptions

For the long run supply assumptions, two years ago, Wood Mackenzie was commissioned to produce supply curves for each fuel[8]. This year BEIS presented evidence on recent cost trends in oil and gas exploration and development that suggest that it is reasonable to assume that the original 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 2017*. 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.

For each fuel, Wood Mackenzie developed a 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.

Oil

This year, the original Wood Mackenzie supply estimates have been modified to reflect the latest developments in the oil sector. The production outlook for Venezuela has been further reviewed, in light of the most recent developments (see below). In the Central scenario the expected productive capacity for Venezuela for 2030 is set around 2.6 million barrels of oil per day (mb/d) – a reduction of 0.5 mb/d compared to our 2017 outlook for 2030.

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

Box 1: Note on Venezuela

Venezuelan oil production and exports have been on a steady downward trend since 2017. The signals emerging from Washington point to rising risks of the US imposing further sanctions, possibly imminently. The disarray in Venezuelan politics and finances continues to worsen and it seems even Russia may be tired of providing a lifeline to the Maduro regime.

There is widespread agreement that Venezuelan output has fallen rapidly in recent years, but views diverge over current output levels, partly due to big swings in recent direct communication numbers. Fluctuating exports in recent months add to the confusion—loadings fell to around 1.2 mb/d in December 2017, recovered somewhat (month on month) in January after PDVSA was able to purchase some diluent, but have slipped back again in February. Currently, Venezuela's production is likely below 1.5 mb/d, a far cry from the 2.4 mb/d it produced even in 2016.

The possible decline on Venezuelan output could be even greater should the US decide to impose sanctions and how much wiggle room they leave. For instance, if the US bans crude imports from Venezuela, cargoes could be diverted to other destinations. Venezuela may be testing the waters for this already offering smaller size cargoes earmarked for Asian buyers alone. Meanwhile, if the US bans naphtha exports, PDVSA would need to turn to alternative sources such as Europe or the FSU, and while this would raise costs it would also leave US refiners to find an alternate home for their naphtha (which tends to be swapped for cargoes of blended Venezuelan crude)—this could hurt the US side as much, or even more, than Venezuela.

Quality issues, financial restrictions and the potential for tougher sanctions have already led some US Gulf Coast refiners to diversify—December 2017 imports totaled just 0.44 mb/d, the lowest monthly average since January 2003 during the PDVSA strikes, and EIA weekly data show flows falling further to 0.43 mb/d in January and 0.38 mb/d over most of February. At the same time, exports to India are running at around 0.4 mb/d, below the 2016 average of 0.47 mb/d and the peak of 0.66 mb/d, so there is scope for Indian refiners to raise imports, especially if PDVSA offers discounts, which have to be hefty given the deterioration in quality. Chinese imports have held up better, underpinned by flows tied to loan repayments, but at just over 0.4 mb/d are still below the peak of 0.55 mb/d. This is why we believe restrictions on shipping insurance could have a greater impact, by complicating exports to all destinations unless governments are willing to step in and underwrite insurance.

A final noteworthy development is the possibility that Russia has joined China in tiring of being the lender of last resort for Venezuela. Russian firm Rosneft has lent Venezuela over $6 billion in recent years, although the outstanding total had fallen to around $3.15 billion in November 2017 when the two sides agreed to restructure repayments over a 10-year period to try and ease the financial pressure. These loans include $1.5 billion lent in 2016 which was collateralised by a lien over 49.9% of PDVSA's US refining subsidiary Citgo. Russia already signalled late last year that it had no plans to offer more loans. But it now emerges that since October 2017 a group of US investors has been seeking agreement to buy out this Rosneft loan and lien right. This would avert potential diplomatic fallout as the Committee on Foreign Investment in the US (CFIUS) was unlikely to agree to Rosneft taking a large stake in a US refiner. But more significantly, in our view, it suggests Russia may be trying to wind down its financial exposure to Venezuela—while it may also represent Rosneft trying to release some cash, the loans were clearly a political as well as financial tool. If Russia is indeed reducing its exposure to the Venezuelan crisis, then it leaves Maduro extremely exposed financially, particularly if the US manages to further restrict oil revenues through sanctions.

Gas

The gas price for the North West European market is based on gas supply/demand[9] with the lowest cost gas and LNG supplier setting the marginal supply price in Europe. As with last year, BEIS's central case gas price assumption assumes that the gas market is moving towards a long-term equilibrium based on the expected cost of marginal gas supplied to Europe, at projected levels of European gas demand. This uses the Wood Mackenzie cost of supply curves that were developed in 2016 and it is viewed that there are no fundamental changes in the long term outlook for gas supply so that the curves are still viewed as reasonably reflecting the market. The BEIS long-term analysis also includes a downside "low prices" case that reflects demand weakness as a result of greater renewables penetration and an upside "high prices" case where gas demand rises reflecting greater use of gas as an alternative to coal and oil.

A key question is the timing of additional LNG supply. With the development of US LNG export projects, and the start-up of LNG projects in Australia and Russia, it was expected that additional global LNG supply could lead to some price weakness in 2017/18. This has not materialised, primarily due to the unexpected increase in Chinese gas demand and therefore LNG demand with China's LNG imports in 2017 being 42.3% (11.6 MT) higher than the previous year.[10] This was a massive increase that was not expected by the market, and resulted in less LNG arriving in Europe. In response, Gazprom increased sales of gas into Europe (7.8% up on 2016 sales) to meet additional gas demand and to make up for shortfalls of gas production from the Netherlands and LNG shortfalls[11]. However, 2018 and more specifically 2019, will see a material growth of US LNG exports and it is expected that additional LNG volumes will be supplied to the European market, potentially weakening gas prices. As noted in last year's report, a key uncertainty is the behaviour of the Russian gas supplier Gazprom, which has historically been the largest gas supplier to Europe. Specifically, with rising LNG supplies, the question is will Gazprom 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?

Dutch gas production from Groningen has continued to fall as a result of increased production caps being introduced by the Dutch government, and could fall further still. Norway is also a critical supplier to Great Britain (GB). In 2017 Norwegian net gas production reached a record high of 122 Bcm in 2017, exceeding the official projections of the Norwegian Petroleum Directorate (NPD) which, in January 2018, made upward revisions to its projections such that current production levels are now expected to remain until 2022

[9] In 2017, the IGU estimated 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 70%.
[10] GIIGNL "The LNG Industry in 2018" https://giignl.org/sites/default/files/PUBLIC_AREA/Publications/rapportannuel-2018pdf.pdf
[11] http://www.gazpromexport.ru/en/statistics/

reducing to 90-92 Bcm pa in 2030-35. In its March 2018 paper, the OIES noted that "meeting projected production between 2027 and 2035 will depend on maintaining the current level of exploration activity, on future commercial discoveries of gas and on continued improvement of recovery rates at producing fields", but concluded that: "The position of Norway as a reliable and competitive supplier of both contracted and flexible gas to NW Europe appears to be secure for the foreseeable future"[12]. The availability of Norwegian gas imports gives GB additional supply security, while falling Dutch production increases long-term gas supply certainty. It should also be noted that the closure of GB's largest gas storage facility, Rough, in 2017, reduces flexibility in the GB gas supply system, but GB continues to have access to a diverse source of supplies.

From 2030-2040 gas prices are flat-lined due to the uncertainty over gas supply conditions post 2030. During this period energy efficiency, greater renewables penetration and enhanced use of technology should mitigate the need for new expensive sources of gas supply. In the low demand case, this will lead to lower gas prices that should be nearer to the "low prices" case.

Coal

Concerning BEIS's medium term coal price assumptions (2020-30), the approach assumes a flat-lining of the 2019 price assumptions for the year 2020 for all scenarios. 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, central and high scenario until 2020 and that, second, after 2020 the coal market moves again towards a long-term equilibrium.

Long-term equilibrium prices of 2030 are derived by the same approach as in BEIS Fossil Fuel Price Assumptions 2016 and 2017. 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 BEIS Fossil Fuel Price Assumptions 2016. These curves cover the main uncertainties of the global coal market and remain useful to be used in this year's analysis since there have no substantial changes in the cost structure of the global coal mining companies (see for example IEA Coal 2017).

For the years between 2030 and 2040 all scenarios assume a flat development of coal prices reflecting that there is no information available that justifies any other price development.

[12] Hall, M, (2018). 'Norwegian Gas Exports: Assessment of Resources and Supply to 2035', Oxford Institute for Energy Studies (OIES) NG 127.

2.3 Long-term demand data sources and assumptions

As was the case for previous version of the assumptions, future demand projections have been taken from the latest International Energy Agency *World Energy Outlook* (WEO). This was published in November 2017. This publication is an established and respected annual source of global analysis, which uses the IEA's World Energy Model to explore scenarios for the global energy system. The IEA is sometimes considered to be relatively conservative with respect to their analysis of renewable energy deployment. Whilst this has been addressed to some extent, successive outlooks by IEA and some other organisations have continued to underestimated the rapid growth of renewable energy[13].

The IEA develops and publishes three scenarios for the global energy system each year that represent a range of potential futures. These include 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. These policies fall far short of limiting emissions to meet the 2°C target. The more ambitious third scenario in the 2017 WEO is different to that in previous years. This 'sustainable development scenario' is designed to meet the sustainable development goal of universal access to electricity and clean cooking by 2030 – and the Paris Agreement's objective to limit the average global temperature increase to 2°C.

BEIS have compared the demand for fossil fuels within the IEA scenarios to demand in other global scenarios or projections. A positive development this year is that the range of comparators is wider than was previously the case, with a more diverse range of sources. They include scenarios published by:

- The US Energy Information Administration (EIA);
- Oil companies: BP, Shell, Statoil and Exxon;
- Independent research organisations: UCL / UK Energy Research Centre and the Institute of Energy Economics Japan. For the first time, these include scenarios that limit the average global temperature increase to 1.5 degrees; and
- Other organisations: Carbon Tracker and DNV GL.

The BEIS report also uses a number of other scenarios 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, the majority of other scenarios include oil displacement within a range between the IEA new policies and sustainable

[13] A summary of some comparisons is available here: https://ftalphaville.ft.com/2017/05/24/2189189/guest-post-why-iea-scenarios-should-be-treated-with-extreme-caution/

development scenarios. The only scenario that has a slightly higher displacement than the IEA sustainable development scenario in 2040 is BP's new 'ICE ban' scenario. This scenario is designed to explore a future where the sale of internal combustion engine vehicles is banned by 2040.

Some caution should be exercised when comparing scenarios since they use different methodologies and assumptions. 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[14]. 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.

The BEIS report summarises these comparisons in Annex B, using standardised units for each fuel. For the case of oil, most comparisons are expressed in terms of total liquids demand, which includes biofuels as well as oil.

Most other scenarios for liquids demand in 2030 are within the range of the IEA scenarios (92 to 112 million barrels per day). Statoil's high demand scenario is slightly higher (115 mb/d), whilst two of the recent scenarios by UCL and UKERC include significantly lower demand in 2030 (81 and 86 mb/d respectively). The lowest demand is from a scenario that aims to model a pathway towards the Paris Agreement's 1.5-degree target. If this demand figure is combined with the high supply curve, it would suggest a long run price that is closer to $50 per barrel than the $60 level in the BEIS low price assumption. Whilst, as was the case last year, a lower price of $35 per barrel is taken into account via a 'stress test', this illustrates the importance of considering future scenarios in which liquids demand is significantly lower than the level in the IEA sustainable development scenario.

The comparison of global gas demand scenarios for 2030 shows that the IEA current policies scenario has the highest demand of all scenarios (4720bcm in 2030).[15] However, at the lower end, there are a large number of scenarios with global gas demand that is lower than the IEA sustainable development scenario (4269 bcm in 2030). These include scenarios from BP, EIA, Statoil, UCL/UKERC and IEEJ. Several have demand that is around 10% lower (3652-3744 bcm in 2030), all of which are designed to meet ambitious climate mitigation goals.

A further important feature of the IEA scenarios is that they include a relatively narrow range of medium-term gas demand in China. Gas demand ranges from 374 mtoe to 395 mtoe in 2030, up from 172 mtoe in 2016. As discussed earlier in our report, gas demand in China

[14] 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

[15] See figure 5 in the BIES (2018) reports for a comparison of gas demand scenarios for 2030.

increased more quickly than expected in 2017 – with LNG imports up over 40% when compared to 2016. This could signal a break with the past trend of modest demand growth in China, and suggests that the IEA scenarios are not capturing a wide enough range of uncertainty about the future.

The important comparison, which is more difficult to make, is between the gas demand figures for Europe in these scenarios. Disaggregated data to make this comparison is not always available. Furthermore, different scenarios use different definitions of 'Europe' which makes comparison difficult. As the BEIS report notes, the high supply curve for gas is relatively flat at the point where it intersects the IEA low demand figure for Europe. If European demand were around 10% lower, the low price assumption would be the same. As BEIS also note, it is possible that European gas demand could be more constrained than demand in other regions of the world in a scenario where stringent climate targets are met. Whilst the impact of lower demand on prices is very uncertain, this suggests that consideration should be given to the possibility of a long run price that is lower than 36p/therm.

The comparison of European coal demand scenarios shows that the IEA sustainable development scenario has the lowest demand in 2030. However, several of the scenarios that include ambitious action on climate change are missing from this comparison, presumably due to lack of specific data on European demand; but there are two scenarios that have significantly higher coal demand in 2030. The IEEJ reference scenario has 50% higher demand than the IEA current policies scenario, partly because it includes a large geographical area (including Eurasia). The impact of higher demand on the high price assumption may be limited, however, because the relevant coal supply curve is flat at the point where it intersects IEA current policies demand.

Overall, the IEA scenarios cover a fair range of long-term demand for oil, gas and coal. The main uncertainty is for oil and gas, where demand could be lower than the levels within the IEA sustainable development scenario. This is a more pronounced uncertainty than in the last two years, partly because there are now more scenarios which aim to be compatible with the Paris Agreement '2 degree' limit on global temperature increases. It is also partly because this year's comparison also includes a more ambitious scenario that examines the consequences of a pathway towards a 1.5-degree limit. This suggests a continuing need to scrutinise the lower end of the range of fossil fuel demand within IEA scenarios, and the consequences of lower demand for future price assumptions.

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 1: Front-month Brent crude prices, 2008-April 2018, $ per barrel
Source: Reuters, Energy Aspects

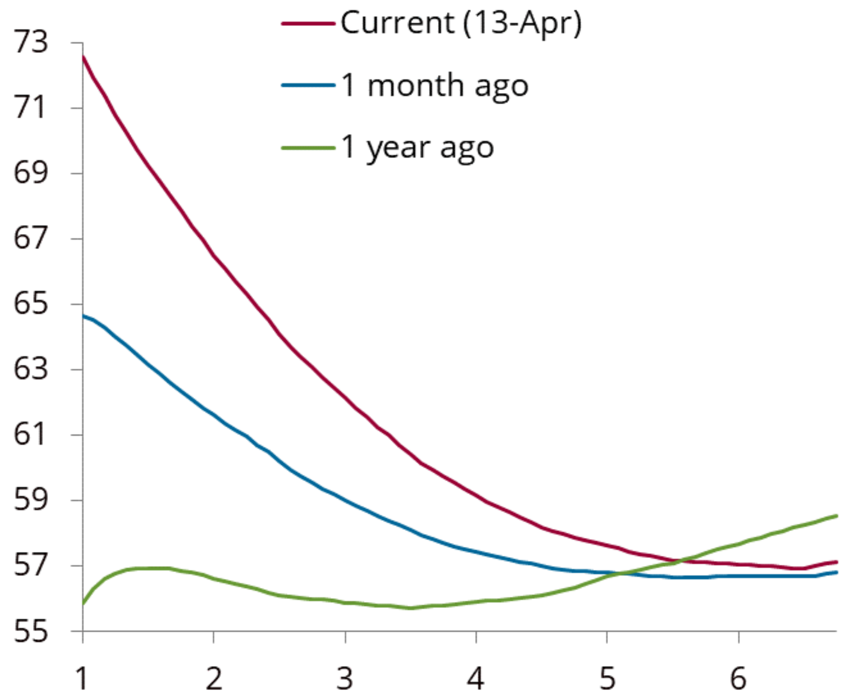

Figure 2: Brent forward curve, April 2018, $ per barrel
Source: Reuters, Energy Aspects

Context

The oil market was on a strong footing entering 2018. The single biggest fundamental difference between now and any outage since late 2014 is inventories, or the lack thereof. Around two years ago, OECD inventories were a massive 350 mb above the five-year average and the global inventory overhang was close to its peak of 600 mb. Today, the global inventory overhang is no more. Adjusted for the growth in linefill and tank bottoms and the stupendous demand growth that we have seen, on a days of forward cover basis, inventories are now below the five-year average. For instance, over Q1 18, US commercial liquids inventories fell by 40 mb. The overall commercial inventory draws stand in stark contrast to the nearly 45 mb average build in Q1 in the last three years. During the tight years of 2013 and early 2014, the respective Q1 drawdowns were 18 mb and 15 mb, while stocks rose by 26 mb in Q1 2012. So, without a Q1 2018 buffer, the inventory overhang now effectively eroded and expected stockdraws from Q2-Q4 2018, the market is likely to be increasingly sensitive to rising geopolitical risks. And there are plenty of them around, especially following the Trump Adminstration’s decision to re-impose sanctions on Iran and growing trade friction between the US and China.

With inventories low, unplanned outages and geopolitical risks will matter again, and because of this, prices can rise disproportionately to the actual scale of outage. And that is what is happening now (Figure 1). So, there is good reason for oil to trade with an upside bias (Figure 2), as the current fundamental backdrop is, for the first time in years, robust enough to attract new investors to the space. In turn, backwardation, driven by falling inventories, can become self-reinforcing.

Key uncertainties

Supply: The biggest uncertainty in the oil market today is about how a US decision to reimpose sanctions would impact Iranian oil exports. Trump announced the US would re-impose all the sanctions it has waived under the JCPOA, following either a 90-day or a 180-day 'wind-down' period—6 August and 4 November respectively. Buyers will have to 'significantly reduce' purchases during the initial six months to be granted an exemption to continue purchases after 4 November. This prevents buyers from boosting purchases now to create a higher baseline. In addition, Iran will be restricted from acquiring dollars after 90 days, forcing transactions to switch to alternative currencies (euros, yuan, etc) or other arrangements such as barter. Sanctions on investment in Iran's energy sector, which will once again close the door on western investment in Iran's upstream and downstream.

In essence, this reapplies the full weight of US secondary sanctions that were eased through the JCPOA. Even without supportive multilateral measures from the EU, UN, etc, the US restrictions will have a significant impact on Iran's oil exports and whole energy sector. In particular, the requirement for buyers to reduce oil purchases during the next 180 days means Iranian exports should start to decline by Q3 18—over Q4 17 and Q1 18, Iranian crude oil and condensate arriving at destinations averaged 2.55 mb/d, as issues at various South Pars phases impacted volumes during this period. This means a 20% cut (for the sake of argument) would amount to 0.51 mb/d. It's still unclear what impact the shipping and insurance sanctions will have on volumes, but if we were to see a repeat of the previous sanctions regime, there is a risk of a much bigger impact on volumes like last time.

Even assuming China does not fully comply the initial reduction could well exceed 0.4 mb/d and, given shipments are already on the water, the reductions may be more heavily weighted towards July-October. With the US adopting such a forceful tone, and no hint of special treatment for EU countries, most buyers will err on the side of caution and compliance. Refineries are likely to start sourcing alternative supplies.

Some of the uncertainties highlighted last year remain. The plentiful supplies thesis based not just on seemingly unstoppable US shale production growth but also on the belief that underlying decline rates in conventional production have somehow been arrested despite sharp cutbacks in oil industry spending, something that is touted aggressively by producer CEOs, is starting to falter. Output from every single country outside of the US and Canada has been underperforming since Q4 2017, as decline rates have stepped up sharply.

One can infer a decline rate of 8–10% per annum in Conoco's conventional production from its recent investor day presentation. Exxon and Shell showed a similar dramatic decline in their outlooks. Likewise, Occidental Petroleum disclosed it must use 58% of its 2018 capital programme to sustain its output with a decline rate assumption of 15%. Colombia's

Ecopetrol is experiencing an even tougher test as it grapples with declines at its mature onshore fields. This year it will raise Capex by 30%, yet it expects production to be flat y/y—a 15–25% underlying decline rate at its fields is the driver. Brazil’s declines in the Campos basin are similarly steep, with new pre-salt FPSOs unable to provide an offset to these falls. In 2016 and 2017, non-OPEC production (ex-US and Canada) declined, but the fall was small, leading to the widespread belief that decline rates are being arrested or that there are plenty of new projects offsetting conventional declines. But since 2015, producers have sought to manage an acute cash-crisis by raising production at existing assets. This may have lowered decline rates temporarily, but it has led to a spike in reserve depletion rates. These factors could lead to higher prices in the future.

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 1.7 mb/d in 2016 and in 2017, oil demand growth is set to grow strongly again, by at least 1.7 mb/d. India in particular is a bright spot despite demonetisation while Latin American economies are recovering. The IMF is maintaining an upbeat forecast for global economic growth in 2018-19, but it notes higher downside risks as a result of trade disputes involving the world's largest economies. Perceptions of escalating tensions over trade between the US and China already may take a toll, even as trade flows remain strong across the globe. 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. But petrochemical demand is set to continue to grow as urbanisation continues.

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 Saudi-Iran rivalry has already spawned various proxy conflicts, from the wars in Yemen and Syria, the Qatar crisis, and political instability in Lebanon. Unprecedented changes in Saudi Arabia are not helping. Crown Prince Mohammed bin Salman is pursuing ambitious domestic reforms, consolidating power and is determined to isolate Iran. This leaves little margin for error, and raises the importance of higher oil prices for Saudi Arabia.

Regulatory changes: The switch to 0.5% sulphur bunker fuels from 1 January 2020 mandated by the International Maritime Organisation (IMO) in late 2016 is rapidly moving to being a reality. All product specification changes cause shifts in prices and volatility and IMO 2020 may well be one of the biggest ever. IMO 2020 eviscerates the last big Sulphur sink in the refined products world and will force refiners to produce a greater proportion of clean products than ever before but at the same time of getting rid of fuel oil—which is an insurmountable challenge in the near term. Getting more clean products out of the same refineries means greater competition among all products for space in secondary units such as hydrotreaters. Effectively, this means the marine fuel sector will soon be in competition with other consumers of clean fuels, be they gasoline consumers or diesel consumers. This means higher prices. The panel recommends further investigation into this issue.

From 2020, bunker fuel content will be capped at 0.5%. HSFO demand approximately 4.2 mb/d currently. Scrubber take up rates will be capped at well less than 10%. Currently there are 1,500 scrubbers installed worldwide, according to ship design consultancy Foreship, a number they think could reach up to 4,000 by 2020, a fraction of the roughly 120,000 million ships in the world, given dock space restrictions and other challenges. So, scrubber adoption will clearly not be enough for business as usual. And even assuming a substantial amount of cheating and some switching to LNG by 2020, the sheer size of the marine fuel oil market (approximately 4 mb/d) means that even a partial switch (likely to be 50-70% at least) to marine gasoil will have a huge impact on the oil market. While LNG may seem like the cleanest option, the cost associated with retrofitting existing ships with LNG is extremely high, especially when bunkering ports have not installed the necessary infrastructure.

So, refiners will need to adapt to a huge change in demand patterns. Price will need to do the work to make this happen. The crudes with the most Sulphur and highest fuel oil content will need to be made cheap enough to get into the most sophisticated refineries, while refiners who have not made the changes necessary will need to fight for light sweet crude or face closure. The laggard plants who have made few investments to deal with the oncoming crisis, by and large state-owned refineries in Latin America, the FSU and elsewhere, will probably be forced to cut runs as economics deteriorate. This means that clean fuels output may well fall too. Indeed, given the very attractive returns that are likely to be available from even partially desulphurising heavy fuel oil, marine fuels demand will compete heavily with gasoline for space in VGO hydrotreaters, for instance. Gasoline markets could therefore find themselves priced out of VGO-making capacity at times. This is one reason why all clean fuels will have to rise in price. Of course, higher prices for fuel will drive efficiency gains across many vehicle categories, but high prices will need to hit consumers first.

The real challenge for the market will come not in 2020 but in 2019, when pricing for fuel oil and crude will be heavily skewed by refiners' fears over what 2020 will look like. While ship owners can be expected to burn fuel oil right up until 31 December 2019, buying patterns further up the supply chain will change long before then. Bunker fuel sellers can be expected to slash purchases, likely from mid-year, as they will need to clean out infrastructure. Far from backing down on its commitment to cleaner fuels regulation, the IMO is strengthening rules to improve compliance, and this is going to ensure it kicks off the IMO 2020 process long before 1 January 2020. A proposal to ban the carriage of high-Sulphur fuel oil by ships that are not fitted with scrubbers is working its way through the IMO regulatory apparatus, which, barring a few minor amendments, has passed. These sorts of measures will encourage shippers and bunker sellers to start to shift their business towards the use of IMO-compliant fuel in time for the 2020 deadline, which will trigger a massive effort to destock higher-Sulphur fuel oil inventories before the end of 2019.

3.2 Natural Gas Price Assumptions

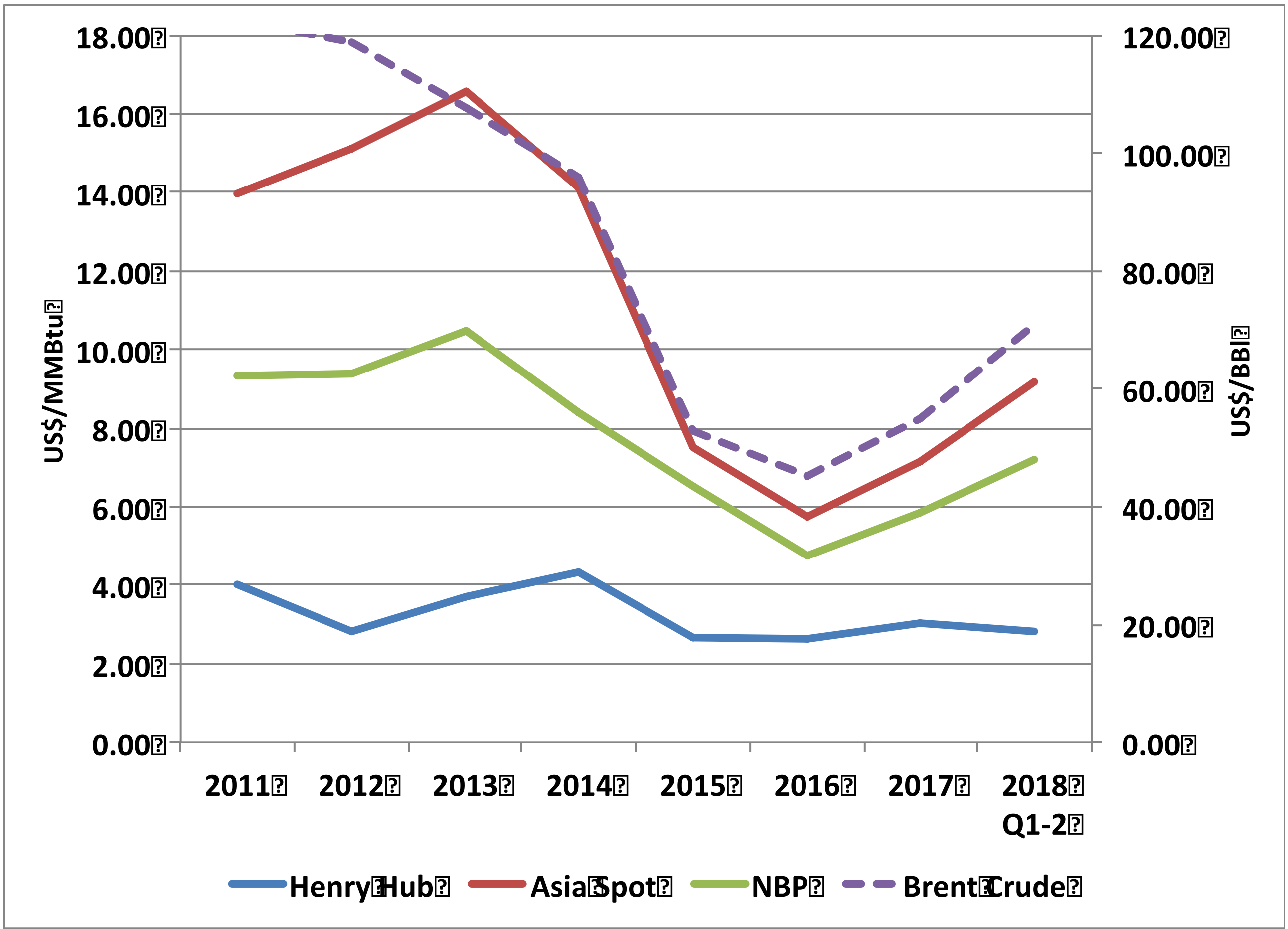

Figure 3: Trends in natural gas prices 2011 to end March 2018
Source: Heren

Context

With no global price for gas and LNG, gas price formation is based on regional markets. That said, increasingly cross regional LNG flows have enabled gas to move easily linking supply and demand. This has led to increasing price convergence, as shown in Figure 3. It also means that LNG, as a truly global commodity, will move to the market that pays the highest price. 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, price volatility is expected as short-term demand fluctuations pull LNG to specific markets. Asian demand for short-term cargoes will directly impact on market based gas prices in North West Europe. This was seen in winter 2017/18 where unexpectedly high Chinese gas/LNG demand led to higher than expected Asian LNG spot prices and UK NBP prices, and an increased premium of Asian LNG vs. NBP when compared to the two previous winters.

Table 1: NBP and Asian LNG spot average prices (November to February)

$/mmBtu	NBP	Asian LNG Spot	Asian LNG vs. NBP
Winter 2015/16	4.95	6.45	+ 1.50
Winter 2016/17	6.25	7.90	+ 1.65
Winter 2017/18	7.40	10.10	+ 2.70

Note: Average of Heren Daily Assessments (Month+1) rounded
Source: Heren

Global LNG is priced in US Dollars while GB gas prices are in pence per therm[16]. As noted in the 2017 Fossil Fuel Price Assumptions, following the EU referendum in June 2016, Sterling's value fell considerably against the US Dollar. The 2016 and 2017 Fossil Fuel Price reports uses the OBR's exchange rate assumptions which have changed over the past three years. The 2016 report assumed a long term (2030) exchange rate of £1 = US$1.529[17] while the 2017 report assumed a 2030 rate of £1 = US$1.313, a 14.1% depreciation. The 2018 report however has been based on the market (using the average of 10 days forward exchange rates (market data) over the period 18th to 29th June 2018 and uses a 2030 rate of £1 = US$1.42, an 8.1% appreciation in Sterling. The impact of this appreciation is to reduce the price of GB domestic gas in Sterling terms. Further exchange rate volatility will correspondingly increase or reduce the cost of gas in GB, in local currency, adding additional uncertainty to GB domestic gas prices.

Global gas supply and demand is facing considerable uncertainty. In 2017, global output of LNG was 396 Bcm (289 million tonnes)[18], 9.9% higher than 2016, and by 2020 the industry is expected to be producing 530 Bcm (385 million tonnes) LNG. Half of this new supply will come from North American LNG supply projects that also bring more contractual flexibility than traditional LNG contracts with ~ 40-45% all cargoes traded in 2020 being contractually flexible and this will drive more liquidity and shorter-term LNG cargo trading[19]. The use of financial instruments to manage Asian LNG price risk has grown dramatically, and in March 2018 Platts reported that 36 full LNG cargo equivalents were traded based on the JKM[20] swaps price, up from almost zero in 2014. Though this still only represents a small volume

[16] 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.
[17] 2016 methodology used the previous calendar year's average exchange rate
[18] GIIGNL "The LNG Industry 2018"
[19] GIIGNL estimated that in 2017 spot LNG (defined as cargoes with contracts of less than 3 months duration) represented 20% LNG trade, compared to 18% in 2016. Source: GIIGNL "The LNG Industry 2018"
[20] JKM – Platts Asian LNG spot reported LNG price the "Japan Korea Marker"

vs. total LNG trade, it does provide an important financial instrument that will underpin greater cross regional LNG trade.

This increase in LNG supply is happening at a time of global energy demand uncertainty. The dramatic increase in Chinese gas and LNG demand (a 42.3% increase in LNG imports 2017 vs. 2016) should be compared against the statement in last year's report where reduced energy demand by China had resulted in a short-medium term surplus of committed LNG. The announcement by the Chinese Government in August 2018 that it was planning to impose 25% import tariffs on imports of LNG from the USA adds a further level of demand uncertainty. The position in Japan, the world's largest LNG market, also remains uncertain due to the lack of clarity over the pace of nuclear restarts, deregulation in its energy market, the pace of renewables penetration, and the impact of energy saving measures. Likewise LNG demand growth in Korea, Taiwan and South East Asian countries is also uncertain, as is the potential for growth market of the price sensitive Indian market. The newer markets of Pakistan and Jordan have given additional LNG demand support while Egypt, a huge growth market in 2016/17, has, since December 2017, reduced its imports as domestic gas production has increased with new reserves being found and developed in the country. With higher than expected LNG demand in winter 2017/18, together with delays in start-ups of new US LNG exports in North America, gas prices have remained firmer than expected. As new North American LNG export projects commence production at the end of 2018, 2019 and 2020, prices could fall as sellers seek to secure markets and, potentially, could be forced to marginal cost[21] their gas and LNG supply until prices are too low to support marginal costs. The NBP price could therefore fall to the lower end of the FFPA range. Gazprom's strategy is unclear and discussed below, but it is likely that it will seek to maintain volume sales to Europe which could weaken prices further as their cost of supply is low and this could 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[22] by 2018/19, in a period of potentially low prices. In parallel, new countries are seeking to import LNG for economic reasons, moving away from oil, and for environmental benefits. The IMO's decision to implement a 0.5% sulphur cap on marine fuels[23] will, no doubt, increase demand for LNG as an alternative low sulphur (and low NOx[24]) fuel. The level of LNG demand for ships bunkers and the rate of demand growth is unclear. However, the reiteration by the IMO on the 1st January 2020 that the deadline for the sulphur cap will not be delayed, and that the IMO is also studying other potential emissions restrictions, means that LNG is a preferred alternative fuel for shipping. In its World Energy Outlook 2017, the

[21] 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.

[22] 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.

[23] International Maritime Organisation

[24] NO x is a generic term for the nitrogen oxides that are most relevant for air pollution, namely nitric oxide (NO) and nitrogen dioxide (NO_2).

IEA forecasts LNG bunker demand in 2030 at 19 mtpa (New Policies Scenario) or 30 mtpa (under its sustainable Development Scenario).

If FIDs do not take place to meet existing and growing demand then the market may face a tightening of LNG supply, and a potential rise in gas prices. At present, the likelihood of new LNG FIDs, of sufficient volume, is low. As such, price rises in the early to mid 2020s are likely with short-term price spikes.

Key uncertainties

The 2016 and 2017 Fossil Fuel Price Assumptions set out a full list of uncertainties, this report updates the points made in that report:

Global gas demand: natural gas is expected to grow faster than oil and coal, growing by 1.6% p.a.[25] between 2015 and 2035, with China, the Middle East and the US being the primary growth regions in both the industrial and power sectors. In its 2018 Outlook, BP also noted that growth may fall to 1.1% p.a. under its “less gas switching” scenario. Higher gas demand for LNG globally from high growth Asian countries could remove the surplus of LNG available to Europe over the next five years. In the longer term, higher prices could lead to demand destruction and this, together with greater use of renewables as countries drive their strategies for lower-carbon economies, could lead to lower gas demand and potentially lower prices.

Gazprom’s strategy: if Gazprom targets to maintain volume sales into Europe as LNG supply increases in 2019/20 then this could lead to additional price weakness in Europe. Likewise, a price-based strategy may result in higher price levels.

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: earthquakes related to the Groningen gas field have resulted in the Dutch government reducing gas production from the field by 60%. In March 2018, the Dutch government announced that it plans to halt production altogether by 2030 to limit the danger posed by earthquakes.

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.

Rising oil prices: should oil prices stay 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

[25] Source: 2018 BP Energy Outlook.

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.

Asian LNG demand growth: if Asian LNG demand does not grow in line with additional LNG production, then this could drive further price weakness. The effect of the imposition of LNG import tariffs by China is not known at the time of writing this report. If the market rebalances cargoes such that non-US LNG moves to China while US sourced LNG moves to non-Chinese buyers then the impact on pricing may be marginal in the long-term. If the market does not “naturally balance” then the impact could be higher Asian spot LNG prices and increased price volatility.

Disruptions to the market: short-term disruptions to 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, this could result in a supply shortfall. Qatar, and other LNG supply countries, have ambitious plans to develop new LNG production capacity. Such projects need to be underpinned by market demand and it is expected that only the lowest cost LNG projects, and those with political support, will move ahead. The imposition of LNG import tariffs by China may encourage the development of non-US projects if Chinese buyers underpin such investments.

Assessment

The basis and factors behind the calculation of BEIS’s 2018 Gas Price Assumptions are viewed as sound. The use of the NBP forward curve in the short term (three years), then “flat lined”, and the use of linear interpolation to the long-term equilibrium price based on the marginal cost of gas supply (for the central and low price cases) in the medium-term and later longer-term flat lining seems reasonable. The use of a market based exchange rate, based on the June 2018, market rather than the OBR’s annual forecasts, is seen as prudent as Sterling has remained weak and the US$/£ exchange rate has such a major influence on the cost of imported LNG into the UK market. For the period 2018-2019, the low price case is roughly inline with the lowest US LNG export cash cost price, depending on the Henry Hub gas price level, which represents the lowest price at which the US will export gas. 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 period post 2030 remains uncertain as the role of gas in global and European energy transition to a low carbon economy is uncertain and, as noted by BEIS, flatlining is a simplification. That, it seems, is a reasonable approach.

Two key uncertainties are whether new FIDs will be taken for additional LNG export capacity, and the level of gas production from Norway and the Netherlands. It is not clear how many of the planned LNG projects will proceed and when. If sufficient FIDs are not taken, then gas prices could rise to the higher end of the range. In the long-term, the market must pay the full cost of marginal LNG supply otherwise investment in new supply capacity will not be made. The level of the BEIS central long run gas price assumption of 63 pptherm, 2018 prices in 2030 ($8.98/MMBtu) should support the economics of new LNG capacity FIDs. In the longer-term, the role of gas in a de-carbonising world is not clear, and 2030+ may see some price weakness should gas's role reduce giving way to greater renewables and other clean sources of energy. Such a scenario is akin to the "disruptive transition" referred to in paragraph 8 of the FFPA report.

There are a considerable number of uncertainties across the whole period of the Fossil Fuel Price Assumptions and these uncertainties, discussed in this section, will no doubt, test the UK and European gas markets. That said, UK gas prices should be contained, on an annual average price basis, within the high and low gas price range set out in the price assumptions which are viewed as reasonable.

3.3. Coal Price Assumptions

Context

Since end 2016, global coal prices have remained on a high level compared to the four years before, which saw extremely low prices. As such, the ARA CIF price marker for European steam coal imports remained above $70/t since October 2016 reaching more than $90/t in June 2018.

In order to understand these trends regarding European coal prices, recent developments in China have to be taken into account, since global coal prices are usually well-integrated among different regions. Starting from 2016, China has reduced the working days for coal miners. Lower Chinese coal production implied higher Chinese coal imports, which made prices soar after 4 years of low prices. Even though working restrictions were relaxed, causing Chinese domestic output to recover partially, other factors made prices remain on a comparably high level: Chinese coal demand from power generation increased due to low hydropower generation and increasing power demand, amongst others due to strong economic growth and high temperatures and, thus, power demand for cooling. On the supply side, lower than expected exports from Indonesia and Australia supported prices. One other important factor is, that according to IEA Coal 2017, Chinese government has set the goal to make coal prices remain in a corridor of $ 82/t and $ 93/t. Even though coal is traded freely in China, the government has certain means to influence price formation, such as production restrictions.

Generally, since transport costs of coal are rather low compared to the price of the good, developments in Asia immediately affect European coal prices because of arbitrage opportunities. However, 2017 exhibited certain time periods, when coal prices between Asia and Europe decoupled. For example at the beginning of 2017, unplanned maintenances of nuclear reactors in France, cold weather and low CO2 prices were compensated by coal power plants and, thus, higher coal imports to Europe. Hence, European and Chinese prices decoupled. However, the arbitrage opportunity for shippers existed only through a limited period of time. When the situation normalized, prices aligned again.

Whereas the example shows that price deviations of European and Asian coal prices are temporarily possible, the equilibrium situation is rather coupled prices. Therefore, 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: Since Chinese steam coal demand is more than three times higher than the global steam coal seaborne market volume, every trend regarding Chinese domestic supply and demand may have a substantial effect on global and European coal prices. On the supply side, China's National Development and Reform Commission (NDRC) has announced it will issue new policies on coal production whenever coal prices fall out of a determined price corridor. Even though the goal of maintaining a price corridor reduces price volatility to a certain extent, it is very uncertain when and how strongly a policy measure will affect global coal prices and if the corridor itself may change over time. On the demand side, air pollution measures (such as coal-to-gas switching in the industry) and diversification targets in the power sector put coal under pressure. On the contrary, coal demand may benefit from increasing GDP and increasing power demand as the utilization rate of coal-fired stations in China is rather low currently.

Global coal demand: Opposing trends create uncertainties concerning global coal demand, especially the developments in Asia (foremost India and ASEAN countries). Since coal markets in Asia and Europe are strongly interrelated because of arbitrage opportunities for Russian or South African coal exports, these trends may have an impact on European coal prices: On the one hand, the Paris agreement, being binding for countries to reduce CO2 emissions, implies a decline of global coal demand. On the other hand, coal is the cheapest primary energy for many emerging countries e.g. in India and several emerging countries in Southeast Asia, where a strong increase of GDP growth and, hence, electricity and coal demand growth are expected. In particular, the future of domestic coal production and demand in India will have a major influence on the international seaborne market for thermal coal.

European coal demand: European coal demand is coming more and more under pressure with decarbonisation initiatives becoming more ambitious. A major source of uncertainty for coal demand and, thus, prices is how fast policy reforms against coal will be implemented: The EU-ETS has been reformed with several measures to strengthen the allowances' prices (e.g. the market stability reserve), or measures to counteract the "waterbed effect" (i.e. the effect that national decarbonisation policies become ineffective due to the EU-ETS). During the last few months, prices of EU-ETS allowance have more than doubled reaching 13 EUR/t in April 2018 making coal-fired generation less attractive. Besides uncertain developments at the EU-level, a variety of (potential) national measures may affect European coal demand in a way which is still unknown today. The UK, France, the Netherlands, Finland and Italy have announced an end to coal-fired power generation during the next decade. In Germany, a "coal commission" will decide by the end of 2018 when and how quickly coal will be phased-out in the power sector. Other countries are likely to follow with their own national measures.

Global long-run supply costs: After several years of cost reductions as a reaction to low coal prices, supply costs have stabilized over the last 2 to 3 years. However, further productivity gains (e.g. through digitalization) are always conceivable in the future, resulting in lower mining costs. In contrast, most studies expect coal quality to decline on average globally implying higher costs. However, coal quality and technological progress through productivity gains in the mining sector are not the only drivers of coal supply costs. The developments in important input factor markets such as labour, oil, machinery and dynamite, as well as the development of foreign exchange rates, will also affect mining costs and therefore create uncertainties for European coal prices.

Assessment

Overall, the approach developed for the BEIS Fossil Fuel Price Assumptions in 2016 and 2017 remains sound, since there has been no structural change in the coal market that would justify a change of the methodology.

Concerning the short-term coal price assumptions for the years 2018 and 2019, the chosen approach (based on spot and forward prices and their historical deviations between traded prices and outturn, with recent smaller adaptations of the methodology) is a sound way to model the central, high and low scenario as discussed in Section 2.1. Furthermore, and as discussed in Section 2.1., it is a reasonable way to model the coal price assumptions for the medium term (2020-2030) by flat-lining the low and central case from 2019 to 2020 and by interpolating the 2020 values up to 2030.

The long-term coal price assumptions (2030-40) are modelled from deriving different market equilibria of long-term supply costs and future European thermal coal import demand for three scenarios for the year 2030. This is a sound and well-known approach for modelling long-term price assumptions.

European thermal coal import demand scenarios are based on the three scenarios CPS, NPS and SDS from IEA's *World Energy Outlook 2017*. Since the IEA's scenarios cover variety of policy developments, WEO 2017 captures most of the uncertainties about European coal demand being known today. WEO 2017 publishes data on the overall EU coal demand and domestic production, that is, including lignite and metallurgical coal. Hence, data need to be transformed in order to derive European thermal coal import demand. 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 the last year's Fossil Fuel Projections, BEIS made a reasonable adjustment to model a higher European coal production in the high price scenario. Implicitly, it was assumed that additional coal production from Poland would be triggered when prices reach a price level of $115-120 USD/t. Without the adjustment coal prices in the high price scenario would have reached an unreasonable level due to the modelling approach of the supply cost curves to Europe, which become very steep at the end. However, since at higher prices, European coal production would rise, mainly in Polish mines, this would set a reasonable upper limit to coal prices. In this year's coal price projections, the same adjustment was applied. However, since the European coal demand is lower in the high price scenario this year, the high price scenario reaches a level, where no substantial increase of European coal production would be expected. Hence, no significant increase of European coal production is observed in the high price scenario in this year's price assumptions.

Long-term supply costs are based on a set of three different supply cost curves provided by Wood Mackenzie (see Section 2.2). Concerning supply side uncertainties, these cost curves account for a wide range of uncertain developments regarding mining capacities and costs (as discussed above). Despite the fact that Wood Mackenzie's analysis has been derived two years ago, it still provides valid results for this year's BEIS price projections. There have not been any substantial changes in the coal industry that would justify a substantial change of the long-run costs for the year 2030. Hence, it is reasonable to continue to use Wood Mackenzie's coal supply curves for this year's report.

Lastly, the panel shares the view to flat line price projections between 2030 and 2040 since there is no additional information available for this time frame, which would justify modelling a certain price movement.

The BEIS's coal price assumptions lie close to those of the external price projections. For the central case (2020, 2030 and 2040), price assumptions are similar to those of IEA WEO 2017 (NPS), whereas they are $14-17/t higher than other external projections for the year 2030. For the low-price scenario, 2030 and 2040 prices are similar to IEA WEO 2017 (SDS), whereas for 2020 BEIS' price assumptions are ca. $22/t lower resulting from BEIS' forward curve approach and subtracting one standard deviation from current forward prices. In the high price scenario BEIS's price assumptions are higher than all the external projections considered. Compared to IEA WEO 2017 (CPS), BEIS' prices are $25/t (2020), $28/t (2030) and $18/t (2040) higher. However, overall, all deviations from external price projections seem plausible and justifiable and result from different methodologies applied.

4. BEIS's Quality Assurance Process

As was the case in the last two years, we have assessed the Quality Assurance (QA) process for the models BEIS uses to generate the fossil fuel price assumptions. The BEIS team have developed three Excel models to generate these assumptions for gas, oil and coal respectively. They shared the models and the associated documentation with the panel.

This documentation explains how each of the models work in detail, and includes a step by step guide to using the model, the sources of data and how to change the input assumptions. Whilst our experience of working with BEIS shows that some of the knowledge required to generate price assumptions can be difficult to codify, this documentation provides very clear guidance. It should help to minimise any problems that could arise due to a loss of knowledge when there are staff changes in the team.

An important limitation of the methodology that has been used is that the long-term demand and supply assumptions that are used are provided by external organisations (the IEA and Wood Mackenzie respectively). In each case, models are used by these organisations. As we have stated in previous years, it is 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[26]. 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 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 scenarios have been derived through a rigorous process. However, it is important for these scenarios to be compared with other scenarios to ensure they cover a reasonable range of possible outcomes. BEIS now do this routinely for each of the three fuels.

Wood Mackenzie used their own models to derive the fossil fuel supply curves were supplied to former DECC in 2016. As we noted in our previous two reports, QA on these models was more difficult than for the IEA model. Whilst Wood Mackenzie provided some basic

[26] 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/

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. BEIS's Quality Assurance Process

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, which is reflected in increased volatility. This past year has seen surprises on the demand side for natural gas—China's surge in LNG imports—and the supply side for oil with growing geopolitical risk pushing up prices. Longer term there is growing uncertainty over the impact of climate change on fossil fuel demand. In such an environment, testing the reasoning and methodologies behind the fossil price assumptions is particularly important. But these are not forecasts and are concern is whether or not future uncertainty will be captured within the range between the high and low assumptions.

This the third year in a row that the current methodologies have been used and the Panel considers them well established and the resultant the fossil price assumptions to be 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. We note that this year some modifications were made in relation to the gas price, and we were fully consulted and support the approach adopted. 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 recognises that because of recent under investment in exploration and production of oil and gas there are significant uncertainties in the early to mid-2020s, just where the current approach draws a straight line from the futures/forward curves to the long-term price assumptions.

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 2017* and its three scenarios to generate future demand scenarios. The Panel appreciates the work done by the BEIS team to 'sense test' the IEA's scenarios against a wider range of publicly available energy forecasts and scenarios.

The Panel received analysis from the BEIS team in relation to cost inflation and while we made further minor adjustments again this year, we consider the supply curves supplied by Wood Mackenzie for the 2016 exercise to still be 'fit for purpose,' but it will be necessary to take an early view on whether new analysis is required for the 2019 exercise.

Annex A of the BEIS report provides a comparison of the 2018 FFPA with those of 2017 and the differences have been justified by supporting analysis and reflect current market conditions and the impact of exchange rate changes. The Panel has noted the impact that changes in the OBR exchange rate between 2017 and 2018 have had on the gas (NBP) price assumptions. The matter was discussed at length, and we support the change in using the June 2018 US$/£ market exchange rate market, rather than the OBR’s March 2018 exchange assumptions.

5.2 Recommendations

Here we reflect on the recommendations that we made last year and suggest some issues to consider for the 2019 price assumptions exercise.

First, we note that as this is the third year that BEIS has worked with an Expert Panel to oversee the price assumptions exercise, the approach is now well established, and the majority of our earlier concerns have been acted upon. This year, following our previous recommendations, deadlines were established at the onset and met, and new staff were well briefed on the workflow. As a result, the process now takes less time, the quality assurance procedures are effective, and we are able to maximise the benefits of face-to-face meetings between the BEIS team and the Panel. We note that this year it was necessary to revisit the price assumption mid-summer and next year we should reflect on the effectiveness of the process and the use of the NBP forward curve to 2020 that were used to review the revised assumptions.

Second, in 2015-16 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 early if they want to appoint an external contractor to produce new cost supply curves for the 2019 exercise; if they do, 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.

Finally, we fully endorse the information now supplied to users of the price assumptions to stress test against the full range of assumptions. The high level of uncertainty around future fossil fuel prices means that only using the central price assumption would give a false sense of certainty, as it is likely the future prices will vary with the range of the higher and lower price levels.

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 and a Senior Visiting Research Fellow at the Oxford Institute of Energy Studies. 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 recently completed a Horizon 2020 project examining the development of unconventional oil and gas (M4 Shale Gas). He is currently working on a UKERC project on the global impact of unconventional fossil fuels and on future UK gas security and the potential impact of Brexit.

Dr Harald Hecking is the managing director of ewi ER&S since June 2015. His research focus lies in the German Energiewende, sector coupling and the German and international natural gas and coal markets. Harald Hecking is the leading scientific advisor assessing pathways of the German Energiewende towards 2050 in a study launched by the German Energy Agency (dena). Additionally, he manages diverse projects concerning the German heat and power markets as well as the German and European gas markets. In his numerous consulting projects at EWI, he analysed the costs of CO2 abatement on the heat and electricity market, the economic impacts of a coal phase-out, the future potential of natural gas in Germany, the economics of long-term gas contracts as well as the security of natural gas supply in Europe. Furthermore, Dr. Hecking contributed to the Medium-Term Coal Market Report while working for several months at the International Energy Agency in Paris.

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 has worked on the development of complex integrated energy projects, been involved in 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 around the world. David is a Senior Research Fellow of the Oxford Institute for 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 and in summer 2017 he was invited to become an advisor to the fuels advisory board for Japanese LNG and utility company JERA. David 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 UCL Institute for Sustainable Resources. 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).

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