ECONOMIC REPORT 2016

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OIL&GAS UK

Contents

1. Foreword

Oil & Gas UK's *Economic Report 2016* has been designed and developed to help our members, from operators through to SMEs, to make informed decisions about the industry and their businesses. We have broadened our analysis, including in-depth insight on the whole offshore oil and gas supply chain, identifying where progress is being made and challenges remain.

Few industries could have survived the downturn the oil and gas sector has experienced over the last two years. The industry had grown accustomed to an oil price in excess of $100 per barrel and the sharp fall to an average of $41 per barrel over the first eight months of this year has been painful, right across the sector. A year ago, many expected prices to recover in 2016 – 12 months on the perception of future price growth has changed significantly. Companies are now positioning themselves to survive and succeed in the long-term at $50 per barrel with the ability to tolerate the possibility of even lower prices.

Even at a time when production taxes are low, we continue to produce around half of the nation's oil and gas that would otherwise have to be imported. Our supply chain remains an active exporter of goods and services, itself generating significant tax revenues for the UK Exchequer.

The UK's decision to leave the EU adds an additional dimension of complexity for many of our members in an already testing business environment. In the short term, we see three main challenges: distraction from managing our way through the downturn; a loss of positive influence over ongoing and future policy development in Brussels; and uncertainty, making it difficult for our members to make longer-term investment decisions. In addition, the ability to access the EU market for our goods and services could become more difficult, unless appropriate provisions are made to facilitate ongoing trade and maintain access to the energy market.

Although both economic and political turbulence may not yet be over, this report details the efforts made by the industry and all of its stakeholders to support this sector in managing its way through the downturn, allowing it to begin to position itself to make the most of any potential upturn.

The industry's focus has increasingly turned towards delivering efficiency improvements, building on cost reductions and rationalisation of activity. The Efficiency Task Force has acted as the catalyst to encourage a pan-industry review of business processes, standards, cultures and behaviours. The efficiency push has been a key driver behind the anticipated 45 per cent fall in unit costs from their peak of $29.30 per barrel in 2014 to $16 per barrel this year. As the report illustrates, such significant gains would not have been realised through natural cost deflation alone, offering some reassurance about the improvement to the long-term health of the business. Lower unit costs have enabled fields to continue operations that would have otherwise been uneconomic. While some of the giant fields of the past, such as Brent, are now being decommissioned, there has not been a widespread rush to cease production on the UK Continental Shelf (UKCS) as may have otherwise been expected.

The recent improvement in UK production is testament to what can be achieved when the basin's competitiveness is addressed and attention is focused on unlocking new developments. Major production efficiency gains in existing assets, coupled with a raft of important oil and gas projects that have come on-stream over the past two years, resulted in a 10.4 per cent increase in production last year, the first upturn in 15 years.

However, with expenditure rapidly declining and few new development projects proceeding, companies across the supply chain have suffered an average fall in revenues of almost 30 per cent over the last two years and for some sectors the decline has been even greater. This has not come without personal impact and, in 2016, the industry is expected to support 120,000 fewer jobs than it did two years prior.

In spite of this, there have been fewer business failures than many expected, a tribute to the companies that have responded to the downturn by differentiating their value offering and diversifying both into new geographies and new products and services.

Looking ahead, many challenges still remain for this sector and the actions we are taking will determine the future of the industry. Some indications suggest that we may have finally hit the bottom of the market in 2016. Provided cost and efficiency improvements continue and commodity prices hold up, revenues may begin to increase in 2017 both for extraction companies and across much of the supply chain.

However, we cannot expect a viable future if we fail to build on past investments. The lack of new development projects must be urgently addressed if we are to avoid a repeat of the sharp production decline that dominated the early part of this decade. While costs have fallen significantly and the fiscal regime has been improved, many potential investors are unable to access the finance they require to develop assets.

As an industry we are producing at four times the rate we are discovering new reserves – this is unsustainable. The rate of exploration drilling has to improve and be more successful, assisted by the £40 million government-funded seismic acquisition. Encouraging all forms of drilling, including development, over the next 12 to 18 months will be vital for the industry's future. We must also begin to tap into the opportunities offered by the undeveloped small pools that have remained on the shelf for many years.

Maximising the economic recovery of the remaining barrels requires the continuation of a constructive and highly focused partnership between governments, the industry, HM Treasury and the Oil and Gas Authority. With a new industrial strategy forthcoming, the oil and gas supply chain must be recognised alongside the likes of aviation, aerospace and automotive as vital components of the UK economy.

Next year, the UK offshore oil and gas industry celebrates a significant anniversary. In March 1967, first gas landed from the West Sole field off the North Humberside coast, marking the beginning of 50 years of successful oil and gas production from the UKCS and one of the country's greatest industrial stories. Over that time, more than 43 billion barrels of oil and gas have been recovered from Britain's offshore fields. With the right frameworks and market conditions, Oil & Gas UK believes that many more billion barrels may yet be recovered and that our industry story has still many chapters to be told over the decades to come.

D E Michie

Deirdre Michie,
Chief Executive, Oil & Gas UK

2. Industry at a Glance

The following summarises the key findings of Oil & Gas UK's *Economic Report 2016*. Figures are given in 2015 money unless stated.

Energy Demand

- Oil and gas provided 70 per cent of the UK's total primary energy consumption in 2015, with oil for transport and gas for heating being dominant uses.

- Global oil demand grew strongly in 2015 by 1.8 million barrels per day (mb/d). Although demand is expected to continue to rise this year, the rate of growth is expected to slow.

- Gas demand in the UK rose moderately by 2.2 per cent in 2015 to 72 billion cubic metres (bcm), but is still 30 per cent below the peak in demand in 2004.

- Gas use in electricity generation changed little at 19.3 bcm last year, accounting for 30 per cent of UK generation compared with 24.6 per cent for renewables and 22 per cent for coal.

Oil and Gas Prices

- The price for Brent oil averaged $41 per barrel (bbl) over the first eight months of 2016, briefly dropping to a 12-year low of $28/bbl in January.

- The price for Brent oil averaged $52.50/bbl in 2015, almost half the average price in 2014.

- After reaching a low of 28 pence/therm (p/th) in April, month-ahead NBP[1] prices have traded in a narrow range of 30-35 p/th this year.

- The NBP month-ahead gas price fell to an average of 42.6 p/th in 2015, down from 51 p/th in 2014.

Profitability

- The UK Continental Shelf (UKCS) is expected to generate a free cash-flow deficit of around £2.7 billion in 2016. This is an improvement on the £4.2 billion deficit seen in both 2015 and 2014 due to the reduction in expenditure and increase in production.

- 2016 will be the fourth consecutive year of free cash-flow deficit. This has led to a rise in the average gearing ratio[2] across the UKCS over the last two years as companies increase their net-debt positions to maintain existing business and develop new capital projects.

- The average rate of return for extraction companies fell to just 0.2 per cent in quarter one 2016 compared to more than 50 per cent over the same period in 2011.

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[1] National Balancing Point (NBP) is a virtual trading location for the sale and exchange of natural gas within the UK.
[2] A financial ratio that compares borrowed funds to the equity in business defined as: long-term liabilities/(equity + long-term liabilities).

- Rising levels of debt are likely to result in a lag between price recovery and an upturn in investment as companies will use free cash-flows to rebalance their corporate finances by servicing debt.

Reserves/Resources

- More than 43 billion barrels of oil equivalent (boe) have been recovered from the UKCS since first production in 1967.

- Oil & Gas UK believes that the remaining recoverable resource potential ranges from 10-20 billion boe:
    - 6-9 billion boe in existing reserves
    - 2-5 billion boe in potential additional resources
    - 2-6 billion boe in yet-to-find potential

- Unsanctioned reserves within company business plans have fallen by over 30 per cent over the last 12 months, from 3.7 billion boe to 2.5 billion boe.

- The reserve replenishment ratio on the UKCS fell to 0.25 in 2015 as the volumes produced were four times higher than new volumes discovered.

Drilling Activity

- The downward trend in exploration and appraisal activity is expected to continue this year, with only six exploration and three appraisal wells spudded over the first six months of 2016.

- Last year, 13 exploration wells and 13 appraisal wells were spudded in total.

- Around 150 million boe of potentially recoverable reserves were discovered through exploration drilling in 2015, more than any year since 2011, although still lower than the average for the past ten years.

- Forty-two development wells were drilled in the first half of this year, pointing to an anticipated annual decline of up to 30 per cent compared with the 129 development wells drilled in 2015.

Total Expenditure

- Total expenditure on the UKCS decreased from £26.6 billion to £21.7 billion in 2015 as companies sought to preserve free cash-flow by postponing discretionary spend.

- Expenditure is likely to continue to decline this year to around £19 billion, as a result of further reductions in operating costs and capital investment.

Capital Investment

- Capital investment is falling rapidly to around £9 billion this year from a record £14.8 billion in 2014.

- Only one new field has been approved so far this year, with less than £100 million of fresh capital committed to the basin. This compares with five greenfield projects sanctioned in 2015 with associated development capital in excess of £4.3 billion.

- The rate of brownfield investment is also slowing. Just five new projects were approved in the first eight months of 2016, compared to ten in total in 2015.

- Unit development costs are falling with like-for-like pre-sanction opportunities now forecast to be around 25 per cent cheaper to develop on a unit basis than 12 months ago.

Operating Costs

- The cost of operating the UKCS is expected to decline to around £7.5 billion this year, a decrease of over 8 per cent on £8.2 billion in 2015.

- When normalising for new start-ups, this will mean £2.8 billion will have been removed from the UKCS on a like-for-like basis since operating costs peaked in 2014.

- Average unit operating costs are expected to be around $16/boe this year, a 45 per cent reduction since peaking at $29.30 in 2014.

- The *IHS Upstream Operating Cost Index* shows that, globally, the average unit cost of oil and gas field operations has fallen by 17 per cent since 2014, revealing that efficiency improvements rather than natural cost deflation have been the main driver for the fall in unit costs on the UKCS.

Production

- The recent upward trend in production has continued into the first half of 2016 with production around 5.7 per cent higher than the first half of 2015. Published data from the Department for Business, Energy and Industrial Strategy show that liquids are up 9.4 per cent and net gas up 1.2 per cent.

- This follows a 10.4 per cent increase in 2015 when 602 million boe (1.65 million boe per day) was produced on the UKCS.

- Production efficiency improvements in existing assets, field restarts and new start-ups are the drivers behind the upturn in output.

- The UK was the world's 21st largest oil and gas producer in 2015, accounting for 1.1 per cent of global production.

Decommissioning

- Decommissioning expenditure reached £1 billion in 2015 and is expected to increase to around £2 billion by 2017.

- In 2015, 21 UKCS fields ceased production when only 14 were anticipated at the start of the year.

- A further 20 fields per annum are expected to cease production on average over the second half of the decade.

Supply Chain

- Revenues across the supply chain are forecast to fall by around 21 per cent this year, taking market revenue below £30 billion for the first time since 2010. This follows a contraction of around 10 per cent in 2015.

- Supply chain EBITDA[3] is forecast to have fallen by almost half over the last two years, reflecting reduced activity levels and the cost of reorganisation.

- Companies specialising in wells or reservoir-based activities appear to have suffered the most, with revenues expected to decline, on average, by 53 per cent and 48 per cent respectively from 2014 to 2016.

- The facilities segment, representing around one-third of the total supply chain, has seen more robust performance to date with revenues increasing by around 7 per cent in 2015. However, concerns over future activity mean revenues in this segment are forecast to contract by almost one-quarter this year.

- Revenues in the marine and subsea segment are thought to have fallen by 14 per cent in 2015 with a further decrease of 11 per cent expected in 2016 to £8.4 billion. However, EBITDA margins are likely to remain higher than other areas of the supply chain at 12 to 13 per cent due to a number of ongoing large-scale subsea projects, such as Schiehallion, Greater Laggan and Kraken.

- Revenues in the support and services segment of the supply chain, comprising a wide range of businesses, are forecast to contract by 13 per cent in 2016, similar to the 14 per cent fall last year.

Employment

- Across the UK, around 330,000 jobs are currently supported by the offshore oil and gas industry:
    - 34,000 direct employees[4]
    - 151,500 indirect employees[5]
    - 144,900 induced employees[6]

- This represents a 27 per cent reduction from peak employment of around 450,000 in 2014.

Upstream Production Taxes

- Over £330 billion has been paid in corporate taxes since production on the UKCS began.

- Production taxes fell to just beneath zero in 2015-16[7], reflecting a lack of profitability and increasing decommissioning expenditure.

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[3] Earnings Before Interest, Taxes, Depreciation and Amortisation (EBITDA).

[4] Those employed by companies operating in the extraction of oil and gas and associated services.

[5] Employment as a result of supply chain effects caused by oil and gas sector activity. For these companies, extraction of oil and gas and associated services will be one part of a wider business.

[6] Employment supported by the redistribution of income from the oil and gas sector.

[7] See http://bit.ly/2ckwOyL

3. Prices and Markets

3.1 Oil Prices and Market Trends

Oil Prices Reflect Persistent Market Imbalance

The collapse in oil prices in late 2014, triggered by the US shale revolution, the acceleration of non-OPEC supply and OPEC's determination not to cede market share, set in motion a gradual adjustment process in both supply and demand that gathered pace through 2015 and continued in the first half of 2016. World oil demand grew more strongly in 2015 (+1.8 million barrels per day (mb/d)). While demand is expected to continue to grow, the rate of growth is expected to slow. On the supply side, non-OPEC supply, which rose by about 1.5 mb/d in both 2014 and 2015, will record a sharp decline this year in response to the fall in discretionary upstream expenditure and the contraction of US tight oil production. In the second half of 2016, the flows of oil on the supply and demand sides of the market are expected to be back in balance but there remains a large overhang of excess stocks built up in 2014 and 2015 that promises to persist well into 2017. Only when both the flows and stocks of crude and products are back in balance can the market find a new sustainable range for crude oil prices.

> Only when both the flows and stocks of crude and products are back in balance can the market find a new sustainable range for crude oil prices.

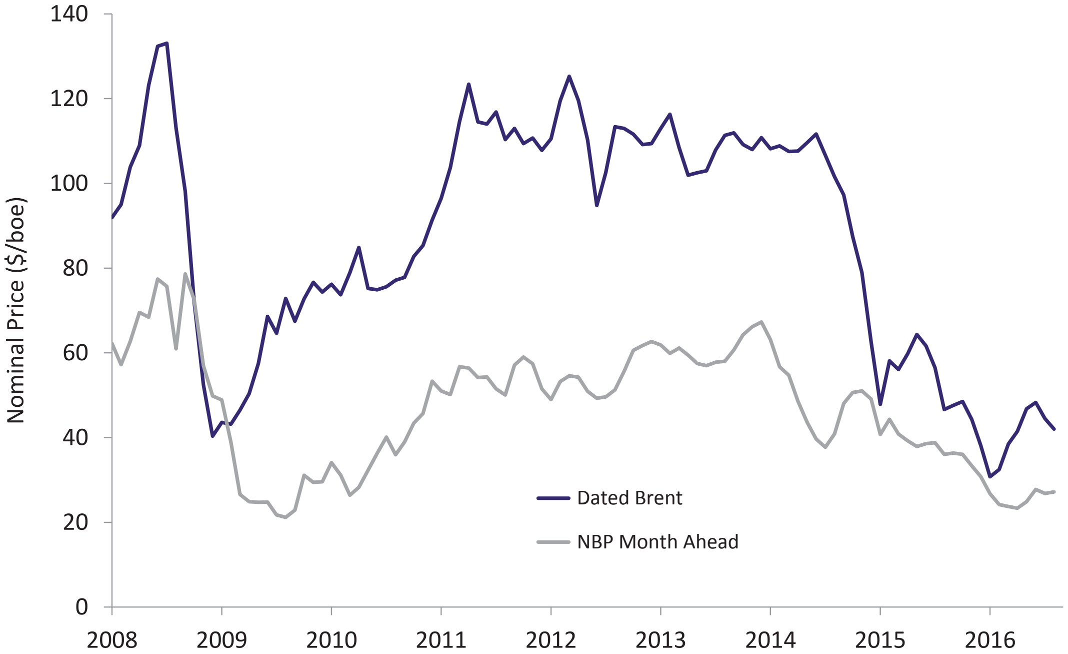
Crude oil prices dropped briefly to a 12-year low of $28 per barrel (bbl) in January 2016, confounding earlier expectations that the recovery in the first half of 2015 would lead to a new trading range of $40-70/bbl in 2016. Prices recovered to $50/bbl in June 2016 and have since traded in a range of $40-50/bbl under the weight of the commercial stock overhang.

Brent has averaged $41/bbl over the first eight months of 2016, reflecting in part the trade-weighted strength of the US dollar, and is likely to record the lowest nominal level since 2004 for the year as a whole.

The structure of crude prices remains in contango[8] with prices for delivery in 2020 ($55/bbl) well above spot prices, encouraging the continued holding of crude stocks and postponing any sustainable recovery in spot prices. The fall in five-year forward crude prices from $80-85/bbl in 2013-14 to $55/bbl today provides a measure of the market impact of the emergence of low-cost US tight oil production as a new price-responsive source of non-OPEC supply and the relaxation of US crude export controls.

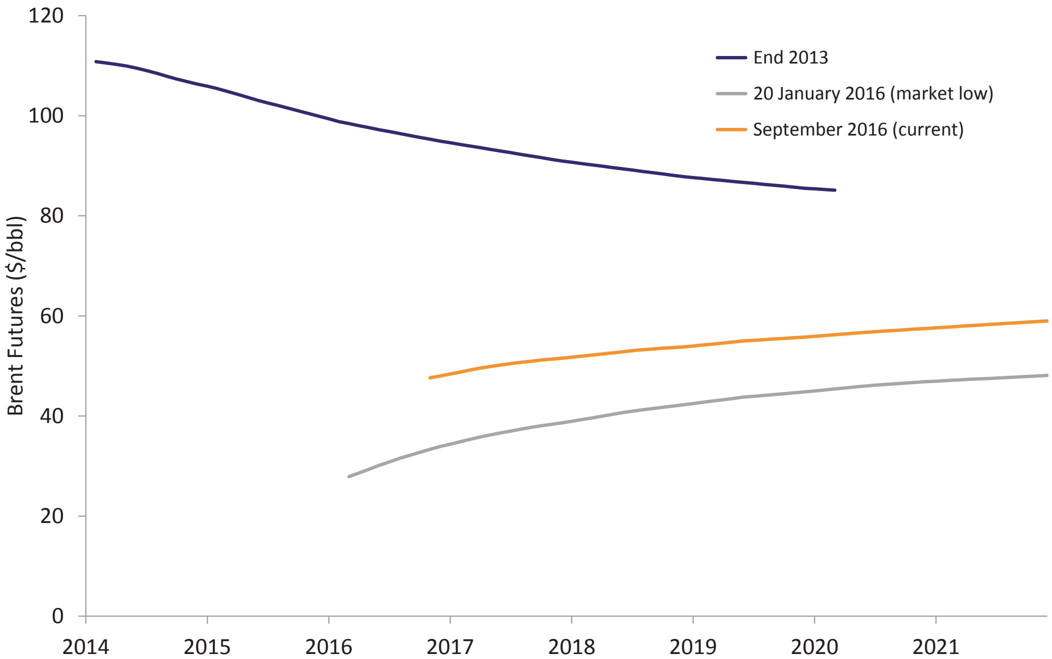
[8] Contango refers to the structure of prices where the price for prompt delivery is below the price for forward delivery.

Figure 1: Monthly Oil and Gas Prices



Source: Argus Media, ICIS Heren

Figure 2: Brent Futures Curves



Source: Intercontinental Exchange

UK Crude Production in International Trade

In 2015, the UK produced almost 0.9 mb/d of predominantly light, sweet (low sulphur) crude oil. This accounted for just over 1 per cent of total world crude supply, yet the Brent price remains the main benchmark for internationally traded crude oil.

The daily dated (spot) Brent price is determined by the trading of four UK and Norwegian crude oil streams known as BFOE (Brent, Forties, Oseberg and Ekofisk) with combined output of about 0.9 mb/d. The Forties system, gathering liquids production from more than 80 fields on the UK Continental Shelf (UKCS), is the largest component of BFOE. In 2015, Forties system production rose to 390,000 b/d, the highest for four years, due to increased output at Golden Eagle and improved operational reliability at numerous smaller fields.

In recent years, there have been market concerns that declining North Sea production would undermine the liquidity of the Brent market and its role as an international benchmark, requiring further reform to widen the deliverable grades under the BFOE contract. The recovery in Forties production in 2015 and 2016 has therefore been a welcome development since it has helped to underpin the liquidity of the traded North Sea crude market.

The UK has been a net importer of crude oil and oil products since 2005 but the deficit has shifted increasingly towards the latter in recent years as UK refinery capacity and throughputs have contracted. Despite the overall net import position, less than one third of domestic crude production is refined in the UK because the six major UK refineries find it more economic to run lower-value imported grades. In 2015, 600,000 b/d of UK crude production was exported to a wide variety of destinations. Markets in north-west Europe were the main destinations, accounting for more than 60 per cent (375,000 b/d). Exports to South Korea reached a new record of 110,000 b/d as Korean refiners took advantage of the EU-Korea Free Trade Agreement signed in 2011 to purchase cargoes of Forties crude moved to Asia by international traders. In the first half of 2016, Korean buying of UK grades waned somewhat while shipments to China picked up. The pivotal role played by North Sea crude oil as a swing source of supply means that Brent prices quickly reflect market imbalances, as we have seen in recent months in a period of oversupply in the Atlantic Basin.

Sterling Weakness Cushions UK Continental Shelf Producers

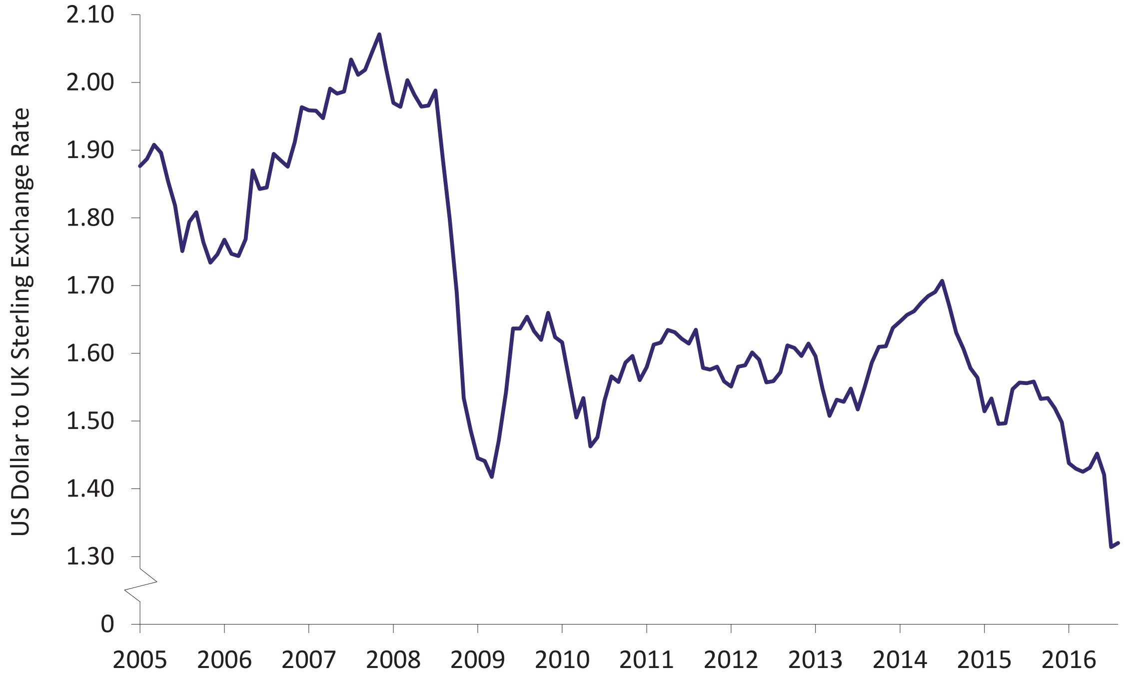
UK offshore oil and gas, as part of the international upstream industry, is largely a dollar-denominated sector. Producers' hydrocarbon revenues are either dollar-denominated or, in the case of gas, are linked indirectly to oil prices even when sales prices are denominated in sterling. The industry's operating cost base comprises both dollar-denominated elements for internationally-traded goods and services and sterling elements such as local labour costs. Major elements of capital expenditure programmes are mostly dollar-denominated. Companies may, of course, choose to hedge any exchange-rate exposure associated with a mismatch between costs and revenues, especially for large-value items of current or capital expenditure.

The progressive decline in oil and gas prices between June 2014 and January 2016 was accompanied by appreciation of the US dollar against sterling of 15 per cent as the $/£ exchange rate moved from 1.70 to 1.44, breaking out of the well-established trading range of 1.50 to 1.70. Over the same period, the trade-weighted value of the dollar rose by 22 per cent against major traded currencies. This dollar appreciation offered some limited relief to UK oil and gas producers wrestling with the fall in the value of their output.

> The strengthening of the dollar may offer some short-term respite to UKCS producers.

The strengthening of the dollar between 2014 and 2016 will have consequences for the profit and loss account, cash-flow and balance sheet of UKCS producers. These will be broadly positive for margins and for competitiveness but the impact on individual companies will depend on the extent of corporate exchange-rate hedging, among other factors. Those with significant sterling operating costs will have seen an increase in unhedged operating margins and some partial relief from the effect of falling dollar oil prices.

Figure 3: Monthly $/£ Exchange Rate



Source: Bank of England

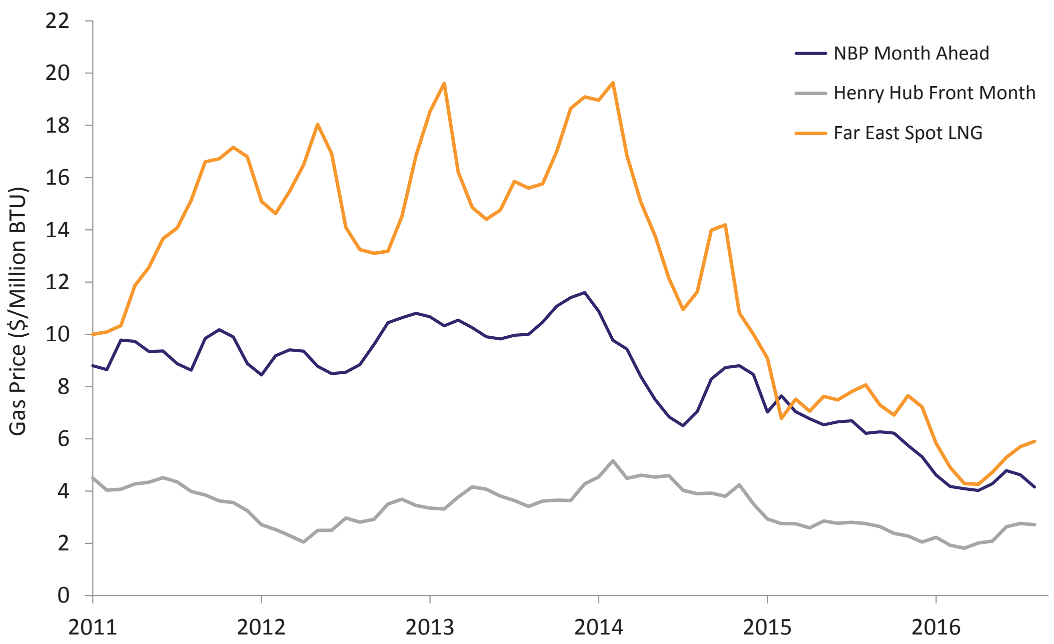
After the UK's vote to leave the EU on 23 June, sterling fell sharply to below 1.30 against the dollar, the lowest since 1985, and now stands at 1.32. This fall may offer further short-term respite to (unhedged) producers on the UKCS but should not diminish industry efforts to fundamentally reform the cost base of its operations in order to restore competitiveness and to attract new investment.

3.2 Gas Markets and Prices

Gas markets are still regional in nature and gas prices respond to factors unrelated to global oil markets, such as the weather-related seasonality of demand, storage capacity utilisation, the investment-led cycles in the world LNG (liquefied natural gas) market and the strategy of a few major gas exporters. Nevertheless, it was possible to discern the influence of oil prices in the behaviour of European gas prices in the last two years through the inclusion of oil price indices in both Asian LNG term contracts and in a diminishing number of European long-term pipeline contracts.

If the influence of oil prices on UK NBP[9] and Dutch TTF[10] hub price-formation is gradually diminishing, the influence of US Henry Hub prices may increase following the long-anticipated start of US Gulf Coast LNG exports in February 2016. From now on, any uncontracted LNG from the US Gulf Coast will be available to European hub markets, presenting more arbitrage opportunities between Henry Hub and NBP/TTF markets.

Figure 4: Regional Gas Prices



Sources: ICIS Heren, NYMEX

The acute oversupply of gas and associated price weakness in 2015 owed much to weaker import demand growth in Asia, the start-up of new sources of LNG exports – notably in Australia – and the fact that 2015 was the warmest year on record worldwide for the second consecutive year, exacerbated by a strong El Niño effect. Gas prices in all major regional markets reached new lows in early 2016 within weeks of the trough in oil prices. Despite the low level of new shale drilling in the US Lower 48 states and rising US gas demand, the productivity of non-conventional onshore operations has kept Henry Hub at $2-3/million British Thermal Units (m BTU). Unless there is an expected increase in the cost of US production, Henry Hub prices at this level will ensure US Gulf Coast LNG exporters are competitive in many parts of the world now capable of importing LNG. In the first four months of operation, cargoes from Cheniere's plant at Sabine Pass in Louisiana have been delivered to South America, Europe and the Middle East (Dubai and Kuwait).

[9] NBP is a virtual trading location for the sale and exchange of natural gas within the UK.
[10] The TTF (Title Transfer Facility) hub market is a virtual trading point for natural gas in the Netherlands.

European gas markets remain very well supplied despite the precautionary restriction of production from the large Groningen field in the Netherlands due to concerns over a possible re-occurrence of localised seismic disturbances. Amid ample pipeline and LNG supply and only modest demand growth, NBP month-ahead prices continued their two-year decline until reaching a low of 28 p/th ($4/m BTU) in April 2016. Unlike the most recent period of low gas prices in 2009-10, there has been no sign of any marketing restraint by major gas exporters to the EU in 2015-16. Indeed, Norwegian production hit an annual record of 117 billion cubic metres (bcm) in 2015. Gazprom's reported exports to Europe increased by 19 per cent to 157 bcm and Qatari LNG exports to the UK also increased by 24 per cent to 12.9 bcm.

Since April, month-ahead NBP prices have traded in a narrow range of 30-35 p/th ($4-4.50/m BTU) in line with TTF hub prices. Barring exceptional demand or supply-side events, the annual average out-turn price in 2016 is expected to lie in this range, marking a further retreat from 42.6 p/th in 2015 ($6.50/m BTU).

Rough Storage Outage Tightens Forward Winter Market

In early 2016, the perception of growing excess supply overhanging the UK and north-west European markets drove NBP prices for delivery in winter 2016 down to 33 p/th. However, the announcement in June of the temporary cessation of all operations at the Rough storage facility in the UK caused prices to rise strongly as traders reassessed the market in the coming winter.

The Rough seasonal storage site at an offshore depleted field is the UK's largest storage facility, accounting for 3.1 bcm of the UK's total capacity of 4.6 bcm. Rough capacity had been curtailed after technical problems on some existing wells were identified in 2015; the unexpected cessation of gas injection in June this year raised concerns about a much tighter winter market that was already adjusting to reduced output from the Groningen field. Other sources of flexibility from Norway, interconnectors, salt storage sites and LNG re-gas terminals currently appear adequate to avert very high prices even in a cold winter. However, the problems at the ageing Rough facility have raised questions once again about the adequacy of UK storage capacity and gas security of supply.

Shifting UK Supply and Demand Patterns

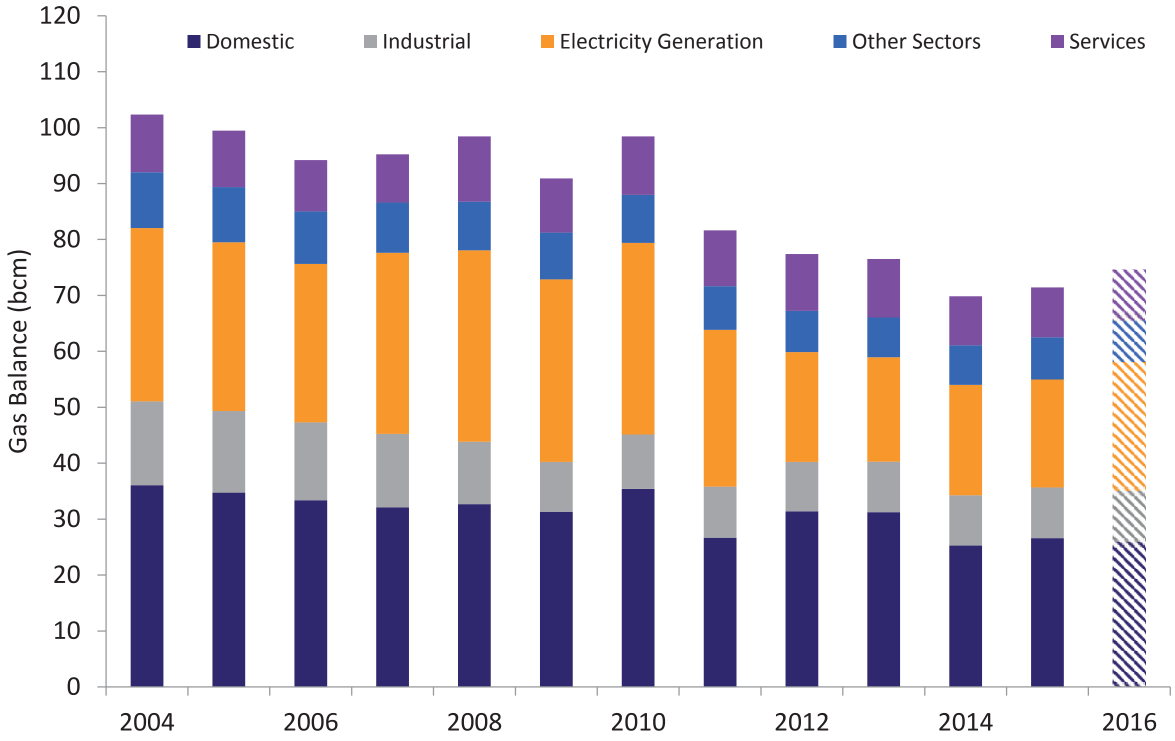
After the weather-induced weakness in gas demand in 2014, the warmest year on record in the UK, gas demand rose moderately by 2.2 per cent in 2015 to 72 bcm. Gas use in electricity generation was little changed at 19.3 bcm, accounting for 30 per cent of UK generation compared to 24.6 per cent for renewables (wind, solar and biomass) and 22 per cent for coal. Consumption of gas in the residential sector was up slightly to 26.6 bcm last year, reflecting the contrasting influences of colder weather in the UK in 2015 and the long-term trend towards improved efficiency.

Provisional data for the first half of this year indicate a further increase in gas use in electricity generation as more coal-fired plant has been retired and gas has demonstrated its ability to meet increasing daily and intra-day variations in renewables output. It is expected that total UK gas demand in 2016 will be about 75 bcm. As Figure 5 overleaf shows, this is still more than 25 per cent below the peak in demand in 2004. However, it is likely that gas will record a significant increase in its share of UK generation in 2016 as gas replaces coal and the carbon intensity of UK generation continues to fall.

> Gas has demonstrated its ability to meet increasing variations in renewables output.

A sustained recovery in gas-fired generation beyond 2020 to allow the phase out of all unabated coal by 2025, as the UK Government intends, will probably require some reform of the existing capacity market to ensure that new gas-fired combined cycle gas turbine (CCGT) plants are able to compete with other sources of generation.

Figure 5: UK Gas Demand by Sector



Source: BEIS, Oil & Gas UK projections

Projections of UK gas demand have been notoriously unreliable because gas is the marginal fuel in the UK energy mix, particularly in electricity generation, and highly sensitive to policy-induced low-carbon penetration and plant retirement. In its latest *Future Energy Scenarios*[11], National Grid projects a decline in UK gas demand between 2015 and 2030 in all four of its scenarios. By 2030, its UK gas demand projections range from 49 bcm to 66 bcm in these scenarios. These projections are highly sensitive, not only to assumptions about renewables and new nuclear build in the power sector, but also to the possible deployment of carbon capture and storage and the pace of decarbonisation within the heating sector, which has recently been the focus of much new thinking within government and the gas industry.

[11] See http://fes.nationalgrid.com/

One consequence of the unexpected fall in gas demand in recent years and the recovery in UKCS gas production is that import dependence has declined since 2013, confounding earlier forecasts of ever-rising dependence. Maintaining this recent trend of greater self-sufficiency will not be easy if NBP gas prices remain in the range of 30-35 p/th, given the access of north-west European markets to lower-cost supply from Qatar, Russia and the US.

As the current government has recognised, UKCS gas production is a critical element for UK energy security and its decarbonisation policy. Crude oil produced on the UKCS is capable of being delivered worldwide but gas (with the exception of gas from some small southern North Sea fields (SNS) delivered to the Netherlands) has to be delivered to the UK onshore network, the National Transmission System (NTS). Furthermore, indigenous gas production permits greater deployment of renewables without incurring the economic risks associated with excessive dependence on gas imports to back-up variable renewable output. In other words, maximising economic recovery of domestic gas from the UKCS will assist in delivering wider energy and climate policy objectives.

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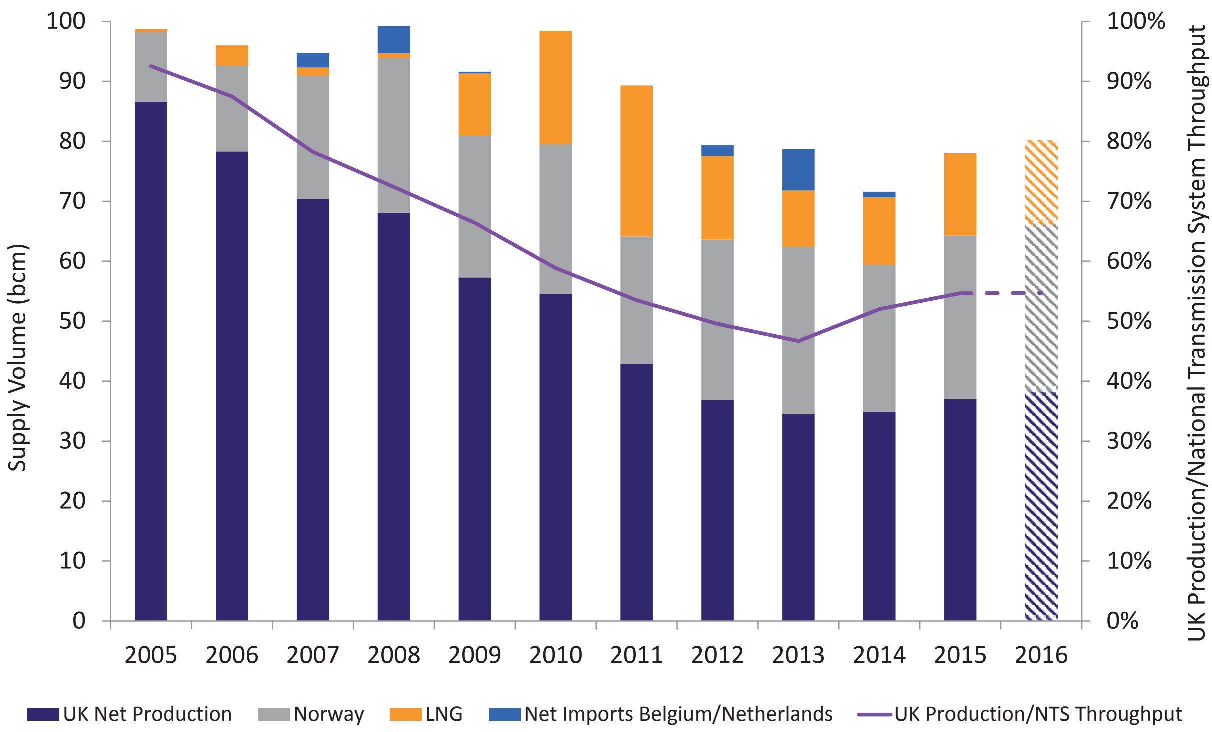
Figure 6: UK Gas Supply and Self-Sufficiency

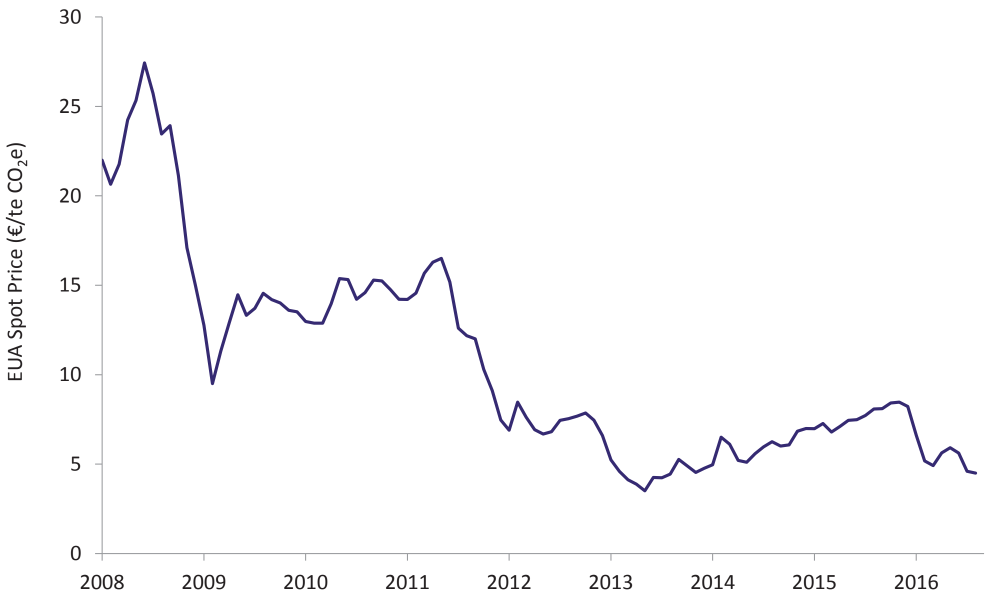


Source: BEIS, Oil & Gas UK projections

3.3 Carbon Markets and CO_2 Emissions

Phase III of the EU Emissions Trading Scheme (EU ETS) (2013-20) has been marked so far by a persistent large surplus of emission allowances (EUAs) and depressed EUA prices. Market demand for allowances has been curtailed by weak economic activity, rising renewables penetration and the continued auctioning of allowances by Member States. Prices began a slow recovery in 2013 as the Eurozone crisis receded to reach €8/tonne (te) CO_2 in late 2015, but the slump in energy prices in 2015-16 and the recent UK referendum vote to exit the EU have brought EUA prices back below €5/te CO_2.

Figure 7: Monthly Spot EUA (Carbon) Price



Source: ICIS Heren, Intercontinental Exchange

Since the recession in 2008-09, ETS carbon prices[12] have not been high enough to induce switching to lower-carbon fuels or to promote the intended investment in low-carbon energy sources. The steady expansion of renewables (mainly wind, solar photovoltaics and biomass) across the EU since 2009 has been achieved through domestic subsidies and other measures, not through EU-wide carbon pricing. In the UK, the switch from coal to gas in power generation since 2013 has been accelerated through the UK's own carbon price floor (CPF), which functions effectively as a market-related tax, not through the ETS. The CPF continues to confer a competitive advantage for gas-fired generation over coal but has now been capped at £18/te CO_2 (€22/te CO_2) to prevent UK wholesale electricity prices from rising further above those on the continent.

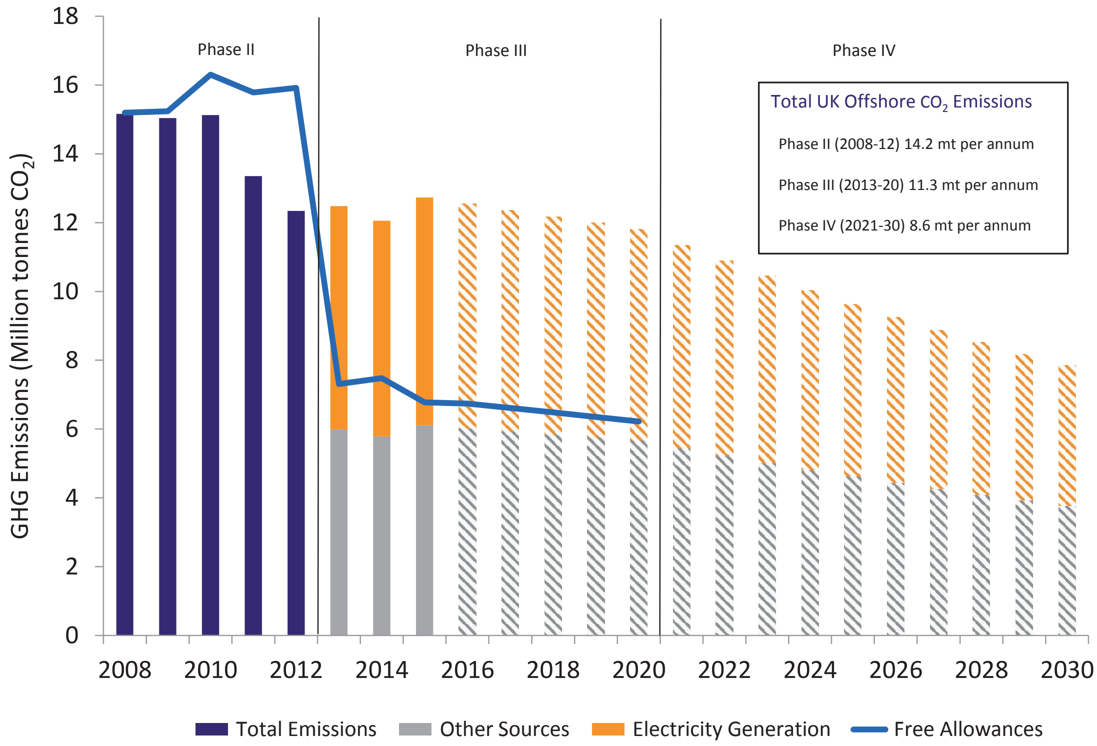
The shortcomings of the ETS have prompted EU efforts to reform the market through 'backloading' (reducing the availability of allowances in later years) agreed in 2013 and the introduction of the Market Stability Reserve (MSR) agreed in 2015, which will take effect in 2019. These may, as intended, raise EUA prices towards the end of Phase III but it is the current review of the EU ETS Directive, due to take effect in Phase IV (2021-30), that may be much more decisive.

The EU ETS remains ostensibly the central pillar of long-term EU decarbonisation policy. Finding a balance between the interests of EU industries concerned about competitiveness and carbon leakage and the desire to deliver an effective carbon price that changes behaviour will be the delicate task of EU legislators and Member States in late 2016 and early 2017.

[12] The amount that must be paid for the right to emit one tonne of CO_2 into the atmosphere.

As a major energy-consuming industrial sector, almost all the UK upstream industry, comprising offshore platforms and onshore terminals, falls within the scope of the EU ETS. In 2014, the EU ETS captured 95 per cent of total upstream CO_2 emissions. Installations responsible for any CO_2 emissions are required to monitor and verify such emissions and to surrender allowances to cover all their emissions each year. Since the industry is deemed to be at risk of carbon leakage, installations receive some free allowances based on an assessment of historical performance relative to an industry benchmark but no free allowances are allocated for emissions from electricity generation. Offshore platforms are not connected to the onshore grid, so they have to generate their own electricity using produced fuel gas for all operational needs. This accounts for more than half the total CO_2 emissions from UK offshore installations. The effect of the ineligibility of emissions from electricity generation is that, uniquely among the six largest industrial sectors in the ETS, upstream oil and gas is short of allowances and has to purchase them in the market each year to meet their ETS obligations.

Figure 8: UK Upstream Offshore Sector Emissions and Allowances



Source: BEIS, DG CLIMA, Oil & Gas UK projections

In 2015, upstream installations within the ETS emitted 15.6 million tonnes (mt) of CO_2, up 4.9 per cent from 14.9 mt in 2014[13]. Offshore installations accounted for 12.7 mt of this figure (+5.6 per cent) and onshore oil and gas terminals handling offshore UK production were responsible for a further 2.9 mt (+1.7 per cent). An estimated 6.6 mt (52 per cent) of all offshore CO_2 emissions were attributable to electricity generation. The increase in total CO_2 emissions in 2015 was smaller than the increase in hydrocarbon production (+10.4 per cent), indicating a decline in the carbon emission intensity of upstream operations contrary to the longer-term trend towards higher intensity observed since 2000 as resource depletion has proceeded.

> Carbon emission intensity declined in 2015 contrary to the long-term trend.

[13] Source: DG CLIMA EU Transaction Log (2016).

4. Profitability and Corporate Finances

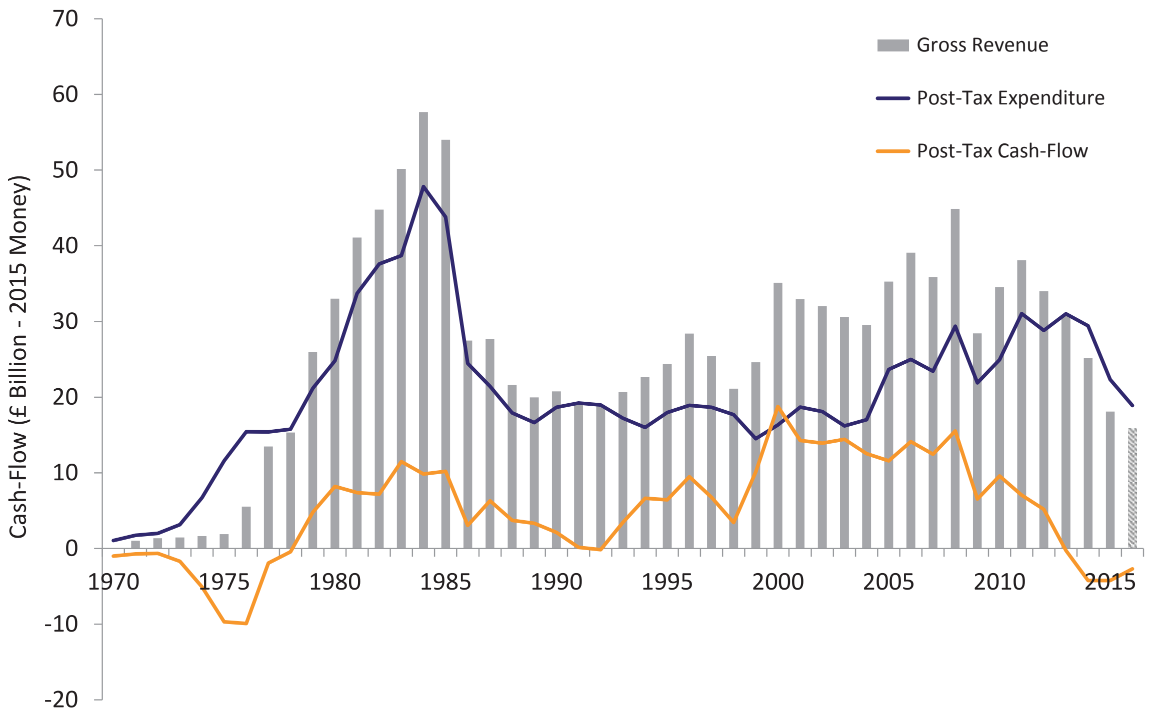
Many companies on the UKCS are reliant on cash-flows from existing operations to fund maintenance and new development projects. With profitability at an all-time low given the market downturn, companies have had to borrow more money to fund ongoing commitments.

4.1 Profitability

Free cash-flow generated on the UKCS is a function of three key variables: price, production and costs. The impact of the fall in oil and gas prices will be partially offset by the sharp decline in capital investment, the continued operating cost reductions and further increases in production. Although the free cash-flow picture for the UKCS has improved from the £4.2 billion deficit last year, there is still likely to be a £2.7 billion deficit in 2016.

When existing operations are generating marginal, if any, returns for investors, the prospect of raising further capital to invest in new projects is extremely difficult, as shown by the lack of new commitments this year (see section 5.3). This has caused a knock-on effect on profitability throughout the supply chain as projects are postponed or cancelled (see section 6 for more on the supply chain).

Figure 9: Revenue, Expenditure and Post-Tax Cash-Flow

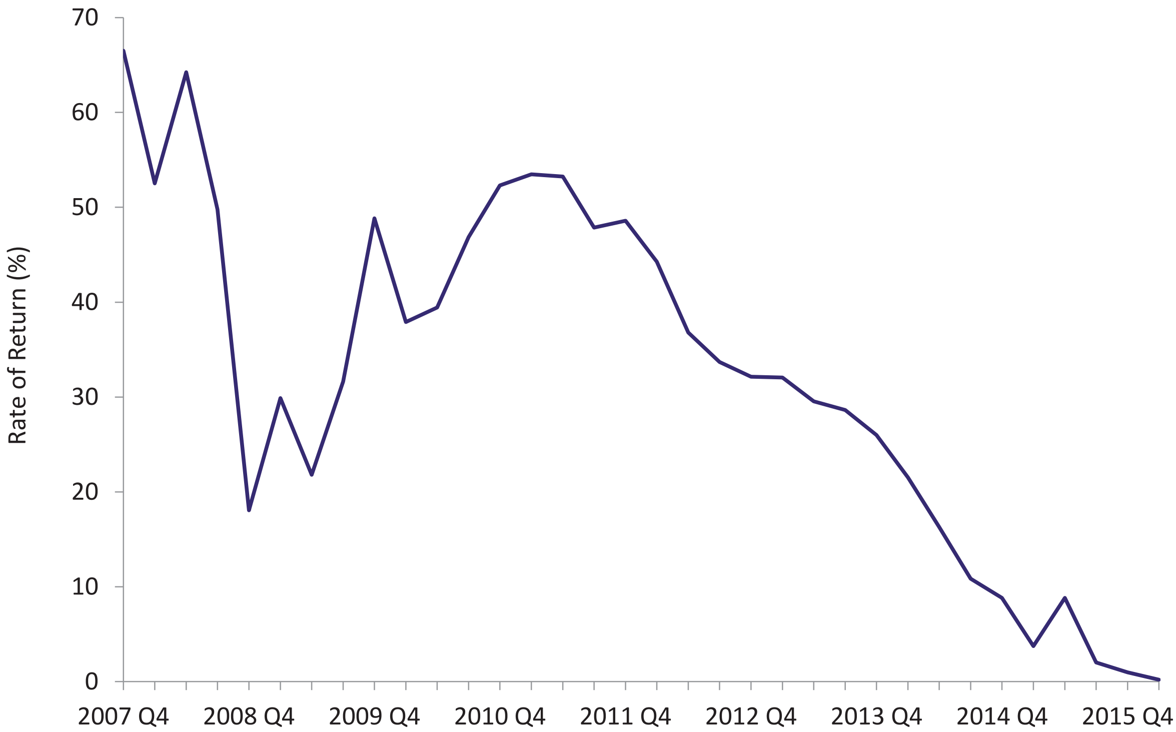


Source: OGA, Oil & Gas UK

The average rate of return for extraction companies fell to just 0.2 per cent in the first quarter of 2016.

Furthermore, with capital employed[14] in the basin continuing to increase and depressed prices causing revenues to fall further, the average rate of return for extraction companies fell to just 0.2 per cent in the first quarter of 2016. Despite ongoing efforts to improve efficiency and reduce costs, it may yet fall further over the rest of the year and into 2017 unless prices begin to recover.

Figure 10: Rate of Return



Source: Office for National Statistics

4.2 Corporate Finances

With the ongoing global market downturn, many oil and gas companies have restructured their corporate finances to fund existing operations and development commitments. Organisations have taken on more debt finance to replace the lack of free cash-flow being generated from existing operations and equity markets are distancing themselves from oil and gas investments.

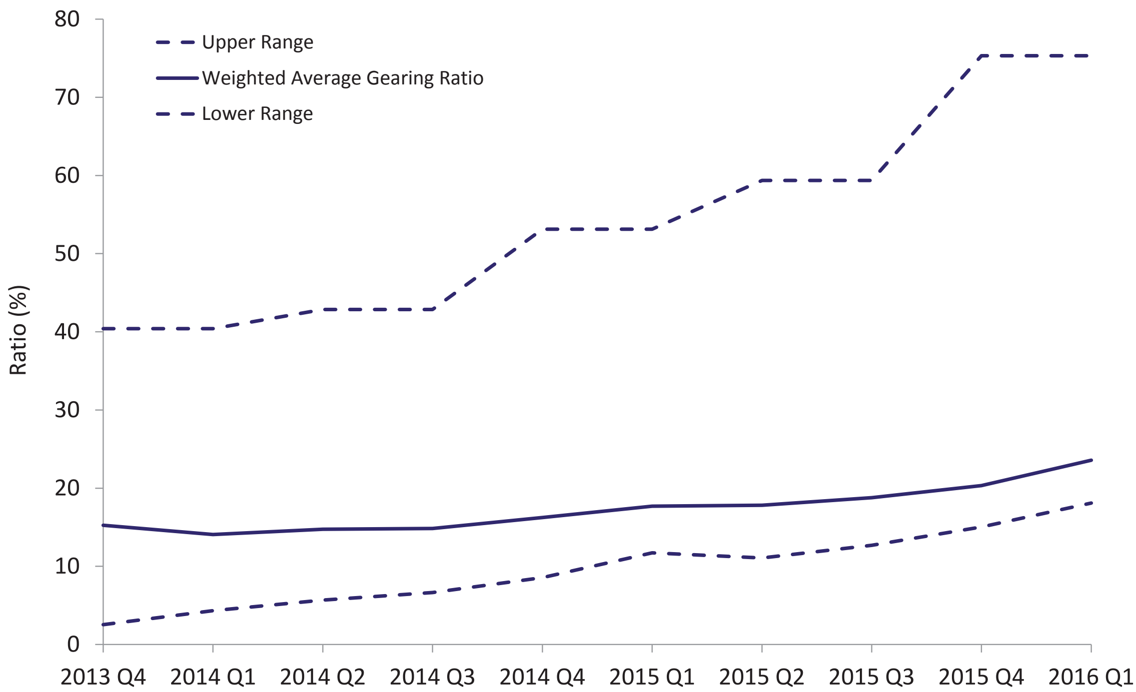
Over the last two years, access to debt has been a blessing for the industry. This has meant some cash-constrained companies have been able to sustain ongoing operations and finance new projects that were committed to before the downturn, while they readjust their businesses in light of lower revenues (see section 5.3 for details on how companies are rationalising their expenditure).

[14] Capital employed – the value of fixed assets employed by the industry.

Debt finance is also commonly used to help businesses grow. Most, if not all, recent UKCS development projects will have been partially debt-financed and many would not have been able to proceed at all without access to such capital. In fact, a quantum of debt within the financial structure is often healthy for a business' overall performance. Within a UK context, it should be noted that interest payments on debt are tax deductible against Corporation Tax but not Supplementary Charge.

Data on 14 companies operating on the UKCS – a broad sample ranging from majors to small independents – show that the average net debt to asset ratio has increased by around one-third over the last two years and is now around 20 per cent. The higher leveraging results in an increased reliance on sustainable access to affordable debt and implies greater financial risk. With the levels of net debt growing and the value of equity within oil and gas companies falling, exploration and production companies on the UKCS are becoming more highly geared, with the average gearing ratio[15] rising to 22 per cent from 15 per cent since the start of 2014, as shown in Figure 11. For a number of smaller companies, however, gearing ratios have risen to above 50 per cent.

Figure 11: Gearing Ratios



Source: Wood Mackenzie

[15] A financial ratio that compares borrowed funds to the equity in business defined as: long-term liabilities/(equity + long-term liabilities).

As the basin has become more reliant on debt finance, a number of potential risks to the industry have emerged:

- **Increased chance of financial distress** – higher net debt and associated interest repayments mean that businesses are more reliant on steady cash-flows to service agreed debt payments. The preferential treatment of debt means that failure to meet repayments can lead to business failure, even for companies with positive EBITDA (Earnings Before Interest, Taxes, Depreciation, and Amortisation). However, a number of smaller companies on the UKCS that have breached their debt convenants with lenders over the last 12 to 24 months have been able to renegotiate new terms. Banks have, for the most part, supported their oil and gas clients resulting in few bankruptcies to date. The increased reliance on the banking sector, however, does give lenders greater bargaining power when negotiating the cost of new debt.

- **Increased cost of equity** – as debt is treated preferentially to equity (creditors get paid before equity holders in the event of corporate bankruptcy), equity often becomes less readily available and more expensive as investors demand higher returns to take on the greater level of associated risk.

> "Rising debt levels mean there is likely to be a time lag between any recovery in long-term price expectations and investment in the UKCS."

- **Slower recovery** – even if the oil price recovers, companies that have exceeded targeted debt levels will likely 'cash-sweep', that is, using excess cash-flow to deleverage by paying off debt rather than reinvesting the returns into new projects. As such, there is likely to be a minimum one to two year time lag between any recovery in long-term price expectations and any recovery in investment in the UKCS as companies prioritise the rebalancing of their financial structure.

5. Upstream Performance Indicators

This section reviews the commercial health of the UK's upstream industry. Using data gathered in June 2016, it provides an updated review of recent trends and assesses potential performance of the basin over the next two to three years.

5.1 Resources/Reserves

Despite the difficult market conditions, Oil & Gas UK considers that the range of total estimated recoverable resource potential on the UKCS still stands at 10-20 billion barrels of oil equivalent (boe). This is despite the fact that the high case outcomes for yet-to-find resources, as published by the Oil and Gas Authority (OGA), have been discounted to reflect the uncertainties involved.

> "The last year in which more reserves were found than produced was 1990."

However, more of the basin's total remaining potential has been downgraded to the less certain resource brackets, reflecting the decreased likelihood of many potential development projects proceeding and the threat of premature cessation of production if the ongoing market downturn persists. Even recovering ten billion boe, the low end of the range, will pose significant challenges.

Compared to 2015, the sanctioned base of recoverable reserves has fallen by around 8 per cent to just under 6.3 billion boe. This is because new commitments to develop fields, such as Culzean and Glenlivet-Edradour, and investment in existing fields (brownfields) do not fully offset the 602 million boe that was produced on the UKCS in 2015.

The unsanctioned reserve base within company business plans has fallen much further, by over 30 per cent from 3.7 billion boe to 2.5 billion boe over the last 12 months. One reason behind this is that the rate of project sanction continues to outpace the rate of discovery. 550 million boe were committed to production in 2015 compared with just 150 million boe discovered through exploration, only half of which is deemed to be potentially commercially viable at this stage.

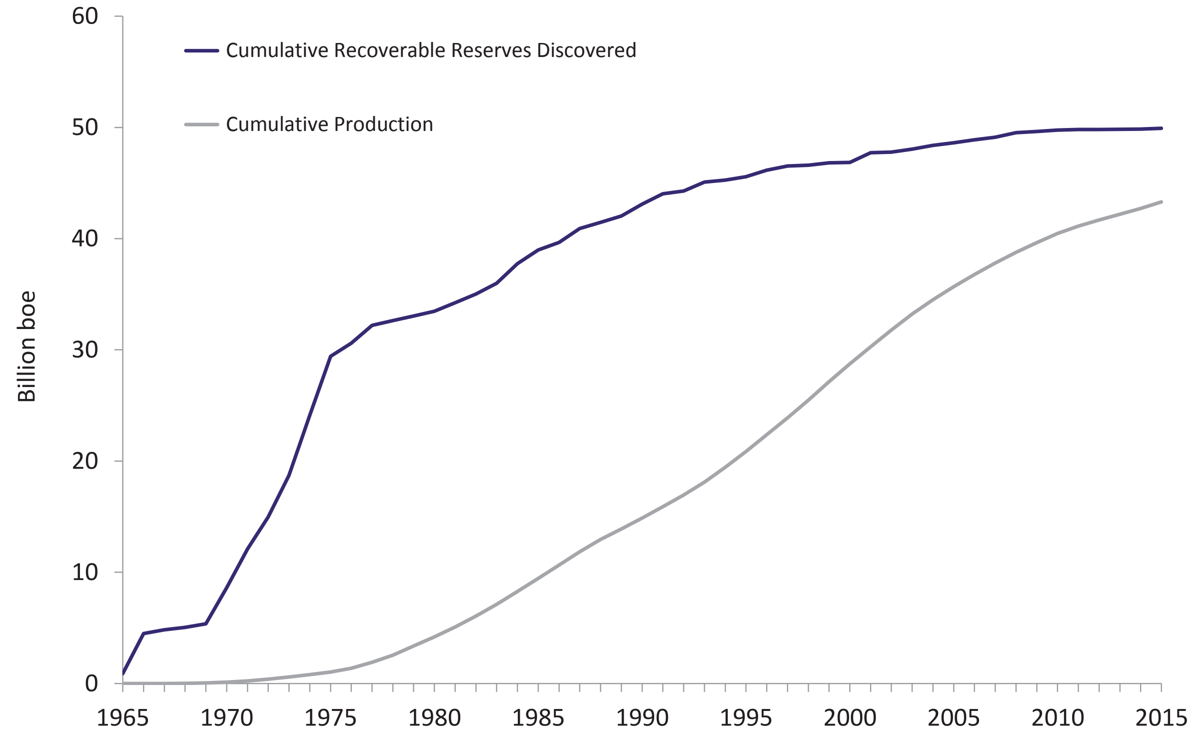
Furthermore, some opportunities have now been removed from companies' immediate business plans and downgraded to potential additional resources (PARs) as they are no longer deemed viable investments under prevailing oil and gas price expectations. This has the knock-on effect of increasing the UKCS' PARs potential from 1.5-4 billion boe to 2-5 billion boe.

The shrinking reserves pool is not a new problem on the UKCS – the last year in which more reserves were found than produced was 1990. Figure 12 shows how the reserve depletion rate has increased rapidly over the last decade, with the gap between cumulative discoveries and cumulative production closing.

While the basin's yet-to-find potential remains unchanged at 2-6 billion boe, fundamental questions remain over how much of that will ultimately be recovered given the significant decline in drilling activity in recent years and the discovery of less than 100 million boe per year on average since 2010. UKCS stakeholders are working hard to stimulate exploration activity and improve the chances of success (see section 5.2 on drilling) to increase the reserve replenishment ratio, which for 2015 was just 0.25[16].

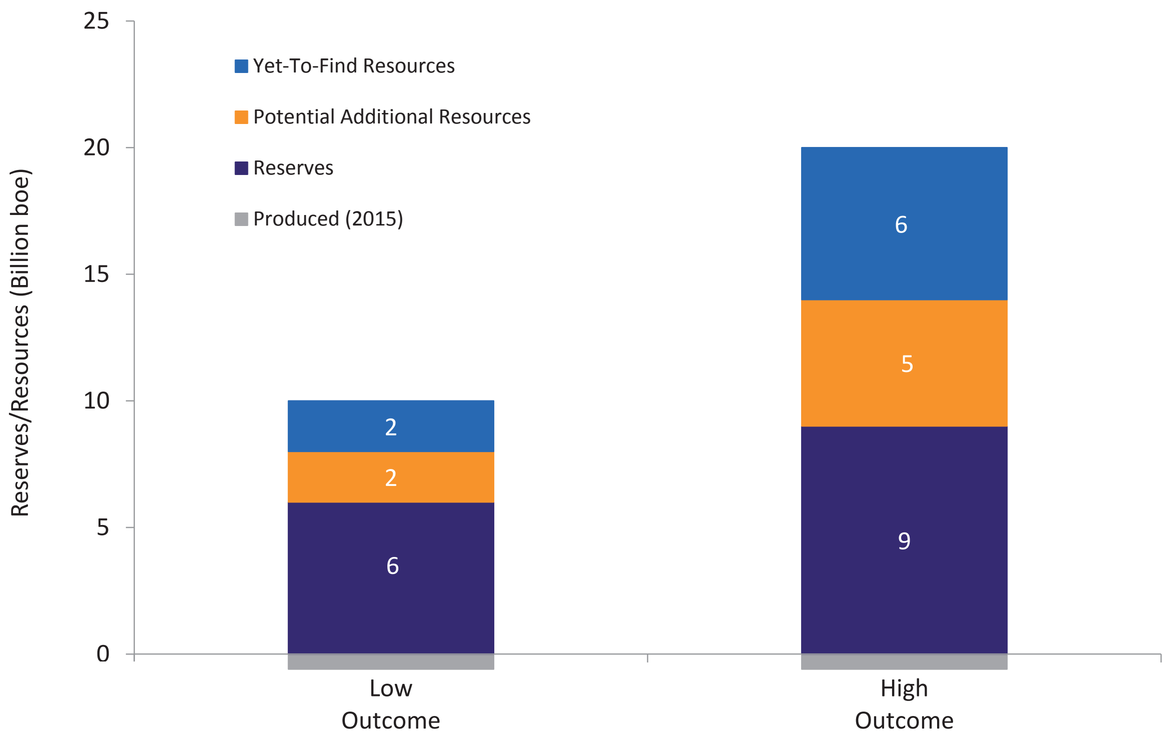
[16] Reserves replenishment ratio = discovered volumes/produced volumes.

Figure 12: Rate of Discovery versus Rate of Production



Source: Wood Mackenzie

Figure 13: Reserve and Resource Potential

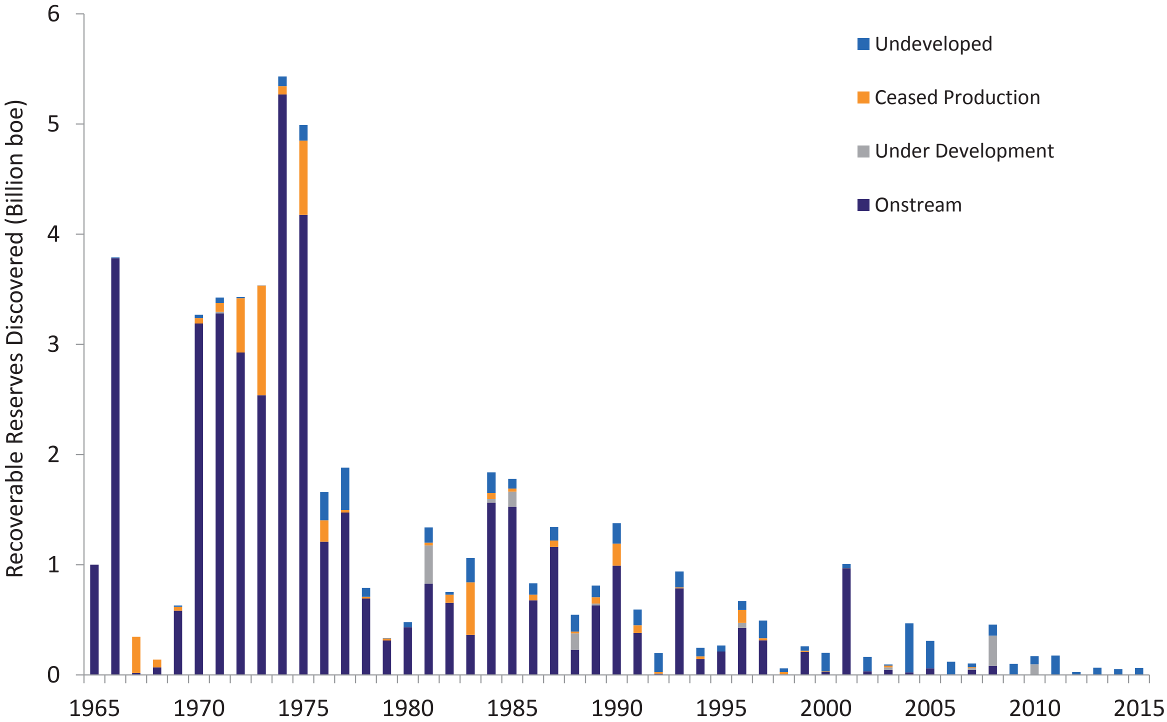


Source: OGA, Oil & Gas UK

Stranded Opportunities

The decline in exploration activity and lack of material exploration success means that many of the current development prospects are not new – more than two-thirds of the associated reserves were discovered before 2000. However, without a significant change in the fundamental economics of these potential projects, either driven by a rise in prices or a fall in costs, many will never be developed.

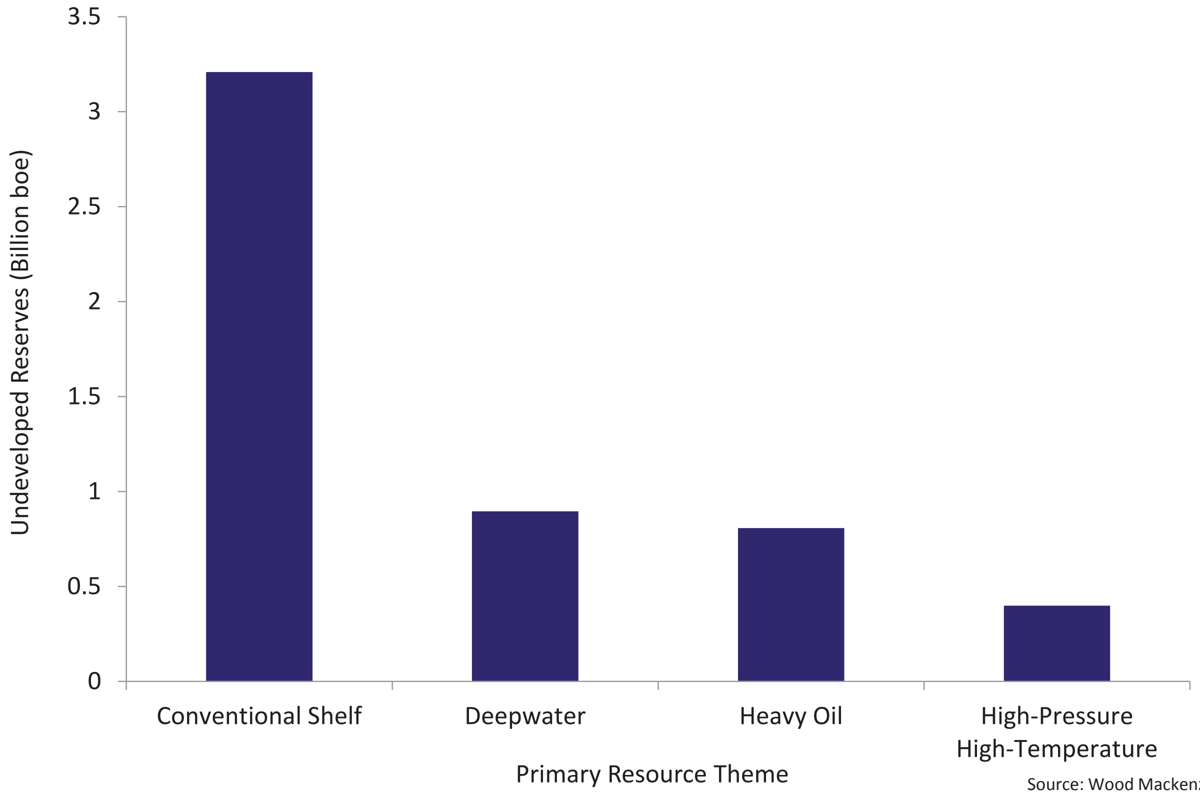
Figure 14: Development Status and Recoverable Reserve Base by Year of Discovery



Source: Wood Mackenzie

Data provided by Wood Mackenzie indicate that up to five billion boe within known discoveries are currently considered commercially unviable for development and categorised as PARs. Around 40 per cent of these reserves are classified as unconventional, meaning the reservoir is high-pressure high-temperature (HPHT), heavy oil or in deepwater and are therefore technically challenging, requiring significant capital investment to extract. Of the conventional stranded discoveries, about 90 per cent are less than ten million boe in size and deemed too small for commercial development. More certain access to infrastructure and the cost-effective deployment of existing and new technologies will be vital to develop some of these small fields and is seen as a crucial opportunity by both industry and the OGA.

Figure 15: Primary Resource Theme of Undeveloped Reserves



Source: Wood Mackenzie

The Technology Leadership Board (TLB), made up of industry, academia and government agency expertise, is seeking to unlock as much of this potential as possible. The TLB was set up in late 2014 to advance technological development to reduce costs, improve efficiency, and maximise UKCS competitiveness and economic recovery. It now feeds into the industry and OGA's joint MER UK (Maximising Economic Recovery from the UKCS) Forum and aims to ensure technology development is collaborative, focused on priority areas and suitable for multi-field application. The four key areas identified are well construction, small pools development, asset integrity and decommissioning[17].

The small pools theme, for example, has already made tangible progress by mapping these discoveries. The OGA has identified over 350 unsanctioned discoveries of less than 50 million boe in size, containing total resources of over 3.4 billion boe (technically recoverable). These are currently not pursued by the licence holders. Preliminary economic modelling by the TLB Small Pools work group[18] shows that if development costs could be reduced by 50 per cent, for instance through better engineering concepts, novel technologies, and improved operational and commercial arrangements, this could unlock over 1.5 billion boe of the above resources. Other work targeting reductions in drilling costs and asset integrity will also help these project developments, further increasing the likelihood of these reserves being extracted.

The TLB is among the bodies supporting the new Oil and Gas Technology Centre (OGTC), announced earlier this year and underpinned by funding from the UK and Scottish Governments through the Aberdeen City Region Deal. The OGTC's priority is to establish Solution Centres that bring together knowledge and expertise from across industry and deliver practical solutions.

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[17] Find out more about the progress of the MER UK Technology Leadership Board at http://cld.bz/qvj13au/28

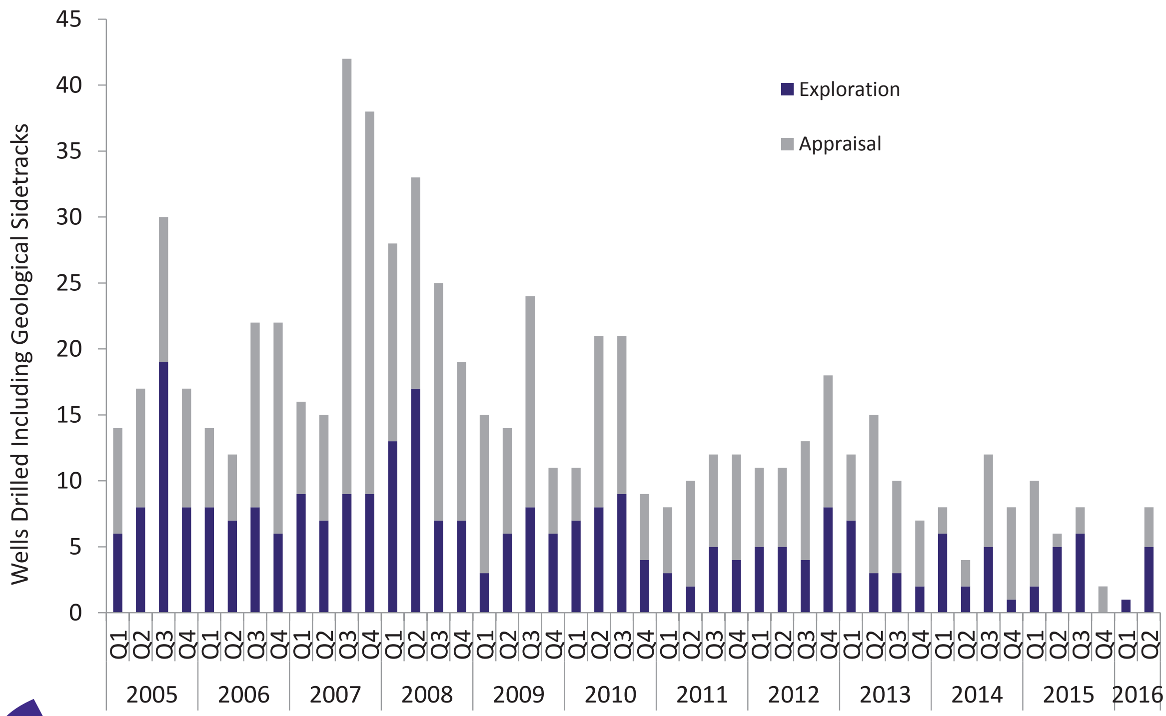
[18] Participating organisations: Centrica, EnQuest, National Subsea Research Initiative, Oil & Gas UK, OGA.

5.2 Drilling Activity

Exploration and Appraisal

The downward trend in exploration and appraisal (E&A) activity continued in 2015 with just 13 exploration and 13 appraisal wells drilled. At the start of this year, Oil & Gas UK forecast a further decline in E&A activity with seven to ten exploration wells expected to be spudded and six to nine appraisal wells in 2016[19]. This remains good guidance although there may be potential upside on the exploration forecast, particularly as a number of companies may be under obligations to drill commitment wells as part of their licence agreement. By mid-2016, six exploration and three appraisal wells had commenced drilling, with a similar number again expected in the second half of the year.

Figure 16: Exploration and Appraisal Drilling



Source: OGA

> Exploration budgets are under severe pressure and companies have cut much of their discretionary expenditure to preserve cash-flow.

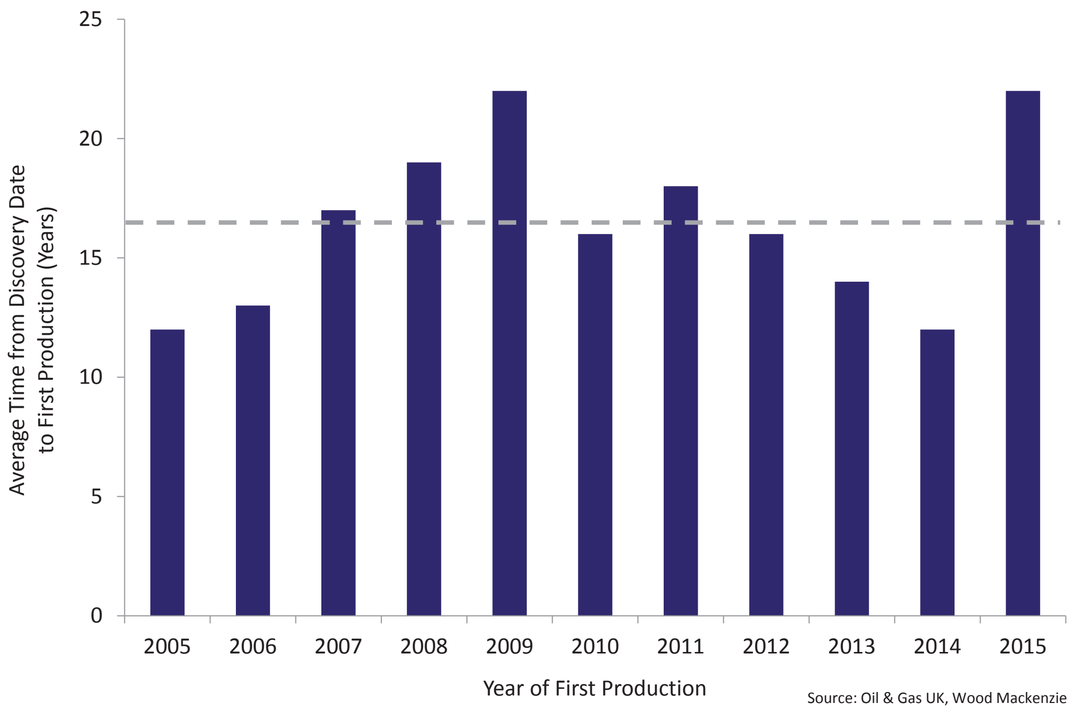
There are a number of factors currently constraining E&A activity globally, not least on the UKCS. Exploration budgets are under severe pressure and companies have cut much of their discretionary expenditure to preserve cash-flow. In some circumstances, companies have even postponed all E&A activity until market conditions improve sufficiently and corporate balance sheets recover.

[19] Forecasts for 2016 activity can be found in Oil & Gas UK's *Activity Survey* at www.oilandgasuk.co.uk/activitysurvey

The scarcity of E&A funds is felt particularly severely in the UK because much of the activity is now undertaken by smaller companies. While larger exploration and production companies may be able to use income from their existing business, smaller companies will need to access the equity market or external sources for capital. In the current market, these means to fund exploration have all but dried up.

On the UKCS, the time it takes to bring a new discovery through to first production varies greatly. While some new discoveries are quickly developed, many can take decades, either because of marginal economics, infrastructure issues or technical challenges. Figure 17 shows that fields entering production over the last decade were, on average, discovered 17 years prior to first oil or gas. This lengthy payback time acts as a disincentive to further exploration when there are already many small fields with the potential to be developed if technological progress allows. Companies may choose to focus on other forms of investment as they seek fast cash-flow generating opportunities that may be more commonly found in small brownfield developments or by targeting increased production from existing fields.

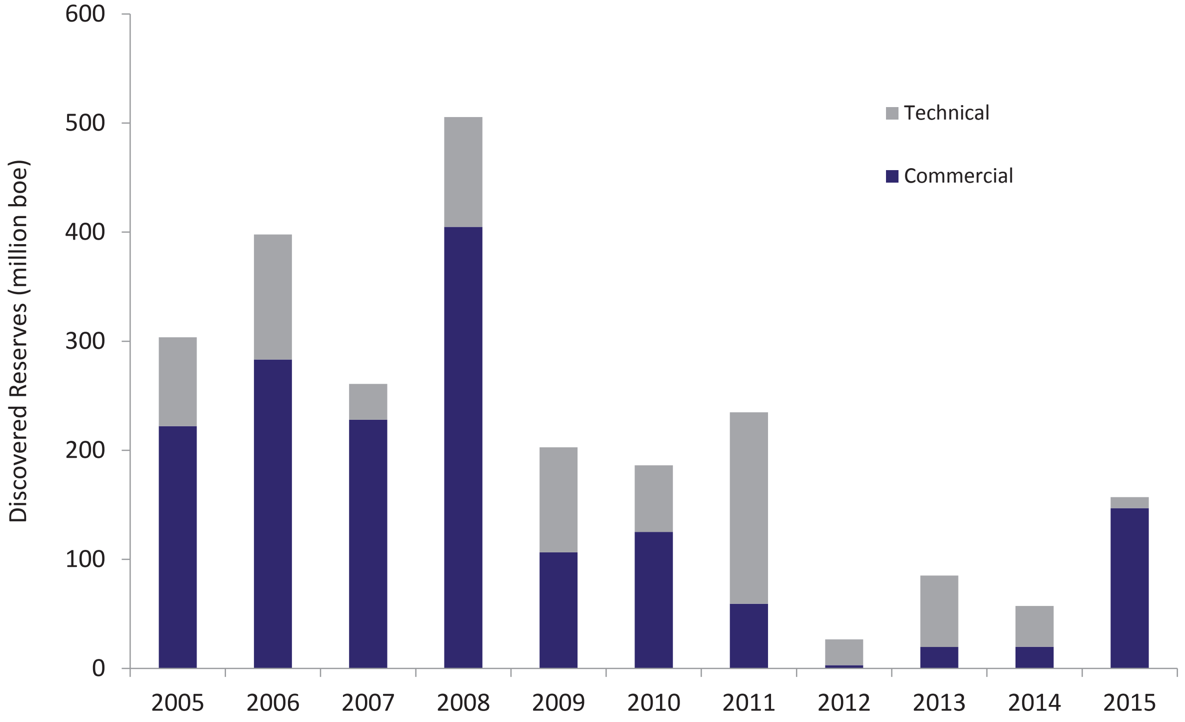
Figure 17: Average Time from Discovery to First Production



In addition, there has been a lack of material exploration success in the UK in recent years, despite last year's performance being the best since 2011 when just over 150 million boe of resource was discovered, most of which appears to be commercially recoverable.

Due to the perceived lack of prospectivity on the UKCS, companies that do have budget to explore are choosing to carry out such activity in other basins. Those targeting larger opportunities will undoubtedly be influenced by the lack of such discoveries on the UKCS in recent years – the last discovery with recoverable reserves estimated at greater than 100 million boe was the Culzean field, discovered in 2008, which is now under development.

Figure 18: Discovered Reserves



Source: Wood Mackenzie

Concerted action is being taken by the government, the regulator and industry to stimulate E&A activity and replenish production with new projects. The positive measures being taken are outlined below, although scarcity of funding and severe competition for capital undoubtedly require further attention.

- **UK Government-funded seismic surveys** – over the last two years, the UK Government has committed £40 million to fund fresh seismic surveys using the latest technology in areas that would otherwise have not been surveyed. This initiative is already proving successful in generating interest in these areas. Data have been released from the first round of seismic surveys of the Rockall Trough and Mid North Sea High regions. Available freely through Common Data Access Limited's (CDA) online repository, the information improves the quantity and quality of subsurface data available for these under-explored areas of the UKCS. There have been over 8,000 downloads of the smaller data packages so far with individuals and companies from over 22 countries requesting the data. PGS and WesternGeco have, meanwhile, been awarded contracts to acquire seismic data from the East Shetland Platform and South West Britain, respectively, in round two of the seismic acquisition and processing programme.

- **Exploration Conference** – Oil & Gas UK's annual Exploration Conference was held in February 2016 with over 170 delegates attending. With a view to sharing best practice, delegates heard about the successes and challenges of exploration in the North Sea and Atlantic Margin, as well as the recent advances in seismic technology.

- **Well failure analysis study** – as part of the industry's 21st Century Exploration Road Map project, findings were released earlier this year from the OGA's well failure analysis study in the central North Sea (CNS) and Moray Firth regions[20]. The work was carried out to improve exploration success, with detailed analyses and interpreted reasons for the failure of 98 wells drilled over the last ten years so that lessons could be learnt.

- **29th Licensing Round** – The OGA has launched the 29th Offshore Licensing Round with more than 1,200 blocks available to support the objective of MER UK. A new concept known as the Innovate Licence has also been developed by the MER UK Exploration Board so that licencees can work with the OGA to design an optimal work programme with better monitoring of progress than the previous licensing regime.

- **Palaeozoic study** – a joint industry-government funded study carried out by the British Geological Society has examined the Palaeozoic rock formation in the CNS, Irish Sea and Orcadian Basin to improve geological understanding. The information has been shared with the project sponsors and will become more widely available after the 29th Licensing Round.

> "Concerted action is being taken by the government, the regulator and industry to stimulate exploration and appraisal and replenish production with new projects."

- **Targeting drilling cost reductions** – Oil & Gas UK's well cost reduction group is investigating means to use technology to reduce well construction costs by up to 50 per cent.

- **Subsurface study contracts** – in August 2016, the OGA awarded four contracts with a combined value of more than £6 million over three years for surface and subsurface studies to improve geotechnical understanding.

All of these initiatives are of utmost importance and are progressing well, but further work still needs to be done to counter the difficulties that industry is currently experiencing in this area. Without an upturn in exploration activity, much of the UKCS' yet-to-find potential will not be accessed and even the low case will prove difficult to achieve.

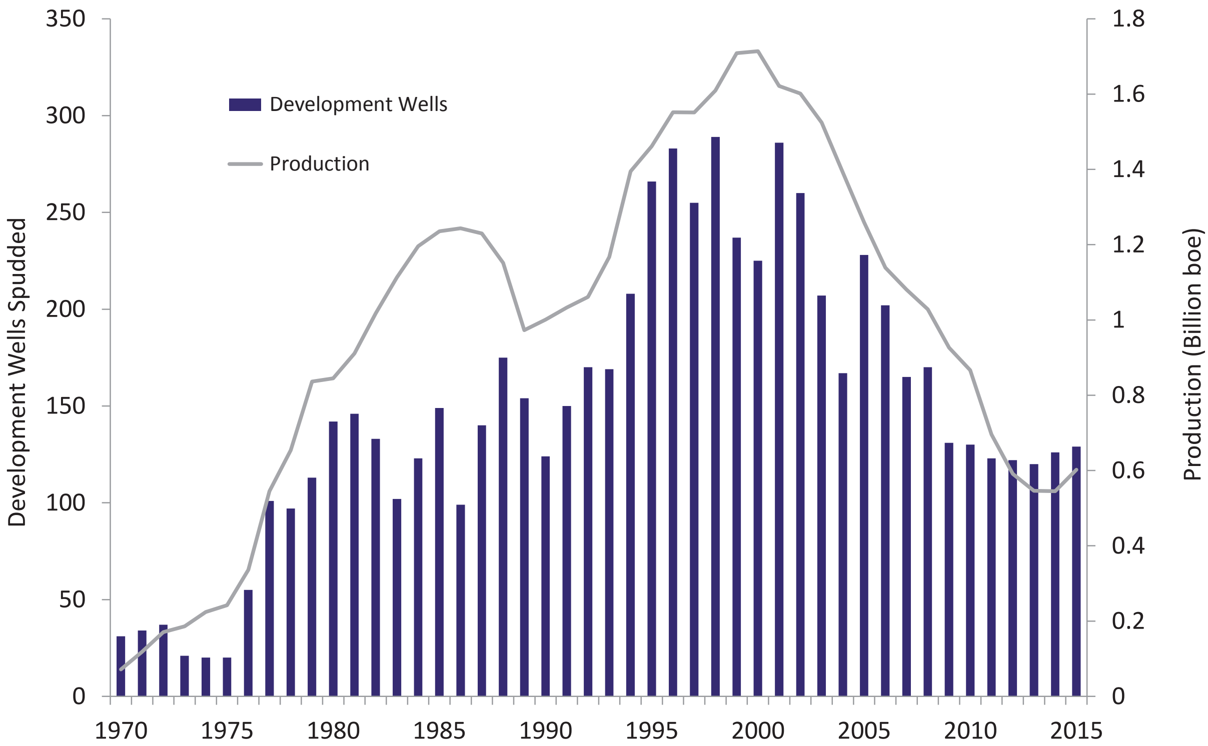
[20] The Well Analysis study is available to download at www.gov.uk/government/publications/moray-firth-central-north-sea-post-well-analysis

Development Drilling

Given that development wells are drilled with the intent of producing oil and gas, it is unsurprising to see the strong correlation (0.9) between development wells spudded and production, as shown in Figure 19. Therefore, the rate of drilling can be used as a strong leading indicator of production.

The rate of development drilling held up very well through the first half of the decade, with 120 to 130 wells spudded in each of the last six years and this has contributed towards stabilising production over the last two to three years.

Figure 19: Development Drilling versus Production

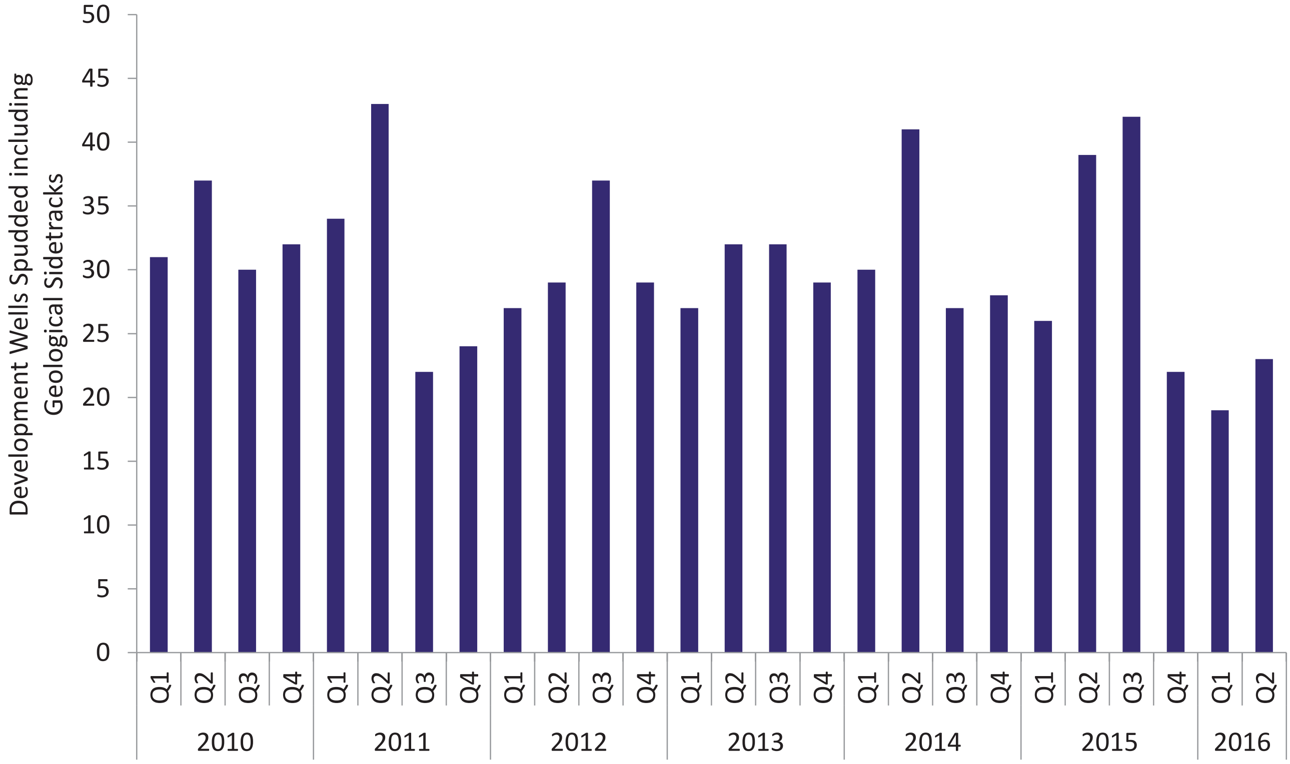


Source: BEIS, Oil & Gas UK

However, there has been a sharp fall in the number of development wells drilled over the last three quarters, as shown by Figure 20 opposite. Forty-two development wells were drilled in the first half of this year pointing to an anticipated fall of up to 30 per cent this year against the 129 development wells drilled during 2015. Fewer producing wells are expected to be drilled this year than in any year since the 1970s, adding to the threat of another production collapse towards the end of the decade.

> "Fewer producing wells are expected to be drilled this year than in any year since the 1970s."

Figure 20: Development Drilling



Source: OGA

5.3 Total Expenditure

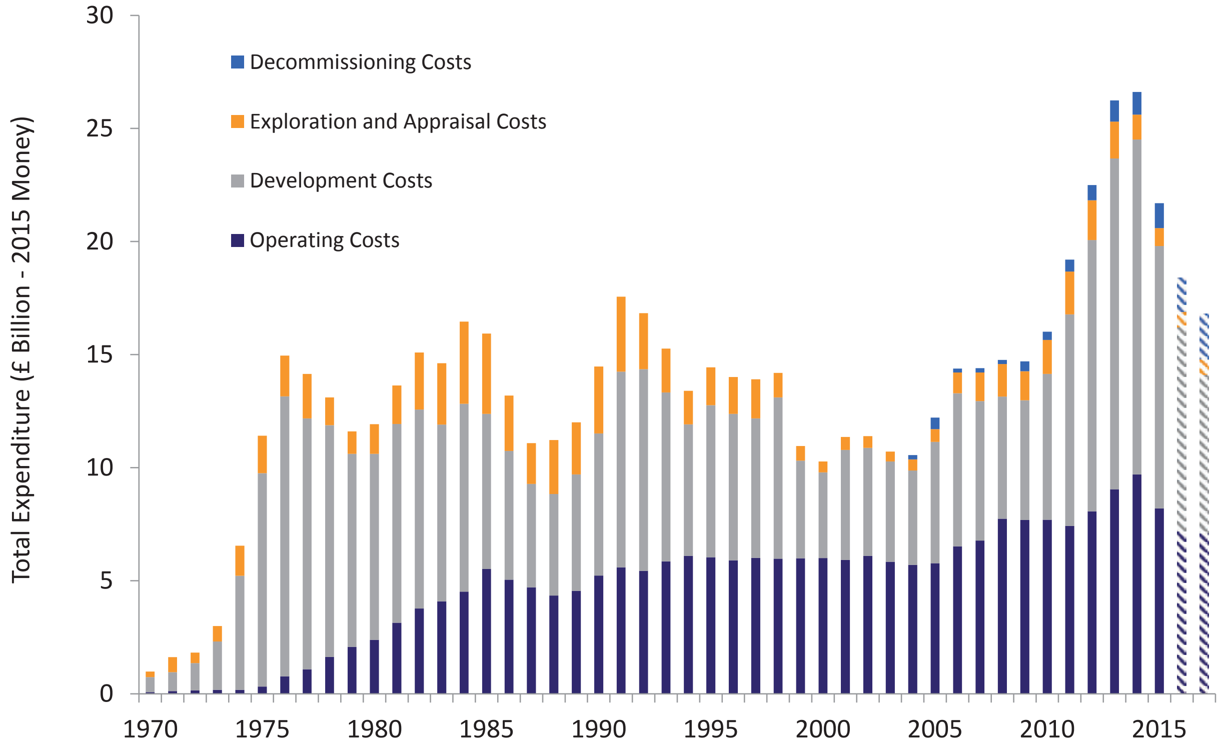
The collapse in oil price since the second half of 2014 has put the industry under immense pressure to reduce its expenditure in all areas to secure sustainable operations, while upholding the imperative to maintain safe production. The readjustment of budgets and rationalisation of expenditure was evident over the course of 2015 and has continued this year, alongside efforts to increase efficiency at a company and pan-industry level (see section 8 for more on the Efficiency Task Force). Many operators have cut capital investments and reduced operational costs to improve their cash-flow.

> Many operators have cut capital investments and reduced operational costs to improve their cash-flow.

Total expenditure on the UKCS fell by almost £5 billion in 2015 from £26.6 billion to £21.7 billion, in spite of an increase in production of 10.4 per cent. Expenditure is likely to fall further this year to around £19 billion as companies continue to make efficiency gains, reduce costs and preserve capital to make their businesses robust at current prices.

Looking ahead to 2017, the downward trend in expenditure is expected to continue, with a steep decline in capital investment being the main contributing factor. Operating costs are also expected to fall, albeit at a much slower rate, while E&A expenditure is forecast to remain weak at around £0.7 billion. There is likely to be a slight upturn in decommissioning expenditure next year, from £1.5 billion to £2 billion, as many fields, particularly in the southern North Sea (SNS), cease production and enter the decommissioning phase.

Figure 21: Total Expenditure by Category



Source: Oil & Gas UK, OGA

Capital Investment

Globally, almost $1 trillion of capital investment earmarked for new oil and gas projects over the next five years has been postponed or cancelled[21]. With long-term oil and gas price expectations now significantly lower than the first half of the decade, potential developments across the world are fundamentally less attractive using almost any investment criteria.

Many investors are simply unwilling to sink capital into new opportunities at this time so it is very hard to raise new equity. Debt financing (see section 4 on corporate financial structures) is also becoming more constrained as the collateral against which banks lend, most commonly reserves, is now worth less, tightening borrowing capacity. Ultimately, in a fiercely competitive and mobile industry, only the most attractive prospects around the world are able to secure development finance.

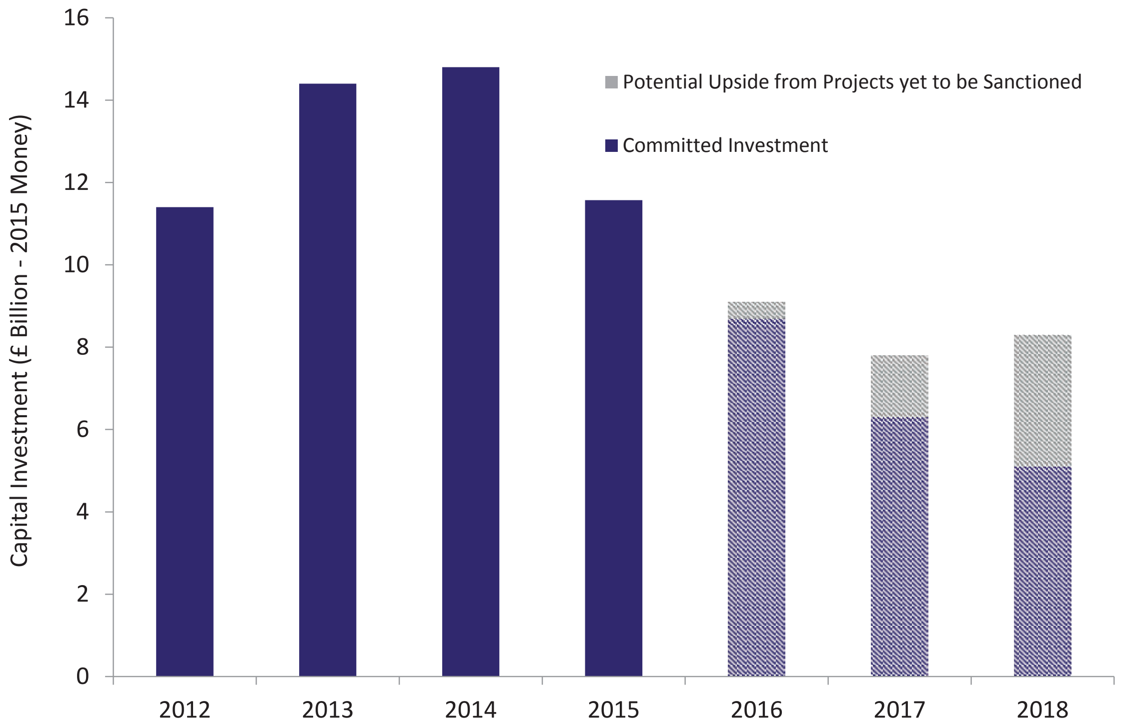
In the UK, capital investment is falling rapidly after years of record expenditure that peaked at £14.8 billion in 2014. Last year, around £11.6 billion was invested and this is likely to decline to around £9 billion this year and £7 billion in 2017.

[21] See www.woodmac.com/analysis/global-upstream-investment-slashed-by-US1-trillion

Ongoing investments in existing development projects, most of which were sanctioned when the oil price was higher than $100/bbl, will hold annual investment up to at least £5 billion in 2018 but the longer term trend remains negative.

With most potential new developments requiring a break-even oil price in excess of $50/bbl, companies are re-evaluating development concepts to achieve significant cost savings before committing to new projects. This project slippage may present some upside on the forecast towards the end of the decade but only if market conditions improve.

Figure 22: Capital Investment

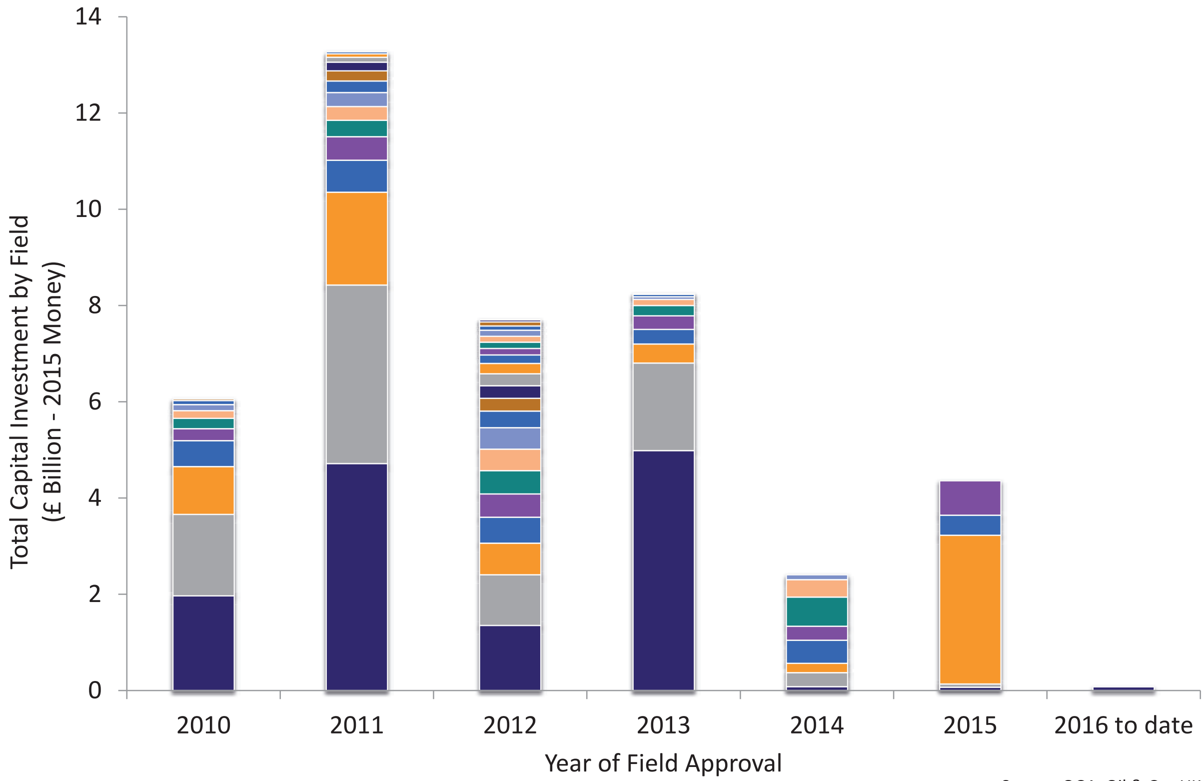


Source: Oil & Gas UK

Figure 23 overleaf shows that only one new field has been approved so far in 2016 at the time of writing, with less than £100 million of fresh capital committed to the basin. With few projects approaching sanction, it is possible that there will be no further commitments to investment in greenfield projects this year. This is set to be the worst year in the history of the UKCS for new field approvals. Brownfield opportunities are also scarce with just five addendums to field development plans sanctioned so far and few expected for the rest of the year. This is compared with ten in 2015 and 28 in 2014.

“Less than £100 million of fresh capital has been committed to the basin so far this year.”

Figure 23: New Field Approvals



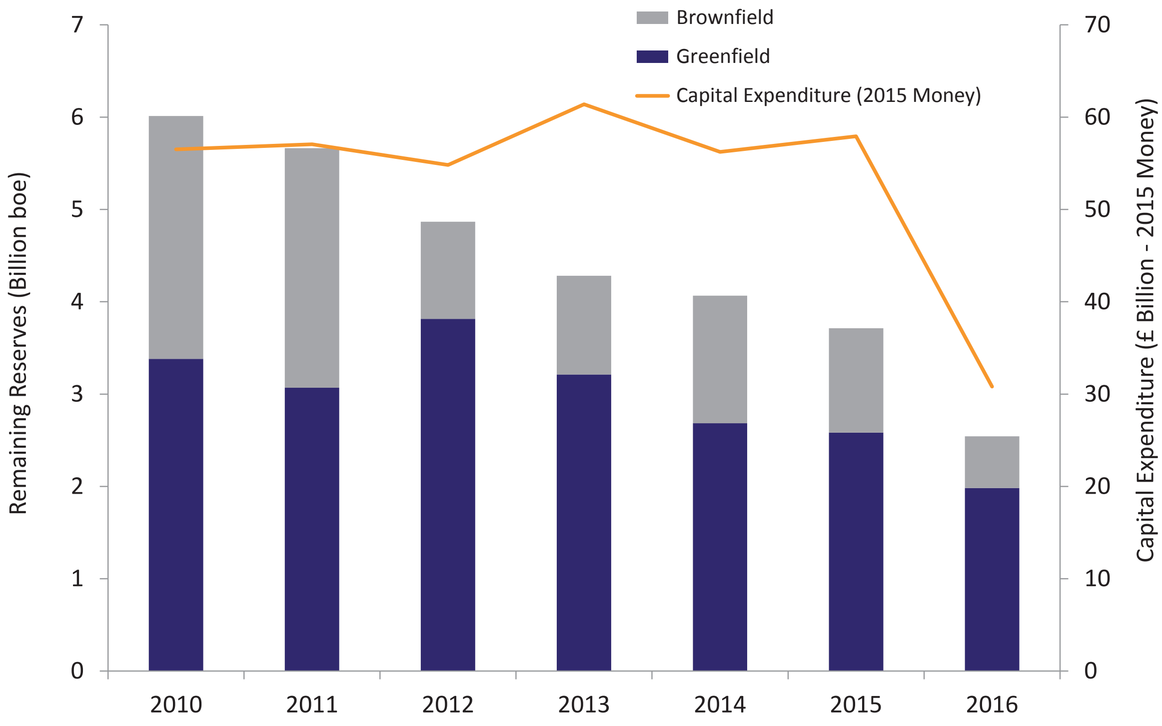
Source: OGA, Oil & Gas UK

The lack of discretionary capital investment being committed to the UK is perhaps the biggest threat to the long-term future of the basin, as it has the potential to accelerate abandonment of infrastructure and diminish the scale of the UK's supply chain. If no new investments are secured over the next few years, investment will fall to as low as £2 billion per year by 2020.

Furthermore, the lack of material exploration success and decline in E&A activity over the last seven to eight years (see section 5.2) means that the pool of new development opportunities in the UK has also fallen. There are now just 26 pre-sanction greenfield opportunities in company plans and only four of these potential projects contain more than 100 million boe.

For the long-term future of the basin, it is important that exploration activity improves and new investment rapidly begins to recover. In the current climate, it is more likely that smaller near-field and brownfield opportunities with faster payback will provide short-term stimulus to investment. However, a continuum of new large field developments is also needed to stabilise the future of the industry.

Figure 24: Undeveloped Reserves in Company Plans and Associated Capital Expenditure

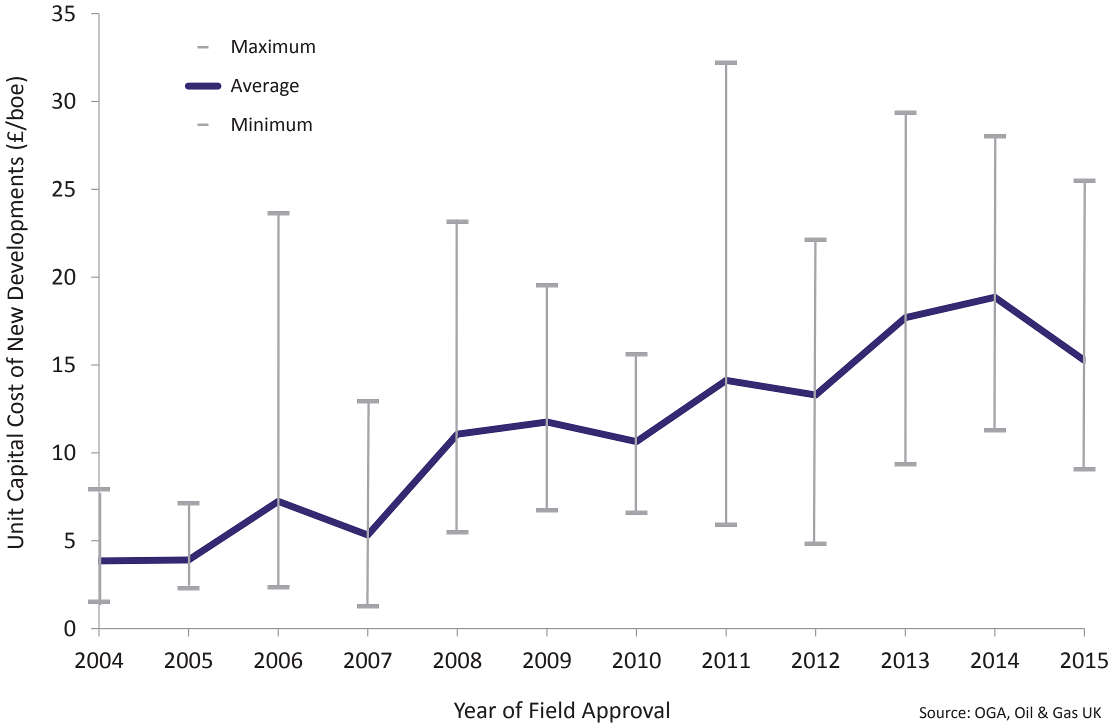


Source: Oil & Gas UK

The amount of capital investment required to develop unsanctioned opportunities in company business plans has halved over the last 12 months from almost £60 billion in 2015 to just over £30 billion this year. This is in part due to there being fewer opportunities that companies are willing to consider and the scope of some projects having narrowed.

Even on a like-for-like basis, development costs are beginning to deflate in response to weaker market demand. Company plans show that like-for-like pre-sanction opportunities are now forecast to be around 25 per cent cheaper to develop on a unit basis than they were 12 months ago. Furthermore, the forecast unit development costs of the five new fields approved in 2015 were, on average, 20 per cent lower than the eight new fields approved in 2014. Although this draws on a small sample of fields of varying technical difficulty and size, it does provide further evidence to support the assertion that development costs are falling.

Figure 25: Unit Development Costs by Year of Approval



Source: OGA, Oil & Gas UK

Operating Expenditure

The Short-Term Reaction

When the Brent oil price averaged $109/bbl and the month-ahead NBP gas price averaged 53 p/th in the first half of 2014, the oil and gas industry was attractive. Even a high cost mature basin like the UKCS, where the average unit operating cost (UOC) was $29.30/boe, was generally profitable.

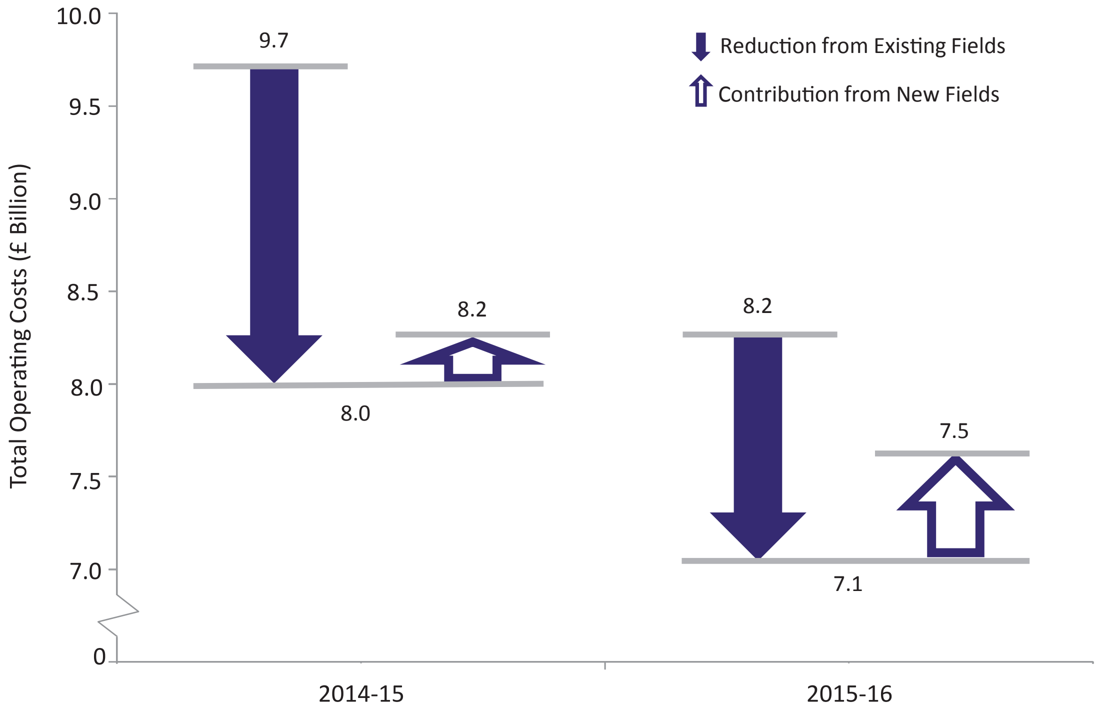
However, by mid-2015, the collapse in prices meant that almost a third of all UK producing oil fields were suddenly in a loss-making position. The only near-term response available to companies was to try and reduce their cost base and improve efficiency as quickly as they could. The industry's delivery was impressive and, although some supply chain companies were unable to survive, the flurry of bankruptcies that might have been expected did not materialise. Instead, £1.7 billion was removed from the cost of operating like-for-like assets in 2015 and the average UOC dropped by 28 per cent to $20.95/boe.

That same focus continued through the first half of 2016 as prices fell further and companies attempted to retain profitability or minimise losses. Average UOCs are expected to fall to around $16/boe this year, driven not only by cost reductions, but also by an increase in production and the depreciation of the pound against the dollar. This means UOCs have almost halved since peaking in 2014.

> Unit operating costs have almost halved since peaking in 2014.

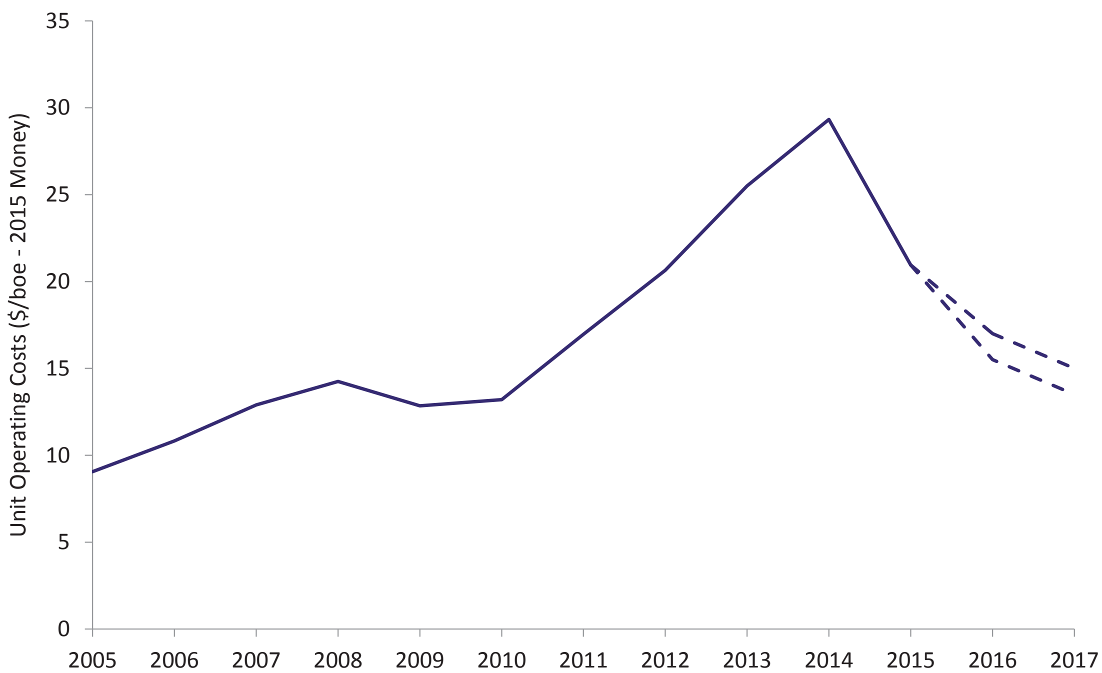
It is anticipated that the fall in operating costs will slow during 2017, levelling off at around £7 billion per annum for total operating costs and a UOC of $14-15/boe. The majority of companies have already carried out significant reduction programmes and streamlined operations as far as they can in the near-term.

Figure 26: Change in Operating Costs with Impact of New Start-Ups



Source: Oil & Gas UK

Figure 27: Unit Operating Costs



Source: Oil & Gas UK

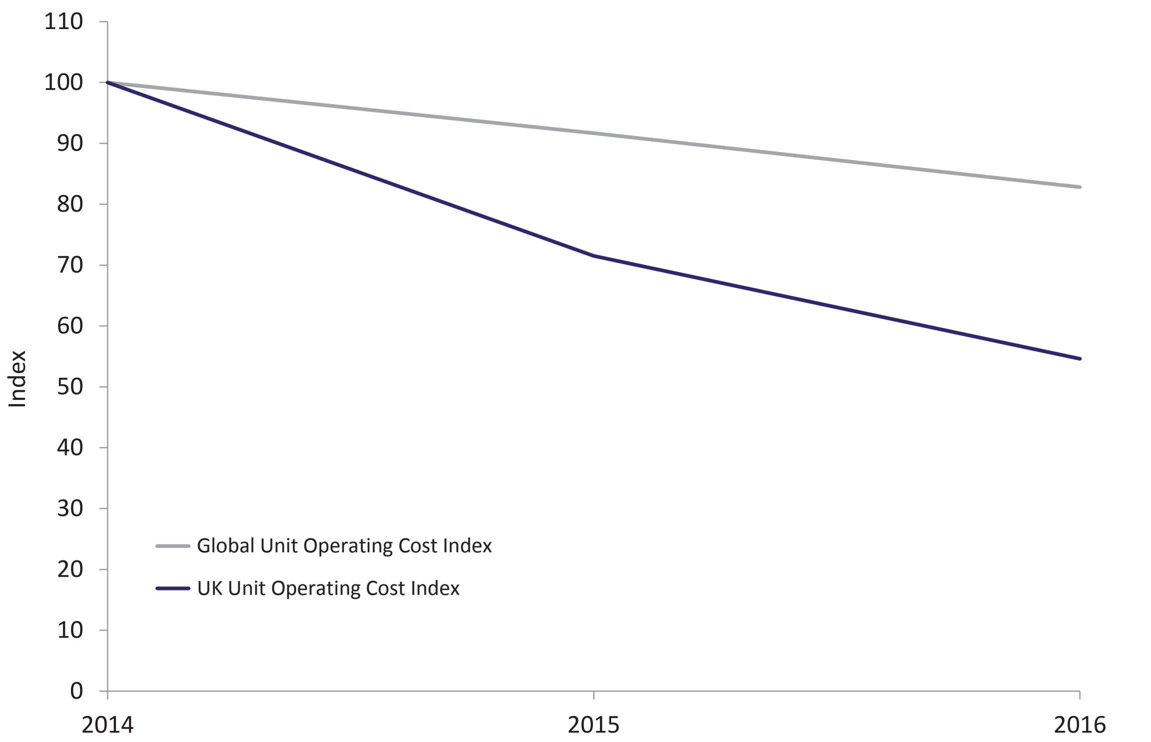
With input costs associated with oil and gas operations falling sharply, it is important to consider the extent to which the reduction in UK operating costs is a result of industry-wide cost deflation compared with operational efficiency improvements.

The *IHS Upstream Operating Cost Index*[22] measures quarterly changes in the costs of oil and gas field operations. This shows that in quarter two of this year, global upstream operating costs were on average 17 per cent lower than at their peak in the second quarter of 2014. Meanwhile, UK UOCs have fallen by around 45 per cent over the same period.

The scale of the cost reduction in the UKCS is more than double the natural upstream operating cost deflation, suggesting that efficiency gains have been key to the improvement in the UK's competitiveness. While the natural cost deflation reported by IHS will inevitably be influenced by oil price, there is a reasonable expectation that the efficiency improvements made will be sustained even if prices recover.

> Efficiency gains have been key to the improvement in the UK's competitiveness.

Figure 28: Global Upstream Operating Cost Index versus UKCS Unit Operating Costs

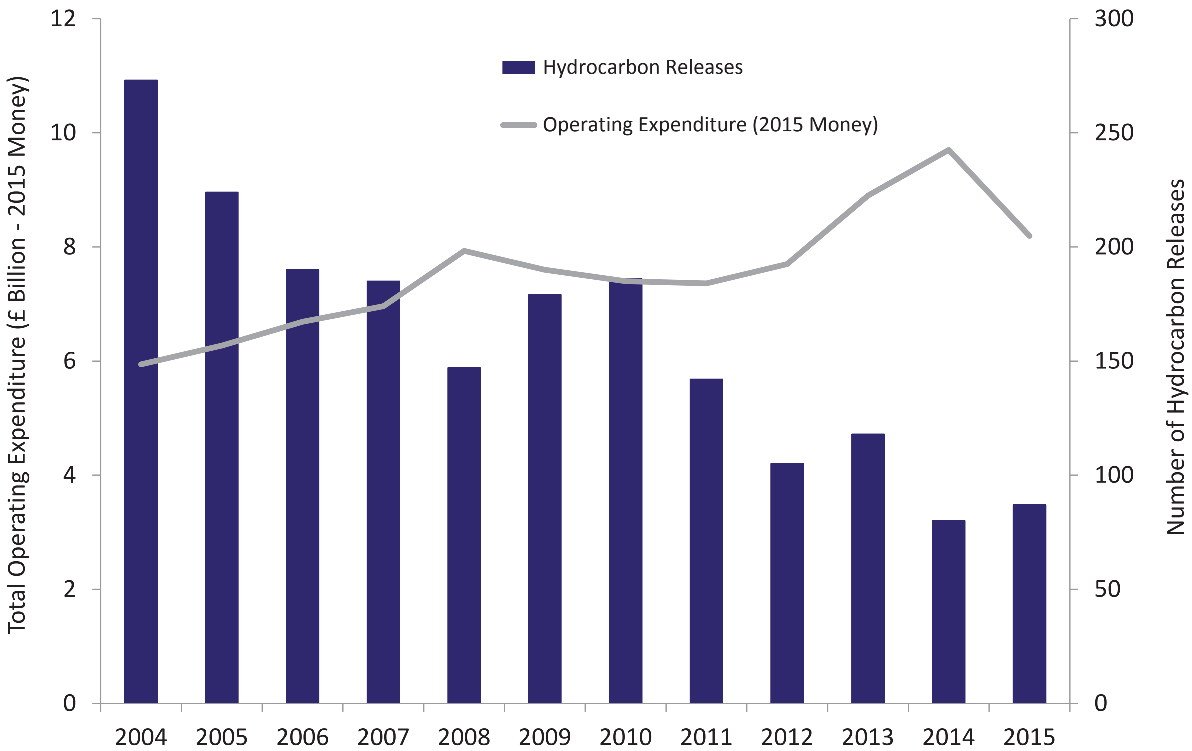


Source: IHS, Oil & Gas UK

[22] See www.ihs.com/info/cera/ihsindexes/Index.html

It is important to note that commitment to safe operations remains key for the industry and the reduction in operating expenditure in no way compromises this objective. Latest health and safety statistics[23] show that in 2015 there were no fatal incidents offshore in the UK and the non-fatal injury rate remains lower than that of other industrial sectors such as manufacturing and construction. Injuries lasting more than seven days reached an all-time low on the UKCS in 2015 and the number and severity of hydrocarbon releases remains on a long-term downward trend at almost 70 per cent lower than its peak in 2004 and almost 20 per cent lower than 2012 – the last time operating expenditure was this low.

Figure 29: Operating Expenditure versus Hydrocarbon Releases



Source: The Health and Safety Executive, Oil & Gas UK

The Long-Term Solution

As the belief in 'lower for longer' oil and gas prices grows, the need for sustained change in how the industry does business has become more apparent to achieve savings over the long-term. There is little room for further cost-cutting activity and industry must instead invest in solutions that will restrict UOC growth into the next decade, even when production begins to fall again.

Oil & Gas UK's Efficiency Task Force is leading a number of pan-industry initiatives to ensure a long-term sustainable business model for the sector that is robust against a backdrop of declining production and a $50/bbl oil price. More information on the Task Force can be found in section 8.

[23] Oil & Gas UK's *2016 Health and Safety Report* is available to download at www.oilandgasuk.co.uk/healthandsafetyreport

5.4 Production

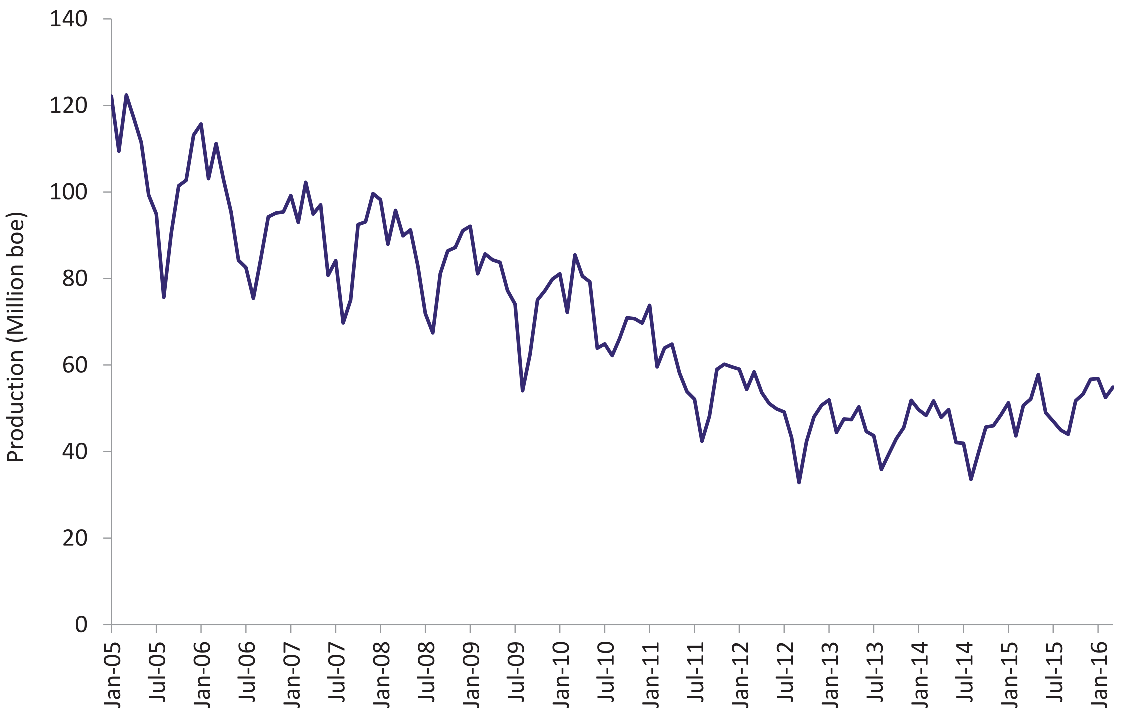
The latest provisional production data, published by the Department for Business, Energy and Industrial Strategy (BEIS), confirms strong performance on the UKCS over the last 18 months. Last year saw the first annual increase in production for 15 years. The start-up of new fields and restart of existing fields have contributed to the rise in production, as well as increased uptime from existing assets due to an improvement in production efficiency from 65 per cent in 2014 to 71 per cent[24].

> Last year saw the first annual increase in production for 15 years.

2015 Production

Figure 30 shows how the traditional period of summer maintenance was less pronounced in 2015 after years of significant integrity work from 2011 to 2014 successfully improved asset reliability and performance. Furthermore, operators have postponed non-essential maintenance to focus on maximising asset uptime to support revenues at lower prices.

Figure 30: Monthly Production



Source: BEIS, DUKES

[24] Production efficiency is the total annual production divided by the maximum production potential of all fields on the UKCS.

Production increased by 10.4 per cent in 2015, with liquids (58 per cent of the total) up 12.8 per cent and net gas[25] (42 per cent of the total) up by 7.2 per cent. This represents a year-on-year production increase of 57 million boe or 155,000 boe per day (boepd).

The key drivers were:

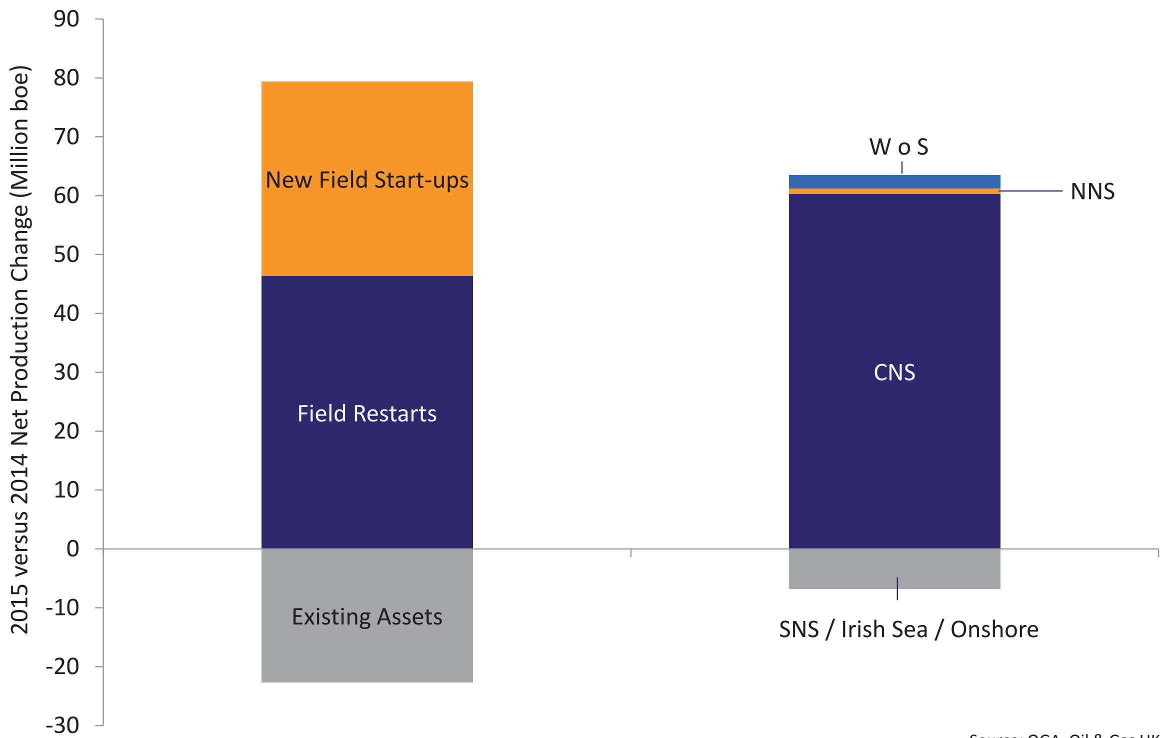
- **Field restarts** (~46 million boe) – Elgin Franklin, Rhum, Shearwater, Banff, Gannet, Pierce and Andrew are all examples of fields that were previously shut-in for various reasons but are now back on-stream and increasing in output.

- **New field start-ups** (~33 million boe) – despite some project delays, 12 fields have come on-stream since January 2014. The Golden Eagle Area, Kinnoul, Enochdhu, Ythan, Alma Galia, and Cladhan made the most notable contributions to 2015 production.

- **Existing assets** (less ~22 million boe) – despite many assets now at the tail end of their productive life, delivery from existing fields was above expectation with the average decline rate slowing from 12 to 4 per cent. Record capital investment and operational expenditure in recent years, as well as the work of the Production Efficiency Task Force, appear to be the catalyst for the improvement in reliability and integrity of existing assets leading to increased output.

Figure 31 illustrates the source of the production increase by asset type and region. Most of the new start-ups and restarts are in the CNS region. A rise in production has also been seen in the northern North Sea (NNS), where many of the efficiency improvements have been realised, and the west of Shetland (W o S), which continues to ramp up production as the basin's least mature region with much ongoing development. In the SNS area, where 15 fields ceased production during 2015, a long-established trend of production decline continued.

Figure 31: Production Increase from 2014 to 2015 by Asset Type and Region



Source: OGA, Oil & Gas UK

[25] Net gas excludes producers' own use offshore.

2016 Production and Beyond

The recent upward trend in production has continued into the first half of 2016, albeit at a slower pace, with production around 5.7 per cent higher in volume terms compared with the first half of 2015. Data published by BEIS show that liquids production was up 9.4 per cent and net gas up 1.2 per cent.

However, the improvement in production performance is likely to slow during the second half of this year as a busier summer maintenance season is anticipated and some recent start-ups, such as Golden Eagle, are reaching production plateau. Nonetheless, production for the year is currently forecast to be around 3 per cent higher than in 2015, in line with the rise estimated in Oil & Gas UK's *Activity Survey*[26] published earlier this year.

With some of the largest developments in the history of the UKCS still to come on-stream, production is expected to continue to pick up through 2017 and into 2018. However, just as this upturn in production is driven by the significant capital investment of preceding years, production on the UKCS into the next decade is dependent on companies investing in the right opportunities now.

“Production in the next decade is dependent on companies investing in the right opportunities now.”

5.5 Decommissioning

In 2015, 21 fields ceased production on the UKCS compared with 14 anticipated at the start of the year. On average, a further 20 fields per annum are expected to cease production over the remainder of the decade, in part due to worsening market expectations.

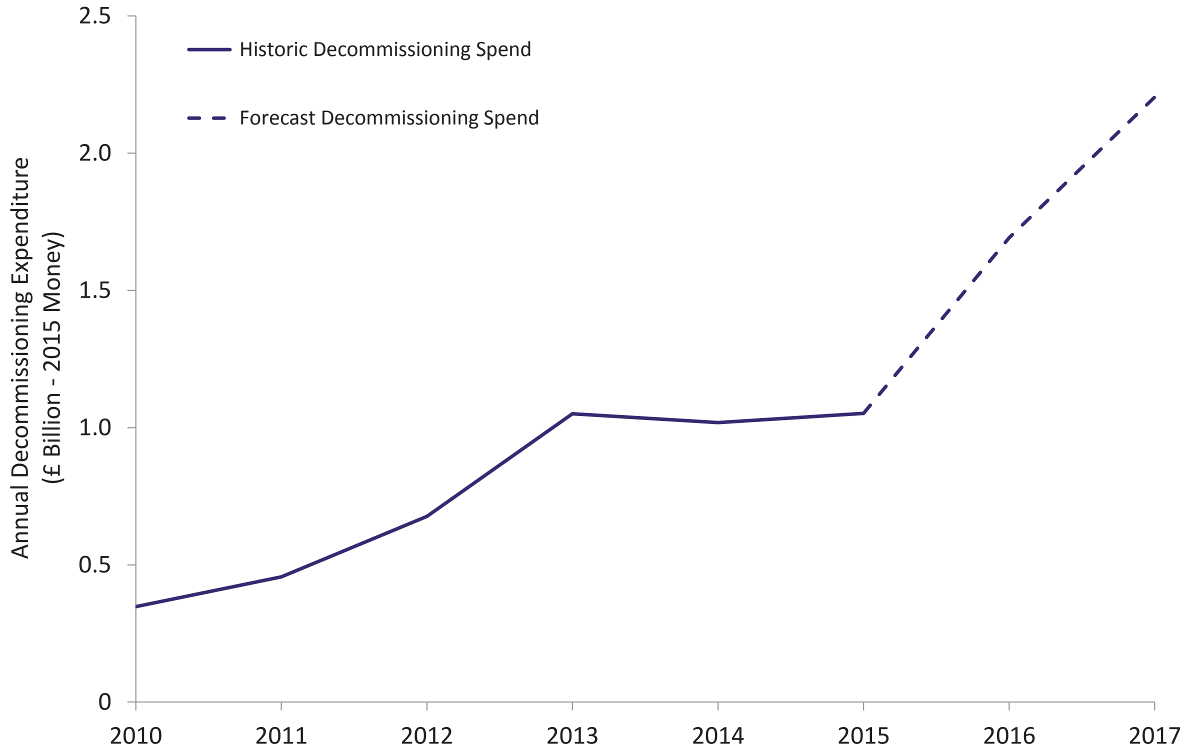
However, many of these fields will not enter the decommissioning phase until the 2020s given the shortage in capital to carry out such activity. This could increase the average period between cessation of production and decommissioning and will be inevitably scrutinised.

Nonetheless, as some of these fields do move into the decommissioning stage, this is the only area of the business where expenditure is forecast to increase. Over £1 billion was spent on decommissioning in 2015 and this is expected to reach £1.5 billion this year before increasing further to around £2 billion in 2017. The outlook beyond 2017 very much depends on the industry's ability to manage its ageing assets so that they remain economically viable even if low prices prevail.

Late-life asset management and decommissioning offers scope for the UK supply chain to diversify into one of the few growth markets and establish a global centre for excellence in this area. Industry and the regulator also have a real opportunity to co-operate to ensure that this phase of a field's life is carried out as efficiently and cost-effectively as possible with the principles of MER UK in mind.

[26] Oil & Gas UK's *Activity Survey* is available to download at www.oilandgasuk.co.uk/activitysurvey

Figure 32: Decommissioning Expenditure



Source: Oil & Gas UK

The recently published *Decommissioning Strategy*[27] developed by the OGA and industry, in conjunction with BEIS, seeks to transform this activity. The strategy is predominantly targeting a total decommissioning cost reduction of at least 35 per cent by focusing on three priority areas:

- **Cost certainty and reduction** – driving targeted cost-efficiency programmes including innovative and regional approaches with extensive and effective knowledge sharing and best practice adoption.

- **Decommissioning delivery capability** – developing an efficient and exportable low-cost and profitable decommissioning delivery capability supported by a competent and efficient supply chain, a selection of business execution models, all designed to appropriately allocate risks, align industry participants and drive down costs.

> Late-life asset management and decommissioning offers scope for the UK supply chain to diversify.

- **Decommissioning scope, guidance and stakeholder engagement** – identifying and evaluating opportunities to further optimise and define parameters for decommissioning scope and improve industry engagement with the regulators.

More information on decommissioning will be available in Oil & Gas UK's forthcoming *Decommissioning Insight*, due to be launched at the annual Decommissioning Conference in November 2016.

[27] The *Decommissioning Strategy* is available to download at www.gov.uk/government/publications/decommissioning-strategy

6. Supply Chain

With the upstream sector experiencing one of its most challenging periods in history, there is considerable ongoing impact on businesses right across the supply chain. While 12 months ago many companies still had a backlog of orders to service, the reality is that many now face an emptying order book and are having to compete fiercely for available business. Some have been able to do so successfully and have grown their businesses this year, others have partially diversified into other countries or sectors or, in a limited number of cases thus far, have had to cease operations entirely. This section identifies both the financial and operational issues facing different areas of the supply chain.

Figure 33: Supply Chain Categories and Sub-Sectors

Tier 1: E&P Companies (End User)	Integrated Majors	Large/Small Independents	Energy Utilities Companies	Non-Operating Companies	Exploration Companies
Supply Chain Categories	Reservoirs	Wells	Facilities	Marine and Subsea	Support and Services
Tier 2: Main contractors and consultants	➲ Seismic data acquisition and processing contractors	➲ Well services contractors ➲ Drilling contractors ➲ Well engineering consultants	➲ Engineering, operation, maintenance and decommissioning contractors ➲ Engineering consultants ➲ Structure and topside design and fabrication	➲ Marine/subsea contractors ➲ Heavy lift/pipelay contractors ➲ Floating, production, storage units	➲ Catering/facility management ➲ Sea/air transport ➲ Warehousing/ logistics ➲ Communications ➲ Recruitment ➲ Training ➲ Health, safety and environmental services ➲ Energy consultancies ➲ IT hardware/ software
Tier 3: Product and services suppliers Components Sub-contractors and sub-suppliers	➲ Geosciences consultancies ➲ Data interpretation consultancies ➲ Seismic instrumentation	➲ Drilling and well equipment design and manufacture ➲ Laboratory services	➲ Machinery/ plant design and manufacture ➲ Engineering support contractors ➲ Specialist engineering services ➲ Specialist steels and tubulars ➲ Inspection services	➲ Subsea manifold/ riser design and manufacture ➲ Marine/subsea equipment ➲ Subsea inspection services	

“

On average revenues across the supply chain fell by 10 per cent in 2015, with a further fall of 21 per cent forecast this year.

”

6.1 Overview

Although the fall in price and turbulence in the upstream sector began in mid-2014, the impact on the supply chain is being felt most sharply this year as existing contracts expire and future orders are scarce.

Figure 34 below reveals an estimated overall reduction in revenue across the supply chain of 10 per cent in 2015, with a further fall of 21 per cent forecast this year, taking the market to below £30 billion for the first time since 2010.

Figure 34: UK Supply Chain Financials by Sub-Sector

Currency £ million	2011	2012	2013	2014	2015E	2016E	2017E
Reservoirs	1,092	1,219	1,355	1,244	878	643	680
Wells	6,360	7,298	7,776	8,020	5,937	3,764	4,389
Facilities	10,089	11,475	13,125	13,135	14,100	10,709	10,905
Marine and Subsea	8,420	8,993	10,275	10,991	9,500	8,424	7,125
Support and Services	5,578	6,297	7,254	7,554	6,462	5,639	5,722
Total	31,539	35,282	39,785	40,944	36,877	29,179	28,822
% Change		12%	13%	3%	(10%)	(21%)	(1%)
EBITDA	2,870	3,534	4,065	4,196	3,312	2,209	2,190
EBITDA margin	9%	10%	10%	10%	9%	8%	8%

Source: EY

Further analysis by sub-sector reveals that certain areas of the supply chain have been impacted more quickly and severely than others. Areas exposed to significant falls in capital expenditure and exploration activity, namely reservoirs, wells, and marine and subsea, have seen revenues and profits erode at a greater rate. However, the facilities segment and some support and services companies were bolstered by the UKCS' strong production performance in 2015.

Indeed, facilities is the only sub-sector of the supply chain estimated to have experienced year-on-year growth in 2015 in terms of revenue, albeit with significant margin decline. This performance is dominated, however, by large international companies and so may not be reflective of the state of smaller UK-focused companies. Small and mid-sized companies will likely have been impacted by the downturn to a greater extent due to less diversity in their revenue streams and customer base, as well as a more limited ability to reduce costs. The indicated reduction in this area of the supply chain in 2016 appears more broadly consistent with the market. Excluding revenue from the facilities segment, the UK supply chain contracted by as much as 18 per cent in 2015.

Figure 34 also highlights the sharp drop in EBITDA during 2015, which, unlike revenue, has been experienced across all segments of the supply chain. Non-essential expenditure and capital projects on the UKCS have frequently been cancelled or delayed amid significant pricing pressure, with reduced activity levels and the costs of reorganisation also affecting margins. Although some parts of the supply chain are more challenged than others, the average profit margin has proved relatively resilient, falling at a slower rate than absolute earnings. This reflects the success that supply chain companies are having in reducing their own cost base and improving efficiencies in line with their operator clients.

6.2 Market Observations

Companies have increasingly adopted strategies to improve their resilience and ultimately survive. These strategies have included cost reductions, innovative and new contracting models, diversification into new geographies and adjacent markets, as well as increased collaboration between companies to expand product offerings and overall solutions for customers.

Those organisations with a more flexible cost base were able to react to falling demand across the sector by readjusting quickly to new client expectations. Similarly, sub-sectors such as facilities and support and services, which derive the majority of their income from production-related activities, have had more time to adjust their operations than those immediately exposed by project delays and cancellations.

Despite the overall downturn in performance, the market has not yet experienced widespread business failures, with some notable exceptions. This is indicative of the success that management teams have had in cost cutting programmes and in realigning business strategies, as well as of the support that funders have shown to the sector to date (read more about industry finance in section 4).

It has been critical that, in general, businesses have been able to successfully renegotiate debt packages and terms with lenders that are more aligned to survival than the growth strategies many packages were initially put in place to support. In some cases, equity funders have injected more capital to secure refinancing, demonstrating overall support for the sector through this period rather than resorting to accelerated mergers and acquisitions or more formal restructuring proceedings.

However, there are still significant challenges ahead with capital investment set to continue to fall. Industrial action by offshore workers (see section 7 on employment) and the UK's decision to leave the EU also present hurdles in an already difficult market.

Currency movements as a result of the UK's decision to leave the EU are affecting companies in the supply chain in different ways. Those who pay most of their costs in sterling yet have dollar-denominated sales benefit from the devaluation of the pound versus the dollar, whereas other companies with significant imported costs are experiencing a negative impact.

> "There still remains a fundamental belief that a rebalanced and more efficient UKCS will bring a strong commercial outlook for service companies in the medium term."

Regardless of macro-economic events, there still remains a fundamental belief that a rebalanced and more efficient UKCS will bring a strong commercial outlook for service companies in the medium term, building upon a highly skilled workforce and safety-conscious working environment.

6.3 Supply Chain Segments

To assess each segment of the supply chain in more detail, forecast financials have been compiled based on publically available global forecasts for listed companies with proportional changes to revenue and earnings applied to UK figures from 2014.

Given the relative maturity of the UK market, the financial forecasts may prove to be optimistic in some cases, particularly for smaller companies with less diverse businesses.

Reservoirs

Tier 2: Main Contractors and Consultants	Tier 3: Products and Services, Components, Sub-Contractors and Sub-Suppliers
Seismic data acquisition and processing contractors	Geosciences consultancies Data interpretation consultancies Seismic instrumentation suppliers

The reservoirs segment comprises companies focused on seismic data acquisition, processing, interpretation and instrumentation, as well as geoscience consultancies. This sector is most sensitive to the oil price, mainly due to its heavy focus on exploration. The lower price environment has led to widespread delays and cancellations of exploration projects globally and on the UKCS. As such, this sub-sector of the supply chain has experienced a greater rate of reduction in revenues and profitability and notably it was the only segment to experience a fall in annual revenues in 2014.

However, there have been relatively few insolvencies, limited to those exposed to heavy assets such as rig or seismic vessel owners (Dolphin Geophysical) or companies focused on non-core technologies (Arkex) in the current market. Existing players in this segment may benefit from the slight reduction in competition, but that remains to be seen.

> The reservoirs sector of the supply chain is most sensitive to the oil price, mainly due to its heavy focus on exploration.

Figure 35: UK Reservoir Segment Financial Results and Forecasts

Currency £ million	2011	2012	2013	2014	2015E	2016E	2017E
Revenue	1,092	1,219	1,355	1,244	878	643	680
% Change		12%	11%	(8%)	(29%)	(27%)	6%
EBITDA	162	171	245	145	99	63	77
EBITDA margin	15%	14%	18%	12%	11%	10%	11%

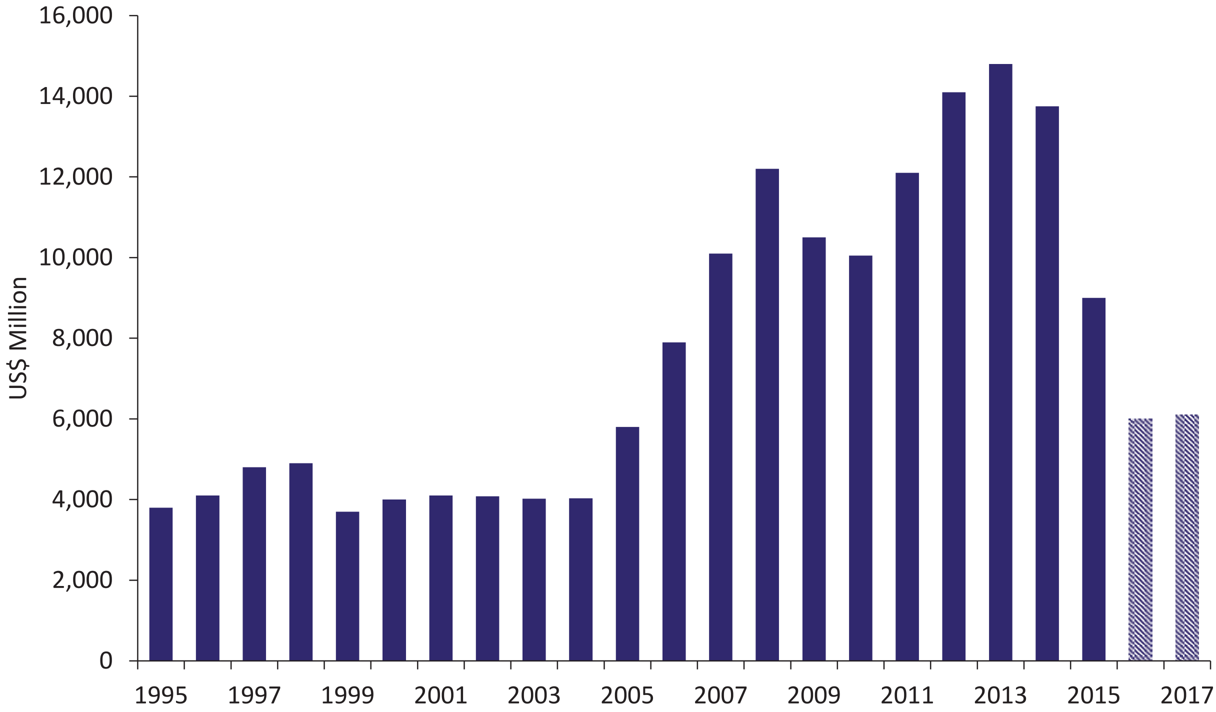
Source: EY

The majority of reservoir-focused companies have been restructuring operations, removing costs and rebalancing headcounts to counter the significantly reduced activity over the last two years. This has been particularly observed among consultancies that are people-based and where the cost base is largely variable. Another important factor has been the changing relationship between companies and their contracted employees, increasingly moving to remuneration based solely on voyage time rather than being paid retainers for periods spent off vessel.

The changing balance between contracted work and more multi-client work has partly driven the continued erosion of EBITDA margin. A stark shift to speculative multi-client work has impacted contractors' bottom line and those companies with extensive multi-client libraries will be best placed to rework existing data for sale to clients.

Even prior to 2014, the UKCS posed challenges for reservoir-focused companies, as the number of E&A wells drilled had been falling sharply since 2008. As such, companies in this part of the supply chain have consistently generated more export revenues than any other segment, particularly as global spending on seismic was on an upward trend until the fall in price, as shown by Figure 36 opposite. However, the over-riding impact of a lower oil price environment has meant that global seismic spend has now fallen dramatically, cancelling out any natural hedging from revenues generated internationally.

Figure 36: Global Seismic Spending



Source: SEB Equities

The outlook for the remainder of 2016 remains challenging. Those companies that have been able to keep profitable contracts, deliver on cost-reduction plans and manage debt levels are best placed to benefit from any growth in market share resulting from further potential business failures.

Looking forward into 2017 and beyond, if commodity prices are less volatile, confidence should improve and investment may return. In the same way that reservoir-focused companies were the first to feel the impact of the downturn, they should benefit quickly from increased activity.

Wells

Tier 2: Main Contractors and Consultants	Tier 3: Products and Services, Components, Sub-Contractors and Sub-Suppliers
Well services contractors Drilling contractors Well engineering consultants	Drilling and well equipment design and manufacture Laboratory services

Companies operating within the wells segment are also among those most exposed to the lower oil price. The majority are focused on the drilling market and activity in this area has continued to fall through 2015 and into the first half of this year. It appears that revenue fell below £6 billion in 2015 with a further decline to below £4 billion (37 per cent) anticipated in 2016, leading to an expected overall market contraction of more than 50 per cent over the past two years.

Figure 37: UK Wells Segment Financial Results and Forecasts

Currency £ million	2011	2012	2013	2014	2015E	2016E	2017E
Revenue	6,360	7,298	7,776	8,020	5,937	3,764	4,389
% Change		15%	7%	3%	(26%)	(37%)	17%
EBITDA	635	876	943	1,202	781	260	436
EBITDA margin	10%	12%	12%	15%	13%	7%	10%

Source: EY

> Wells contractors are cutting day-rates for rigs to break-even levels or below to keep them active.

Since 2015, significant cost-cutting measures have been under way to reduce the negative impact of falling activity on margins. Drilling contractors with heavy asset pools are increasingly looking at restructuring their businesses as covenants and cash-flow come under increasing scrutiny and the value of assets face further impairment.

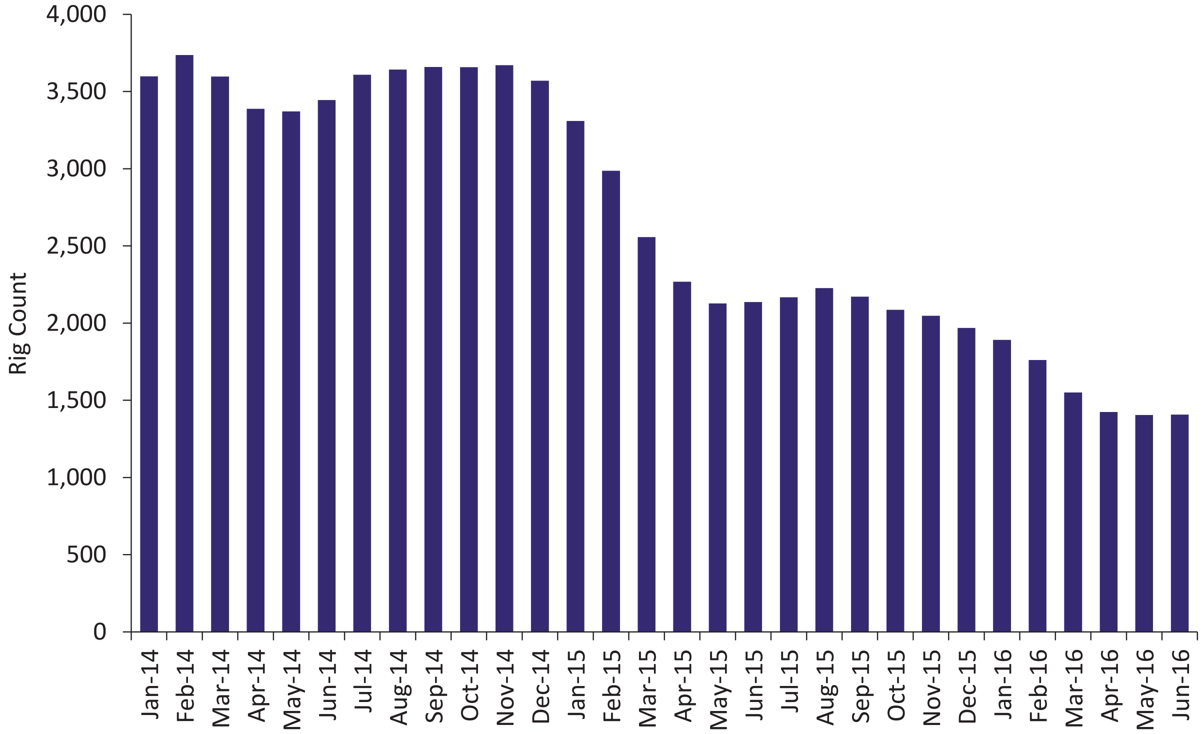
Such has been the decline in activity and oversupply of rigs to the market that many fourth, fifth and sixth generation rigs coming off contract are facing immediate stacking. There are limited prospects for their redeployment in a market that already has newer, higher specification rigs available at increasingly attractive long-term rates as companies struggle to find business.

Contractors are cutting day-rates for rigs to break-even levels or below to keep them active. Break-even day rates for new build 7G floaters are expected to be in the region of $300,000 per day in 2018 compared with rates of $450,000 per day for high specification semi-submersible rigs in early 2014.

Furthermore, the global oversupply of assets is reflected in recent rig sales at significant discounts to build cost, including Ocean Rig's purchase of the UDW Drillship Cerrado for $65 million compared with an estimated outlay for the rig originally in the region of $300 million.

Ultimately, as rigs are stacked and the active worldwide rig count declines, it will make it even harder for the UK to secure rigs in the future in comparison to other basins that may be able to commit to longer contracts.

Figure 38: Monthly Global Rig Count



Source: Baker Hughes

Unsurprisingly, some companies in the sector have ceased operations, mostly in the asset heavy drilling side of the wells market, although business failures have been limited in the UK. The bankruptcies of Hercules Offshore, Vantage Drilling and C&J Energy Services represent some of the more notable international cases.

The performance of companies manufacturing products within this segment differs significantly depending on their geographical focus. Organisations heavily exposed to the UK or other markets, such as onshore US, where drilling activity has been particularly affected, have typically been hit harder than those well placed in more robust markets such as the Middle East.

However, there may be cause for cautious optimism. The world's two largest providers of oilfield drilling services are suggesting that the North American market may have reached its lowest point in the second quarter of 2016 and is now poised for a return to modest growth[28].

[28] See http://bloom.bg/2cFoSgp

Facilities

Tier 2: Main Contractors and Consultants	Tier 3: Products and Services, Components, Sub-Contractors and Sub-Suppliers
Engineering, operation, maintenance and decommissioning contractors Engineering consultants Structure and topside design and fabrication	Machinery/plant design and manufacture Engineering support contractors Specialist engineering services Specialist steels and tubulars Inspection services

The facilities segment is the largest of the UK supply chain, representing one third of total supply chain revenues in 2014. Given its focus on supporting production, it has had the most robust performance of all sub-sectors with revenues increasing by around 7 per cent in 2015. However, the capital expenditure-led engineering, procurement and construction companies have been under more pressure than those geared towards operations and maintenance and are likely to have experienced poorer financial performance.

Production performed well in 2015 and continues to increase during 2016 (see section 5.4 for more information), but there remains concern around future activity levels should production decline occur as a result of the lack of current upstream investment.

Another key driver for the segment is decommissioning where spend is likely to rise from £1 billion in 2014 to over £2 billion in 2018, by which time over 50 fields will either be approaching or undertaking decommissioning. This is viewed by some as a natural hedge should the low oil price environment endure for longer than anticipated.

Figure 39: UK Facilities Segment Financial Results and Forecasts

Currency £ million	2011	2012	2013	2014	2015E	2016E	2017E
Revenue	10,089	11,475	13,125	13,135	14,100	10,709	10,905
% Change		14%	14%	0%	7%	(24%)	2%
EBITDA	814	985	1,105	822	794	643	627
EBITDA margin	8%	9%	8%	6%	6%	6%	6%

Source: EY

> The facilities segment has had the most robust performance of all sub-sectors with revenues increasing by around 7 per cent in 2015.

Despite this sector's resilience in 2015, facilities companies have experienced increasing challenges this year through industrial action, the delay of non-essential maintenance, the cancellation of capital projects, the renegotiation of existing contracts and price competition for new work intensifying. There is also evidence that, where possible, operators are conducting planned shutdowns and turnarounds of platforms less frequently as part of their drive towards more efficient operations[29].

Contracting models are also being changed as certain oil and gas operators are consolidating their work to fewer suppliers, while others are unbundling contracts and engaging directly with companies further down the supply chain rather than through the traditional tier one contractors. There is also a trend towards more performance-based contracts rather than traditional cost plus arrangements[30].

Positively, there have been limited business failures in this segment, with the majority of casualties heavily exposed to cancellations in capital projects, reliant on a limited pool of customers, or operating in particularly low margin markets. Enterprise Engineering, which went into administration earlier in the year, is an example of this.

Marine and Subsea

Tier 2: Main Contractors and Consultants	Tier 3: Products and Services, Components, Sub-Contractors and Sub-Suppliers
Marine/subsea contractors Heavy lift/pipelay contractors Floating production storage units	Subsea manifold/riser design and manufacture Marine/subsea equipment Subsea inspection services

The falling commodity price did not impact the marine and subsea segment as quickly as reservoir or wells. Indeed, marine and subsea focused companies recorded revenue growth of 7 per cent in 2014, reflective of a number of large-scale subsea projects, such as Schiehallion, Greater Laggan and Kraken, incurring significant investment. Each of these projects is forecast to require ongoing expenditure to 2018.

Although there remains a steady stream of long-standing business, companies in this sector are becoming increasingly exposed to the fall in the number of new development projects. Revenues are thought to have fallen by 14 per cent in 2015 with a further fall of 11 per cent expected in 2016 to £8.4 billion. Reduced activity has also led to an oversupply of vessels domestically and globally, placing downward pressure on day-rates.

Figure 40: UK Marine and Subsea Segment Financial Results and Forecasts

Currency £ million	2011	2012	2013	2014	2015E	2016E	2017E
Revenue	8,420	8,993	10,275	10,991	9,500	8,424	7,125
% Change		7%	14%	7%	(14%)	(11%)	(15%)
EBITDA	793	979	1,143	1,395	1,222	971	796
EBITDA margin	9%	11%	11%	13%	13%	12%	11%

Source: EY

[29] Oil & Gas UK's *Guidance for the Efficient Execution of Planned Maintenance Shutdowns* is available to download at http://bit.ly/plannedMS

[30] A contracting model where the client pays the contractor an agreed mark-up based on the cost of the work.

EBITDA across the segment is also expected to fall from a high of almost £1.4 billion in 2014 to just under £1 billion this year, although the impact of cost and efficiency improvements means the margins are likely to remain fairly consistent.

It would appear that the delayed impact of the downturn has given these companies time to consider fleet management and secure revenues from adjacent markets, such as offshore wind. Contracting models are also being modified with noted success coming from shorter term contracts and performance-led remuneration, highlighting the savings available to operators through more efficient solutions rather than simply cutting the headline cost.

> Companies in the marine and subsea sector are becoming increasingly exposed to the fall in the number of new development projects.

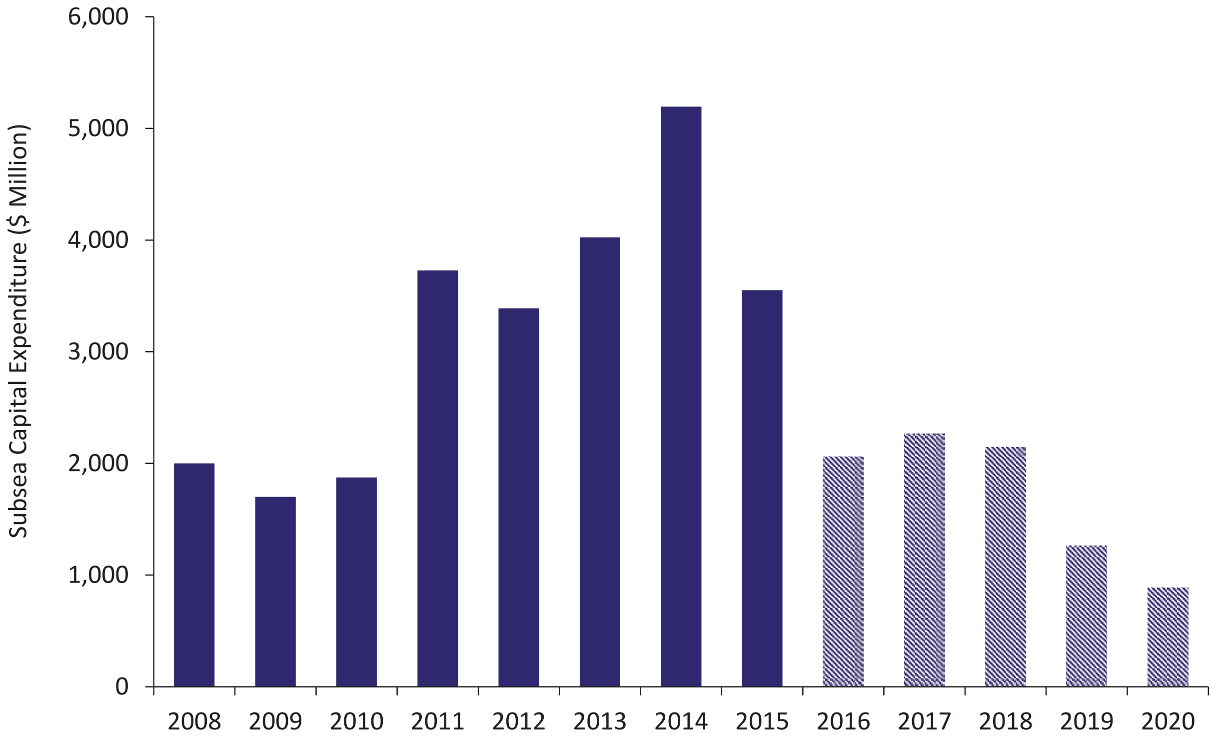
Moreover, companies in this area are collaborating with their customers and one another to improve their competitiveness through more targeted product and service offerings.

Several companies (including Fletcher Shipping, Harkand and Atlantic Offshore) have, however, gone into administration and removed supply from the market, creating an opportunity to increase market share for surviving incumbents.

Overall, despite significant falls in revenue over last year and into this year, the rate of decline has been slower compared to some other segments of the supply chain.

Looking ahead to 2017, the combination of falling forecasts in subsea expenditure (shown by Figure 41) and a continued oversupply of vessels means that analysts expect revenue to fall further. Any stabilisation or recovery is heavily linked to a return to subsea development spend, which, in turn, is likely to lag behind any initial growth in exploration and drilling.

Figure 41: UKCS Subsea Capital Expenditure



Source: Wood Mackenzie

Support and Services

Tiers 2 and 3 Main Contractors and Consultants, Products and Services, Components, Sub-Contractors and Sub-Suppliers	
Catering/facility management	Recruitment and Training
Sea/air transport	Health, safety and environmental services
Warehousing/logistics	Energy consultants
Communications	IT hardware/software

The support and services segment of the supply chain comprises a wide variety of businesses ranging from recruitment and IT services, to air transport and energy consultants. For the purposes of this analysis, organisations that indirectly interact with the oil and gas supply chain (such as hospitality and infrastructure) have not been considered, and neither have those companies that do not disclose financial performance from oil and gas activities.

> The support and services part of the supply chain saw a slower rate of decline in their revenues than most sub-sectors as it is closely linked with production activity.

The majority of customers tend to use local companies to provide support services and so suppliers in this space are heavily reliant upon revenues generated from the UKCS with less opportunity to enter overseas markets.

In general, the support and services sub-sector is more closely linked with production activity rather than exploration or development. Therefore, companies in this part of the supply chain saw a slower rate of decline in their revenues than most sub-sectors, with a 14 per cent reduction between 2014 and 2015.

Figure 42: UK Support and Services Segment Financial Results and Forecasts

Currency £ million	2011	2012	2013	2014	2015E	2016E	2017E
Revenue	5,578	6,297	7,254	7,554	6,462	5,609	5,685
% Change		13%	15%	4%	(14%)	(13%)	1%
EBITDA	466	523	629	632	415	262	251
EBITDA margin	8%	8%	9%	8%	6%	5%	4%

Source: EY

However, in what has traditionally been a lower margin segment of the supply chain, continued focus by operators on reducing costs and increasing efficiency has caused significant pressure on profitability, despite the relatively modest reduction in revenue. The annual results for the sample of listed companies indicate a 34 per cent reduction in EBITDA with a similar fall expected in 2016.

This is consistent with the challenges being experienced by specific disciplines within the segment:

- **Helicopter operators** are facing continued pricing pressure as customers seek to tie cost to flight time, rather than accepting high availability premiums even when the aircrafts are not in use.

- **Recruitment companies** are experiencing more revenue pressure than many other organisations in the support and services sector as revenues are closely linked with employment, which is significantly down (see section 7 on employment). However, relative fixed costs in these businesses will be limited and, for larger diversified companies, some form of natural hedge will have existed with an improved UK economy in 2015-16 prior to the referendum vote to leave the EU.

- **IT companies** have seen a general cut-back in purchases of non-essential hardware, as well as delays to scheduled upgrades of IT systems. While software packages to support ongoing production have been in high demand, support and maintenance contracts have come under increasing price pressure, reducing profitability.

- **Logistics companies** engaged with the transport of goods to and from platforms have experienced relatively stable activity as production on the UKCS continues to increase. Like a number of other parts of the supply chain, margin pressure and contractual models now linked to performance and, specifically, efficiency are increasingly common, as is a desire for more collaborative options such as sharing deck space with other operators.

6.4 Case Studies

While the general commercial pressures being felt across the supply chain are clear, there are companies who have been successful in adapting their businesses to meet the changing needs of their clients. Strategies to succeed through the downturn include the expansion of product ranges, diversification into adjacent sectors, building stronger business capabilities overseas, or differentiating to create value in the UKCS. The following examples illustrate how UK-based supply chain companies have applied these techniques to grow their businesses over the last two years.

The company

BEL Valves manufactures valves, controls and actuators for application in the oil, gas and petrochemical industries.

How has the company shown resilience in this difficult climate?

BEL Valves provides an example of a company that has extended its product range to great effect. It quickly identified that its clients would be seeking more cost-effective solutions to develop smaller pools and brownfields with faster payback. To that effect, it is developing a new product, a motorised pneumatic actuator, as an alternative to the more common solution of hydraulic actuation for heavy duty valves, removing the extra associated costs such as the need for additional infrastructure to accommodate hydraulic power units.

BEL Valves also expanded its international supply chain by opening a site in Milan, Italy. This enables the company to source materials and expertise in a more cost-effective way and act as a single source of provision for their customers. Large development projects are now satisfied through a single valve provider with the introduction of surface ball valves to complete the company's portfolio.

What are the results?

The motorised pneumatic actuator has been proven to provide clients with savings in the order of 30 per cent for a single well tie-back, unlocking developments that would have previously not gone ahead. The expansion into Milan has allowed BEL Valves to access more opportunities overseas while the domestic UK market is struggling. The investment in Milan, coupled with the expansion of the company's UK presence, has resulted in a 20 per cent growth in export share over the last five years. Forecasts suggest that exports will make up over 85 per cent of turnover in 2017, from an average of 66 per cent over the last five years.

The company

Sky-Futures provides asset inspection services using unmanned aerial vehicles (UAVs) commonly referred to as drones.

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How has the company shown resilience in this difficult climate?

Originally based in the UK, Sky-Futures sees the opportunity to extend its geographical reach and build stronger business capabilities overseas as the demand for cost-saving technologies grows. Its service means offshore inspections on installations can be carried out without incurring the labour and logistics costs associated with traditional manned inspections. It also eliminates the human risk factors presented by rope access, working at height and in confined spaces and prevents shut-downs allowing assets to remain productive through the inspection period.

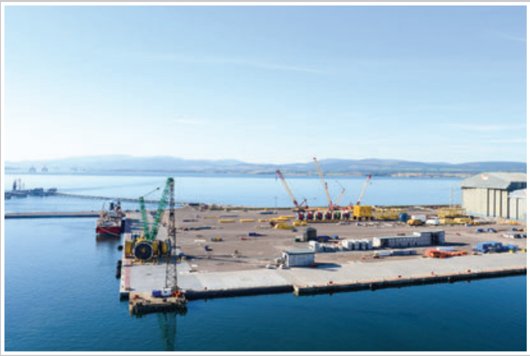
What are the results?

Sky-Futures has gained 36 clients and is now working in over 16 countries with the ability to inspect approximately 85 per cent of the world's oil and gas offshore platforms.

Since 2014, the company has grown from having two offices to six located across the UK, Abu Dhabi, the US and Southeast Asia, and expects its revenue to double this year as it invests in new sensors and analytics so that the UAVs can capture more varied and higher quality data.

The company

Global Energy Group specialises in construction and maintenance solutions for mobile and platform drilling, floating production, marine construction and inspection, repair and maintenance, and fixed production. It also manufactures bespoke products for the subsea, topsides and downstream markets.



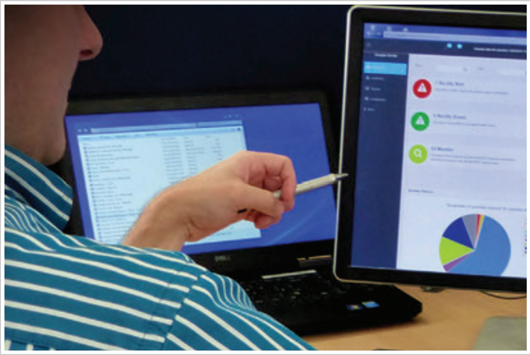
How has the company shown resilience in this difficult climate?

Over the last few years Global Energy Group has focused on diversification into adjacent sectors. It has spent over £45 million on developing quayside space and support facilities at its Nigg site, transforming it into a multi-user Energy Park with capability to cater for contracts from the nuclear and renewables sectors. This is in addition to the already thriving oil and gas contracts that have been undertaken since acquiring the site in 2011. In September 2015, Global Energy Group officially unveiled its newly refurbished deepwater quayside space with enhanced dry dock, fabrication and laydown facilities.

What are the results?

Much of the slack in oil and gas-related business is starting to be replaced following successful diversification into adjacent sectors. Global Energy has won a number of contracts on pioneering projects including the world's first floating wind farm – Statoil's Hywind pilot park offshore from Peterhead in Aberdeenshire. Global Energy will also be supporting Siemens at Nigg Energy Park on the groundbreaking £2.6 billion Beatrice Offshore Windfarm project and is currently working with Atlantis Resources on delivering the MeyGen project and leading the global development of tidal power generation.

The company



Apollo is a technically-led provider of engineering services to the oil industry, including consultancy, repairs and modifications, marine and subsea, and software products.

How has the company shown resilience in this difficult climate?

As part of its product range, Apollo's technical software team provides engineering data solutions to enable its clients to manage their engineering processes efficiently and effectively. The company sought to increase value for clients by expanding its product range in developing fit-for-purpose software solutions. Examples include a subsea integrity management solution for North Sea FPSO (floating, production, storage and offloading vessel) operators, as well as an offshore data harvesting tool for topsides inspection customers. To develop these solutions, the latest software techniques have been applied, improving the efficiency of operations compared with more conventional approaches. Apollo's tools allow data to be harvested and uploaded instantly avoiding double entry and duplicate reporting.

What are the results?

Both products have saved over 20 per cent in operating costs for clients and associated end-users. This over-arching approach has been rewarded with a number of significant contract wins, including a multi-million pound contract to supply engineering support services to Repsol-Sinopec, which is allowing Apollo to recruit and expand its engineering base. Being a technically-led provider of engineering services, rather than project management led, has enabled Apollo to win significant contracts with clients such as NOV, Stena Drilling, EnQuest and ConocoPhillips, totalling more than £2 million. This has allowed sustainable growth of 20 per cent in 2016 to date with further growth planned in 2017.

7. Employment

Over the last 12 months, employment in the industry has continued to fall, particularly onshore, due to depressed upstream activity in the current economic climate. Changes to equal time working rotas by a number of operators have also led to reductions in the offshore workforce as companies have targeted efficiency and productivity improvements and cut costs.

The industry has also been experiencing more turbulent industrial relations than has been the case for many years. In 2015, there was a threat of industrial action by construction and maintenance personnel as well as catering workers and, at the time of writing, there is industrial action taking place – the first offshore strike action for more than 25 years.

Employers and trade unions recognise that morale is impacted both on and offshore and that engaging the workforce is key to achieving the goal of MER UK. Improving the international competitiveness of the UKCS is critical for the industry to be able to attract the capital required to sustain employment in the long term. The industry recognises that it must involve and engage with the people behind its success to help shape its future.

> The industry recognises that it must involve and engage with the people behind its success to help shape its future.

The work of the Efficiency Task Force (see section 8), particularly the co-operation, culture and behaviours stream, is taking into account the imperative of improving workforce engagement by sharing success stories and good practice, and by developing understanding of the challenges facing the industry and the positive future that could lie ahead if the sector makes the necessary adjustments now.

7.1 Total Employment

Across the UK, around 330,000 jobs are currently supported by the offshore oil and gas industry through direct employment[31], indirect employment[32] and jobs that are induced by the sector's wider economic contribution[33].

Although the industry continues to support a significant level of employment across the UK, the 2016 estimate represents a 27 per cent reduction from peak employment of around 450,000 in 2014, when Brent crude was trading at over $100/bbl. The decline is made up of around 84,000 job losses in 2015 and a further 40,000 during 2016.

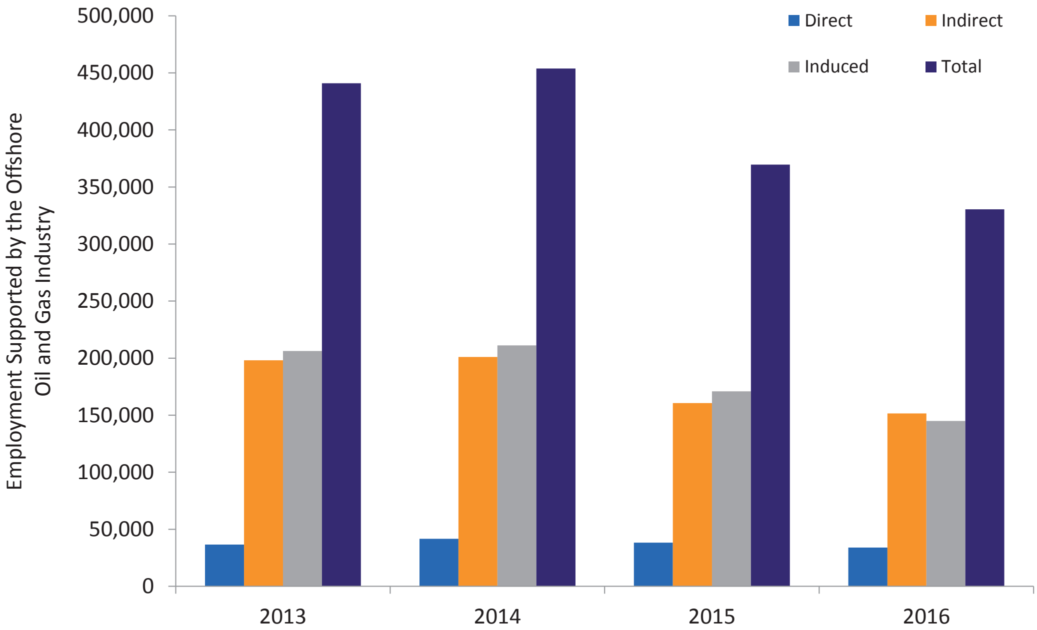
[31] Those employed by companies operating in the extraction of oil and gas and associated services.

[32] Employment as a result of supply chain effects caused by oil and gas sector activity. For these companies, extraction of oil and gas and associated services will be one part of a wider business.

[33] Employment supported by the redistribution of income from the oil and gas sector.

Figure 43: Employment Supported by the UK Offshore Oil and Gas Industry

	2013	2014	2015	2016E
Direct	36,600	41,700	38,200	34,000
Indirect	198,100	201,000	160,600	151,500
Induced	206,200	211,100	170,800	144,900
Total Employment	440,900	453,800	369,600	330,400



Source: Experian

Although the industry continues to support around 330,000 jobs across the UK, this represents a 27 per cent reduction from peak employment of around 450,000 in 2014.

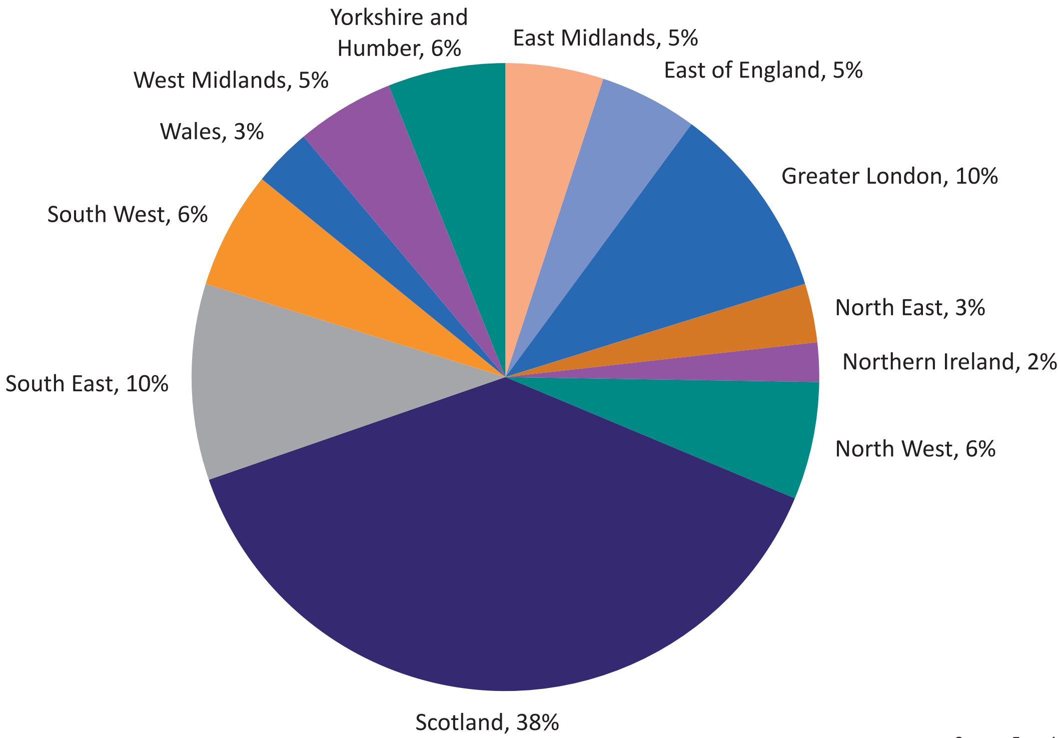
7.2 Regional Employment

Scotland's share of the total number of jobs supported by the sector has increased by three percentage points to 38 per cent from when it was last measured in 2013.

Of the 330,400 jobs supported by the sector, 124,500 are based in Scotland accounting for 81 per cent (27,500 jobs) of total direct employment, 41 per cent (62,000 jobs) of indirect employment and 24 per cent (35,000 jobs) of induced employment.

Outside of Scotland, London and the South East of England hold the second largest share of jobs supported at around 10 per cent each.

Figure 44: Employment by Region



Source: Experian

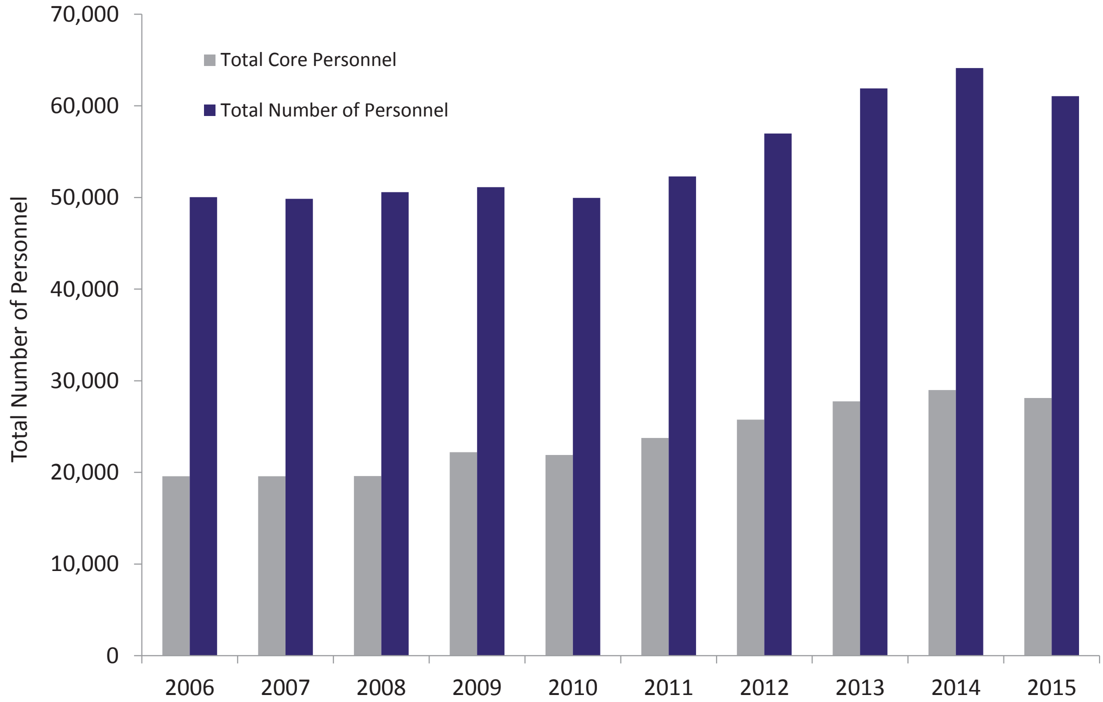
Annual employment data by local authority is only available up to 2014, prior to the full impact of the decline in oil price being felt. In 2014, 22,000 direct oil and gas jobs were based in Aberdeen City and Aberdeenshire. Since then, the unemployment rate in Aberdeen City has risen from 4.1 per cent in 2015 to 4.9 per cent in March 2016 and a similar trend is seen in Aberdeenshire where unemployment has increased from 2.7 to 3.2 per cent over the same period. The reduction in employment supported by the oil and gas industry is likely to be a leading contributing factor to this.

7.3 Offshore Workforce

In 2015, over 61,000 people travelled offshore for oil and gas exploration and production. While this represents a decline of 5 per cent against 2014, it is a significantly lower rate of decline than across the industry as a whole, confirming that the majority of job losses have come in onshore roles.

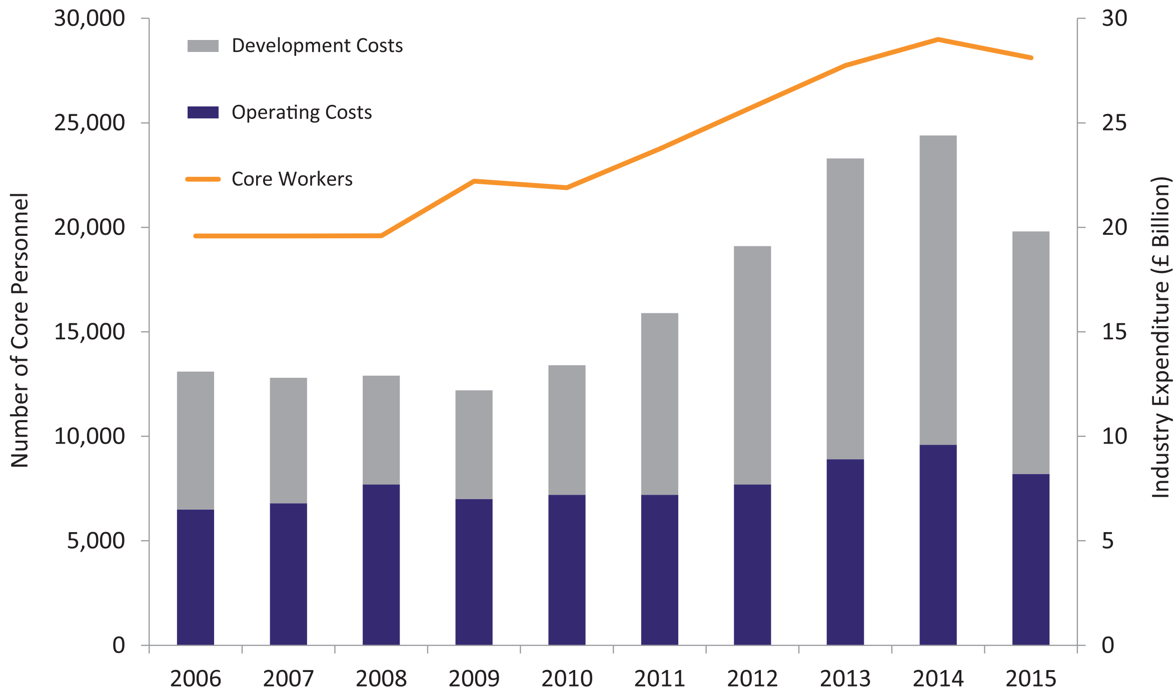
Forty-six per cent of the offshore workforce in 2015 were classed as core workers, defined as those who spend more than 100 nights offshore. Although the number of core personnel last year was 3 per cent lower than in 2014 (875 workers less), the ratio of core to non-core workers was one per cent higher.

Figure 45: Relationship between Total and Core Offshore Workforce



Source: Vantage POB

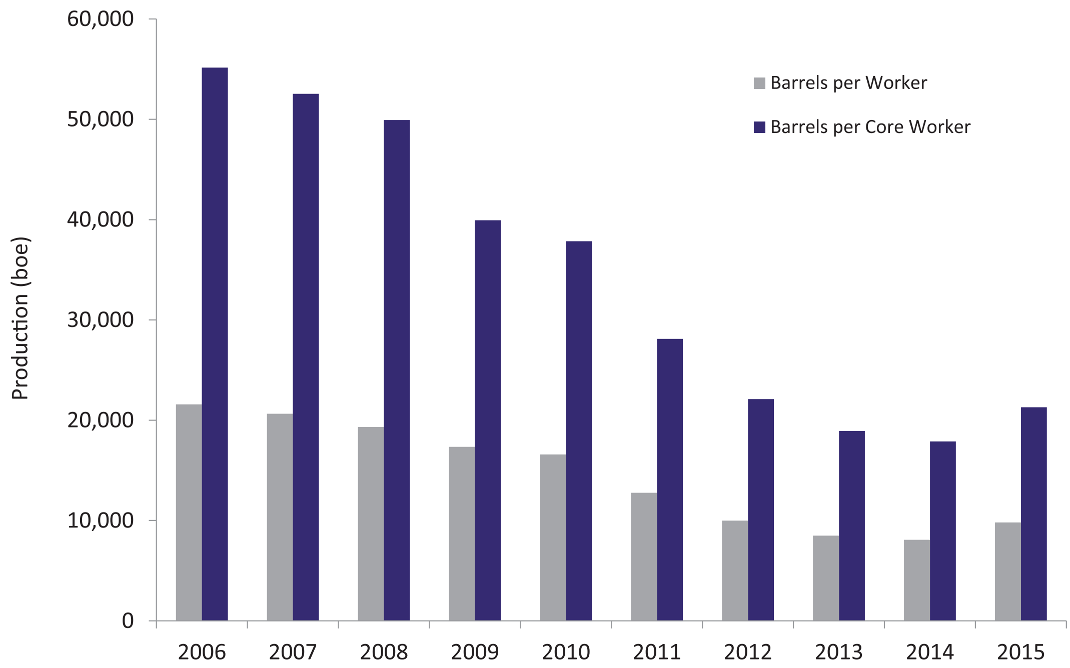
Figure 46: Relationship between Offshore Core Workforce and Industry Expenditure



Source: Vantage POB, Oil & Gas UK

The recent increase in production, outlined in section 5.4, was realised despite reductions in the offshore workforce, demonstrating an improved rate of productivity on a barrel per worker basis. In 2015, the UKCS produced over 21,000 boe per core worker, a 19 per cent increase compared with 2014.

Figure 47: Relationship between Offshore Workers and Production



Source: Vantage POB

> In 2015, there was an improved rate of offshore productivity on a barrel per worker basis.

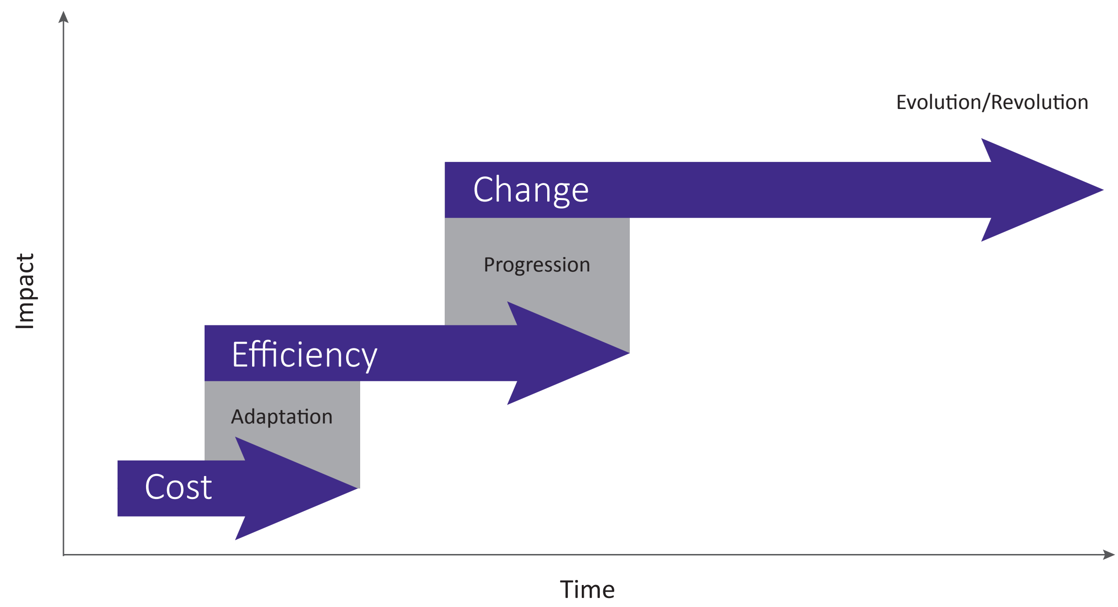
8. The Efficiency Task Force

After a period of reactive change where survival was the priority, costs were cut and efficiencies sought to ease cash-flow pressures, the industry is now reaching the stage where there is little further opportunity to remove costs from the business without fundamentally changing company processes, standards and behaviours. As businesses accept the ‘lower for longer’ price environment, they recognise that strategic long-term change in how they operate is going to be critical to sustain an industry where revenues have fallen by around 40 per cent over the last two years.

Figure 48 below shows the path industry has followed since the fall in price. There is a limit to what more can be done on the cost reduction side, with significant progress already achieved in that area. Efficiency improvements are now well under way and the associated knowledge sharing is vital to help ensure the gains are delivered basin-wide. Radical change is ongoing as some companies make more structural adjustments through adaptation, differentiation and diversification in both sector and geography.

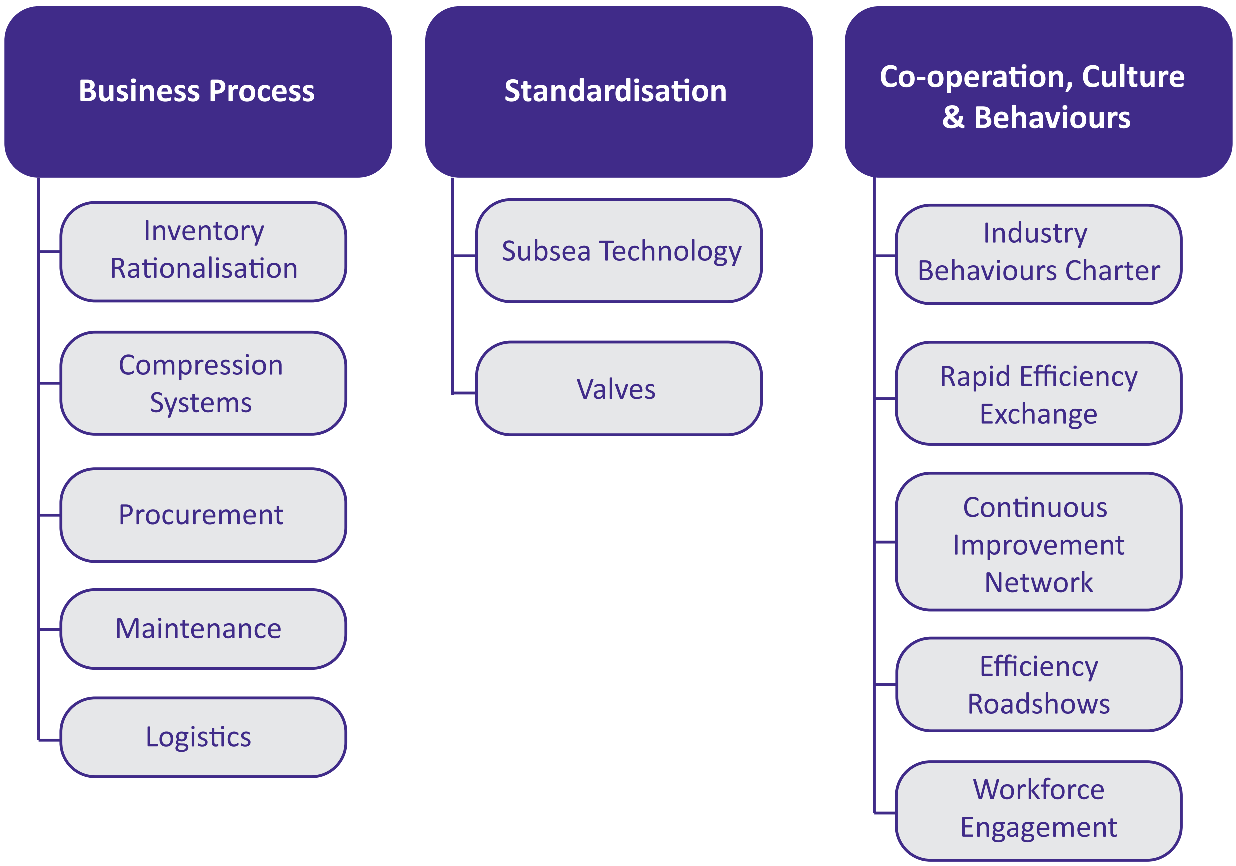
> “The industry is now reaching the stage where there is little further opportunity to remove costs from the business without fundamentally changing company processes, standards and behaviours.”

Figure 48: The UKCS’ Cost Structure



As well as individual company efforts to work smarter and reduce the cost base, the industry's Efficiency Task Force (ETF), led by Oil & Gas UK, is intensifying its efforts to act as a catalyst to make the UKCS more resilient and as competitive as it possibly can be in the global marketplace[34].

Figure 49: Efficiency Task Force Work Streams



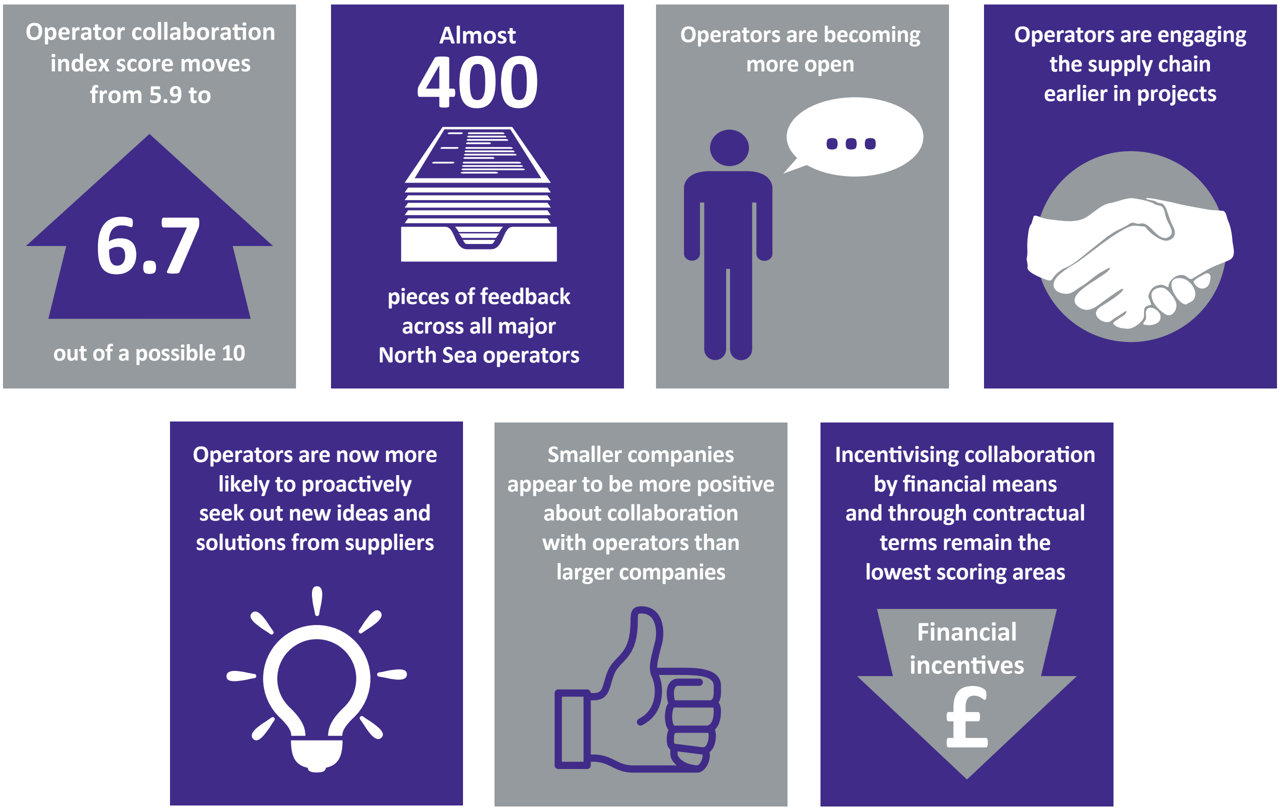
8.1 Co-operation, Culture and Behaviours

The ETF is calling on companies to rally behind the ***Industry Behaviours Charter***[35], launched at the end of last year to help define and drive the cultural change needed to secure a sustainable future. Only by securing a collective commitment to work effectively, efficiency and co-operatively, can fundamental progress be made in the ETF's other work streams of standardisation and business processes.

To measure how well industry is progressing against the Charter's principles, Oil & Gas UK partnered with Deloitte to survey the sector and review where concerted effort is still needed. The *Collaboration Index* is based on an electronic survey of suppliers to 13 operators carried out from March to April 2016. Direct feedback from companies in the supply chain about their dealings with all major operators across the North Sea reveals that the sector is heading in the right direction and becoming more collaborative, as shown in Figure 50 opposite.

[34] An animation on the industry's drive to improve efficiency is available to view at https://vimeo.com/170788055
[35] Companies can view and sign up to the *Industry Behaviours Charter* at www.oilandgasuk.co.uk/charter

Figure 50: Collaboration Index Results



The Collaboration Index survey is being conducted again in quarter four 2016, this time expanded to give operators an opportunity to feedback on the behaviour of their suppliers.

The **Rapid Efficiency Exchange (REE)** is a portal for sharing successful stories in improving efficiency and common industry challenges. Response has been positive so far with over 50 case studies of how companies are working smarter, innovatively and co-operatively. By accessing the portal, companies can find out how:

- Maersk Oil adapted an inspection technique for scanning flexible hoses, which is forecast to reduce costs by more than 80 per cent over the next five years.

- Performance Improvement People used behavioural diagnostic tools to improve communication and reduce duplication of work within a project team dedicated to extending the life of a major North Sea asset.

- Wood Group deployed a remotely operated aerial vehicle to inspect a derrick during well plugging and abandonment, avoiding an estimated three-week shutdown and saving over £1.5 million.

- Perenco applied pipe-in-pipe technology to reinstate mothballed pipelines in six months, less than half the usual time and at a cost of £2.2 million, cheaper than conventional methods.

- The Clair joint venture team completed a turnaround in 58 days instead of 108, adding around one million boe to the field's production.

- Halliburton has installed a vendor-managed inventory machine in its Aberdeen workshop to dispense fast moving consumable items such as personal, protective equipment, abrasives and glue. This gives technicians controlled access to these goods and saves them time, avoiding trips to stores or raising requisitions. The average consumable spend has dropped by almost 60 per cent.

- Nexen has improved the efficiency of its safety briefings to the 1,000 or so new workers, known as ‘green hats’, who work on its North Sea assets each year. It has created a ‘buddy system’ of seasoned and new contractors working together for more rapid and effective dissemination of information. Non-productive time associated with ‘green hats’ has been reduced by 11 per cent and saved approximately £500,000, as well as delivering improvements to safety.

The **Oil and Gas Continuous Improvement Network**, established in September 2015, has been brought under the banner of Oil & Gas UK and the ETF and expanded to include efficiency champions across industry. The network identifies success stories and challenges from the industry and shares them on the REE platform, supporting work to embed changes in behaviour across the sector.

The ETF proposes to run a series of **Efficiency Roadshows** in company offices as a way to engage the workforce in the pan-industry efficiency drive. These roadshows will be rolled out to Oil & Gas UK member companies throughout the remainder of 2016 and into 2017.

8.2 Business Process

The **Inventory Rationalisation** project enables companies to share a virtual pool of resources so that they can reduce their individual stock holdings and the costs associated with their storage and maintenance, as well as cut lead times for access to vital equipment. Twenty-one companies so far from the oil, gas, construction, chemical and food processing sectors are sharing information about over 200,000 inventory items on an online trading platform developed by Ampelius Trading. It holds items ranging from valves and drill bits to gas turbines and subsea equipment. A number of successful trades have now been facilitated through the system.

In the **Compression Systems** project, a group of operators who are accountable for the bulk of compression systems outages on the UKCS – the main cause of unplanned maintenance – are working together to reduce the number and duration of outages. As well as workshops to discuss best practice in this area, an industry guideline document for gas compression operations is being developed.

Two additional projects have started this year to address inefficiencies in **procurement** and to further optimise **logistics** operations. A work group comprising operators and contractors is exploring opportunities to simplify and standardise the tendering process. Within logistics, a test case in the Mariner Area is examining how operators can collectively optimise helicopter and vessel movements. The ETF is also championing work by Oil & Gas UK to optimise **maintenance** as part of a drive to continuously improve major accident hazard management, and, in turn, operational efficiency.

8.3 Standardisation

The **Subsea Technology** work group comprising 30 companies has been analysing the potential cost savings from carrying out projects to existing industry standards rather than bespoke requirements. It has identified that savings of up to 30 per cent are possible. To share these findings, operator engagement sessions were held in May 2016 in Aberdeen and London. The next steps are for operators to consider how they can adopt the learnings within their own organisations and explore how standardisation could be applied to specific case study projects to make them economically viable.

The **Valves** group is exploring how companies can work together to reduce the costs associated with valve maintenance and supply across the basin through standardisation and simplification. Analysis of current costs in the basin revealed that savings of up to 30 per cent are possible. These findings will be investigated by assessing industry case studies in quarter four 2016.

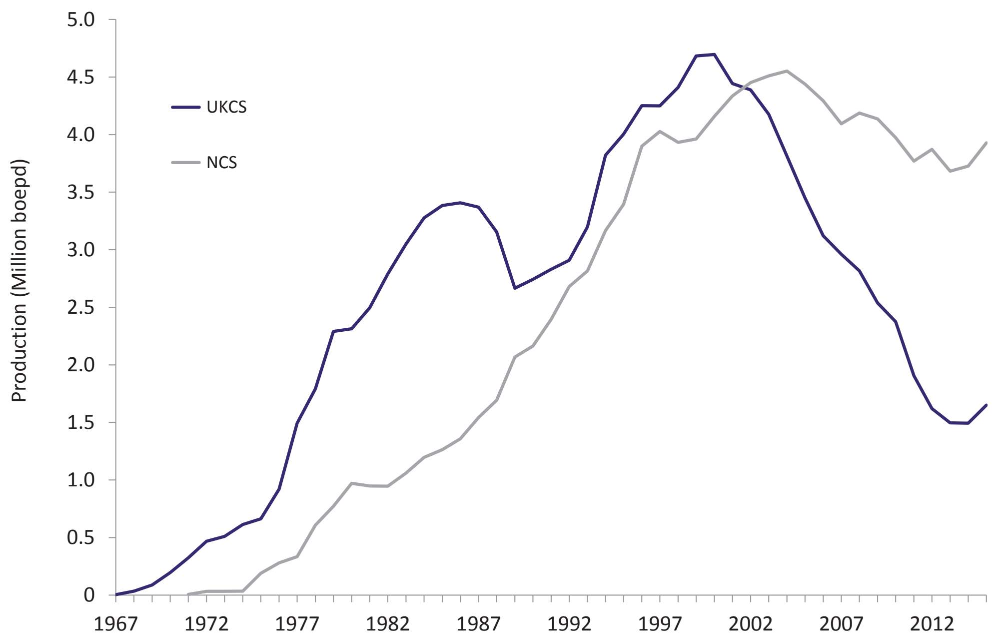
9. Comparisons and Contrasts – the UK and Norwegian Continental Shelves

The performances of the UK and Norwegian Continental Shelves are often compared due to the geographical proximity and perceived similarities of these two North Sea regions. Exploration drilling commenced just two years apart, in 1964 on the UKCS and 1966 on the Norwegian Continental Shelf (NCS). This soon led to the first commercial discoveries in 1965 and 1967, respectively.

The two regions initially experienced similar production trajectories following first production from the West Sole Gas field in the SNS area of the UKCS and the Ekofisk oil field in the Norwegian North Sea. Output grew across both sides of the North Sea during the 1970s and early 1980s, as shown by Figure 51.

However, the two basins have since developed very differently. In the ten-year period following peak production on the UKCS in 2000, production fell by 53 per cent. On the NCS, the equivalent figure was less than 10 per cent. The regions now experience a mixture of comparable and contrasting issues that are outlined in this section and have led to more stable production volumes on the NCS.

Figure 51: Production



Source: OGA, Oil & Gas UK, Norwegian Petroleum Directorate

9.1 Scale

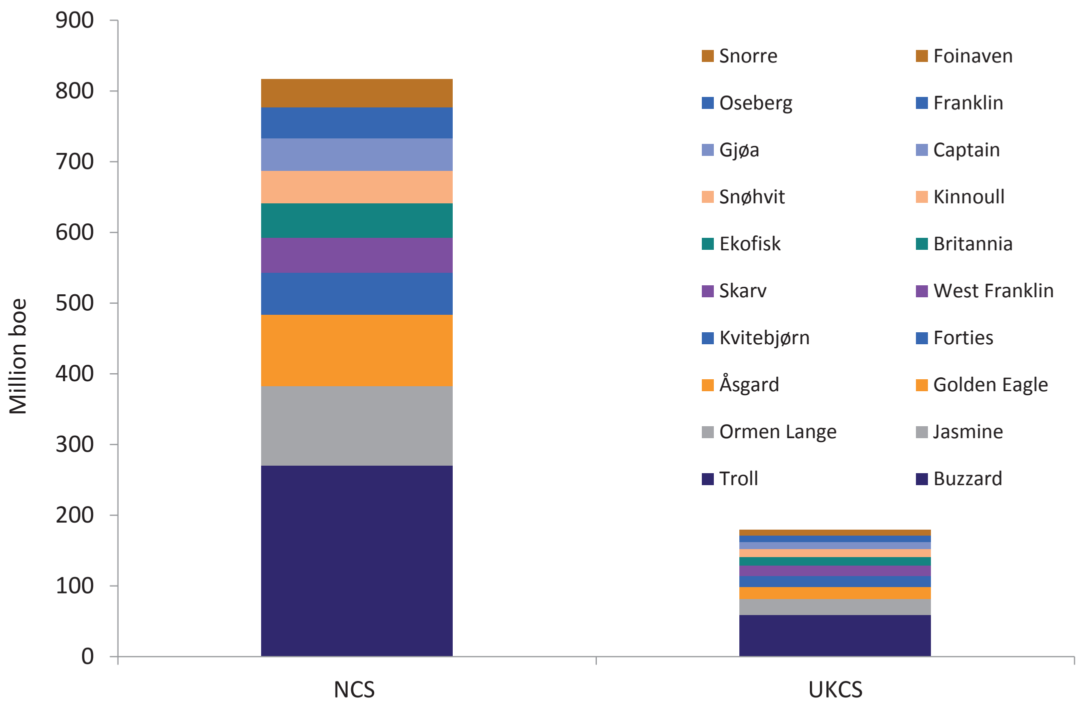
Production on the NCS is characterised by fewer fields with larger output per field, although smaller fields are now becoming more common. From 1976 to 2007, Norwegian fields each produced, on average, 35 million boe per year. This has declined somewhat in recent years with each of the 81 fields in 2015 producing just under 18 million boe on average.

In contrast, there are four times as many fields in production on the UKCS and output per field is almost ten times lower. In 2015, 306 fields were in operation, producing on average just two million boe per field. With smaller fields in the UK, access to infrastructure and export routes present a far greater challenge as many opportunities are not economically viable standalone developments. This results in a greater number of tie-back developments to infrastructure hubs, making UKCS production more interdependent and, subsequently, more at risk of shutdowns from planned or unplanned maintenance.

The Nexen-operated Buzzard field, currently the most productive on the UKCS, produced just over 60 million boe in 2015. Meanwhile, the Statoil-operated Troll gas field, the largest in Norway, accounts for almost 20 per cent of the country's total oil and gas output at 270 million boe. The volumes produced from Troll alone were the same as the total from the 25 largest fields on the UKCS in 2015. The presence of larger fields with higher volumes of recoverable reserves means the NCS has a more stable production base and benefits from greater economies of scale.

"With smaller fields in the UK, access to infrastructure and export routes present a far greater challenge as many opportunities are not economically viable standalone developments."

Figure 52: Top Ten Producing Fields in 2015

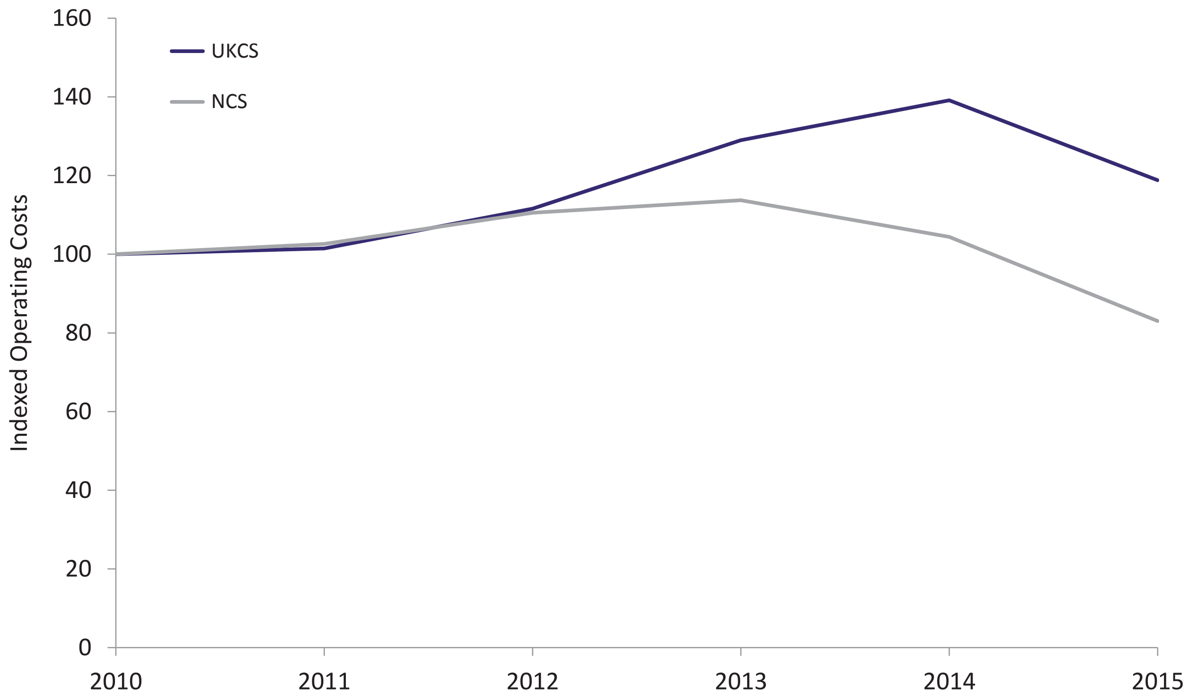


Source: Norwegian Petroleum Directorate, Wood Mackenzie

9.2 Cost Control

Operating costs in the North Sea have been well managed over much of its producing life and have generally been internationally competitive. However, over the last five years, it has become more difficult to control operating costs as global competition for resources has intensified. This scenario has been particularly stark in the UK, with more fields producing beyond their initially intended field life, needing more regular maintenance and intensive asset integrity interventions. In Norway, earlier government intervention ensured that both cost and activity were kept at more sustainable levels with annual operating cost growth never surpassing ten per cent.

Figure 53: Indexed Operating Costs

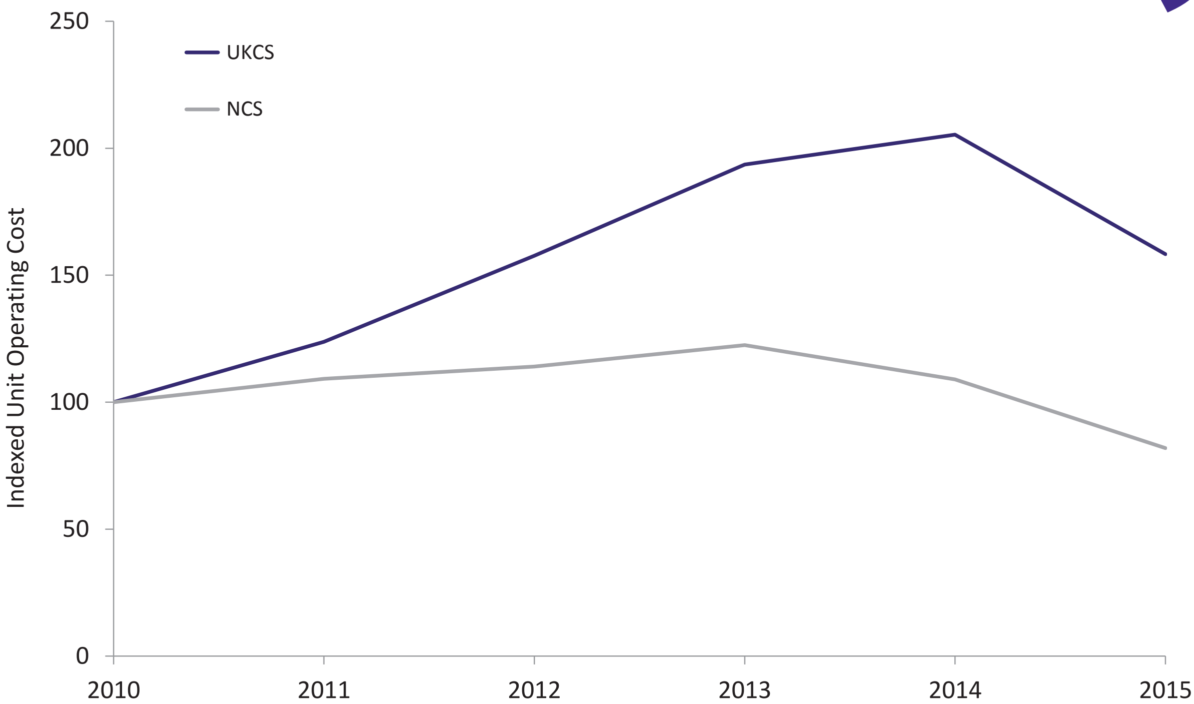


Source: OGA, Oil & Gas UK, Norwegian Petroleum Directorate

Cost growth on a unit basis, as shown by Figure 54, has been a far bigger problem in the UK, more than doubling between 2010 and 2014. On the other hand, Norway was able to limit growth to 15 per cent over the same period as they maintained more stable levels of production. The better unit cost performance in Norway demonstrates that not only addressing the cost base, but also investing sufficiently to maintain production levels, is critical to prevent premature decommissioning of assets.

Cost growth on a unit basis has been a far bigger problem in the UK.

Figure 54: Indexed Unit Operating Costs



Source: OGA, Oil & Gas UK, Norwegian Petroleum Directorate

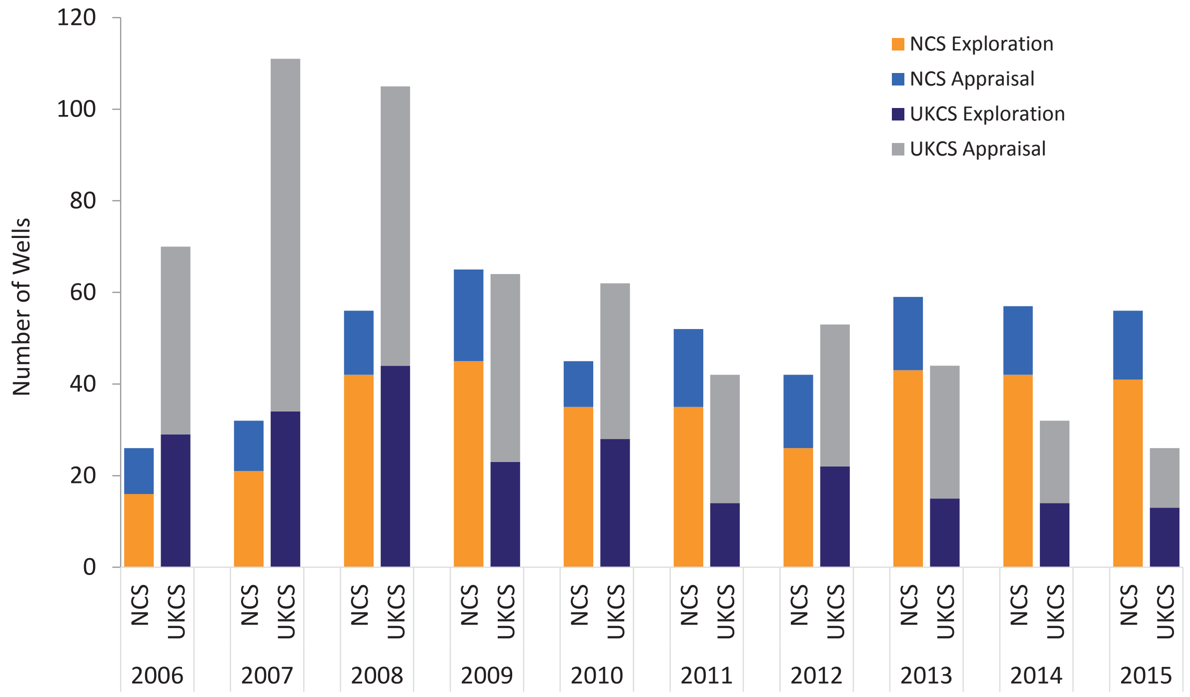
9.3 Exploration Opportunities

Exploration drilling activity has historically been higher on the UKCS than the NCS, but in recent years the NCS has performed better in both drilling numbers and volumes discovered despite efforts to stimulate exploration in the UK. Activity in the UK has declined year-on-year since 2012 and the volumes of hydrocarbons discovered have been disappointing. By contrast, drilling activity on the NCS has remained consistent since 2012 and a number of discoveries have been made leading to greater confidence in exploration in Norway.

Johan Sverdrup was discovered on the NCS as recently as 2010 with recoverable reserves estimated at up to three billion boe[36]. On the other hand, the UK has not seen a discovery greater than 100 million boe in size since the HPHT Culzean field was discovered in 2008.

[36] Source: Lundin Petroleum.

Figure 55: Exploration and Appraisal Activity



Source: Common Data Access Limited, OGA, Norwegian Petroleum Directorate

Factors constraining exploration activity and success on the UKCS over the last five years have not been as prominent in Norway. Access to finance is easier and more affordable due to the certainty provided by the exploration tax credit (more detail below); there is not a perceived lack of prospectivity on the NCS as exploration success has continued through maturity; and partner alignment is not as problematic due to more active state involvement and fewer incumbent players.

Efforts have been made by the state over the past two years to stimulate exploration on the UKCS (see section 5.2 on drilling activity) but it will take several years for the full effects to be seen. The Norwegian state was quick to act to incentivise exploration some 10 to 15 years earlier in response to declining activity during the early 2000s. Coupled with the rising oil price during that period, the basin responded with an upturn in activity and some major discoveries over recent years.

An example of early state intervention in Norway is the changes to the licence regime that have successfully stimulated activity in mature and frontier regions. By making it simpler for new entrants to secure acreage through licence awards and allowing them to buy and swap licence interests, there has been greater diversity and a doubling in the number of companies operating on the NCS.

The annual system of Awards in Predefined Areas (APA), introduced in Norway in 2003, offers licences for large areas close to existing and planned infrastructure to promote activity in mature regions. This is complemented by a system of concession licence rounds held every second year that focus on under-explored frontier regions.

A further intervention by the Norwegian Government was an amendment to the Petroleum Tax Act adopted in 2004, known as the Exploration Tax Credit. This gave companies with a tax loss and no other production profits the right to claim tax relief at the prevailing rate of 78 per cent on any exploration costs the year after they are incurred. Financiers will typically allow companies to borrow against this credit, making funds for exploration far cheaper and more accessible. This policy is made possible due to the high tax rates levied on oil and gas profits that generate a healthy return for the government once fields enter production. While the UK Government has considered a similar system, it has instead opted to focus on incentivising development expenditure through various field allowances, and, more recently, the Investment Allowance (see section 10 for more information on the Investment Allowance).

9.4 Stability

The regulatory environments and tax regimes under which companies operate is also substantially different across the two basins. The Norwegian state has a greater stake in operations through a 67 per cent equity share in the largest producer, Statoil, via the state-owned company Petoro. Petoro manages substantial assets on behalf of the Norwegian Government, with a portfolio representing around one-third of the country's oil and gas reserves. In the UK, there is no direct state ownership in assets so a more hands-off approach to regulation has typically been the norm.

Fiscal management of the two basins is also very different, although both generate a return to the state through a concession tax regime[37] rather than any production-sharing arrangements. Norway has always had a high but stable tax rate of 78 per cent over the long term. This contrasts to the drastic variations in tax rates in the UK, ranging from 30 to 81 per cent over the last 20 years, increasing uncertainty and deterring investment.

There are, however, promising signs of a different approach being taken in the UK. The establishment of the OGA provides a much needed independent economic regulator and a number of fiscal measures introduced by HM Treasury over the last two years have reduced the burden on UKCS fields and promoted competitiveness (see section 10 on the UK's fiscal regime).

> MER initiatives now under way in the UK may form a blueprint on how to manage a mature oil and gas province.

9.5 The Future

While there are certainly lessons to be learnt from the Norwegian approach to managing its natural resources, as the NCS continues to age over the next decade new strategies may have to be considered. If managed well, MER initiatives now under way in the UK may form a blueprint on how to manage a mature oil and gas province. This could allow the domestic supply chain to develop valuable techniques and experience that will be required in other basins, like Norway, in years to come.

It is important that the two regions continue to learn from each other to instill best practices as the North Sea still has many decades left as an important producer and many more as a centre of supply chain excellence.

[37] A regime in which a company receives a licence to explore, develop, produce and sell hydrocarbons and the host government is compensated by receipt of tax payments.

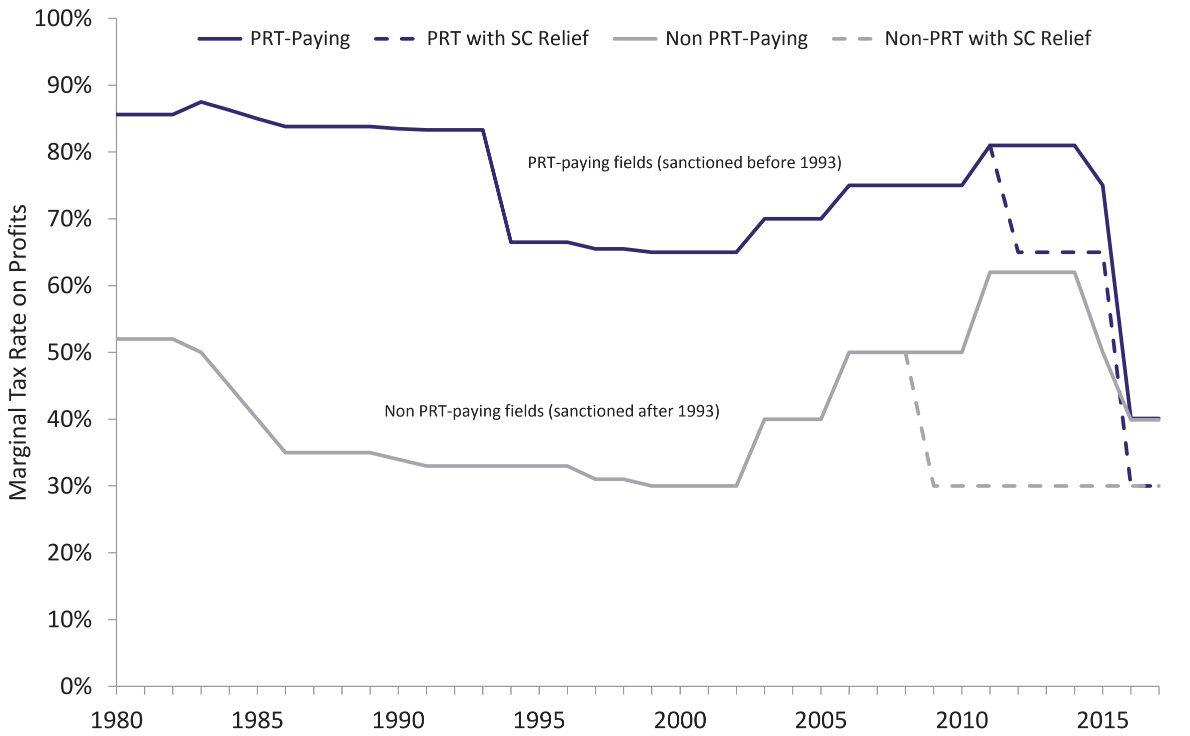
10. The Upstream Fiscal Regime

10.1 Changes to the Regime

Announcements by the UK Government at Budget 2015 and 2016 have transformed the upstream oil and gas tax regime to make it more internationally competitive and to boost investor confidence in light of the UKCS' increasing maturity, reduced profitability and perceived lack of prospectivity. Profits are now taxed at a flat 40 per cent headline rate. The UK Government's policy desire is to attract investment into the region to safeguard its productive future.

> "Budget 2015 and 2016 have transformed the upstream oil and gas tax regime."

Figure 56: Historic Upstream Tax Rates



Source: HMRC

The number of taxes paid by UKCS fields has fallen from three to two. The Chancellor announced in the March 2016 Budget that the Petroleum Revenue Tax (PRT) was being permanently zero-rated from 1 January 2016. The PRT was previously chargeable on fields that had received development consent prior to March 1993, albeit with allowances that ensured that it was only actually charged on the most productive fields.

With further reductions also applied to the Supplementary Charge this year, the headline rate of tax paid on UK oil and gas production has reduced from 50-75 per cent to a flat rate of 40 per cent across all fields, with the fiscal regime now made up of two taxes:

- **Ring Fence Corporation Tax (RFCT)** – a tax on company profits computed in a similar way to normal Corporation Tax (CT) but levied at a higher rate of 30 per cent. It has not benefitted from the rate reductions made outside the ring fence in recent years and is currently 50 per cent higher than the 20 per cent CT rate applicable to the rest of the UK in 2016-17. There are, however, enhanced loss flexibilities[38] and 100 per cent first-year capital allowances to reflect the high levels of investment and project life cycles typical of the UKCS.

- **Supplementary Charge (SC)** – this additional layer of corporate taxation is computed like RFCT but finance costs are not deductible. The rate is chargeable at 10 per cent from 1 January 2016, having halved from 20 per cent in 2015 and 32 per cent before then.

Furthermore, while PRT has now been effectively abolished for income and profits, the tax remains relevant for the purposes of generating tax relief on future losses, especially arising from decommissioning. PRT paid by a field in the past is refundable on a last in first out (LIFO) basis[39] at the rate of tax levied on profits in the respective period.

The 2015 Budget also transformed and simplified the tax allowance regime by moving away from bespoke Field Allowances, which have been replaced with the Investment Allowance. The two main features of the allowance regime are:

- **The Investment Allowance (IA)** – this is a basin-wide capital investment-based allowance against a company's SC liability. It is available for all capital investment incurred on or after 1 April 2015 at a rate of 62.5 per cent. If a company has access to the allowance, only RFCT will be levied on its profits, reducing the effective tax rate to 30 per cent. The government has also committed to extending the IA's scope to certain types of operating expenditure that are intended to add to the asset's productive capacity.

- **100 per cent first year Capital Allowances** – for almost all investment expenditure incurred on the UKCS an immediate deduction against RFCT and SC is available within the year, making the regime a true cash-flow tax. Any expenditure (whether capital or operating) that cannot be relieved in the year it was incurred can be carried forward for an unlimited number of periods until the company returns to having taxable profits. In addition, a company can claim up to ten instances of Ring Fence Expenditure Supplement (RFES)[40] that enhances the cash value of the loss by 10 per cent per period claimed.

The ultimate effect of all these changes to the UKCS' fiscal regime is a major improvement in post-tax materiality, especially for former PRT-paying fields where the tax burden has more than halved in two years. Whether these radical changes are enough to bring about the desired investment response and offset the collapse in cash-flow and profitability, driven by enduring low oil prices, remains to be seen. The short-term view seems to suggest that this has not (yet) occurred as both greenfield and incremental brownfield investment remain extremely low, as outlined earlier in section 5.3.

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[38] Enhanced ability to carry back or carry forward losses, especially in regard to decommissioning losses, to generate a repayment of tax.

[39] The loss is carried back in chronological order to generate the repayment at the same rate that profits in that period were taxed.

[40] RFES assists companies that do not yet have sufficient taxable income to fully offset exploration, appraisal and development costs. The RFES currently increases the value of losses carried forward from one accounting period to the next by a compound 10 per cent per year for a maximum of 10 years, not necessarily consecutively.

10.2 The Balance of Taxes and Allowances

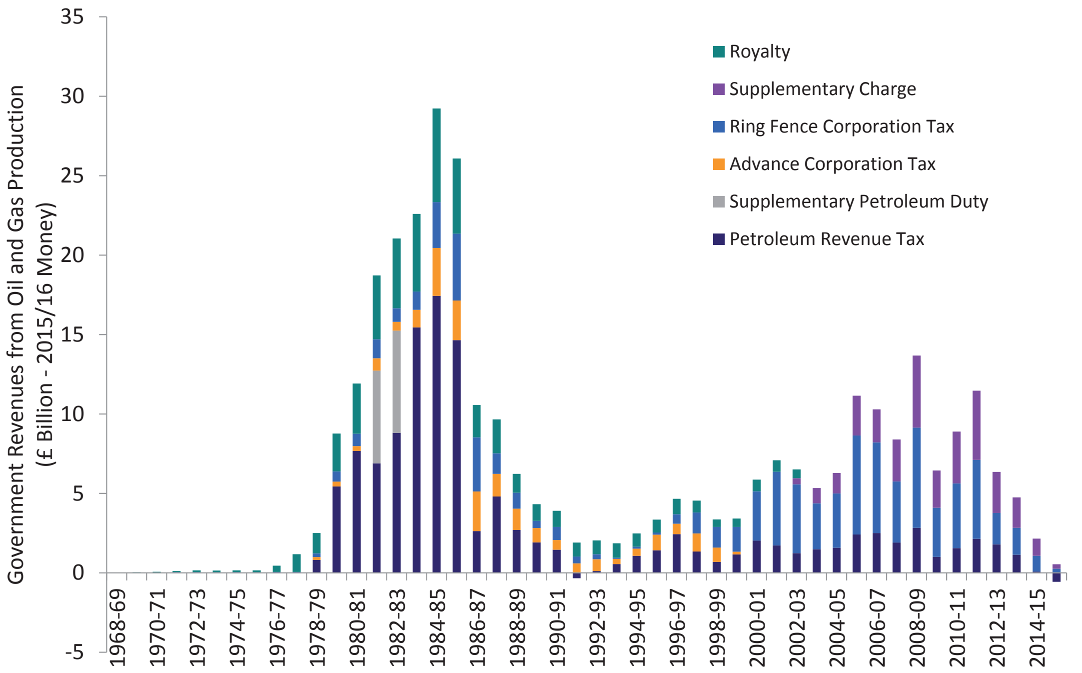
As upstream profits are always taxed separately under the ring fence regime at a minimum rate of 30 per cent, the tax burden, even in instances where companies benefit from the Investment Allowance, remains higher than for all other parts of the UK economy. The allowances therefore do not represent a subsidy for the industry, they seek to partially alleviate the additional layer of tax that applies to UKCS activity only.

Furthermore, companies may also have taxable activities outside the ring fence, for example downstream businesses on which they will pay the normal 20 per cent CT. Organisations cannot offset their profits or losses between the downstream and upstream regimes to reduce their overall tax liability.

10.3 Current Tax Issues Impeding MER UK

Profitability and therefore the direct production taxes paid by the UK offshore oil and gas sector in recent years have declined sharply. In 2013-14, the sector contributed tax receipts on upstream profits of £4.7 billion. For the current tax year of 2016-17, tax receipts are forecast to be negative by around £1 billion. This is due to rising decommissioning activity, pressure on operating margins, and historic investment and losses built up in the past.

Figure 57: Government Revenues from Oil and Gas Production



Source: HM Treasury, Office for Budget Responsibility

> The allowances do not represent a subsidy for the industry, they seek to partially alleviate the additional layer of tax that applies to UKCS activity only.

There remains some issues with the current tax regime that present barriers to investment and the UK Government's stated objective of MER UK. These are outlined below:

Decommissioning

One of the most significant barriers is the asymmetric availability of decommissioning tax relief between the seller and buyer of a mature asset, known as a 'value gap'. The seller of an old asset will often have substantially more tax history for RFCT and SC to achieve full relief for the total decommissioning liability if they continue to operate the field until it ceases production. The potential buyer, on the other hand, is likely to have accumulated less tax history at the point of purchase and there is a risk that the asset's profitability is insufficiently high to offset the final decommissioning tax liability. This makes the post-tax value of the asset lower for the potential buyer, even if more pre-tax value can be generated from the remaining hydrocarbons in the field.

Industry is providing evidence to the UK Government about the number of mature assets for which this tax mismatch impedes transfer to new ownership. It is hoped that corporate tax history can transfer to the new owner along with the asset and the associated decommissioning liability. Fixing this issue would represent a significant improvement to the fiscal terms available on the UKCS and would make it much easier for new investors to enter the market, facilitating MER UK.

Access to Finance

Companies are also experiencing difficulties in accessing finance to invest on the UKCS. With operating cash-flow continuing to be squeezed, very few companies can take advantage of good value oilfield services and invest counter-cyclically to boost the productive capacity of the UKCS when the market recovers. The necessary cost cutting is hurting the domestic supply chain and risks the loss of skills and export potential over the medium term.

Encouraging investment and kick-starting activity now will not only prolong the life of the industry for many more decades but will also ensure vital skills and expertise are not lost in the short term.

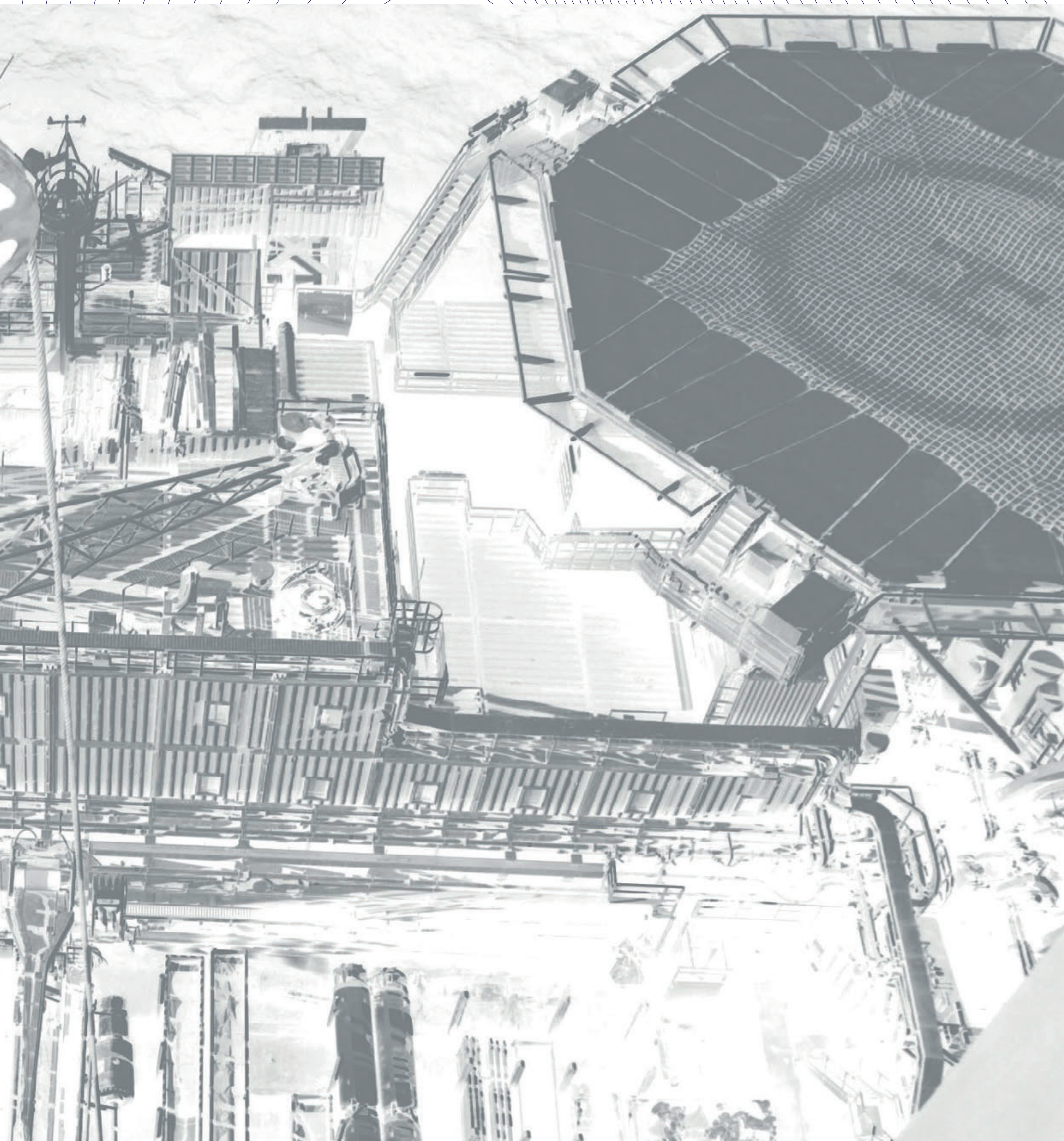
One option might be for HM Treasury to allow companies who have previously invested in the UKCS at a loss, to trade in their tax losses at a discount for a cashable tax credit. This could unlock finance for projects including, but not limited to, exploration and drilling.

This discount would almost certainly mean HM Treasury gives less tax relief to companies than it otherwise would have in the longer term, and it would, of course, also benefit from production taxes in the future if the capital generated new taxable profits, for example, through a field being discovered. The UK Government and the OGA could specify that the tax credit is invested in particular projects within a set timeframe. Oil & Gas UK is currently discussing this proposal with HM Treasury, and calls on government and the OGA to keep working with industry to find a solution to the low levels of investment and activity in the UK North Sea.

11. Glossary

bbl	Barrel (of oil) (one barrel = 0.16 m^3 and 7.55 barrels = one tonne)
bcm	Billion cubic metres (one $metre^3$ = 35.3 cubic feet)
BEIS	Department for Business, Energy and Industrial Strategy
BFOE	A blend of crude from the cargoes of Brent, Forties, Oseberg and Ekofisk
boe	Barrel of Oil Equivalent – this includes oil, gas and other hydrocarbons and equates all of these with oil, in energy equivalent terms, so that a common measure can be made of any of them
boepd	Barrel of Oil Equivalent per day
Brownfield	An oil or gas field already in production
Brent	As applied to trading, the standard quality of oil in Europe and elsewhere comprising a blend of four North Sea crudes from the Brent, Ekofisk, Forties and Oseberg fields
BTU	British Thermal Unit (of energy)
Capital allowances	A term used to describe the availability of an immediate deduction against Ring Fence Corporation Tax and Supplementary Charge payments for almost all investment expenditure incurred on the UKCS
Capital employed	The value of fixed assets employed by the industry
Carbon leakage	A situation in which companies move their production abroad to countries with less ambitious climate measures, which can lead to a rise in global greenhouse gas emissions
Carbon price	The amount that must be paid for the right to emit one tonne of CO_2 into the atmosphere
CCGT	Combined Cycle Gas Turbine
CDA	Common Data Access Limited (a subsidiary of Oil & Gas UK)
CNS	Central North Sea
Concession tax regime	A regime in which a company receives a licence to explore, develop, produce and sell hydrocarbons and the host government is compensated by receipt of tax payments
Contango	Contango refers to the structure of prices where the price for prompt delivery is below the price for forward delivery
Core offshore worker	Workers who spend over 100 nights a year offshore
Cost plus contracts	A contracting model where the client pays the contractor an agreed mark-up based on the cost of the work
CO_2	carbon dioxide (one of the six greenhouse gases under the Kyoto protocol)
CT	Corporation Taxes (see also RFCT)
Direct employment	Those employed by companies operating in the extraction of oil and gas and associated services
E&A	Exploration and appraisal (drilling)
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortisation
Enhanced loss flexibilities	Enhanced ability to carry back or carry forward losses, especially in regard to decommissioning losses, to generate a repayment of tax.
EUA	EU Allowances
EU ETS	EU Emissions Trading System
Gearing	A financial ratio that compares borrowed funds to the equity in business defined as: long-term liabilities/(equity + long-term liabilities)

Greenfield	An undeveloped oil or gas field (as opposed to brownfield)
Heavy oil	Crudes with an American Petroleum Institute gravity of less than 20°
HPHT	High-pressure, high-temperature (of reservoirs)
Indirect employment	Employment as a result of supply chain effects caused by oil and gas sector activity. For these companies, extraction of oil and gas and associated services will be one part of a wider business
Induced employment	Employment supported by the redistribution of income from the oil and gas sector
Investment Allowance	A basin-wide capital investment-based allowance against a company's Supplementary Charge liability
LIFO	Last-In, First-Out – loss is carried back in chronological order to generate tax repayment at the same rate that profits in that period were taxed
LNG	Liquefied Natural Gas
mb/d	Million Barrels per Day (of oil)
million boepd	Million Barrels of Oil Equivalent per Day
MER UK	Maximising Economic Recovery from the UKCS
mt	Million Tonnes
MSR	Market Stability Reserve
NBP	National Balancing Point (NBP) is a virtual trading location for the sale and exchange of natural gas within the UK
NNS	Northern North Sea
NTS	National Transmission System (high pressure gas transmission system in Britain operated by National Grid – the 'motorway' network for gas)
OGA	Oil and Gas Authority
OPEC	Organisation of Petroleum Exporting Countries
PAR	Potential Additional Resources
Production efficiency	The total annual production divided by the maximum production potential of all fields on the UKCS
PRT	Petroleum Revenue Tax
p/th	Pence per Therm (for gas)
Reserves	Hydrocarbons that are anticipated to be recovered from known accumulations from a given date forward
Resources	Productive potential assuming no economic or time constraints
RFCT	Ring Fence Corporation Tax (as applied to upstream oil and gas production in the UK)
SC	Supplementary Charge (a corporate tax applied to upstream oil and gas production in addition to RFCT)
Small pools	Fields in the size range of 0 to 50 million boe for which there is no plan nor intention to develop a plan by operators
SNS	Southern North Sea
Stacking	Reducing a crew on a rig to either zero or just a few key individuals and storing the rig in a harbour
UKCS	UK Continental Shelf
Unconventional resources	Resources that are produced or extracted using techniques other than the conventional method
UOC	Unit Operating Cost
US Lower 48 States	All the states in the United States that are adjoining
W o S	West of Shetland



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