BUSINESS OUTLOOK 2019

OIL&GAS UK

OIL&GAS UK

Contents

1. Foreword		**5**
2. Key Performance Indicators		**6**
3. Business Environment		**8**
3.1	Oil Market	9
3.2	Gas Market	11
3.3	EU ETS Carbon Market	12
3.4	The Continued Importance of Oil and Gas in a Lower-Carbon Economy	13
3.5	Mergers and Acquisitions	15
4. Exploration and Production Outlook		**18**
4.1	Production	19
4.2	Drilling Activity	22
4.3	E&P Expenditure	31
5. Supply Chain Outlook		**39**
5.1	Supply Chain Sentiment	40
5.2	Financial Performance	40
5.3	Share Price Performance	44
5.4	Realising New Opportunities for Supply Chain Companies	45
5.5	Employment Trends	46

Oil & Gas UK's vision is to ensure the UK Continental Shelf becomes the most attractive mature oil and gas province in the world with which to do business.

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1. Foreword

Welcome to Oil & Gas UK's (OGUK) *Business Outlook* 2019, which continues to provide the only comprehensive review of UK industry performance and a sector outlook for the coming years.

This year's report shows that industry continues to grapple with some fundamental challenges in a business environment that we should all consider to be the "new reality".

In this context, exploration and production companies will continue to maintain their tight budgets and relentless focus on efficiencies, whilst innovation, new technologies and new ways of working will be required to unlock the full potential of the UK Continental Shelf (UKCS).

The hard-won benefits of this new reality are starting to show: production is at its highest level since 2011, competitive costs are being sustained and there is building momentum around exploration, with more new opportunities being drilled and the largest two conventional discoveries for a decade made in the second half of 2018.

However, challenges remain across parts of the supply chain, as pressure on revenues and margins continues and cash flow is stretched. If capabilities and resources are to stay anchored here in the UK, there must be a competitive proposition for supply chain companies to invest in too.

Therefore, industry's new reality requires the innovative business models and co-operation we have seen so far to gain critical mass across the whole industry — operator to operator, operator to supply chain, supply chain to supply chain — to allow new projects to be unlocked while providing sustainable returns. This will be crucial to the basin sustaining a competitive position and laying the ground for achieving Vision 2035.

Vision 2035 means we add a generation of productive life to the UKCS while expanding supply chain opportunities at home, abroad and into other sectors.

Our report identifies that in extending the productive life of the basin, around £200 billion will need to be spent in the coming years in terms of finding, developing and operating the reserves of the future. This is an attractive opportunity that can stimulate activity and revenue for both the supply chain and E&P companies and contribute positively to the UK economy for years to come.

We also recognise that the transition to a lower-carbon future is already underway. As we look ahead, oil and gas will have an important and constructive role to play in supporting this transition. UK government estimates show that by 2035, oil and gas will still be needed to meet two-thirds of the UK's energy needs. Our industry currently provides almost 60 per cent of that demand, underlining the criticality of this industry for security of energy supply, supporting hundreds of thousands of jobs and contributing billions to the economy. Achieving the aims of Vision 2035 will mean we remain a vital economic asset for the UK in the decades to come.

Safeguarding the competitiveness of the basin will be key to maintaining a strong and sustainable industry in the new reality while positioning us for a successful future that works alongside decarbonising challenges.

This report shows how industry is responding to current issues and if it stays the course in embracing the new reality, it has a positive future to work towards.

D E Michie

Deirdre Michie,
Chief Executive, Oil & Gas UK

2. Key Performance Indicators

Year-On-Year % Change	'14	'15	'16	'17	'18	Forecast '19	Our outlook explained
Total Production (million barrels of oil equivalent)	517 0%	571 +11%	598 +5%	595 0%	619 4%	610-630 +0%	*Production in 2018 was up 4% compared with 2017 and 20% higher than 2014. This has mainly been driven by new fields starting up along with continued improvements in production efficiency.*
Liquids Production (million barrels of oil equivalent)	311 -1%	352 +13%	371 +5%	365 -2%	397 9%	390-400 0%	*The fields which have started production in recent years have been predominantly oil and have led to significant increases in total output. Oil production will continue to be supported by new fields coming on stream.*
Net Gas Production (million barrels of oil equivalent)	206 +1%	220 +7%	227 +3%	230 +1%	222 -3%	220-230 +1%	*Gas production is expected to increase, driven by the start-up of the Culzean field which at peak production will supply 5% of UK gas demand.*
New Field Approvals	8 -20%	5 -38%	2 -60%	3 50%	13 333%	12-15 0%	*With improved investment conditions, three more fields were approved in 2018 than the previous three years combined. A similar number is expected in 2019.*
Capital Expenditure (£ billion)[a]	16.3 -1%	12.5 -23%	8.7 -30%	5.7 -34%	5 -12%	5-5.5 +5%	*Capital investment looks to have levelled, at least in the short term, and will be supported by recent project announcements. A continued stream of approvals will be required to support investment into the 2020s.*
Operating Expenditure (£ billion)[a]	10 +7%	8.4 -15%	7.2 -14%	7.1 -1%	7.1 0%	7-7.5 +2%	*E&P companies are focused on maintainting business and operational improvements. However, a small increase in operating expenditure is possible this year, driven by new fields coming on stream.*
Unit Operating Costs ($/barrel of oil equivalent)[a]	31.7 +13%	22.4 -29%	16.2 -28%	15.4 -5%	15.3 -1%	15-16 0%	*Unit operating costs (UOCs) have remained flat, with companies focused on maintaining improvements.*
Decommissioning Spend (£ billion)[a]	1.1 -6%	1.1 +0%	1.3 +18%	1.2 -8%	1.7 42%	1.8-1.9 +8%	*Industry is demonstrating that it is able to manage expenditure effectively, with cost reductions and efficiencies seen. Following a 'peak' in 2019, decommissioning spend is expected to average £1.5 billion per year to 2027.*

a. All data shown in 2018 money.
b. Including geological sidetracks but not mechanical sidetracks or respuds.
c. 2018 Supply Chain Revenue is currently an estimate.

	'14	'15	'16	'17	'18	Forecast '19	Our outlook explained
New Field Start-Ups	4 -69%	8 +100%	9 +13%	12 +33%	5 -58%	3-5 -20%	*The relatively low number of new field start-ups is a reflection of the low number of new fields approved during the downturn. However, the scale of many start-ups will mean that production is supported in the short term.*
Exploration Well Count[b]	13 -13%	13 0%	14 +8%	14 0%	8 -43%	10-15 +60%	*2018 saw the lowest number of exploration wells spudded since 1965, but there were significant successes with up to 485 million boe reported so far. More activity is expected in 2019, with several potentially high-impact prospects.*
Appraisal Well Count[b]	18 -38%	13 -28%	8 -38%	9 +13%	8 -11%	8-12 +25%	*Low exploration activity in recent years has suppressed appraisal drilling. A number of exciting opportunities are expected to be tested in 2019.*
Development Well Count[b]	126 +5%	129 +2%	88 -32%	71 -19%	85 +20%	80-90 0%	*An increase in development drilling was seen in 2018 and it is expected that levels will now plateau in the coming years. Efficiency and technology are helping to ensure maximum value from the wells drilled.*
Supply Chain Revenues (£ billion)[c]	39.8 +4%	34.8 -13%	29.5 -15%	27 -8%	26 -4%	26-29 +1%	*Reductions in revenue and margins have put many companies in a position of financial distress. It is hoped that revenues will begin to stabilise with new capital approvals and operational investment.*
Brent Oil Price ($/barrel)	99 -9%	52.5 -47%	43.7 -17%	54.2 +24%	71.2 +31%	60-65 -12%	*Although the Brent price has shown annual increases, the volatility within the market is reinforcing investor caution. Lower project break-even costs are required to offset uncertainty within the oil market.*
National Balancing Point Day-Ahead Gas Price (pence/therm)	50 -26%	42.6 -15%	34.6 -19%	45 +30%	60.3 33%	50-60 -10%	*The NBP gas price has been supported by increased demand from electricity generation, cold weather in the the first half of 2018 and domestic and European supply disruption.*
EU ETS Carbon Price (€/tonne)	5.96 +35%	7.68 +29%	5.36 -30%	5.54 +3%	16.15 +192%	19-21 +22%	*Carbon prices have increased significantly, with a reduced number of available permits in the EU ETS. Industry is committed to reducing its emissions and managing the increasing cost of carbon.*

3. Business Environment

In Summary

Commodity markets were characterised by uncertainty and volatility in 2018, reinforcing investor caution across the industry.

Exploration and production (E&P) companies benefited from increases in the Brent spot price, which averaged more than $70 per barrel (bbl) — almost one-third more than 2017, but below the ten-year average price. Brent saw a decline of more than 40 per cent in late 2018 and the forward curve indicates that prices in the $60–$65/bbl range will persist, at least in the short to medium term. The National Balancing Point (NBP) gas price also saw gains of one-third on 2017, buoyed by increased gas demand for power generation as coal continues to be phased out, as well as some supply disruptions in the UK and Europe. However, with some contracts linked to oil price, gas prices too saw a decline in late 2018 and early 2019.

Carbon prices are a commodity of increasing importance. Prices within the EU Emissions Trading Scheme (ETS) increased almost three-fold in 2018, adding significant costs to E&P companies. A focus on reducing carbon emissions will help offset these costs.

Despite the volatility, several asset and corporate transactions took place in 2018, albeit to a lesser extent than in 2017. New investors are attracted by the value which can be generated on the UKCS, whilst other companies continue to rationalise their portfolios. This trend looks set to continue in 2019.

Whilst uncertainty reigns within the markets, what is clear is that industry is adapting to a changing energy landscape driven by the need to transition to a lower-carbon economy. The oil and gas industry has a vital role to play in this transition and will continue to provide the majority of energy needs, both in the UK and globally, for at least the medium term. However, industry cannot stand still and must retain an unrelenting focus on being an attractive investment vehicle, both in terms of returns and its positive contribution to the economy and wider society.

Market uncertainty continues to drive investor caution

Brent crude prices averaged $71.20 per barrel in 2018, however saw a swing of more than 40% in the final quarter

The NBP gas price averaged around 60 pence p/th in 2018

33% higher

than 2017

3.1 Oil Market

A recovery in oil prices was seen in 2018, with Brent crude prices averaging $71.20/bbl across the year. This was 31 per cent higher than 2017 (which averaged $54.20/bbl) but remains around 10 per cent below the ten-year average of $79/bbl. A conservative outlook for Brent in the coming years reinforces the caution that investors and businesses continue to demonstrate.

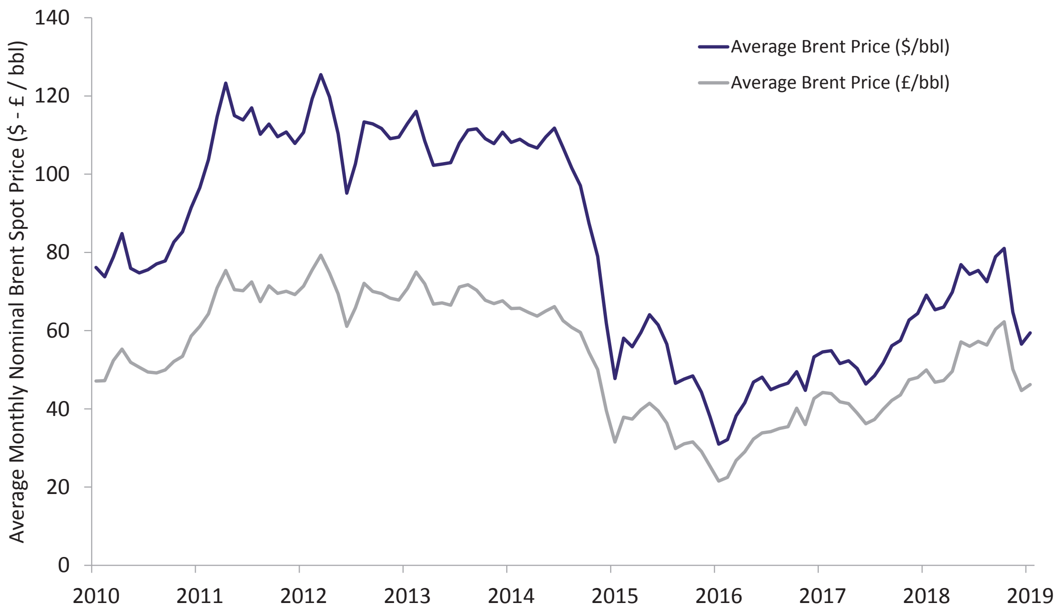
The oil market continued to be characterised by volatility last year, with a spread of more than $35/bbl was seen in Brent prices during the final quarter and intraday fluctuations of up to 8 per cent. Spot prices early in the year sat at around $67/bbl and increased steadily to hit a four-year high of $86/bbl in early October. During the remainder of the fourth quarter Brent prices returned to decline, falling by more than 40 per cent in less than three months to close the year at just over $50/bbl.

There has been some pick up in price in early 2019, with Brent averaging $62/bbl for the first two months of the year. The general market outlook for the year anticipates prices to remain around this level, at $60–$65/bbl.[1]

When considered in pounds, the decline in Brent price in recent years is less pronounced than in dollars (see Figure 1). The reduced value of the pound against the dollar, driven by a conservative growth outlook for the UK economy coupled with uncertainty over the future relationship with the European Union (EU), has gone some way to offset the dollar decline in Brent price. Between 2014–18 Brent fell by 28 per cent in dollar terms ($98.90 to $71.20/bbl) and 11 per cent in pounds (£60 to £53.30/bbl). In 2014, the USD/GBP rate averaged 1.64 compared to 1.34 in 2018.

A relatively weak pound against the dollar can have a somewhat positive effect on UK E&P companies, in areas where costs are paid in sterling and revenue collected in dollars. A further positive impact could potentially be seen in supply chain exports, with a weaker pound acting to make UK exports more internationally competitive.

Figure 1: Brent Crude Prices



Source: EIA

[1] www.eia.gov/outlooks/steo/pdf/steo_full.pdf

The volatility within the market in 2018 was the result of an ever-changing supply and demand picture, heightened by geopolitical tensions. Global economic growth forecasts, a key indicator of oil demand levels, have been revised down for both 2018 and 2019.[2] The impact of the ongoing US-China trade war is a primary factor in the concern over a potential economic slowdown, acting to dampen oil demand.

Demand uncertainty is being compounded by continued supply volatility. This is driven by factors such as the continued growth of US shale output — with ExxonMobil and Chevron announcing that they expect to see continued growth until at least 2024 — the re-imposition of US sanctions on Iran, and ongoing economic challenges in Venezuela, along with OPEC restrictions.

With supply and demand uncertainty persisting the forward price curve for Brent crude, shown in Figure 2, demonstrates that any sustained increase in price is unlikely, at least in the short term. Throughout 2018 the market swung between backwardation — where current spot prices are higher than prices for future delivery — and contango, where prices for future delivery are higher than the current spot price. In late 2018 the market shifted into contango, demonstrating that there are still widespread concerns around oversupply, acting to dampen prices.

Figure 2: Brent Futures Prices

Source: CME Group, Intercontinental Exchange

Examining the price for delivery of a barrel of Brent crude in early 2020 suggests little upside in prices. A futures contract for 2020 delivery purchased in early 2014 (when spot prices were greater than $100/bbl), prior to the market crash, would have cost around $85/bbl. In mid-2016, at the height of the downturn, this was trading at just under $56/bbl (with spot prices of around $45/bbl). In January 2019, delivery in early 2020 was trading at around $61/bbl, in line with the spot price at the time.

[2] www.imf.org/en/Publications/WEO/Issues/2019/01/11/weo-update-january-2019

This demonstrates that the market still holds a significantly more conservative outlook than prior to the oil price crash and only a marginally more positive outlook than at the middle of the downturn. The current outlook reinforces the decision by E&P companies to maintain a focus on cost and investment discipline, with many requiring that new investments break even at less than $50/bbl. Companies are also looking to sustain business and operational efficiencies to ensure they are able to maintain positive cash flow within a volatile market.

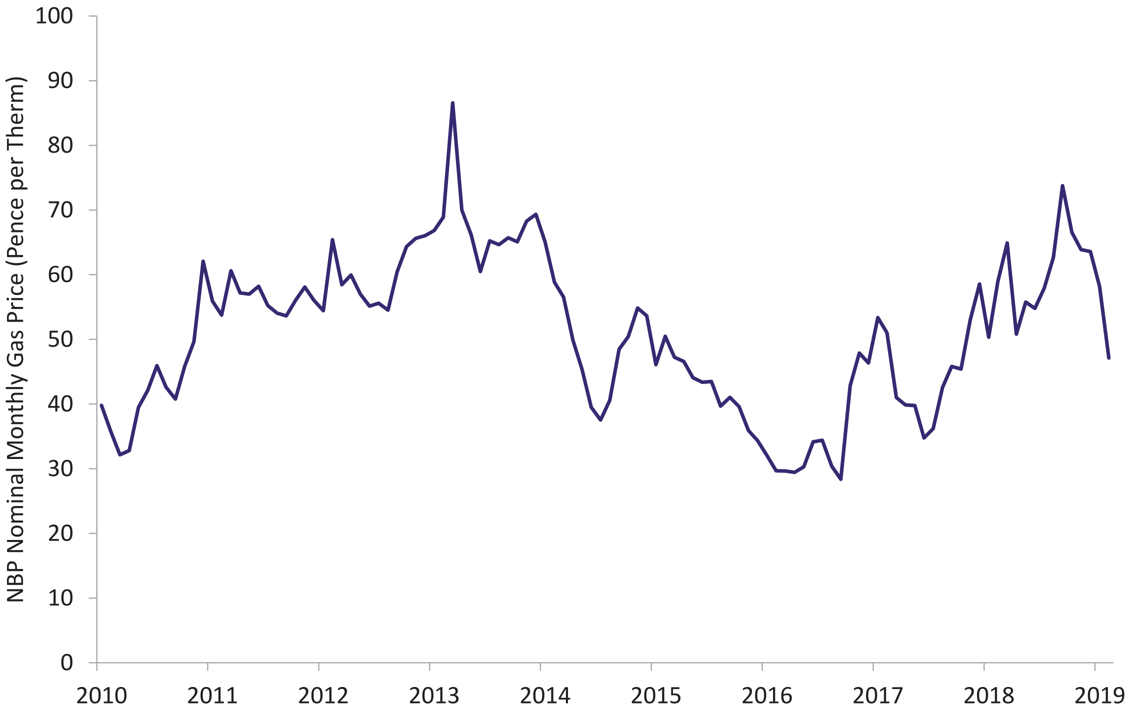
3.2 Gas Market

The day-ahead National Balancing Point (NBP) gas price averaged around 60 pence per therm (p/th) in 2018, an increase of 33 per cent from 2017 and around 18 per cent higher than the ten-year average of 51 p/th.

A colder-than-average 2017–18 winter period and substantial increases in the cost of carbon allowances were both underlying factors in the increase in price. As the price of carbon has risen there is an increased incentive for coal-to-gas switching within electricity production, resulting in increased gas demand. In addition to this, disruptions to UK supply, such as at the Rough gas storage site, have helped apply upward pressure throughout the year. When combined with supply issues, the extreme cold weather in the first quarter of 2018 led National Grid to issue a gas deficit warning as nominal gas prices reached a 12-year high in March, with intraday prices spiking at more than 300 p/th.

Average prices in January and February 2019 sat at just under 53 p/th, with declines seen in spot prices throughout February to around 44 p/th.

Figure 3: NBP Gas Price



Source: ICIS Heren

Historically the summer period is associated with lower gas prices, as warmer weather reduces gas demand and the UK can export much of its produced gas to European storage. In recent years however, the seasonal swing in price has been less pronounced, owing to the increased diversification of gas supplies, including liquefied natural gas (LNG), interconnectors with continental Europe and domestic short-term gas storage capacity.

3.3 EU ETS Carbon Market

The EU Emissions Trading Scheme (ETS) carbon market is of increasing significance for UK producers, with companies required to ensure that they have the equivalent number of ETS permits to cover their offshore emissions. Companies are issued with a limited number of free permits and are required to buy additional permits from the market to cover any shortfall.

Recent reforms to the ETS — helping to address an oversupply of available permits — led to a sharp increase in the ETS carbon price in 2018. The cost to emit a tonne of carbon dioxide (CO_2) increased from around €8/tonne to around €25/tonne by the end of the year, a rise of over 200 per cent. Prices in 2018 averaged €16.15 and are anticipated to remain relatively high in future, with forecasts in the range of €19/tonne and €21/tonne for 2019 and 2020, respectively.

Figure 4: EU ETS Carbon Price

Source: ICIS Heren

As UKCS offshore installations are not connected to the National Grid, the majority of industry carbon emissions (71 per cent) are the result of offshore power generation. OGUK estimates that the EU ETS currently costs the industry around £125 million per year, a charge which could double by 2030, even assuming lower carbon intensity as carbon prices continue to rise. Consistent with the wider climate agenda, industry will take progressively further action to reduce the carbon intensity of its operations aided by the EU ETS (Phase IV) which begins in 2020.

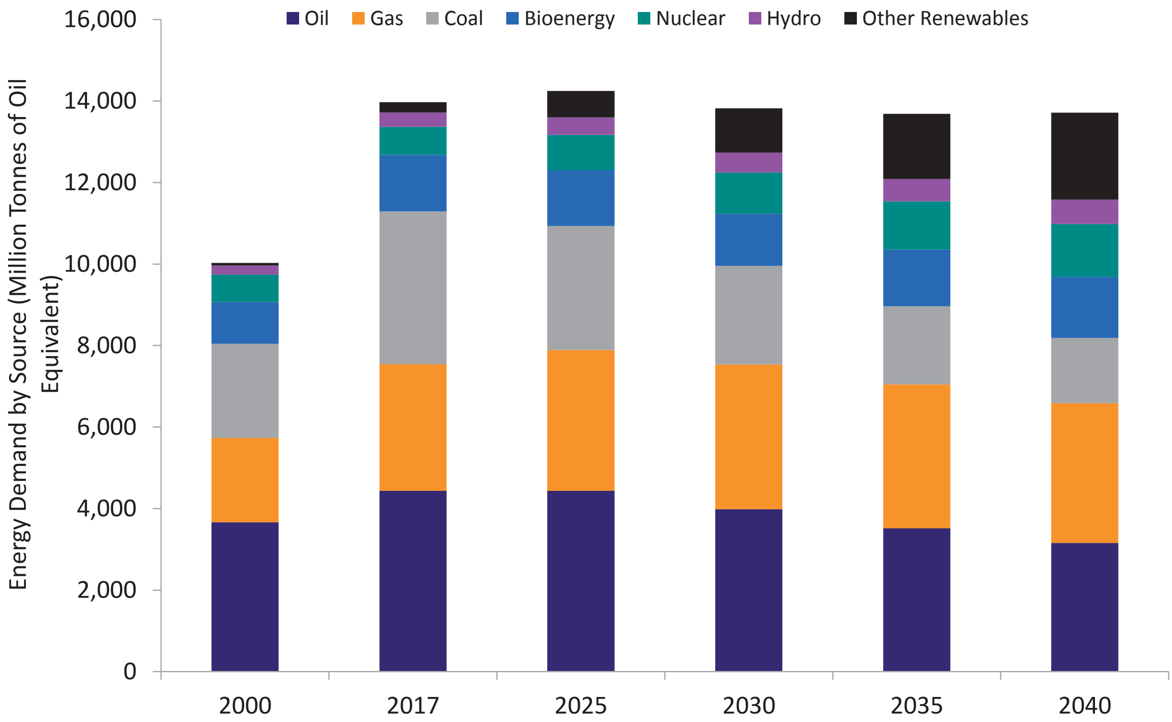
There are a number of options for pricing carbon emissions following the UK's withdrawal from the EU. In the event of leaving without a deal, the UK government has stated its intention to introduce a carbon tax of £16/tonne for all emissions in excess of those which that would have been allocated in allowances under Phase IV of the EU ETS. If a withdrawal agreement is approved by parliament, the political declaration gives scope for the UK to design a trading scheme aligned to the existing EU arrangements, so that UK-issued allowances could be traded in the EU and vice versa, as is currently the case for Switzerland.

3.4 The Continued Importance of Oil and Gas in a Lower-Carbon Economy

OGUK recognises the need to transition to a lower-carbon economy, however it is clear that both oil and gas will play a vital role within this transition, globally and in the UK.

Within the International Energy Agency (IEA) Sustainable Development Scenario,[3] which is compliant with the aims of the Paris Agreement, oil continues to be the greatest energy source in the short to medium term. Although a gradual decline can be seen over time, oil continues to account for almost 25 per cent of global energy demand in 2040 in this scenario.

Figure 5: IEA Sustainable Development Scenario



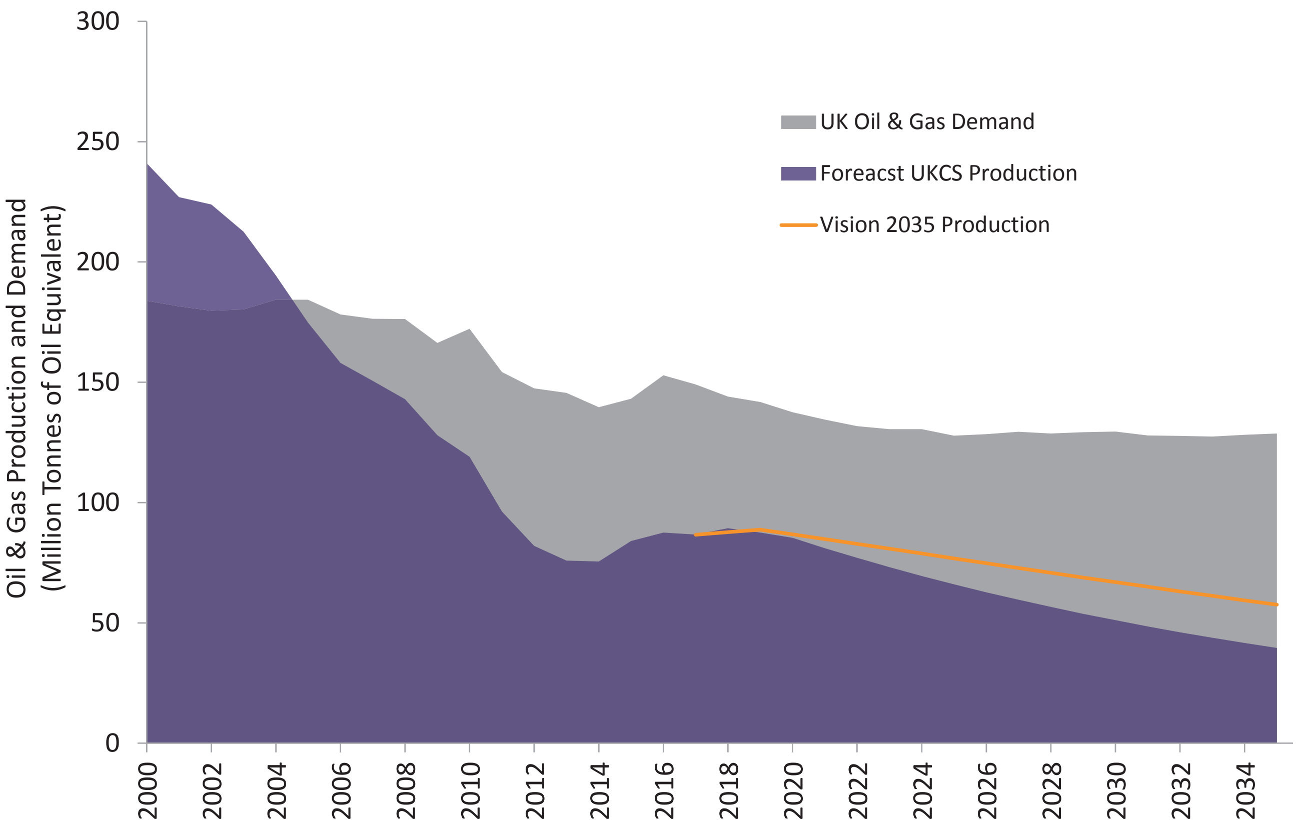
Source: IEA

Almost all future energy scenarios, including that seen in Figure 5, show gas demand remaining strong until at least 2040, when it could be expected to meet at least 25 per cent of global energy demand. This is the result of increasing demand within developing economies and the continued displacement of coal-fired power from electricity generation amidst efforts to reduce carbon emissions. Gas will continue to provide an economical, flexible and relatively low-carbon fuel source, with its relative importance in the future energy mix continuing to increase.

[3] www.iea.org/weo/weomodel/sds/

Maximising economic recovery from the UK's indigenous oil and gas resources can be achieved alongside the reduction in carbon emissions, with production from the UKCS remaining a critical component of the country's energy mix for at least the medium term. In 2018, oil and gas accounted for 75 per cent of the UK's primary energy demand and the UK Government forecasts that it will still be required to meet around two-thirds of primary energy needs in 2035.[4] UKCS output currently meets 59 per cent of the country's primary oil and gas demand (see section 4.1), and even in the most ambitious scenarios UK production will not meet future demand levels. From an energy security and economic perspective, it is crucial that indigenous sources continue to meet as much domestic demand as possible.

Figure 6: UK Oil and Gas Production and Demand Outlook



Source, BEIS, OGA, Oil & Gas UK

[4] www.gov.uk/government/uploads/system/uploads/attachment_data/file/666259/Annex-e-primary-energy-demand.xls

3.5 Mergers and Acquisitions

Deal activity did not reach levels seen in 2017, but there were a number of mergers and acquisitions (M&A) on the UKCS last year. Activity was seen across all aspects of the oil and gas development cycle including exploration prospects, pre-development opportunities, producing fields and late-life assets.

While some corporate transactions were seen in 2018, the majority related to the transfer of assets, as companies continued to optimise their portfolios. Having investment opportunities in the most appropriate hands is a key enabler in the drive to maximise economic recovery. The transactions have resulted in a more diverse corporate landscape on the UKCS, with the largest ten companies accounting for just over half of production in 2018, compared with more than two-thirds of production in 2008. Sustained fiscal and regulatory certainty will help to ensure that buyers continue to be attracted to the basin and that opportunities are held by companies with a greater focus on growth on the UKCS.

Examples of significant transactions announced in 2018 include:

Exploration Prospects and Pre-Development Opportunities	
NEPTUNE ENERGY	Neptune Energy acquired stakes in the Seagull development opportunity and Isabella exploration prospect from Apache North Sea
Cairn	Cairn secured a farm-in to the Azinor Catalyst-operated Agar-Plantain exploration prospect
SPIRIT ENERGY	Spirit Energy farmed into the Greater Warwick Area, operated by Hurricane Energy
equinor	Equinor acquired a stake in the Rosebank development from Chevron and assumed operatorship
	Shell acquired a stake in the Cambo area from Siccar Point

Producing Fields	
bp	BP enhanced its stake in the Clair field, acquiring the interest held by ConocoPhillips
EnQuest	EnQuest acquired the remaining interest in the Magnus field from BP
SERICA ENERGY	Serica Energy acquired an increased stake in the Keith and Rhum fields from Total, Marubeni and BHP Billiton and closed out the deal to buy BP's share of the Rhum field
VERUS PETROLEUM	Verus Petroleum acquired a stake in the Babbage area from Premier Oil
ROCKROSE ENERGY	Rockrose Energy purchased an interest in the Arran field from Dana Petroleum
CHRYSAOR	Chrysaor took on the remaining stake in the Seymour and Maria fields from Spirit Energy
Tailwind ENERGY	Tailwind Energy acquired the Triton cluster assets from Shell and ExxonMobil

Corporate Acquisitions and Mergers		
ORANJE-NASSAU ENERGIE	dyas	Oranje-Nassau Energie (ONE) merged with Dyas to form ONE-Dyas. The merger allows the companies to expand production and pursue new development opportunities
VERUS PETROLEUM	CIECO	Verus Petroleum acquired CIECO Exploration and Production with the aim of expanding its UKCS footprint
wintershall Shaping the future.	DEA	Wintershall merged with DEA to form Wintershall DEA. The aim of the merger is to create new growth potential and open up new opportunities
DNO EST - 1971	Faroe	DNO completed the acquisition of Faroe Petroleum in a hostile takeover in early 2019. This included stakes in a number of UK fields.

The spread of companies involved in deal activity was notable, with divestments and acquisitions made by major E&P companies and independent operators, while private equity-backed companies and national oil companies (NOCs) enhanced their UKCS footprints. General trends can be seen across each category:

Private Equity

An increasing proportion of UK assets, production and investment opportunities are owned by private equity-backed companies. In 2018, a number of these companies increased their exposure to the UKCS across the lifecycle, including exploration and pre-development opportunities and producing assets.

They are generally able to view investment opportunities with a different focus to previous owners and are able to adopt a flexible and efficient approach to maximise the value of their operations and investments.

Independents

There are varying positions across independent oil and gas companies, with some increasing their focus on the UKCS and some choosing to either reduce their exposure or use cash flow from UK operations to fund other investments.

The companies that have increased their UK footprint have generally done so by picking up late-life fields, applying their experience and adopting a 'fit-for-purpose' approach to maximise potential value.

Majors and National Oil Companies

There have been examples of major E&P companies and integrated NOCs enhancing their exposure to the UKCS. This can be driven by various strategies, such as increasing their stake in core hubs, or picking up exploration and pre-development opportunities. Overall, this enables these companies to capitalise on the significant value available on the UKCS and helps to balance international portfolios by providing a relatively fast return on investment.

Divestments have generally been driven by continued portfolio optimisation, with many companies choosing to reduce their exposure to non-core, often later-life assets. In line with the challenges faced by some independents, international capital allocation is also a challenge for many companies, with North American shale plays attracting the majority of available capital. This underlines the importance of ensuring the UKCS is as competitive as possible to attract investment to the basin.

Potential Deal Activity in 2019

In late 2018 and early 2019 there have been various reports of ongoing discussions regarding the divestment and acquisition of UK assets and corporate portfolios. However, the ongoing volatility in the market, and increased optimism and cash flow within E&P companies, is likely to dampen the overall level of deal activity.

Divestments are likely to be driven by continued portfolio rationalisation as some companies look to reduce, or right-size, their UK footprint. This may provide opportunities for UKCS-focused companies to increase their exposure. Rockrose Energy's purchase of Marathon Oil's UK business in February was the first example of this in 2019, with the former securing a deal that will help to increase production significantly and double its owned reserves. Private equity investors may also begin to consider their exit strategies, with many rumoured to be considering initial public offerings (IPOs) in the coming years.

Having assets and investment opportunities in the most appropriate ownership will support industry in achieving the ambitions of Vision 2035, to add a generation of productive life to the basin.

4. Exploration and Production Outlook

In Summary

The business and operational improvements implemented during the downturn have positioned the UKCS as a much more attractive basin for E&P companies to invest in. The improved cost profile of the basin, along with a stable and competitive fiscal regime and an extensive network of infrastructure mean that significant returns can be made from UKCS investments. Investors recognise this value, with more new projects committed to in 2018 than in the previous 3 years combined — providing a much-needed boost to investment and future reserves. Maintaining this level of new project commitments in the years to come will be crucial to maximising economic recovery.

Production from the UKCS is crucial for the UK's energy security and recent performance has been strong, with output now 20 per cent higher than it was in 2014 — meeting 59 per cent of UK oil and gas demand. This performance is all the more impressive considering it was preceded by 14 years of continued production decline. The challenge now facing industry is to manage production in an effective manner when it is expected to return to a position of decline post-2020.

To ensure this, it is important that there is a healthy portfolio of prospects for companies to invest in. The discovery of new fields is a key aspect of this. Despite record-low levels last year, there is building optimism around exploration activity in the basin. The two largest conventional discoveries for a decade were made from wells spudded in 2018, and a pick-up in exploration drilling is expected this year. If successful, some of the opportunities have the potential to open up new plays in the basin, while others could be monetised relatively quickly, making use of existing infrastructure.

There is also significant potential in undeveloped discoveries and opportunities for resource progression not currently recognised in near-term business plans. To move these forward, all companies across the industry need to be open to new ways of working, collaborative models and innovative thinking. This will be central to meeting the aims of Vision 2035 — to add a generation of productive life to the basin.

Total production from the UKCS was 1.7 million boepd in 2018

20%
since 2014

There is building momentum around exploration activity, with up to 15 wells expected this year

More new projects were approved in 2018 (13) than the previous 3 years combined. A similar number is expected in 2019

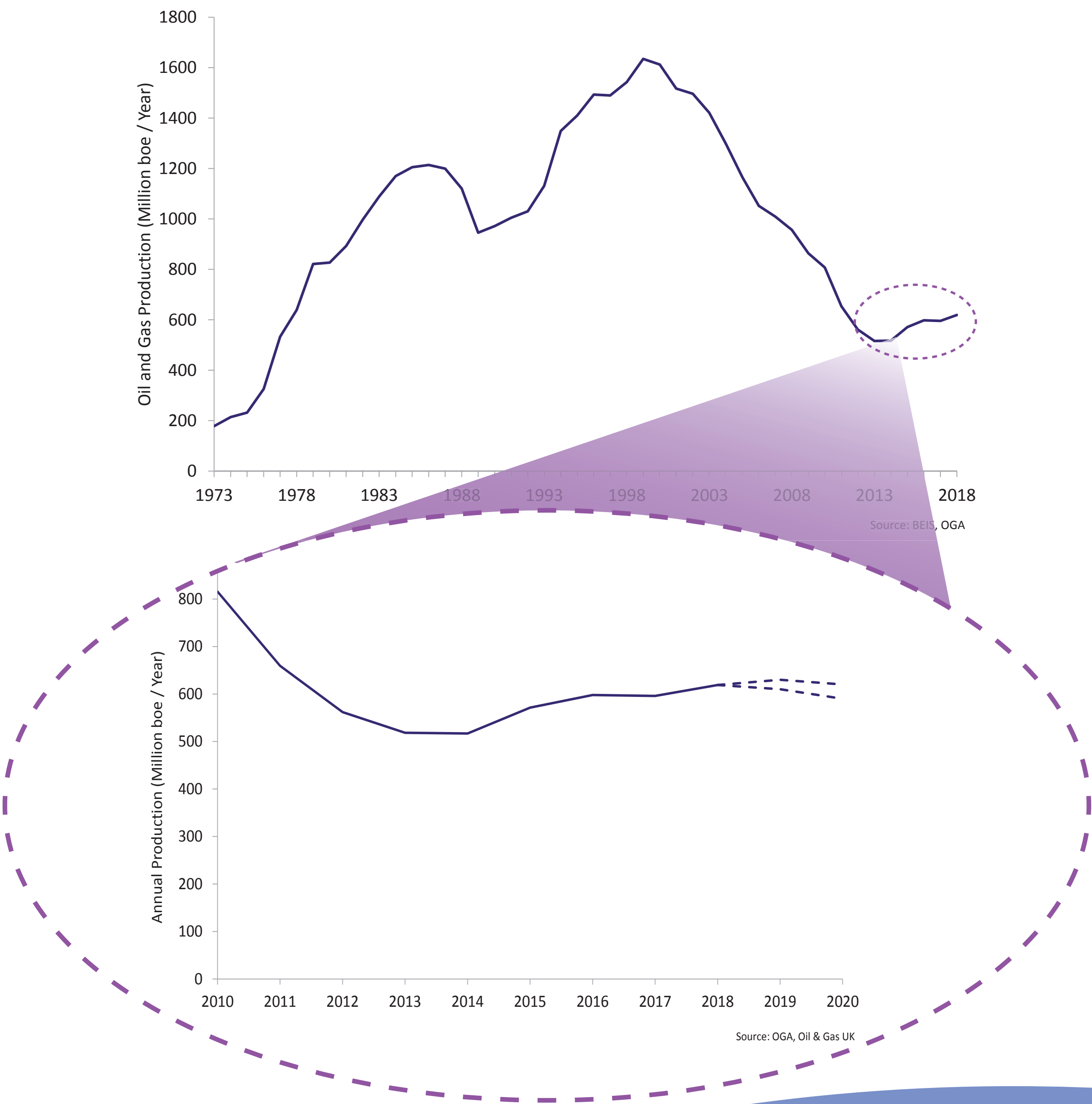
4.1 Production

Production Performance

Total production from the UKCS was around 619 million barrels of oil equivalent (boe) in 2018, or 1.7 million boe per day (boepd). This is 4 per cent higher than 2017 and means that production has now increased by 20 per cent over the past five years. Considering the long-term trend and recent challenges faced, this should be regarded as very positive progress. This performance has been underpinned by new field start-ups, with peak output from fields which have commenced production over the last five years accounting for around half of expected 2019 output, reinforcing the importance of progressing a steady stream of new projects.

Production from the basin continues to be crucial for the security of the UK's energy supply, with production last year meeting the equivalent of 59 per cent of primary oil and gas demand and around 44 per cent of total primary energy requirements.

Figure 7: Oil and Gas Production From the UKCS



Oil production increased by almost 9 per cent in 2018, to 397 million bbls (1.09 million bpd), accounting for 64 per cent of total basin output and enough to meet 75 per cent of the UK's total oil demand. This increase was largely driven by the nature of the new fields which have come on stream in recent years. The five which commenced production in 2018 are predominantly oil-based:

- Clair Ridge, west of Shetland
- Varadero and Burgman in the Catcher area and Garten in the Beryl area — all in the northern North Sea
- Harrier in the Stella area of the central North Sea

At peak production, these fields will contribute in excess of 170,000 boepd — 10 per cent of current output from the basin — and will target total recoverable resources in the region of 735 million boe. These figures are, however, dominated by the Clair Ridge development which is the largest project to start-up on the UKCS, in terms of peak production, since the Buzzard field in 2007.

Conversely, gas production saw a decline of around 3 per cent in 2018 to 222 million boe (0.61 million boepd), around 36 per cent of total production and the equivalent of 43 per cent of UK gas demand. This trend was driven by lower-than-expected performance within key gas hubs and the lack of new gas fields coming online in recent years. Only two gas fields have begun producing since 2014 — the Cygnus field in the southern North Sea and Aviat, within the Forties area of the central North Sea — both of which came onstream in 2016.

Production Outlook

It is anticipated that there could be increases in both oil and gas production this year. OGUK forecasts that total production will be in the range of 610–630 million boe in 2019 (1.67–1.73 million boepd), with oil and gas accounting for a similar respective proportion of production as in 2018.

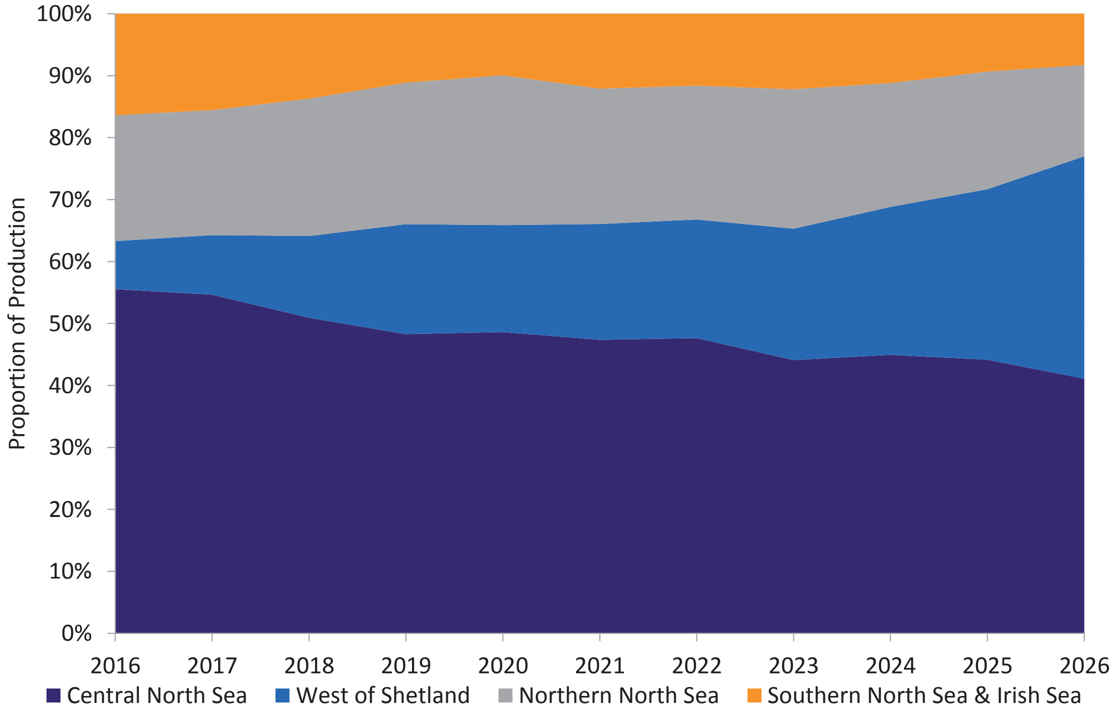
Oil production will be boosted as the Clair Ridge development ramps up towards peak production and the start-up of the Mariner field in the northern North Sea. Total recoverable reserves from Mariner are expected to be around 300 million bbls, with peak flow rates of 55,000 bpd. At the time of field development plan approval in 2013, Mariner was the largest new investment commitment for more than a decade. Oil production will also be supported by the Orlando field in the northern North Sea commencing production and the potential start-up of the Lancaster field early production system, west of Shetland. Gas production will benefit from the start-up of the Culzean high-pressure, high-temperature (HPHT) gas field in the central North Sea. The Culzean field is the largest gas project to be sanctioned in the UK for the last 25 years and will target total recoverable reserves of up to 300 million boe. At peak production it will supply around 5 per cent of total UK gas demand.

Looking further out, it is expected that the strong recent production trend will continue until at least 2020, before returning to a position of decline. Current projections indicate that this decline is likely to be at least 5 per cent per year through the first half of the 2020s.

Achieving Vision 2035's aspiration of adding a new generation of productive life to the basin means successfully managing this production decline to ensure production from the UKCS is at least one million boepd in 2035 — the equivalent of 40 per cent of projected UK oil and gas demand and 26 per cent of primary energy demand. If this ambition is to be achieved, continued investment in capital projects of at least the range seen in 2018 will be required (see section 4.3), along with increased progression of resources and sustained exploration success (see section 4.2). There was positive progress in each of these areas last year, and continued improvements in the coming years will be equally crucial. Ensuring the basin continues to be seen as both valuable and competitive on a global scale will be central to achieving this.

Although production trends are forecast to return to a position of decline in the early 2020s there are still areas of significant growth potential within the basin, primarily west of Shetland. Based on current developments and fields expected to come on stream, production from the west of Shetland area could increase from 8 per cent of total UKCS output in 2016, to 36 per cent in 2026. The production increase here in recent years, seen in Figure 8, has been driven by major start-ups such as Quad 204, Clair Ridge and Solan. Through to 2026, it is expected that further new fields will be progressed through to development, including Lancaster, Cambo, Rosebank and Glendronach. This could be further boosted by potential new developments which could arise from exploration opportunities such as Lyon, Warwick and Blackrock, among others (see section 4.2).

Figure 8: Regional Production Outlook



Source: Oil & Gas UK, WoodMackenzie

However, the more mature regions off the east coast of the UK will also continue to provide significant value-adding opportunities for E&P companies. There are currently new developments being progressed within the northern, central and southern areas of the North Sea, as well as additional exploration activities within each area. Companies are increasingly adopting hub strategies, making effective use of existing infrastructure and their extensive geological understanding to maximise recovery from these areas. Competitive fiscal terms, improved costs and commercial alignment allow companies to realise significant value from smaller opportunities. It is important that companies continue to be open to adopting strategic and collaborative approaches, across both E&P companies and the supply chain. This can help improve the economic and technical feasibility of projects which are not currently seen to be viable opportunities. There are a number of examples of constructive models which have helped to unlock and progress new opportunities, such as CNOOC's Buzzard Phase II and Apache's Garten field.

As well as progressing new field developments, it is crucial that industry retains a focus on maximising recovery from existing fields. Positive progress has been made in this area in recent years, and production efficiency is now at its highest level for a decade (74 per cent), with the improvements in 2017 adding an additional 12 million boe to basin-wide production.[5] Driving increased well intervention activity to maximise flow rates and return shut-in wells to production will also play an important role in maximising recovery from existing fields.

[5] www.ogauthority.co.uk/media/4967/ukcs-production-efficiency-2018.pdf

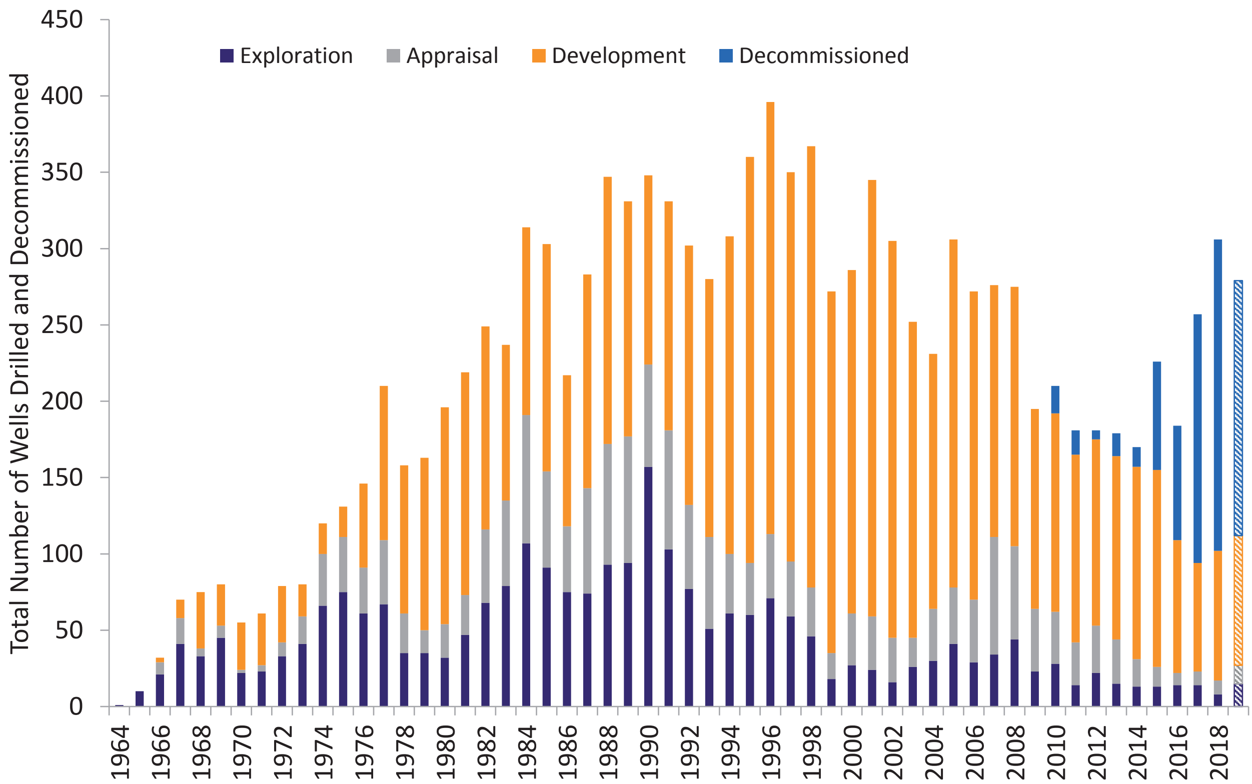
4.2 Drilling Activity

In total, 102 wells were drilled on the UKCS in 2018 (85 development, eight exploration and nine appraisal). Although this represents a slight increase from 96 wells in 2017, well construction activity — key to progressing resources to production — remains among record-low levels. This is largely the result of only the most valuable work programmes being progressed amid continued capital discipline and reduced investor risk.

Despite this, there is optimism that there could be further improvements in 2019, with some increases possible across all types of drilling activity. It is hoped that this signals a stabilisation in terms of resource progression activity, and the beginning of a steady recovery. However, it should be acknowledged that these improvements remain somewhat uncertain, with companies closely monitoring market conditions and adjusting their strategies to match.

Many of the opportunities within E&P portfolios are relatively small, a reflection of the maturity of the UKCS and the increased diversity of ownership. It is important that companies continue to work collaboratively to create scale within and across portfolios to improve the chances of resource progression opportunities being realised.

Figure 9: Total UKCS Drilling and Well Decommissioning Activity[6]



Source: OGA

[6] Note that well decommissioning data is only available from 2010.

Figure 9 shows that, in line with the reduction in actual drilling activity, there has been an increase in well decommissioning activity, with more wells decommissioned than drilled in both 2017 and 2018. Well decommissioning is part of the lifecycle of an oil and gas field, with increased activity in recent years partly driven by reduced rig rates and a lack of activity in other areas. However, decommissioning activity needs to be considered alongside other opportunities and pressures on budgets, as companies adopt a life-of-field approach and therefore it is important that the competing demands on E&P companies for capital allocation are understood.

When combined, total activity across development, appraisal, exploration and well decommissioning is at the highest rate for more than a decade, increasing competition within companies for capital, equipment and resources. Although this provides some benefits for the supply chain in terms of activity levels, it is vital that industry retains its focus on barrel-adding and resource progression opportunities.

Exploration Activity

Despite low levels of activity in recent years, there is increasing optimism around exploration on the UKCS and companies continue to be encouraged by the value that can be realised from the basin.

Eight exploration wells were drilled in 2018, the first year that there have been less than ten exploration wells drilled on the UKCS since commercial volumes were first discovered in the basin in 1965. Yet despite the low level of activity, the recent track record of successful finds continued in the form of significant discoveries made in four of the six wells for which results have been announced so far (Garten, Glendronach, Agar-Plantain and Glengorm). In total, these four wells have discovered up to 485 million boe (equivalent to 78 per cent of produced volumes in 2018), with the Glendronach and Glengorm wells providing the largest conventional finds on the UKCS for a decade. The results of the Rowallan well in the central North Sea, operated by ENI, and the Neptune Energy-operated FB9 well in the southern North Sea have yet to be announced.

It should also be noted that this 485 million boe is a similar number to the total discovered volumes in Norway last year, but was achieved with 20 fewer wells.

The Oil and Gas Authority (OGA) estimates that, as of the end of 2017, the range of total yet-to-find resources was 2.2–9.4 billion boe, with a likely estimate of 4.1 billion boe. Around 73 per cent of this is estimated to be in the central North Sea (46 per cent) and west of Shetland (27 per cent), with gas expected to account for 61 per cent of prospective resources. This demonstrates a shift within UKCS resources, with oil accounting for around 70 per cent of currently known resources.[7]

[7] www.ogauthority.co.uk/media/5126/oga_reserves__resources_report_2018.pdf

Exploration Highlights of 2018

March 2018

Garten

Discovery announced by Apache in March 2018

The 10 million boe discovery in the Beryl area of the northern North Sea was a result of Apache's near-field exploration strategy and the benefits of investing in high-quality data and modern technology to maximise recovery from mature areas. The field was progressed from discovery to first production within just eight months.

September 2018

Glendronach

When announced in September, this was the largest conventional discovery on the UKCS since Culzean in 2008

With initial reserve estimates in the region of 175 million boe, this west of Shetland discovery is in close proximity to infrastructure already operated by Total E&P. Following further appraisal, it is possible that this discovery could be developed relatively quickly, making use of the existing infrastructure put in place to service the fields within the Greater Laggan and Tormore Area.

November 2018

Agar-Plantain

The private-equity backed operator Azinor Catalyst, along with partner companies, announced success at the prospect in November 2018

This discovery in the northern North Sea is a further example of the benefit modern seismic techniques have in helping to de-risk opportunities. The discovery, which could hold up to 50 million boe, will be examined further to determine a potential development concept. However, it is possible that this could be developed quickly due to its proximity to infrastructure within the area.

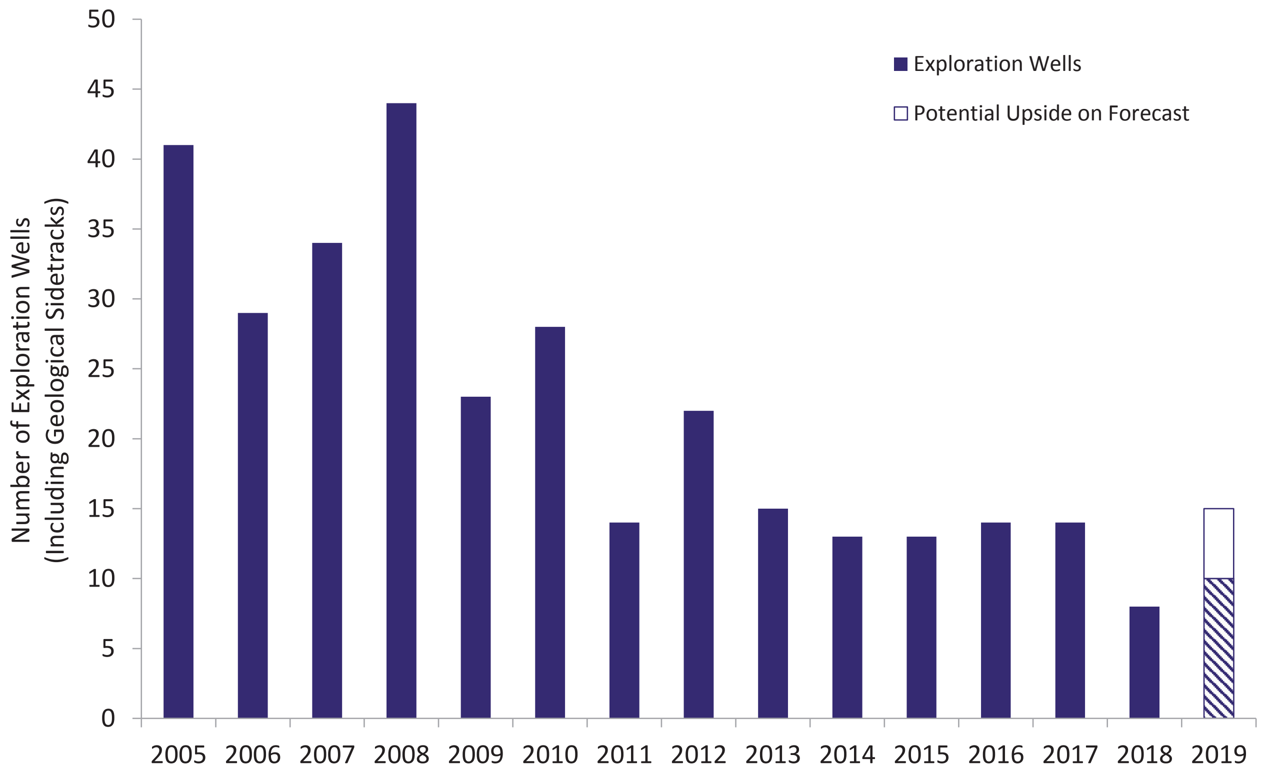
December 2018

Glengorm

Discovered by CNOOC and partner companies in 2018, and announced in early 2019

The HPHT Glengorm well in the central North Sea has overtaken the Glendronach discovery as the largest conventional find for a decade. With initial reserve estimates of up to 250 million boe, the field is close to infrastructure operated by one of the partner companies (Total E&P) and after further appraisal could be potentially progressed relatively quickly.

Figure 10: Exploration Drilling on the UKCS



Source: Oil & Gas UK, OGA

Although there has been relatively low exploration activity in recent years, significant effort has continued to mature and de-risk prospects to a drill-ready state. OGUK anticipates that an increase in exploration drilling will be seen in 2019, with up to 15 exploration wells expected to be spudded this year. This should be seen as positive news and would signal a return to levels of exploration drilling seen between 2013–17. The first two of these wells have been spudded, at the Bigfoot prospect in January, followed by Pip in February, both operated by Equinor.

Several of the 2019 opportunities are high-impact wells which, if successful, have the potential to add more resources than were discovered in 2018. These wells could help to open new areas or plays in the UKCS by providing the materiality required to justify investment in new infrastructure. The so-called 'Northern Gas Area' west of Shetland is a good example. There are a number of smaller gas opportunities in this area which are not viable as standalone developments but, if successful, the Siccar Point-operated Lyon well could allow the creation of a new gas hub for the area.

Close attention will also be paid to the Warwick prospect, west of Shetland, as Hurricane Energy looks to prove the potential of the fractured basement plays. If successful, this could help unlock other basement opportunities across the UKCS, bringing significant new resources. The Pip, Ossian-Darach, Isabella, Blackrock and Chimera wells also have the potential to be similarly high-impact discoveries.

***Figure 11: UKCS 2019 Exploration Opportunities Under Consideration*[8]**

It is also crucial that industry maintains a focus on near-field exploration. These opportunities can unlock significant value, while also providing much-needed additional throughput to improve the ongoing economic viability and life of existing infrastructure. The strategy adopted by Apache in the Beryl area is a good example of maximising near field potential, with four discoveries made in the area since 2015. Many of the opportunities planned for 2019 are near to existing hubs, including Total E&P's Alwyn East prospect in the northern North Sea, and Bigfoot, which could make use of Equinor's Mariner infrastructure.

Although near-field opportunities often target relatively small volumes, the value of the UKCS can make these opportunities more commercially attractive in the UK compared with other basins. Competitive fiscal terms, good access to infrastructure and improved costs mean that these smaller volume projects are more likely to be developed here.

Near-field projects can provide important capital flexibility, by allowing for quicker payback in terms of return on investment. Discoveries made in the last five years on the UKCS which have been, or are being developed have reached first production in an average of less than four years and in some cases significantly less time; Apache's Garten field, for example, reached production just eight months after discovery. Opportunities such as these are important aspects of exploration portfolios, helping to bring a balance alongside more frontier projects which carry higher associated risks and capital exposure.

[8] Please note that this list is not exhaustive and not all wells may be drilled. Some prospects may require more than a single exploration well.

Appraisal Drilling

Following discovery, companies may choose to further appraise prospects in order to improve understanding of the reservoir and to help inform potential development concepts. The level of appraisal drilling therefore relies heavily on the amount of exploration activity and number of discoveries. There were nine appraisal wells drilled on the UKCS in 2018, in line with levels since 2016. However, the appraisal wells that have been drilled do provide a positive indication that these developments are likely to move forward in the near future.

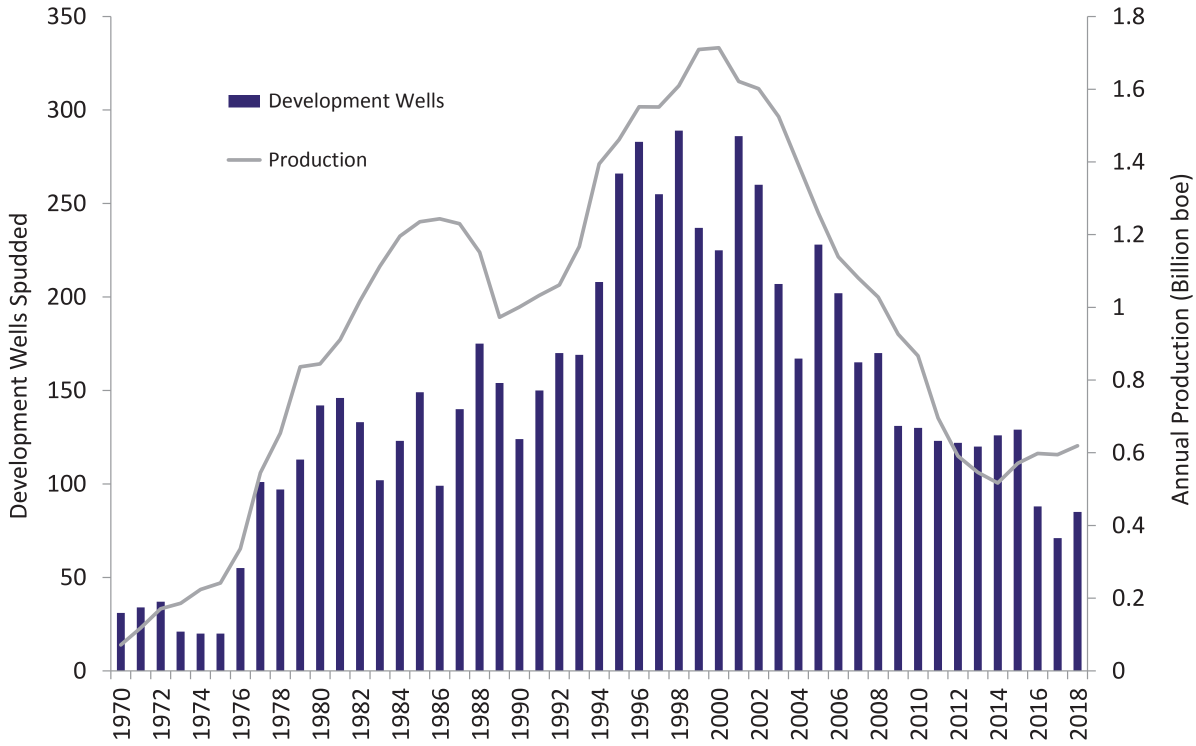
The first appraisal well spudded in 2019 at the Colter field off the south coast of England has reported encouraging results, followed by Chrysaor's Mabel well in February and Equinor's Verbier appraisal in March. It is expected that up to 12 appraisal wells will be drilled in 2019, with a number of discoveries in recent years requiring further appraisal work to improve understanding. This could include the Glengorm and Glendronach fields, as well as the BP-operated Capercaillie and Achmelvich discoveries. Further appraisal work is also being planned at the Agar-Plantain prospect in the northern North Sea and the Cragganmore and Lincoln opportunities west of Shetland, a number of other appraisal opportunities are also being considered across the basin.

Development Drilling

Eighty-five development wells were spudded in 2018 and OGUK expects that development drilling will plateau at this level, at least in the short term, with activity remaining subject to constant funding challenge.

Development drilling is crucial to progressing resources, with a strong historic correlation between the number of development wells spudded and total basin production. In recent years (2014–18) this trend has been broken, with overall production remaining strong despite a reduction in development well spuds of around one-third since the beginning of the downturn. Production has been supported by improvements in facilities, infrastructure and reservoir optimisation, helping to drive production efficiency improvements. However, the current levels of production cannot be sustained in the long term if drilling and wells activity remains low.

Figure 12: UKCS Development Drilling and Production



Source: BEIS, Oil & Gas UK

A key driver of the decline in development drilling has been the relative lack of new project approvals between 2015–17. Most of the projects which were approved were relatively small, with fewer than five wells in the development phase. However, new technology and advanced drilling techniques have also helped companies improve well placement, meaning that fewer wells are often required to achieve the same level of recovery. The Catcher field in the northern North Sea is a good example of this; project partners were able to reduce the number of required wells from 22 to 18, resulting in significant cost savings, without compromising on reserves recovery.

Along with the decline in new projects, there has also been a decrease in drilling on existing fields (e.g. infill well campaigns). This is the result of several factors, including:

- **Relatively high well costs, despite reductions in recent years.** Infill well targets are often marginal, especially within late-life fields, meaning that high costs can prevent opportunities from being progressed. Companies also need to consider the costs of supporting increased production in the existing facilities and any infrastructure access charges.
- **Full understanding of reservoir characteristics.** This can be difficult if there is a lack of relevant, high-quality data (such as seismic imagery) and can increase investment risk and uncertainty.
- **Internal challenges and competition.** Internal competition for capital can be intense and business cases to drill new infill targets may need to be evaluated against other investment opportunities and required expenditure (including exploration, appraisal and well decommissioning). Companies need to ensure a balanced investment portfolio whilst meeting any regulatory and legal obligations. The wider company and asset strategy should also be taken into account to ensure an integrated approach to reserves progression.

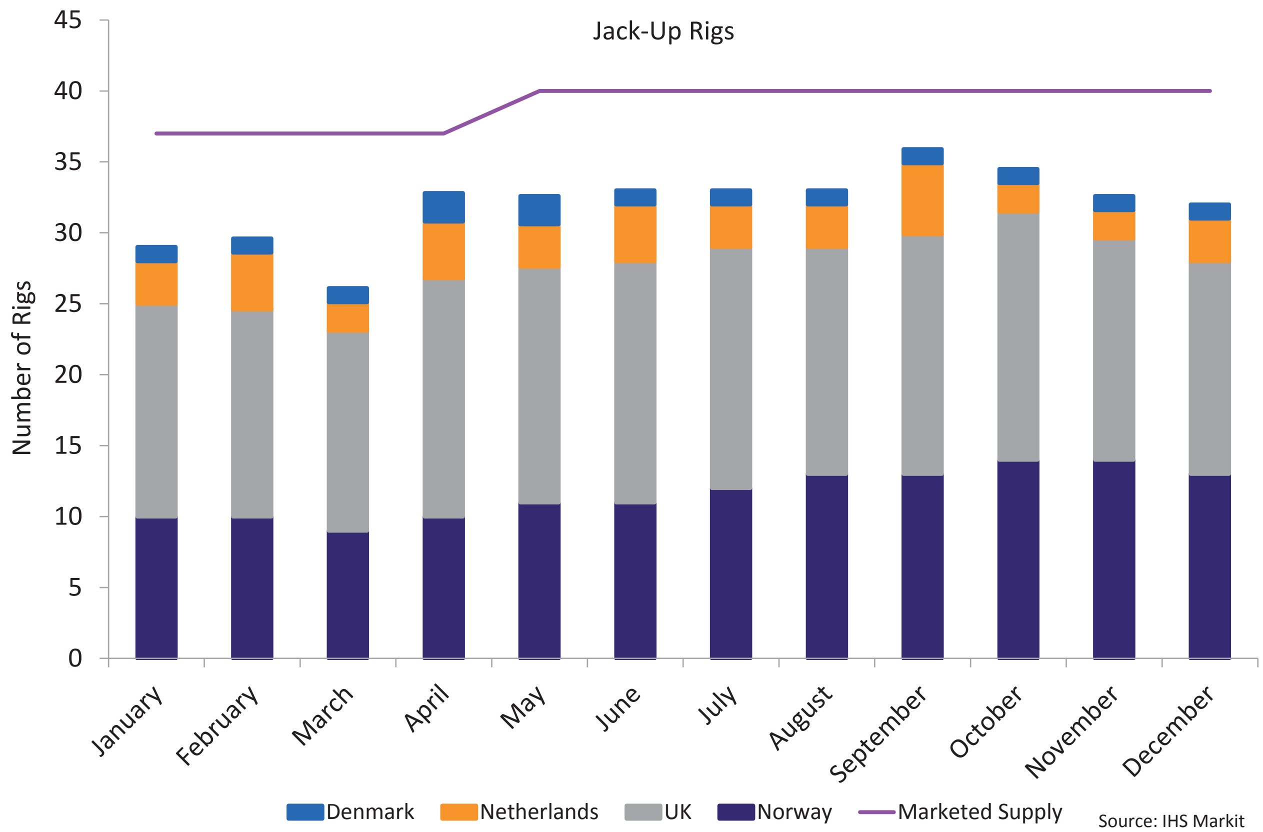
Progressing reserves to replace production through development drilling will help ensure production levels are managed effectively going forward. There is significant cross-industry action ongoing to help ensure a sustainable level of drilling activity is achieved. OGUK's Wells Forum facilitates the sharing of good practice and the development of guidelines and tools to improve performance in this area. This is resulting in improvements in well delivery, however many of the work areas will require time to embed and impact on industry performance.

Drilling Rig Market

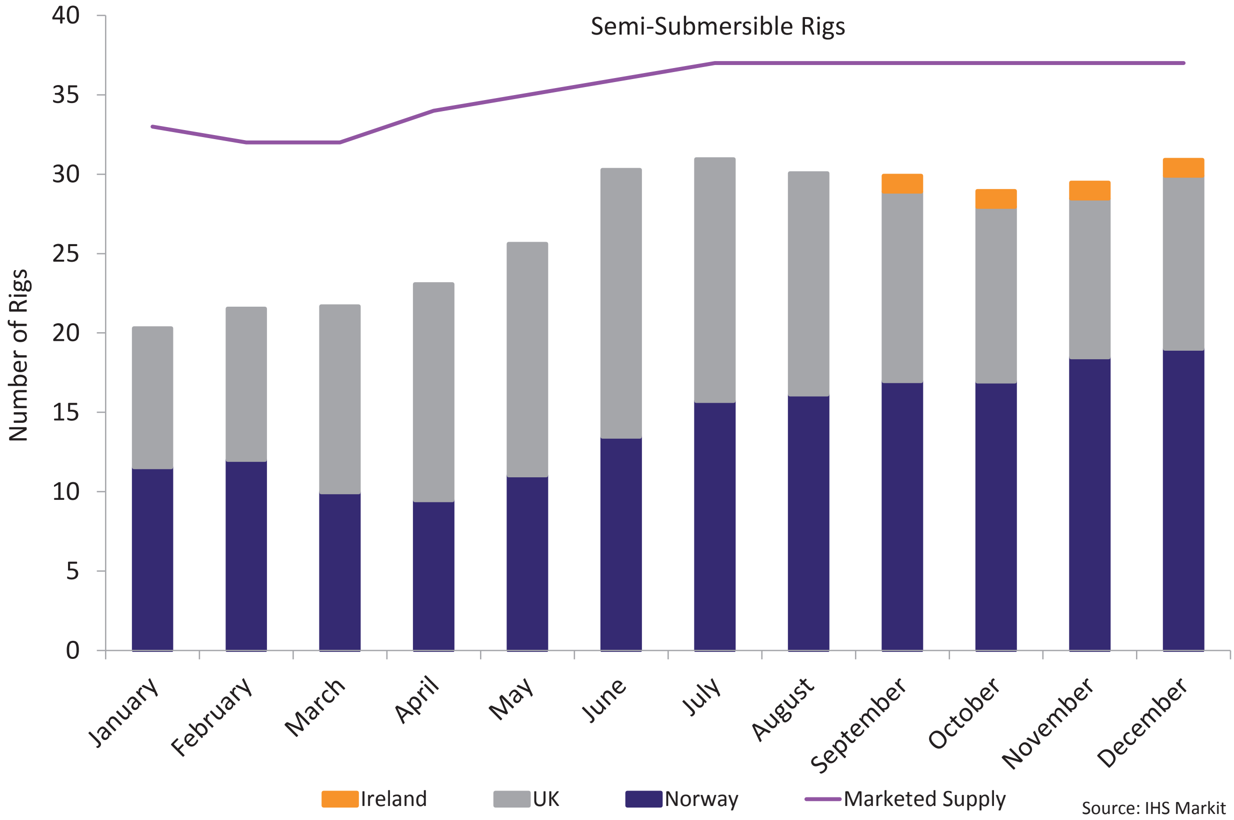
As outlined in section 5, there has been significant pressure on the supply chain in recent years. Drilling contractors have been amongst the most affected, due to the relative reductions in drilling activity. Throughout the downturn there has been spare capacity within the North Sea, meaning several drilling rigs have been stacked, scrapped or moved out of the UKCS. A loss of capacity and resources within the drilling sector is a real threat to the ability of industry to meet any increase in drilling activity in a sustainable manner. The availability of a well-resourced supply chain will be crucial to maximising economic recovery from the basin.

Looking forward, it is anticipated that the rig market will tighten this year, especially for higher specification rigs. However, there is clear seasonality within work programmes, with E&P companies preferring to complete work scopes in the summer months due to more favourable weather conditions. A tightening of the market is therefore expected during the summer, with further overcapacity during the winter months.

Figure 13: Mobile Drilling Rig Market Outlook



Source: IHS Markit



Although utilisation rates are forecast to increase to a certain extent, with the gap between demand levels and marketed supply closing, drilling and wells services contractor companies still face significant challenges. Many of the proposed work programmes are relatively short-term and fragmented, and E&P companies therefore need to continue to work collectively to generate a sufficient scale of work scopes in order to improve the chances of these opportunities being progressed and to ensure that contractors are able to anchor resources in the basin to service this demand. The UKCS is also in competition with other basins, including north-west European countries such as Norway as well as eastern-European and Middle-Eastern countries, for supply chain resources. The basin needs to be seen as an attractive place for contractors to do business in, otherwise there is an increased risk that work in other basins will be prioritised.

4.3 E&P Expenditure

Pre-tax expenditure on the UKCS was £14.3 billion in 2018 (£15.4 billion post-tax), slightly less than had been anticipated as companies retained strict capital and operational budgets. However, a slight increase in pre-tax expenditure to more than £15 billion (£16.4 billion post-tax) can be expected this year. This will be underpinned by:

- A pick-up in capital investment, driven by new project approvals
- Increased operating expenditure as major new projects come onstream
- Increased decommissioning expenditure as the market continues to mature
- A projected increase in exploration and appraisal activity

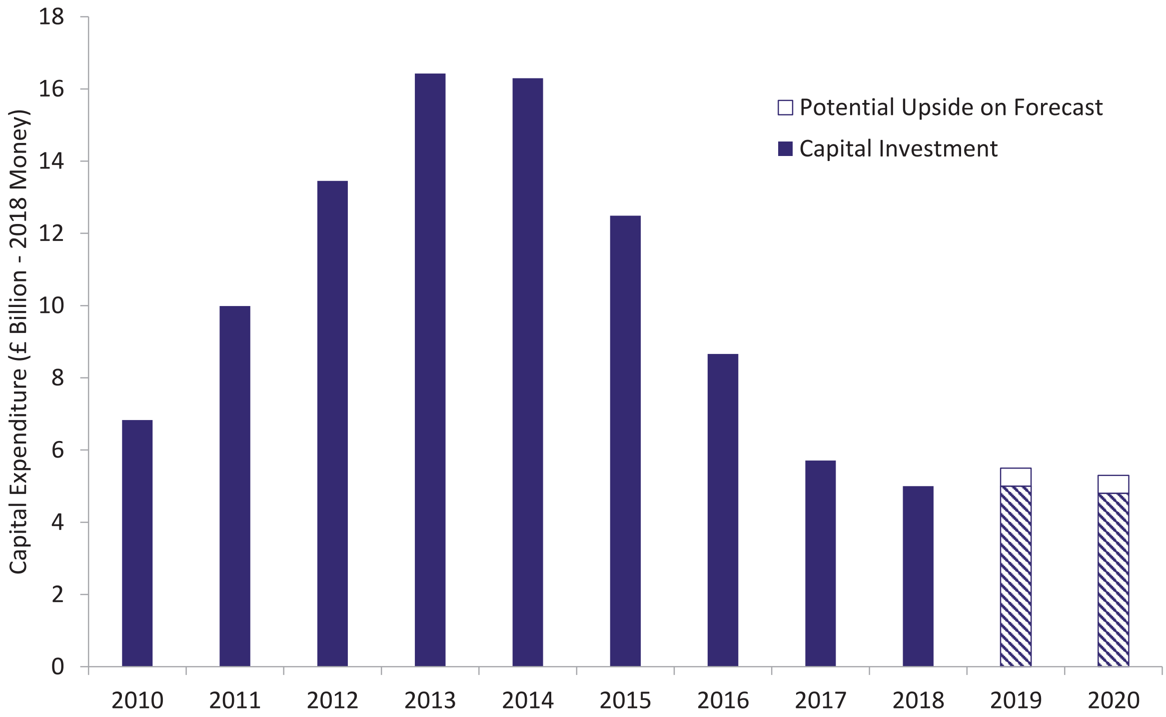
Maintaining expenditure levels will be crucial to achieving Vision 2035, with around £200 billion required to be spent between 2019–35 to add a generation of productive life to the basin. This would also provide a significant opportunity for supply chain companies.

Capital Expenditure

Attracting a steady stream of capital investment to the basin will be crucial to managing production in line with Vision 2035. This is required to develop new fields, drill new wells and upgrade infrastructure to ensure that industry is well positioned to maximise economic recovery. New capital approvals also provide much-needed new opportunities for supply chain companies.

Total capital investment has fallen by more than two-thirds since 2014, to £5 billion in 2018. The decline has been driven by capital efficiencies in development projects, cancelled or deferred work scopes and fewer new project approvals. However, it should also be taken into account that the decline has been from record levels; for that reason, reductions would have been seen even if the downturn never occurred, albeit to a lesser extent.

Figure 14: Capital Investment

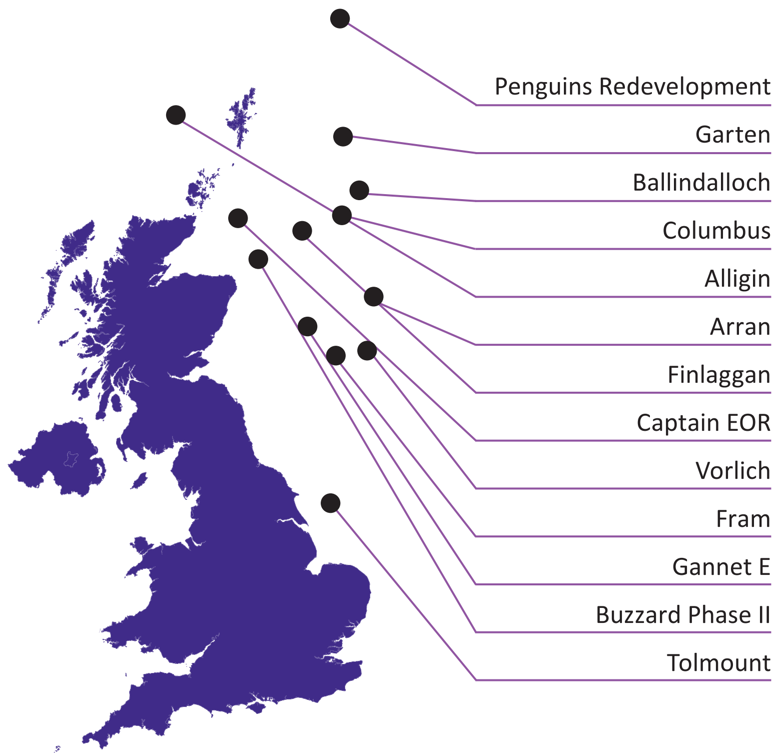


Source: OGA, Oil & Gas UK

OGUK expects that levels of capital investment will stabilise in 2019 and 2020, with the potential for a marginal increase to £5–£5.5 billion this year; this will be driven by the growth in new field approvals seen in 2018. Companies are having to work harder than ever to create business cases to bring investment to the UK amid strong international competition and tight budgets, however the significant increase in new projects last year demonstrates the attractiveness of the basin.

Thirteen new fields and/or field redevelopments were approved by operators and the OGA in 2018, three more than the previous three years combined. Overall, these approvals have an average capital investment of £8 per boe, unlocking more than £3.3 billion of new investment, and are expected to produce more than 400 million boe throughout their operational lives. These projects have benefitted from improvements in unit development costs of up to 50 per cent since 2014. The basin has also seen new brownfield investment to upgrade existing facilities and put new export routes in place, helping to ensure maximum economic recovery from existing fields.

Figure 15: New Fields Approved in 2018



Most of the projects approved in 2018 were subsea developments, with the majority being tied back to existing infrastructure. Only two of the projects will require the development of new host facilities: the Penguins Redevelopment project will consist of a new-build FPSO, and the Tolmount development will see the construction of a new platform and export infrastructure. Looking forward, most of the pre-development opportunities in the basin will be progressed using subsea infrastructure, making use of existing host facilities and export routes where possible in order to maximise value. Some of the larger projects will see the use of FPSOs, however, there are relatively few opportunities on the horizon which would require the development of new platform-based facilities.

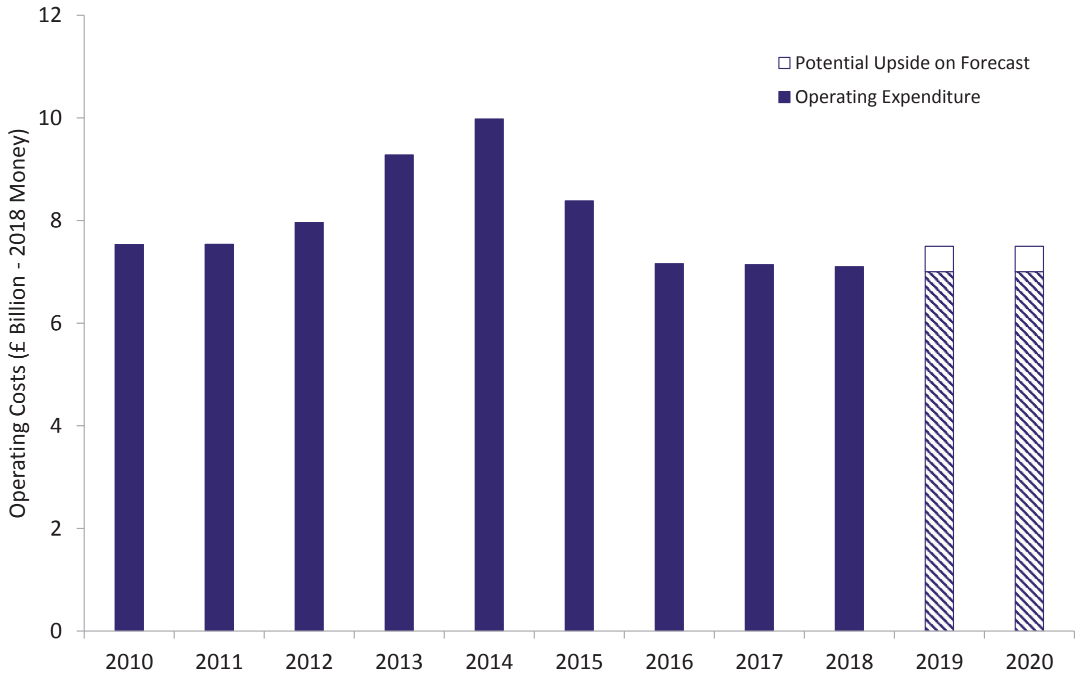
OGUK expects that 2019 will see a similar number of new projects approved as in 2018. The 12–15 projects likely to be approved could unlock £2.5–£3.5 billon of new capital and 300–400 million boe of new reserves. However, these commitments should not be taken for granted and will only be delivered if the attractive investment conditions are maintained.

Operating Expenditure

E&P company budgets remain tight and companies are focused on maintaining business and operational improvements. As such companies are looking to sustain recent cost reductions and will not allow unit operating costs (UOCs) to increase.

Operating expenditure has been reduced significantly during the recent downturn, from £10 billion in 2014 to £7.1 billion in 2018. OGUK expects that operating expenditure will now stabilise at around £7–£7.5 billion through to 2020, with new fields coming on stream leading to a slight increase in expenditure.

Figure 16: Operating Expenditure



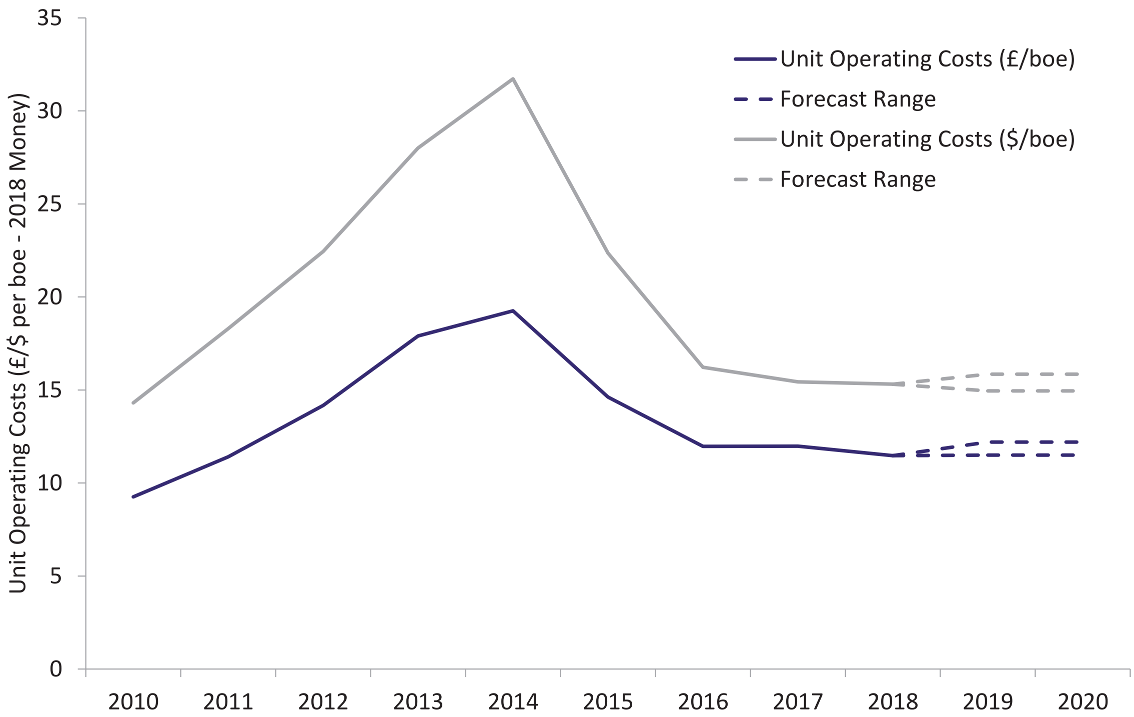
Source: OGA, Oil & Gas UK

UOCs are the key measure used by E&P companies to track cost control and efficiency, and there has been a determined focus in industry to sustain recent improvements. When the decline in operating expenditure is considered alongside the relatively strong production performance in recent years, UOCs have been reduced by more than 50 per cent in dollar terms since 2014 to $15.30/boe (40 per cent in GBP terms to £11.50/boe). However, it should be acknowledged that, despite improvements, there is significant variation in UOCs across E&P companies, with a range of around $5–$35/boe.

The cost improvements have been central to improving the cash flow position of E&P companies active on the UKCS and have boosted the competitiveness of the basin. However, as outlined in OGUK's *Economic Report* 2018,[9] these figures do remain relatively high in comparison with other basins. As a mature basin, it is important that the attractiveness of the UK is measured in more than just cost; competitive fiscal terms, the extensive network of infrastructure, proven resources and a strong supply chain all mean that significant value can be achieved by UKCS investments.

[9] OGUK's *Economic Report* 2018 is available to download at www.oilandgasuk.co.uk/economicreport

Figure 17: Unit Operating Costs



Source: Oil & Gas UK, OGA

It is crucial that the improvements that have been seen in the cost profile are sustained in the long term – the UK industry cannot afford to return to boom and bust cycles. Good progress is being made, but closer collaboration and more innovation within contracting models will need to continue to emerge to ensure that efficiency improvements are sustained whilst also ensuring that supply chain companies are able to make a reasonable margin which allows them to reinvest in UK capabilities (see section 5.2).

The development and adoption of new technology also has a vital role in sustaining, and building on, cost and efficiency improvements and to help unlock new investment opportunities. The Oil & Gas Technology Centre (OGTC), formed through the Aberdeen City Region Deal, is leading industry efforts on this front across digital transformation, asset integrity, wells, marginal developments and decommissioning.

Decommissioning Expenditure

Alongside exploration, development and production operations, decommissioning activity is a natural part of the lifecycle of any oil and gas basin. Despite being the only increasing area of expenditure in the basin in recent years, industry is committed to reducing the overall forecast costs of decommissioning by at least 35 per cent by 2022, ensuring that total out-turn costs do not exceed £39 billion (projected from baseline estimates made in 2016).

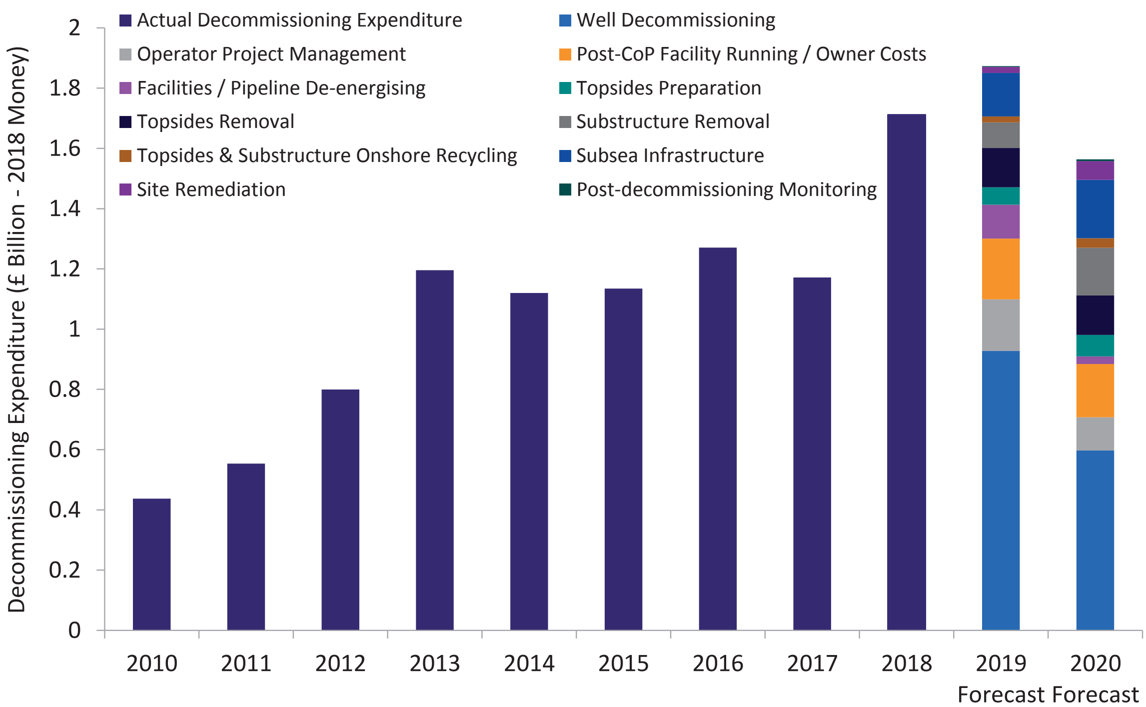
Industry is liable for all costs associated with decommissioning, with companies able to offset these against current or historic profits for tax purposes. Given this responsibility, it is demonstrating its ability to manage decommissioning activity in an effective manner, and increased experience, technological improvements and enhanced collaboration mean that decommissioning activity is being delivered more efficiently and cost effectively. OGA figures show that the total cost of decommissioning has reduced by 7 per cent compared with 2017[10] and expenditure is expected to be around £15 billion between 2018–27, roughly 20 per cent less than the previous ten-year estimate.[11]

[10] www.ogauthority.co.uk/media/4999/decommissioning-a5-2018-pdf-version.pdf

[11] OGUK's *Decommissioning Insight* 2018 is available at www.oilandgasuk.cld.bz/Decommissioning-Insight-2018

In many cases, improved investment conditions and the transfer of assets to new owners are helping to delay cessation of production (CoP). As a result, decommissioning activity is being moved to the right. Timings for CoP are continually being assessed to ensure maximum economic recovery is achieved.

Figure 18: Decommissioning Expenditure



Source: Oil & Gas UK, OGA

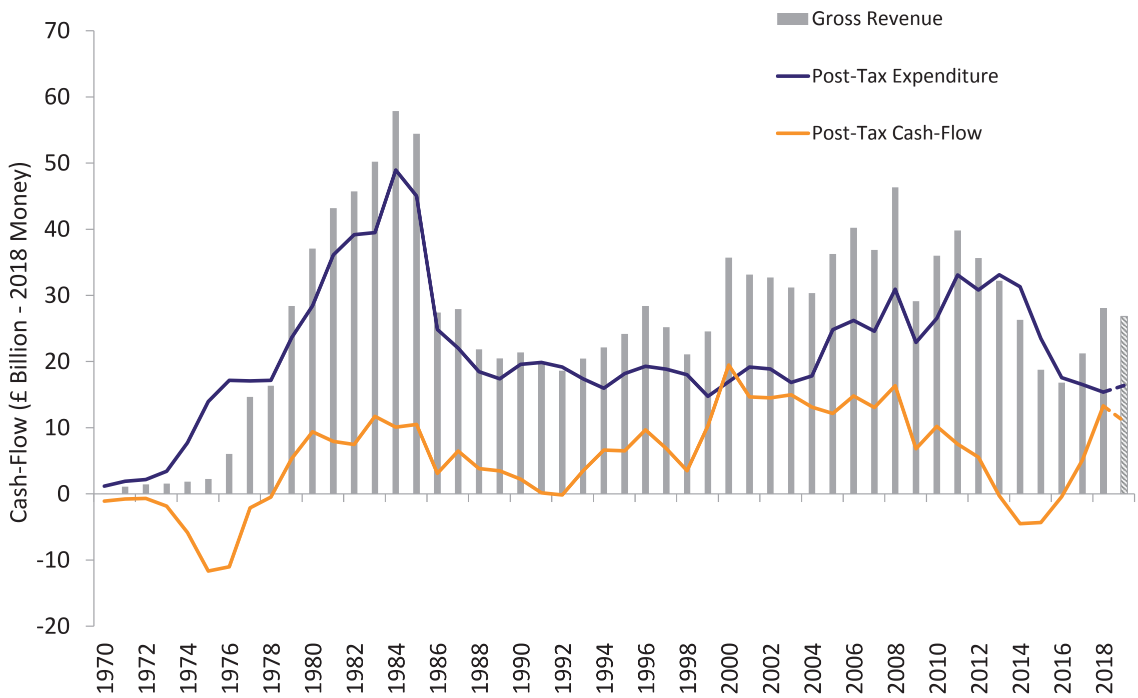
Decommissioning activity also provides the opportunity for the UK to develop world-leading capabilities which can be exported globally. UK regulation and guidance are sought after, and the supply chain already has the skills, expertise and resources to meet the majority of the work scope of UK decommissioning over the next decade. The UK government is currently undertaking a call for evidence on establishing the UK as a centre of decommissioning expertise — an opportunity which will play an important role in meeting the ambition of Vision 2035.

Cash Flow and Taxation

It is estimated that around £13 billion of total free cash flow was generated from UKCS production operations in 2018. Production revenues increased from £21 billion in 2017 to £28 billion last year, the result of higher oil and gas prices as production remained relatively stable. Alongside this, there was a reduction in overall expenditure, mainly due to lower-than-anticipated capital investment and exploration and appraisal activity. However, the 2018 figure should not be taken in isolation and must be considered in line with rates over the prior decade when cash flow was low, and often negative.

Despite positive returns in 2018, it should be acknowledged that this is a basin-wide estimate and the cash flow position of individual companies will vary significantly depending on their cost, investment and production profiles, corporate and financing structures, and the period of time in which they have been active on the UKCS. Some companies have accumulated losses during the downturn which they can carry forward to offset against profits in future years, reducing their tax bill temporarily.

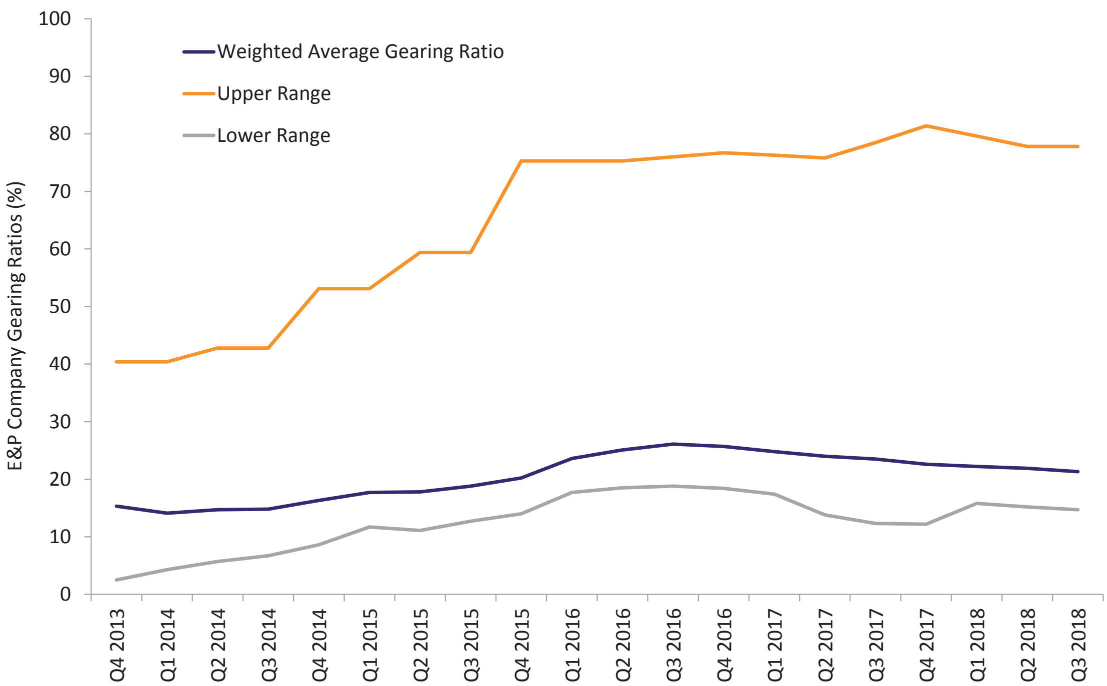
Figure 19: Production Revenue, Post-Tax Expenditure and Cash Flow



Source: Oil & Gas UK, OGA

Companies need to use the cash generated from their portfolios to satisfy various requirements. Funds are used to reinvest in UK and global portfolios, return value to shareholders via dividends and share buy-back schemes and reduce debt levels. Analysis of UKCS E&P companies shows that average gearing ratios (net debt compared to equity) are reducing, however there is a significant spread and debt leverage levels remain above those prior to the downturn. Gearing ratios of UK-focused operators are generally higher than their global counterparts, in part due to company size and strategy, but also as these companies have used the debt market to fund growth projects through mergers and acquisitions.

Figure 20: UKCS E&P Company Gearing Ratios

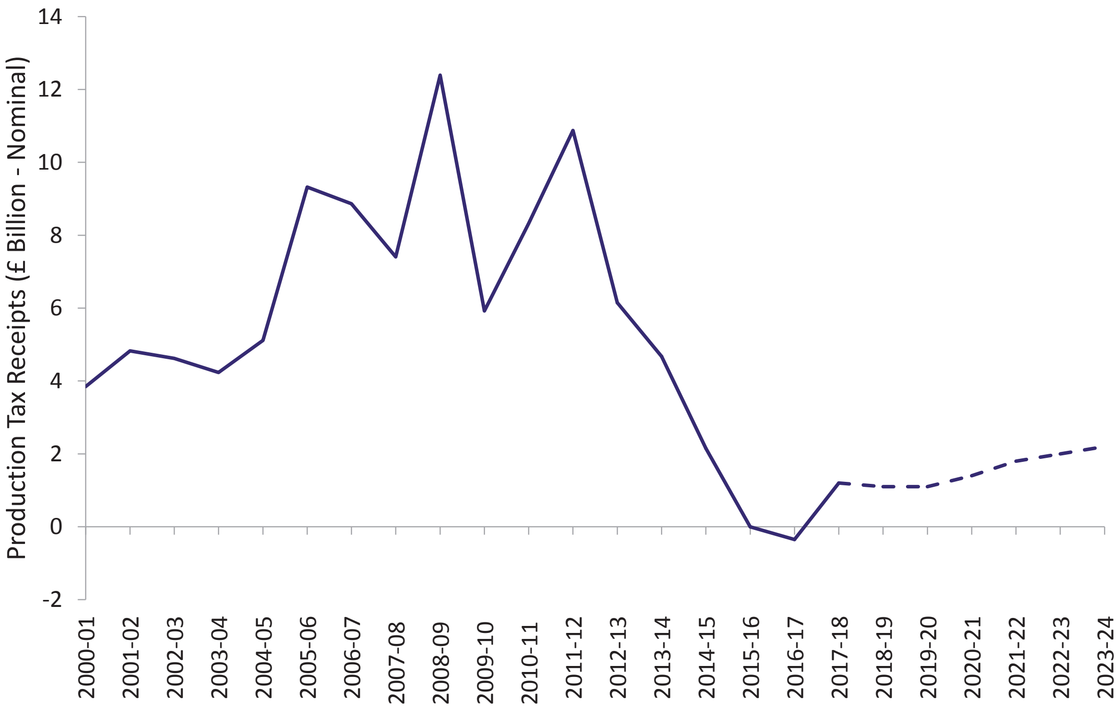


Source: WoodMackenzie, Rystad Energy

Many companies will continue to prioritise debt repayments prior to pursuing significant new investments. However, OGUK estimates that around 60 per cent of cash generated from the UKCS in 2018 across a sample of 20 E&P companies will be reinvested in the UK. This is comparable to rates in Norway and significantly higher than other basins including Australia, Angola and Qatar, demonstrating company commitment to the UKCS.

The structure of the UKCS fiscal system means that direct tax payments correlate strongly with the cash flow of companies. UKCS E&P companies paid almost £1.2 billion in direct production taxes in the fiscal year 2017–18 and contributed a total of £3.4 billion since the beginning of the recent downturn. The Office for Budget Responsibility (OBR) forecasts that the industry's production tax contribution will remain at around £1.1 billion in 2018–19 and increase to £2.2 billion in 2023–24.

Figure 21: Production Taxes



Source: HMRC, OBR

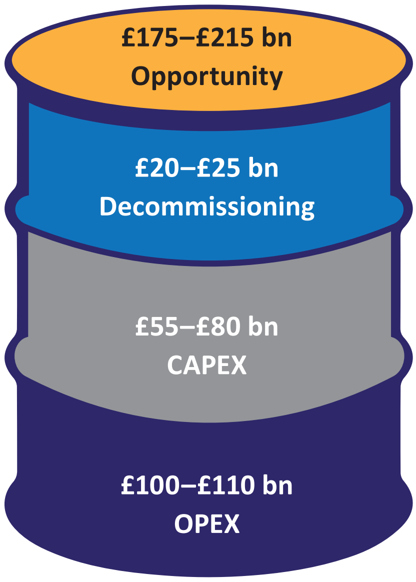
E&P companies have paid more than £350 billion in direct production taxes over the last 50 years and will continue to contribute significantly in the years to come, with £9.6 billion expected to be paid between fiscal years 2018–19 and 2023–24 — even after tax relief associated with decommissioning is taken into account. The wider economic and fiscal benefits provided by industry must also be considered; EY estimates that more than £300 million per year is paid in corporation taxes by supply chain companies, along with billions more in employment taxes and national insurance contributions.

Maintaining attractive investment conditions is key to ensuring that as much cash as possible is reinvested into the UKCS. Regulatory certainty and fiscal stability are key to investors, and the relative stability experienced over the previous years has nurtured a slow but much-needed return of investor confidence in the basin.

Adding a Generation of Productive Life to the Basin

Ensuring that the UKCS is an attractive investment destination will be key to achieving the aims of Vision 2035. The UK oil and gas industry is aiming to add a new generation of productive life to the basin — a goal which would see total output of at least one million boepd in 2035 and a cumulative 8.4 billion boe produced between 2019–35. OGUK estimates that to achieve this, around £200 billion will need to be spent by E&P companies over the period, providing a significant opportunity for supply chain companies. This is compared with a scenario without any further capital investment decisions, in which just over £100 billion in total would be expected to be spent during the period. In addition to operational expenditure and committed investment, around £45–£70 billion will need to be attracted to the basin to unlock known opportunities and to ensure that new resources are discovered and subsequently progressed. The deployment of new technology will have an important role to play in unlocking new investment opportunities, by helping to improve efficiencies and the economics of marginal projects. Alongside this, it is crucial that the UK has a competitive, sustainable and well-resourced supply chain which can efficiently service demand.

Figure 22: Expenditure Required to 'Add a Generation of Productive Life'



This £200 billion expenditure can be broken down as follows:

- **Securing committed capital investment —** Around £9 billion of expenditure is currently confirmed within company business plans to maximise recovery from existing fields and the development of committed new projects. This will deliver around 3.5 billion boe.
- **Unlocking new investment opportunities —** Almost 5 billion boe will need to be unlocked in order to achieve the aims of the vision, requiring £45–£70 billion of investment. Of this, around 2.5 billion boe in contingent resources are known to be under consideration by E&P companies, with varying probabilities of proceeding. Between £20–£30 billion would be required to unlock these projects, although further work is required to improve the economic and technical viability of many of these opportunities. A further 2.4 billion boe will need to be discovered and matured to production, requiring around £5–£10 billion in exploration and appraisal expenditure, rising to £25–£40 billion to progress prospects after discovery.
- **Operational expenditure to support production and operations —** Around £100–£110 billion will need to be spent over the next 16 years to support production from the basin.
- **Effectively managing decommissioning expenditure —** It is estimated that around £1.5 billion will be spent each year over the next decade on decommissioning activity. Based on this, and accounting for potential new efficiencies, between £20–£25 billion will be spent between 2019–35.

5. Supply Chain Outlook

In Summary

The UK oil and gas industry has a world-leading and highly developed supply chain, established through servicing the needs of the UK offshore operations over the last five decades and exporting goods and services to other basins and industries around the world.

Ready access to a competitive, top-class supply chain is a key component of the attractiveness of the UKCS as a place in which to invest and do business. However, many businesses have suffered throughout the recent downturn, with margins and revenue reduced and cash flow stretched. This may continue to hinder the ability of many companies to invest and rebuild capacity in the UK.

E&P companies remain focused on sustaining cost improvements, however this has to be balanced with ensuring a competitive, healthy and well-resourced supply chain, otherwise the industry's ability to maximise economic recovery of reserves will be impacted.

New contracting models, increased collaboration and new ways of working are emerging, and this trend must continue to help unlock new projects and for the supply chain to be able to effectively manage demand in future. This will be crucial to meeting the aims of Vision 2035 — to add a new generation of productive life to the basin and to double the opportunity for the supply chain through exports and diversification. It is therefore encouraging to see that most companies report an improved outlook for 2019, in terms of sentiment and revenue expectations; it is now crucial that this optimism translates to reality.

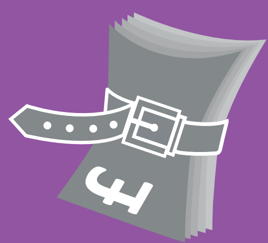
Around

£200bn

will need to be spent by E&P companies to add a generation of productive life to the basin – providing a significant opportunity for the supply chain

Almost two-thirds of contractor companies have a more positive outlook for 2019, compared to 2018

Supply chain turnover and average EBITDA margins fell by around one-third during the downturn

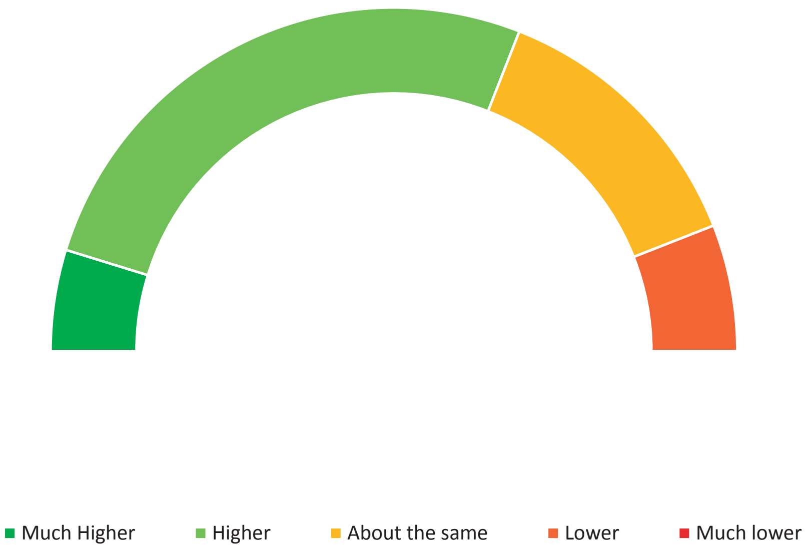


5.1 Supply Chain Sentiment

With an increase in capital commitments and expectations that operational expenditure has stabilised, there is a trend of improving sentiment and outlook within contractor companies. The OGUK *Contractors Sentiment Survey* indicates that 62 per cent of member companies have an improved outlook for 2019 compared to 2018, with only 12 per cent reporting a more pessimistic tone.

However, this improved sentiment must be kept in perspective with industry only just beginning to emerge from one of its most difficult periods. With many areas of the supply chain still experiencing significant financial stress, further effort will be required to turn this increased optimism into sustainability.

Figure 23: Snapshot of General Sentiment Among Contractor Companies for 2019 Versus 2018



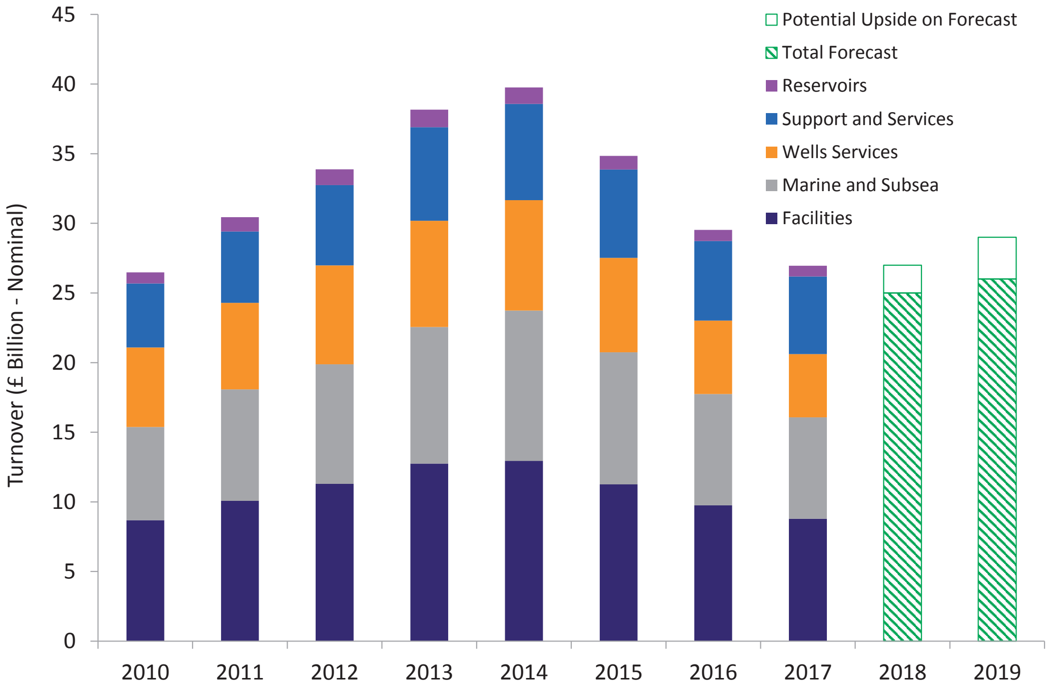
Source: Oil & Gas UK

5.2 Financial Performance

Figure 24 outlines revenue by supply chain sector between 2010–17, the most recent data published by the EY *Review of the UK Oilfield Services Industry*.[12] Total supply chain revenue is shown to have fallen by almost one-third between 2014–17, from just under £40 billion to £27 billion, as E&P companies reduced costs and investment in the face of significant market challenges.

[12] www.ey.com/uk/en/industries/oil---gas/ey-review-of-the-uk-oilfield-services-industry-january-2019

Figure 24: Supply Chain Revenue by Sector



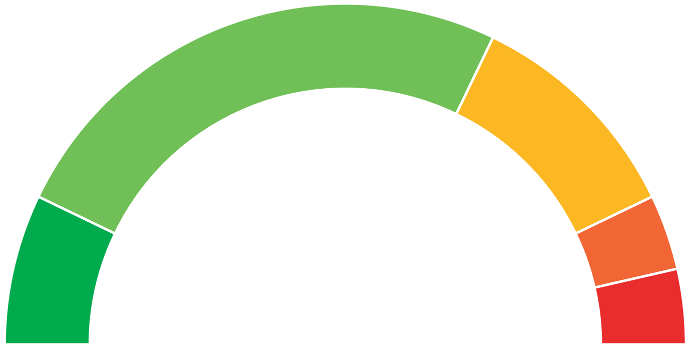
Source: EY, Oil & Gas UK

The wells services sector is reported to have recorded the largest reductions in revenue (43 per cent), driven by the significant rate reductions and the decline in drilling and wells activity seen during the period (see section 4.2), while support and service companies saw the least reductions (19 per cent). Facilities, marine and subsea and reservoir-focused companies all saw reductions of around one-third overall. However, it should be noted that these figures represent sectoral averages, with variations within this dependent on individual company positions.

As expected, the pace of revenue decline slowed in 2017 as companies began to see increasing activity levels, however these figures will still reflect the challenges posed by the industry downturn. Overall, the year-on-year reduction in revenue between 2016–17 was 9 per cent, in comparison with 15 per cent between 2015–16. OGUK forecasts that the trend of declining revenues will have continued in 2018, however this trend is likely to have slowed further.

There are indications that 2019 could bring an overall stabilisation, and potential improvement, in revenues for the supply chain as a whole for first time since 2014, as the increase in investment commitments and activity seen in 2018 begins to flow through the supply chain. Around two-thirds of respondents to OGUK's *Contractor Sentiment Survey* indicated that they expect revenue to increase this year. However, it must be recognised that some sectors, especially those which are asset intensive such as aviation and drilling rigs, remain under severe pressure and, in some cases, unsustainable positions as a result of reductions during the downturn.

Figure 25: Snapshot of Contractor Company Revenue Expectations for 2019 Versus 2018

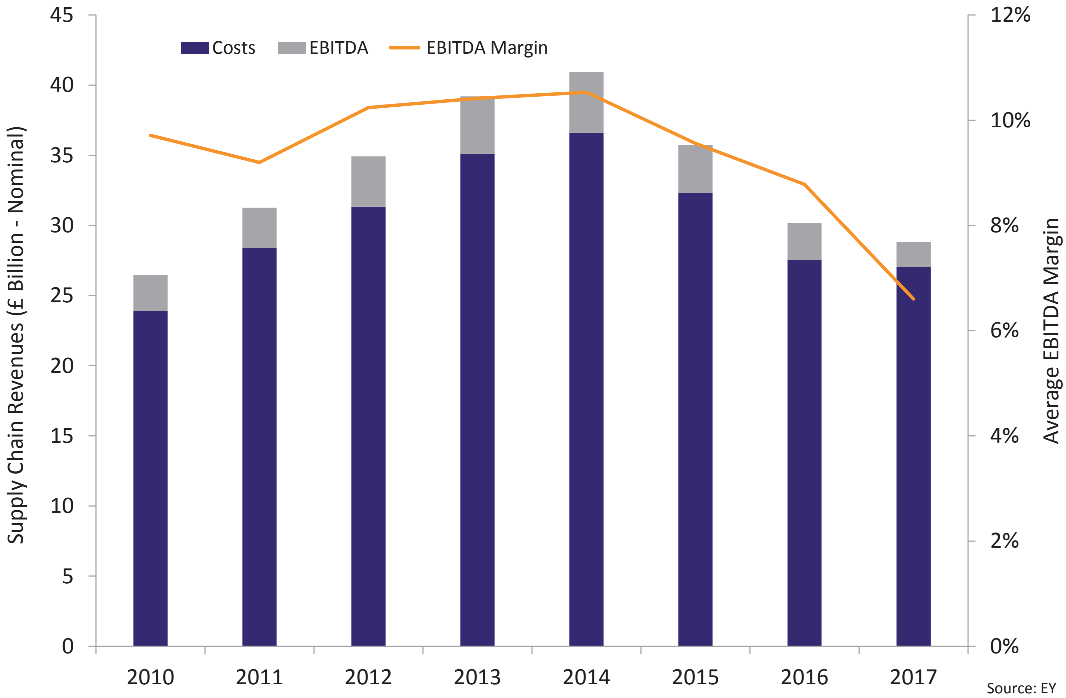


Source: Oil & Gas UK

Despite the increase in new investment commitments, E&P companies have retained a focus on cost discipline amidst ongoing market uncertainty. Continued pressure on companies can be seen in the ongoing decline in EBITDA[13] margins, which fell at a faster rate than revenues in 2017.

EBITDA margins are a commonly used indicator of a company's operating profitability, shown as a percentage of total revenue. However, since they do not consider exceptional costs (such as restructuring) and capital costs, they can provide a more positive outlook than the true financial position of some companies — especially capitally intense sectors such as rig contractors, which are required to purchase expensive equipment and assets.

Figure 26: Supply Chain EBITDA Margins



Source: EY

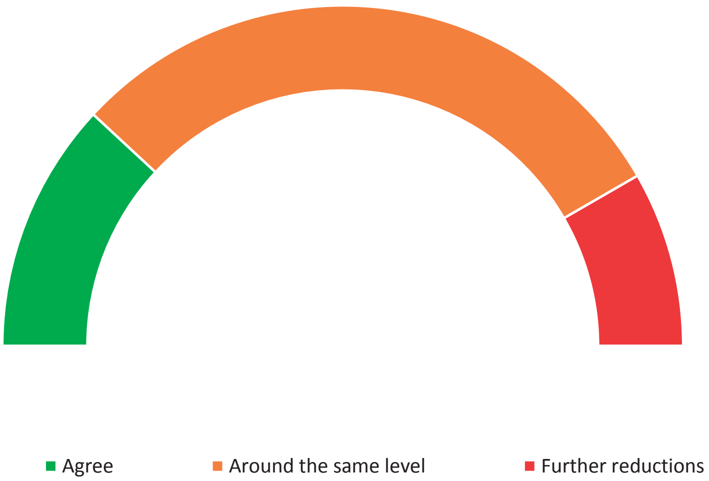
[13] Earnings before interest, tax, depreciation and amortization.

As a whole, EBITDA margins fell from 10.5 per cent in 2014 to 6.6 per cent in 2017. Despite this reduction, overall the supply chain has managed to maintain a positive margin. As well as further cost reduction throughout the supply chain tiers, this demonstrates that companies have managed to implement significant efficiencies throughout their operations and supply chains. However, it should be acknowledged that some companies will have recorded a negative EBITDA margin, inferring that they are using up any available cash reserves to cover operating costs, or increasing debt levels. A comparison between supply chain finances in 2010 and 2017 provides a good indicator of the increased stress that has been placed on this sector. While total revenues in 2010 and 2017 were in the same range, overall EBITDA margins have fallen from around 10 per cent to 6.6 per cent.

Whilst the supply chain has demonstrated its resilience and adaptability in recent years, reductions in revenue, margins and cash flow have placed many companies in a position of financial distress. With the trend of efficient and lean operations expected to continue across the UKCS, an increase in supply-chain margins will be required to allow companies to reinvest in the capacity and capability required to meet demand from UKCS operations. Current margin levels are not sustainable in the long run and will, if they continue, compromise the ability of industry to meet the aims of Vision 2035.

There is some optimism that there may be some positive movement in margins in 2019, however this will need to be driven by new ways of working and new contracting models with E&P companies focused on maintaining improved UOCs (see section 4.3). Only 17 per cent of respondents reported that they expect to see a further decrease in margins in the coming year.

Figure 27: Snapshot of Contractor Company Margin Expectations for 2019 Versus 2018



Source: Oil & Gas UK

All areas of industry need to continue to work collectively to ensure a balance between maintaining competitive investment and operating conditions and retaining a healthy supplier base to support demand effectively. Further collaboration, new contracting models and new ways of working must continue to emerge and be embraced. E&P companies should also be open and receptive to the benefits that these approaches can bring.

5.3 Share Price Performance

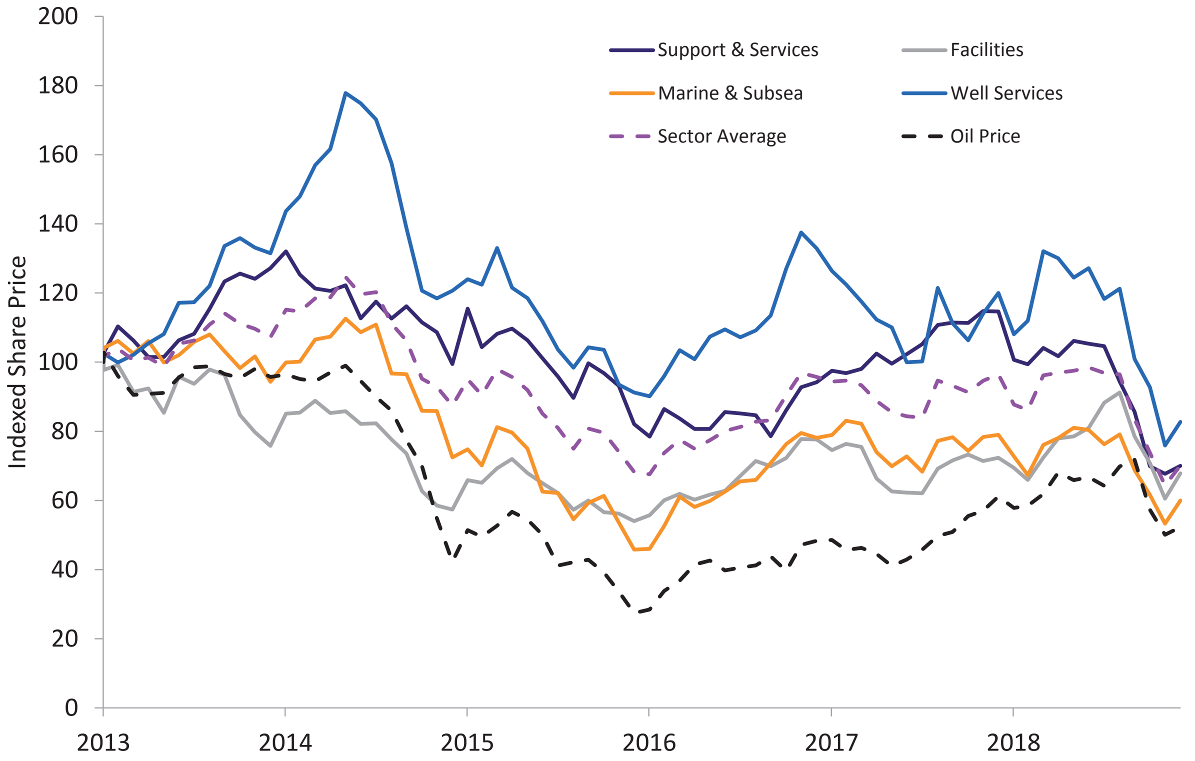
Figure 28 outlines the average indexed share price performance of a representative cross-section of listed supply chain companies with a strong UK footprint, within various supply chain sectors.

In general, the first three quarters of 2018 saw an upward trend in terms of market value, reflecting increasing oil prices (see section 3.1). However, the decline in oil price in the fourth quarter sent the share price of the listed companies into a downward trend, offsetting the gains made throughout the year. Despite a slight pick-up in early 2019, average share prices are amongst the lowest levels since prior to the downturn — indicating that, in general, investor confidence in supply chain companies remains low. However, it is also important to note that positions within each sector will vary depending on individual company performance.

Whilst there has been some stabilisation in early 2019, companies will continue to closely monitor market trends and geo-political events which could impact prices. The conservative spending from E&P companies worldwide is also continuing to filter through, supressing share prices for at least the short term.

It is crucial that the UK is seen as an attractive investment destination not just for E&P companies, but for contractor companies as well, to ensure that capacity is retained and built here. For this to occur, companies need to realise a reasonable return on their investment. For many however, the current margins across the supply chain do not provide this.

Figure 28: Share Price Performance of a Cross-Section of Supply Chain Companies



Source: Yahoo Finance, Oil & Gas UK

5.4 Realising New Opportunities for Supply Chain Companies

Increasing the opportunity for the UK-based supply chain from export activity and diversification is a core aim of industry's Vision 2035 — with the ambition to double the opportunity for supply chain companies.

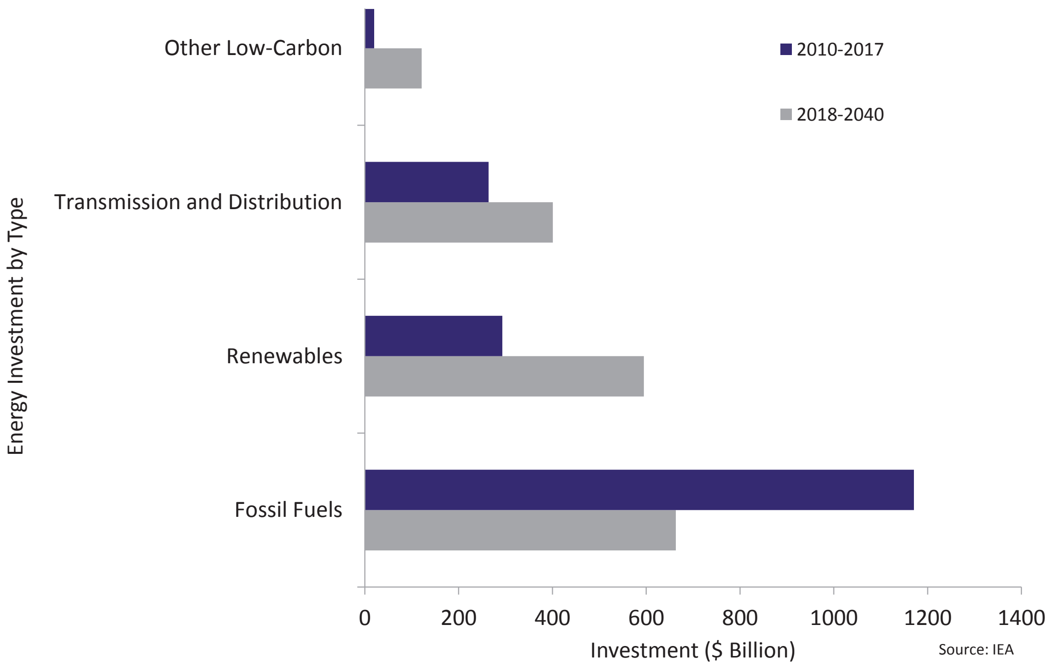
EY's *Review of the UK Oilfield Services Industry* shows that UK supply chain revenue originating from the export of goods and services fell from £12.1 billion in 2016 to £10.6 billion in 2017. This represented 39 per cent of total supply chain revenue generated in 2017, a level which has remained relatively consistent over the last five reported periods, demonstrating that reductions in export revenue have declined by a similar level to revenue from UKCS-based operations.

The supply chain sector with the highest proportion of revenue from export activity was reservoirs, at 56 per cent. This is reflective of the nature of sub-surface work, which can often be carried out remotely for locations across the globe, and for which London and the surrounding regions form a global hub. Conversely, support and services accounted for the lowest export percentage, generating 71 per cent of revenues from UK-based activity.

Along with export activity, diversification into new markets forms a key pillar of Vision 2035, ensuring that companies are able to apply their skills, expertise and resources to meet the needs of other energy industries. A survey of OGUK members indicates that more than half of supply chain companies provide goods and services to other energy industries, although the majority of revenue still relates to oil and gas-based activity – however companies are beginning to report that the margins on offer within alternative energy sectors are often greater than those in the oil and gas sector.

While oil and gas will continue to be a crucial aspect of the future energy mix (see section 3.4) increased investment in alternative energy sources will be required to meet the aims of the Paris Agreement. Figure 29 outlines the change in global investment trends that will be required within the IEA Sustainable Development Scenario. Oil and gas-focused supply chain companies should view the changing dynamics as an opportunity to diversify further and realise new revenue streams.

Figure 29: Investment in Fuel Sources Required to Meet IEA Sustainable Development Scenario



Source: IEA

Collaboration has been shown to provide opportunities to unlock new projects and recent data indicates that the collaborative efforts of industry have been sustained throughout 2018, evidenced by an increase in the OGUK and Deloitte Collaboration Index score from 6.1 to 7.1 between 2015–18.[14] The results show that the majority of companies now recognise that collaboration is integral to improved business performance and realising new opportunities.

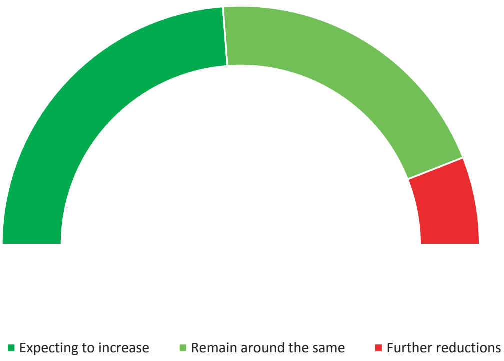
Along with the industry Cultural Change Champion, OGUK's Efficiency Task Force (ETF) is leading industry efforts to improve collaboration and sustain the efficiency improvements seen in recent years.[15]

5.5 Employment Trends

It is estimated that in the region of 40,000 new people will need to be attracted to the industry to achieve Vision 2035, a quarter of these into roles which currently do not exist. In order to achieve this, the industry needs to be seen as being diverse, innovative and forward thinking.[16]

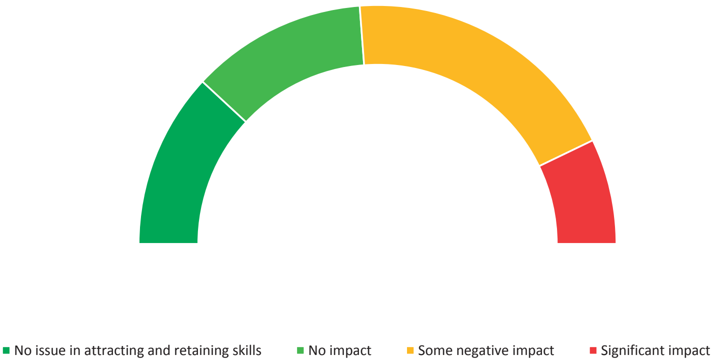
A survey of OGUK member companies indicated that almost half of companies are expecting to see some increase in headcount throughout 2019, with only 10 per cent expecting to reduce employee numbers further. However, there are concerns over the ability of some companies to attract and retain the skills to manage and grow their businesses effectively. More than half of survey respondents reported that they expect this issue to have a negative impact on their business in 2019. It should be noted, though, that this is likely to be in specialist, technical disciplines and is not necessarily indicative of general trends across industry. Conversely, almost half of organisations who responded see no issues with regards to attracting and retaining skilled personnel.

Figure 30: Snapshot of Contractor Company Employment Trends for 2019 Versus 2018



Source: Oil & Gas UK

Figure 31: Snapshot of Contractor Company Skills Issues

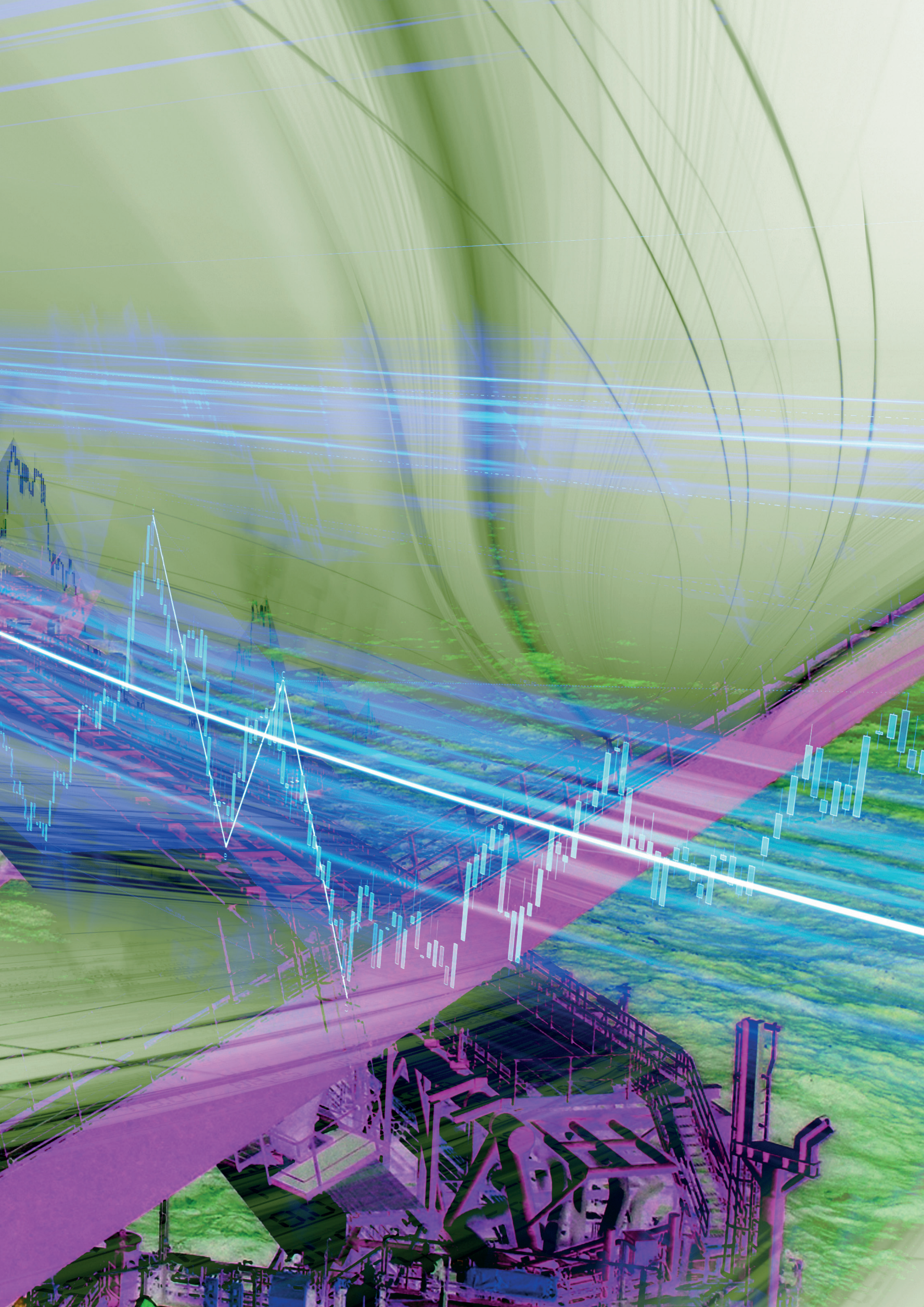


Source: Oil & Gas UK

[14] www.oilandgasuk.co.uk/wp-content/uploads/2018/08/Deloitte-UKCS-upstream-supply-chain-collaboration-survey-2018.pdf

[15] Further information can be found on OGUK's Efficiency Hub www.oilandgasuk.co.uk/efficiencyhub/#efficiency-hub+category:efficiency-task-force

[16] www.opito.com/policy-and-research/research/ukcs-workforce-dynamics-review



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