ACTIVITY SURVEY 2015

Oil & Gas UK
the voice of the offshore industry

ACTIVITY SURVEY 2015

OIL & GAS UK

Contents

1. Foreword

Oil & Gas UK's *Activity Survey 2015* provides the most authoritative, comprehensive and up to date picture of the state of this vital sector of the UK economy.

If the challenge facing our industry was significant when oil was at $110 per barrel, the scale of the issue has greatly escalated with the oil price collapse. However, whilst that drop has exacerbated the serious challenges the basin faces, it is not the root of the problem.

We noted in the 2014 *Activity Survey* that the UK's offshore oil and gas basin faced three major challenges: high costs, high taxes and an under-resourced regulator. Whilst some progress has been made, the pace and extent of change for all of them has not been sufficient.

Industry recognises that its cost base is unsustainable and has been taking steps to reduce its costs and improve efficiency. However, it will take time for this to achieve a substantial impact and, unfortunately, the cost of operating the UK Continental Shelf (UKCS) has continued to rise from £8.9 billion to £9.6 billion in 2014. This report demonstrates that cost reductions of up to 40 per cent per barrel of oil equivalent must be achieved to secure a sustainable future for this basin. This can be done but only through combining major effort on cost reduction, production improvement and fresh investment.

We must get the balance right between investment and cost control. Cost cutting alone will diminish this industry. To survive, we must sustain investment, which is why this province is in urgent need of significant regulatory and fiscal reform.

Inadequate stewardship coupled with an unstable fiscal regime and steep production decline have made the UKCS, on a unit of production basis, one of the least competitive places to operate in the world. Without sustained investment, critical infrastructure could disappear, taking with it important North Sea hubs, effectively sterilising areas of the basin for further oil and gas production.

A permanent shift to a lower and simpler tax regime is now urgently required to allow investors to shift their focus away from fiscal risk and towards investment opportunities in the UKCS, of which there still remain a very significant number. Successive governments have been all too willing to increase headline rates, which now range from 60 to 80 per cent. Unless those rates are now swiftly and permanently reduced, our collective efforts to reduce costs and improve the efficiency of our operations will be to no avail.

This report also conclusively shows that exploration activity on the UKCS has collapsed. In 2014, just 14 exploration wells were drilled, the lowest number since the beginning of the industry in the 1960s. We expect the number for 2015 to fall even lower, possibly into single figures. Appraisal drilling is also falling away. These are exceptionally worrying leading indicators of where this industry might be heading.

On the other hand, capital investment in the UKCS reached £14.8 billion in 2014. At first glance this seems to be good news. However, this rise was primarily a result of cost over-runs on ongoing development projects. Furthermore, half of total capital investment last year was spent on just 12 fields, all of which were sanctioned prior to 2014. There is very little fresh investment. The UKCS is just not generating new projects.

Both the British and the Scottish Governments have recognised, in their industrial strategies, that the value of this industry is much more than simply a source of production taxes. I also hope government is alert to the danger that, without immediate radical action to improve the tax regime, hundreds of thousands of jobs supported by this industry will be left in jeopardy and the UK's energy security and balance of trade would also stand to suffer serious damage.

The UK offshore oil and gas industry is a national asset. Our indigenous resources hold the promise of a successful industry for years to come. However, we face exceptional challenge and, without concerted effort, an uncertain future. Industry and government must now do what is needed to reduce costs, encourage investment and avoid premature decline.

Malcolm Webb

Malcolm Webb
Chief Executive, Oil & Gas UK

2. Summary of Findings

Oil & Gas UK's *Activity Survey 2015* is based on the latest data supplied to us by all exploration and production companies operating on the UK Continental Shelf (UKCS).

2.1 Industry Performance in 2014

- Delivered production revenues of £24.4 billion, the lowest since 1998.
- Spent £9.6 billion operating the UKCS, almost 8 per cent higher than in 2013.
- Invested £14.8 billion of capital, half of which was spent on only 12 fields.
- Spent £1.1 billion on the acquisition and interpretation of seismic data and on drilling 14 exploration and 18 appraisal wells (including sidetracks).
- Spent over £1 billion on decommissioning activity, the highest annual spend on record.
- Paid £4.7 billion in production taxes in the fiscal year 2013/14, and expects to pay substantially less than £2.8 billion in the fiscal year 2014/15[1], the lowest in over 20 years.
- Experienced a negative cash flow of £5.3 billion in 2014, the worst position since the 1970s.
- Produced 1.42 million barrels of oil equivalent per day (boepd), the best year-on-year performance in 15 years, slowing production decline.
- Saw unit operating costs rise to £18.50/boe, up from £17/boe in 2013.
- Discovered around 50 million boe of potentially commercial reserves, significantly lower than the average of over 250 million boe per year over the last ten years.
- Drilled 126 development wells (including sidetracks), slightly higher than the 120 in 2013.
- Sanctioned the development of 8 new fields and 28 brownfield opportunities.

2.2 Oil and Gas Prices

- Oil price averaged $99 per barrel (bbl) in 2014, although the average price in quarter 4 was significantly lower at $76/bbl as the price crashed to $55/bbl by the end of December.
- Gas prices averaged 50 pence per therm in 2014 (day ahead price), 26 per cent lower than in 2013.

2.3 Reserves

- A total of 10 billion boe are reported in the survey as potentially recoverable.
- Sanctioned reserves in production or under development have fallen from 6.6 billion boe to 6.3 billion boe in 2015.
- There are a further 3.7 billion boe that could potentially attract investment, down from 4 billion boe reported a year ago.
- Of the 3.7 billion boe of potential investment opportunities, less than 2 billion boe are likely to be developed based on quarter 4 2014 intentions, and we now expect a further reduction in this number.

[1] See OBR *Autumn Statement* December 2014 at www.gov.uk/government/publications/autumn-statement-documents

2.4 Drilling Activity

- Exploration activity was significantly worse than expected in 2014, with only 14 of the expected 25 wells actually drilled (including sidetracks). This compares with 15 wells in 2013 and reflects a downward trend since 2009.
- Inability to access capital was cited as the main reason for low exploration activity, which led to the discovery of just 50 million boe that has the potential to be commercially developed.
- As few as 8 to 13 exploration wells are forecast to be drilled in 2015 as the lower oil price adds to existing barriers.
- 18 appraisal wells were drilled (including sidetracks), 7 more than were forecast but a significant fall from the 29 wells drilled in 2013.
- No more than 5 appraisal wells are forecast for 2015, a fall that is driven by poor exploration results over the last 4 years.
- 126 development wells (including sidetracks) were drilled in 2014, compared with 120 wells in 2013.

2.5 Production

- Production averaged 1.42 million boepd in 2014, 1.1 per cent less than in 2013, representing the best year-on-year performance in 15 years.
- Liquids production declined by 2.6 per cent, but was offset to some extent by a 1.1 per cent increase in gas production.
- Following production falls of 19 per cent, 14 per cent, and 8 per cent in each of the last 3 years, respectively, the improvement in performance in 2014 has been driven by an increased focus on production efficiency, the impact of new start-ups and no major unplanned shutdowns during the year.
- Despite steady production, revenues fell to just over £24 billion for the year, the lowest since 1998.
- Looking ahead, up to 15 new fields could begin production in 2015, many of which are expected in the first half of the year. If there is no major project slippage, production could increase to around 1.43 million boepd this year.
- The impact of new start-ups is so great that, by 2019, more than half of UKCS production is likely to come from fields that started production since the end of 2012.

2.6 Capital Investment

- At £14.8 billion, capital investment was higher than anticipated, largely because of cost over-runs and project slippage on some of the biggest investments.
- Investment is forecast to fall sharply to £9.5–11.3 billion in 2015, depending on current project performance and the amount of new investment that is sanctioned this year.
- Feedback from operators indicates that very little new investment is expected to be sanctioned in 2015 as companies review their business plans in light of the falling oil price.
- It is expected that new investments will amount to less than £3.5 billion over the next 3 years. Last year's survey forecast up to £8.5 billion would be invested over the same period.
- Annual investment in currently sanctioned projects will decline rapidly and could collapse to £2.5 billion by 2018 once the wave of recent large investments enters production.
- Quarter 4 2014 data suggest a total of £38 billion will be invested in currently sanctioned projects on the UKCS, though some of these may now be at risk of cancellation as there will be continued pressure on costs and contract rates.
- A further £26 billion is required to develop projects with a 50 per cent or greater chance of proceeding, potentially delivering 2 billion boe. This represents a fall of £9 billion compared to the previous year.
- Further still, £30 billion could be invested in 1.7 billion boe of projects that, at prevailing conditions, are not sufficiently attractive or mature to proceed to sanction.
- Fresh investment will rely on sustained improvements in the cost base and a significant improvement in fiscal terms; without such changes, the impact on the UKCS and the wider supply chain will be severe.

2.7 Operating Expenditure

- Whilst operating expenditure rose by almost 8 per cent to £9.6 billion in 2014, it is anticipated to fall in 2015 as a consequence of the cost reduction initiatives currently being undertaken by industry in reaction to falling revenues.
- Unit operating costs have risen to a record high of £18.50/boe in 2014 as a result of cost increases and a small decline in production.
- Macro-level cost and efficiency improvements in the order of 20-40 per cent per boe must be achieved to ensure a sustainable future for the UKCS. This can be delivered through a combination of cost reduction and brownfield investment.

2.8 Decommissioning

- Just over £1 billion was spent on decommissioning activity, representing almost 4 per cent of total expenditure.
- The annual average expected spend on decommissioning over the second half of the decade has increased to £1.8 billion from £1.5 billion, as a result of cost escalation and acceleration of activity.
- The impact of the recent change in oil price has yet to be fully factored into decommissioning plans and may ultimately lead to further acceleration in decommissioning.

3. Prices and Markets

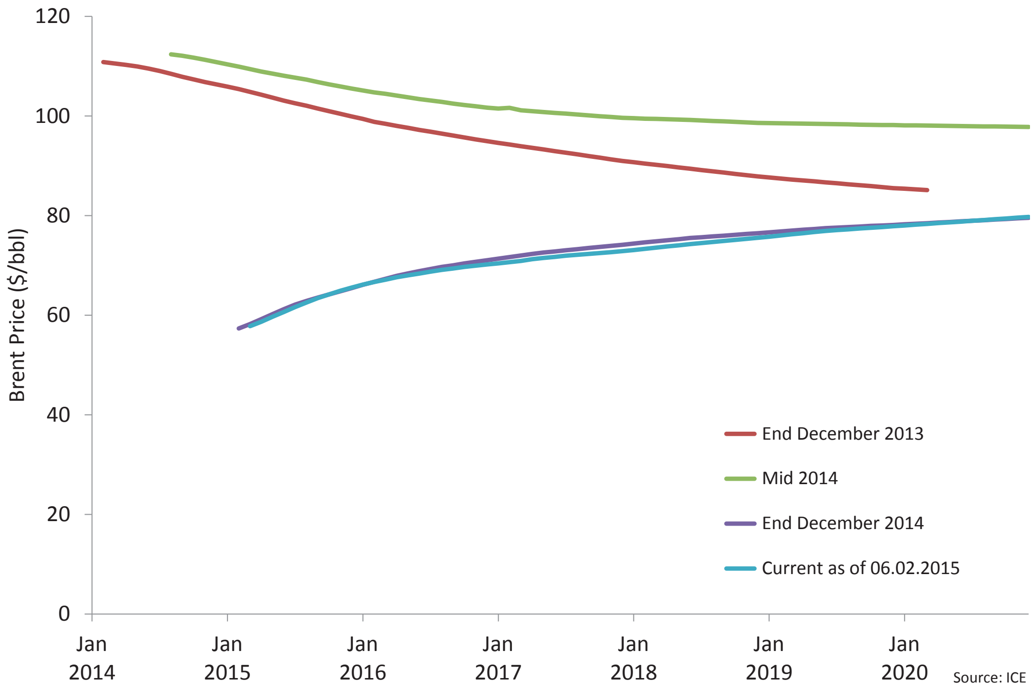
Oil Markets and Prices

After more than three years of unusual stability in the range of $100-115 per barrel (bbl), Brent prices collapsed dramatically in the second half of 2014. Dated Brent fell from $110/bbl in mid-year to $55/bbl at the end of December and traded below $50/bbl in January 2015, the lowest level since the first quarter of 2009 during the depths of the world recession.

This slide in crude oil prices began in mid-2014 as the slowdown in demand growth in developing countries reinforced the effect of the continuing expansion of crude oil supply in North America, leading to a rapid build-up of excess commercial stocks. The decline in price accelerated in late-November when the Organisation of Petroleum Exporting Countries (OPEC) declined to cut its output to rebalance the market and abandoned its earlier, successful, short-term management of supply in an effort to regain market share. This decision represented the most significant shift in Saudi and OPEC strategy for many years and ushered in what may be an awkward period in 2015 in which the market seeks to establish a new equilibrium without guidance from OPEC over its target price. The price elasticity of both supply and demand in oil markets is notoriously low, so the market will take some time to rebalance. Already, the projected reduction in worldwide upstream capital expenditure of about 15 per cent in 2015 will slow supply growth in high-cost basins and the fall in end-user prices will gradually stimulate oil demand.

Long-dated Brent futures prices, which reflect market expectations and the hedging activity of producers and consumers, declined by much less than dated Brent in 2014. In the second half of 2014, Brent for delivery in 2018 fell from $100/bbl to $75/bbl, reflecting the view that lower prices will eventually reduce supply growth and stimulate demand, therefore bringing the market back into balance at prices considerably above $50/bbl. At the time of writing, in early February, the 2018 Brent futures prices have found support at $75/bbl. Whilst there are now early signs of a gentle recovery in Brent oil price, it remains to be seen whether this will be sustained. It should certainly not be seen as a ‘solution’ to the challenges facing the UK’s offshore oil and gas industry.

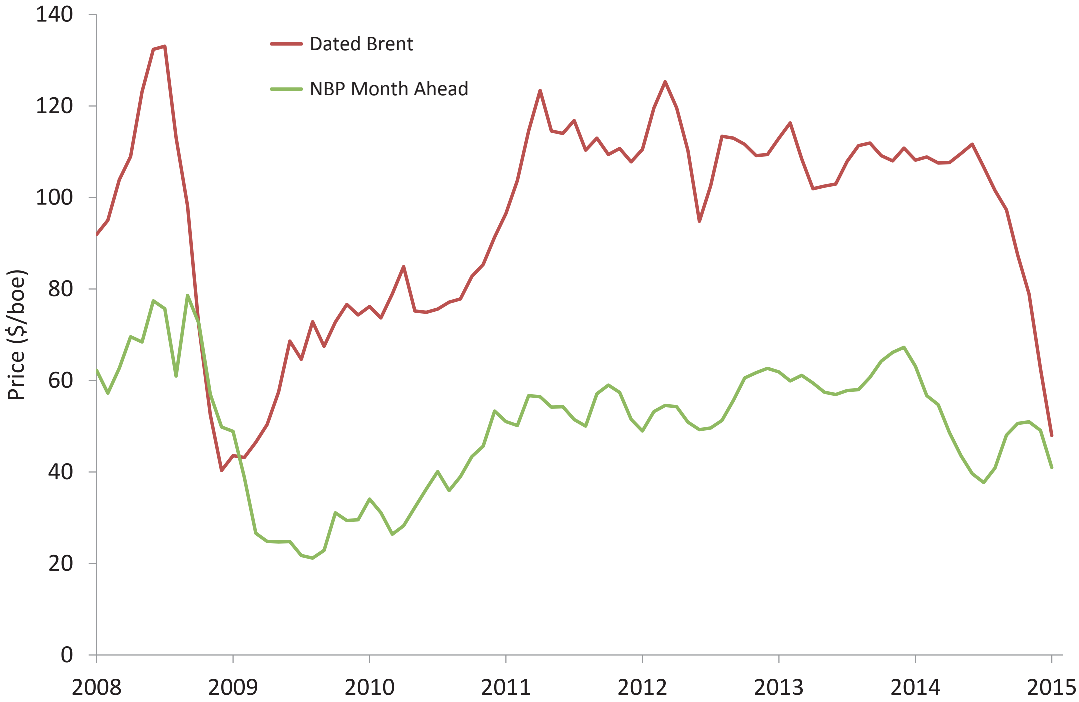
Figure 1: Brent Futures Curves



Gas Markets and National Balancing Point Prices

The wholesale gas market price followed a different but equally dramatic path in 2014. The annual average price at the National Balancing Point (NBP) fell from 68 pence per therm (p/th) in 2013 to 50 p/th in 2014. However, this decline had little to do with the slide in the oil price, at least until the last few weeks of 2014. The collapse in oil prices was not matched by those of gas and, by January 2015, the gap between Brent and NBP prices, expressed in barrels of oil equivalent (boe), was the narrowest since the 2009 recession.

Figure 2: Dated Brent and National Balancing Point Prices

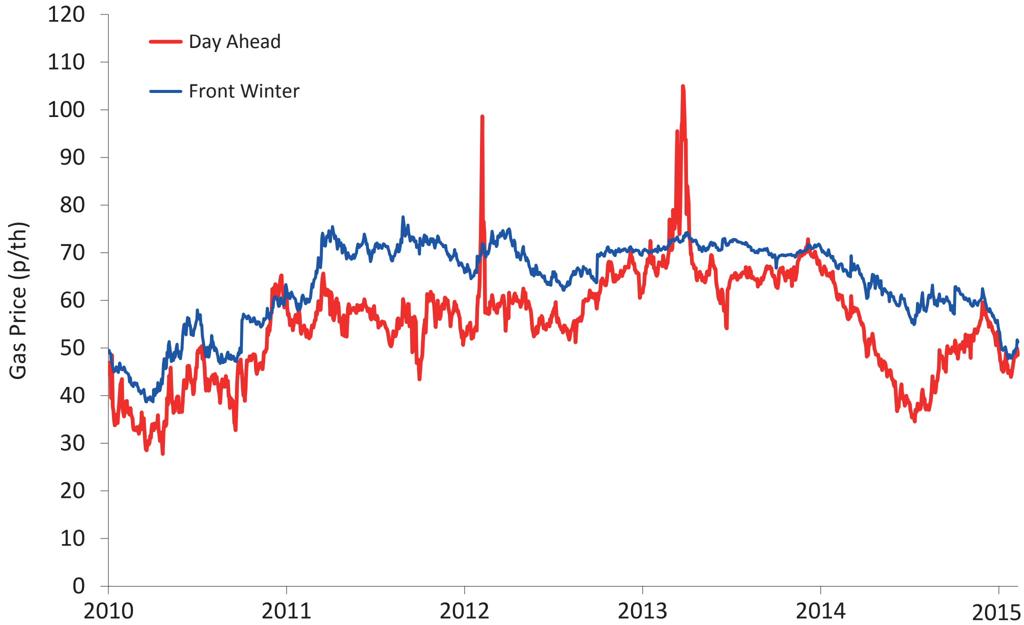


Source: Argus Media, ICIS Heren

The influence of oil prices on NBP gas prices is reflected in forward winter prices because of the inclusion of oil prices with a lag in some long-term contracts in continental Europe, and the need for the UK to attract gas from the continent to meet peak winter demand. The slide in Brent prices from \$110/bbl to \$55/bbl in the second half of 2014 was accompanied by a decline in forward NBP prices for delivery in winter 2015-16 from 60 p/th to 48 p/th. If oil prices stabilise at \$50-60/bbl, NBP month ahead prices are expected to settle in the range of 40-50 p/th, assuming normal weather and supply patterns.

The main reason behind the fall in NBP prices from 60 p/th to 35 p/th between January and June last year was the extraordinarily warm weather in the winter of 2013-14. This left the entire European market with excess stocks at the end of the winter and depressed demand for storage injection in the summer months. The slide in NBP prices was all the more remarkable because it occurred against a background of persistent fears that there would be an interruption to Russian gas supplies to Europe arising from the Ukraine-Russia crisis and European and US sanctions against Russia following its annexation of Crimea in March. Prices then recovered ahead of the winter but still reflected the effects of warmer than normal temperatures.

Figure 3: Daily National Balancing Point Prices



Source: ICIS Heren

Last year was the warmest on record in the UK with an average temperature of 9.9ºC, compared to a 30-year average from 1981 to 2010 of 8.8ºC. Every month, except August, was warmer than the long-term average. This was the principal factor behind the fall in total UK gas demand from 78 billion cubic metres (bcm) in 2013 to an estimated 70 bcm in 2014, the lowest since 1994, despite the slight recovery in gas use for power generation. This compares to peak demand for gas in the UK of more than 103 bcm in 2004. Demand for gas in Europe shows a similar trend, falling by about ten per cent in 2014 and markets across the continent remained well-supplied throughout the year.

4. Fiscal and Regulatory Reform

In response to the various business challenges posed by a mature UK Continental Shelf (UKCS), a number of regulatory and fiscal changes are required. This should assist with maximising the UKCS' hydrocarbon potential, as advocated by the recommendations of the *UKCS Maximising Recovery Review,* undertaken by an independent team led by Sir Ian Wood (the Wood Review)[2]. The necessary regulatory and fiscal changes are:

1) The establishment of a properly resourced, independent and expert regulator, the Oil and Gas Authority (OGA), backed by primary legislation enacted in the Infrastructure Act 2015. The OGA has been tasked with facilitating collaborative behaviour to maximise the realised value of the UKCS' reserves to the economy as a whole. The OGA will also focus on industry priorities and act as a centre of expert knowledge to inform wider UK Government policy, building on the government's *Oil and Gas Industrial Strategy* launched in March 2013[3].

2) Wide-ranging reform to the UK's upstream fiscal regime to ensure it regains international competitiveness and reflects the opportunities of a mature and high-cost offshore environment. This is best achieved by a substantial reduction in the headline rate of tax as well as a commitment from government that it recognises that rates will have to continue to fall as the resource opportunities diminish as the basin matures. Furthermore, there must be a significant simplification of the current field allowance incentives through a single, basin-wide incentive that is based on investment size. A commitment to implement an Investment Allowance was given in the *Autumn Statement* and industry is working closely with government to deliver the Allowance at Budget 2015.

[2] The *UKCS Maximising Recovery Review* is available to download at www.woodreview.co.uk
[3] The *Oil and Gas Industrial Strategy* is available to download at www.oilandgasuk.co.uk/OilandGasIndustryCouncil.cfm

5. 2014 Performance

2014 was a challenging year for the UK offshore oil and gas industry. This report predominantly focuses on the UKCS' headline performance, displaying data from throughout the business cycle, from exploration to decommissioning, to provide insight into recent performance and near-term trends.

To provide context, it is also useful to consider the events of the last 12 months. Some have had an immediate impact on the business, others will be significant in shaping the future of this industry.

In February 2014, the recommendations of the Wood Review were published. The review highlighted the benefits of the industry to the UK economy and brought a sharp focus on the challenges it faced even at, what were then, much higher oil and gas prices. It recommended a fresh tripartite strategy uniting industry, HM Treasury and a new independent government regulator to maximise economic recovery from the UKCS (MER UK). There has been significant progress since, with the formation of a new regulatory framework and the establishment of an arms-length regulator, the OGA.

Meanwhile, the UK Government Budget in March last year brought about an industry-wide review of oil and gas taxation led by HM Treasury. It also saw the birth of a new field allowance for ultra-high pressure, high temperature (HPHT) fields, which, unlike previous allowances, is designed to incentivise exploration activity and the development of field 'clusters'. The cluster concept is one of the first tangible signs of the Wood Review in action.

Looking at specific projects, the biggest field development approval of the year was announced in June, when the Catcher Area development, operated by Premier Oil, was formally approved by the Department of Energy & Climate Change (DECC). The project's equity holders announced plans to invest over £1 billion to secure total reserves of around 96 million barrels of oil equivalent (boe).

Political events in 2014 shone a spotlight on the industry and its important contribution to local and national economies across the UK, particularly the lead up to the Scottish Referendum on 18 September.

September also marked the beginning of the oil price fall, a trend that is addressed in detail in the Prices and Markets section of this report. From a Brent spot price of $100.2/bbl at the beginning of September, the year ended with a Brent spot price of just $55.3/bbl and it fell yet further through the early part of 2015. Industry was already undertaking initiatives to improve its cost efficiency, but with around one third of UKCS oil fields operating at a loss as their revenue stream is halved, these measures have been accelerated and are rapidly being implemented.

In late October, Shell announced the cessation of production from the Brent Alpha and Bravo platforms as a further tangible step in the gradual decommissioning of the giant Brent field.

On 3 December, Chancellor George Osborne delivered the *Autumn Statement* and announced a reduction in the rate of supplementary charge on corporation tax from 32 per cent to 30 per cent. In response to the fiscal review, an Investment Allowance was also proposed to potentially replace all other existing field allowances in a move that would greatly simplify the fiscal regime and make it less distortionary. Whilst industry has responded positively to both measures, as this report shows, swift action is required to deliver further significant changes in the headline tax rate as well as rapid implementation of the Investment Allowance.

The year ended with the Golden Eagle Area development producing its first oil, signalling the start-up of a field with large enough potential to provide a new hub.

Figure 4 shows industry's key performance metrics in 2014 against forecasts made 12 months ago.

Figure 4: Key Metrics Scorecard for 2014

	Forecast	Actual
Exploration Wells	25	14
Appraisal Wells	11	18
Production (Million boe per day)	1.4-1.5	1.42
Expenditure (£ Billion) • Capital Expenditure • Operating Expenditure • Exploration and Appraisal • Decommissioning	25 13 9.6 1.4 1	26.5 14.8 9.6 1.1 1
Unit Operating Cost (£/boe)	18	18.5

Source: Oil & Gas UK

Exploration and Appraisal Drilling in 2014

In February 2014, based on operators' forecasts, Oil & Gas UK anticipated that 36 exploration and appraisal (E&A) wells would be drilled with the majority (25) being exploration. Although 32 E&A wells were drilled, the dynamic was not as expected, with more appraisal wells drilled than exploration.

Despite hopes of an upturn, exploration drilling activity failed to recover with just 14 exploration wells drilled (including sidetracks) last year. The current rate of exploration drilling is the lowest since 1965 and urgent action is required to stimulate activity in this area and generate future development opportunities. There were a number of factors that meant 11 wells failed to materialise in 2014, although nine of them are still planned but slipped into 2015 or later. The key constraints were inability to secure finance, lack of affordable rigs and cost escalation.

Furthermore, exploration drilling continued to yield disappointing results. Whilst half of the wells drilled encountered hydrocarbons, only four were reported as sufficiently attractive to potentially be developed. These four discoveries contain combined recoverable reserves of around 50 million boe, which represents a third successive poor year for exploration volumes discovered, particularly when compared to the annual average of over 250 million boe over the last ten years.

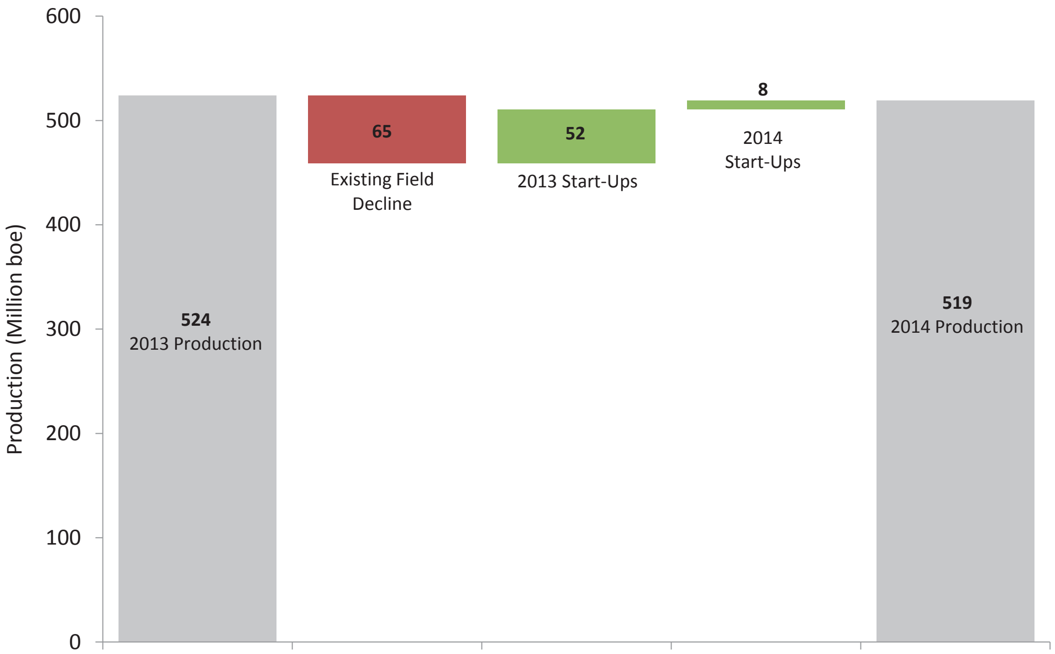
Ongoing initiatives to try and improve the success of exploration drilling include: plans to initiate new seismic data acquisition in the UKCS' frontier regions; the creation of a digital exploration map illustrating new, previously unexplored and near-field opportunities; a conference for exploration specialists to share information and best practice; and a review of 97 wells in the central North Sea (CNS). In addition, the impact of the fiscal regime on exploration is being reconsidered, not least in light of the Wood Review and the recently completed fiscal review.

Appraisal drilling, on the other hand, exceeded expectations in 2014. Eighteen wells were drilled, seven more than were forecast. It is hoped that appraisal activity will encourage further resources to be matured.

Production in 2014

Total production in 2014 was 519 million boe (1.42 million boe per day (boepd)). This fell within the forecast range of 1.4-1.5 million boepd, representing only a slight 1.1 per cent year-on-year decrease compared to 2013. This is a positive outcome as this is the first year since peak production in 2000 that output has remained at an almost constant level, after three successive years of decline of 19 per cent, 14 per cent, and eight per cent, respectively. 2014 saw no major unplanned outages or incidents to disrupt output. An improvement in production efficiency and the impact of new start-ups also helped last year's performance.

Figure 5: Production Change from 2013 to 2014



Source: Oil & Gas UK

Net gas production (less the gas producers' use for their own purposes offshore) was up by about one per cent for the year, boosted in part by the Juliet and Kew fields start-ups, but also by increased production from the Jasmine field that came onstream in late 2013.

In contrast, liquids production (oil and natural gas liquids) fell by around 2.6 per cent last year. Production over the first half of the year showed a minor increase compared to the same period in 2013, but disappointing delivery in the second half of the year resulted in an annual liquids production rate of 0.84 million boepd. This was partly because of the delay in new projects that were initially expected to produce first oil in the second half of 2014 and partly due to extended shutdowns on some of the biggest oil producing fields on the UKCS.

Operating Expenditure in 2014

The cost to operate on the UKCS increased again in 2014 to reach a record £9.6 billion, representing a rise of almost eight per cent on 2013. Following increases of 10 per cent and 15.5 per cent over the previous two years, respectively, companies were braced for a further rise in 2014 as the costs of labour, rigs and raw materials were rising at a rate well above general inflation.

The combined impact of a small production decline and aggregate operating cost increase led to a rise in unit operating costs (UOCs) from £17/boe in 2013 to almost £18.50/boe in 2014. The largest proportion of operating expenditure came from the CNS, however, significant overspend occurred in the northern North Sea (NNS) where ageing assets, construction work at the Sullom Voe Terminal and fuel gas shortages all contributed to an increased cost base.

It is clear that a rapid change in the UKCS cost base began in quarter 4 last year and has continued to pick up pace in the early part of 2015. Accelerated by the falling oil price, work on macro-level cost reductions on the UKCS commenced at the end of 2014 and will undoubtedly become more visible this year.

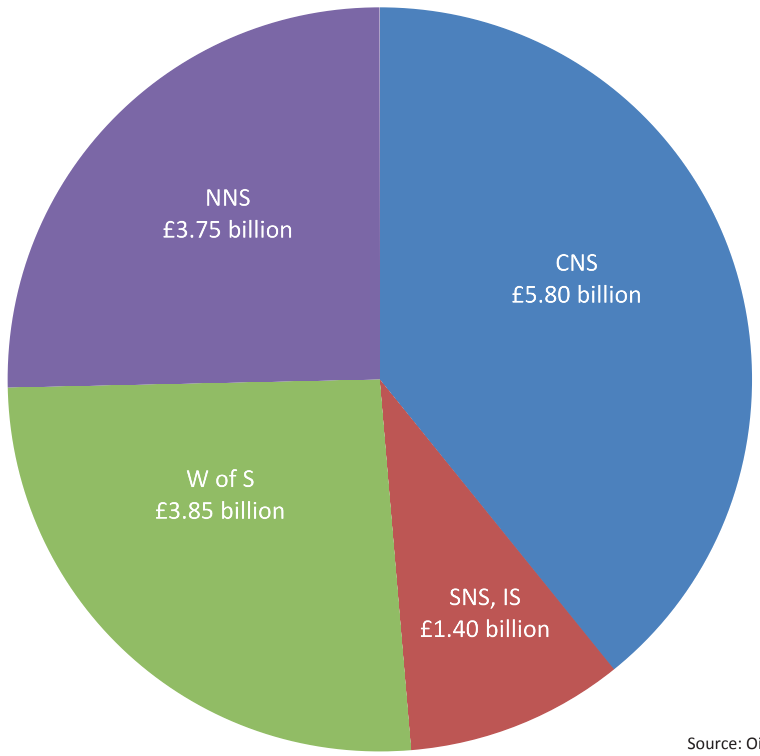
Capital Investment in 2014

In early 2014, Oil & Gas UK forecast that capital investment would fall from £14.4 billion in 2013 to around £13 billion in 2014 as a number of major projects approached completion and commenced production. However, significant cost over-runs and start-up delays on a number of projects have meant that capital expenditure last year represented a new record at £14.8 billion.

There were cost over-runs in a small number of large developments to the extent that the five fields with the biggest overspends accounted for more than £1 billion of the £1.8 billion increase. Conversely, capital investment was lower than forecast on 30 assets, in part, offsetting big project overspend elsewhere, helping to contain overall expenditure growth.

Around two-thirds of the £14.8 billion was invested in new field developments and one third in brownfield projects to increase recovery from existing fields. Geographically, nearly £6 billion of investment was spread over more than 100 fields in the CNS region in 2014, over half of which was on existing assets. Six fields each attracted more than £500 million of investment last year, four of those are located west of Shetland (W of S). Development in this frontier region of the UKCS is reliant on ground-breaking technology and, as shown in Figure 6, secured almost £4 billion of investment last year.

Figure 6: Capital Investment by Region in 2014



Source: Oil & Gas UK

6. Business Outlook

Given the recent sharp fall in oil price, company plans are under intense internal scrutiny and face significant revision, almost on an ongoing basis, as investors seek to adjust to the new business environment.

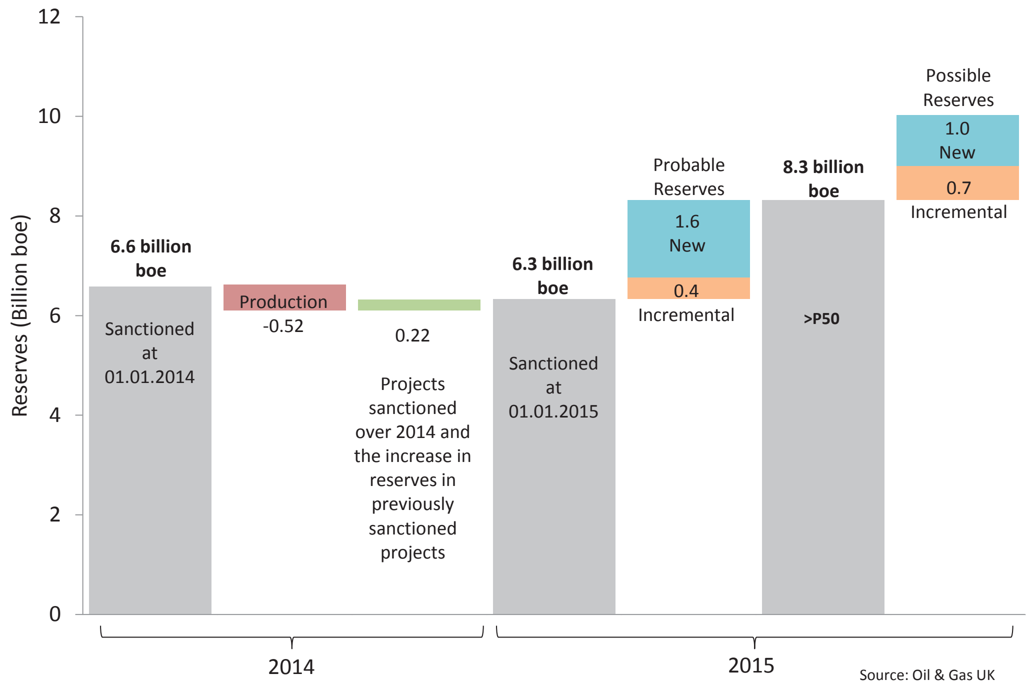
For previous Activity Surveys, the data have been collected over quarter 4 of the preceding year with little need for update. This worked well when the business environment was stable and there was greater certainty when collating operators' plans. However, the 2015 survey has been compiled during a period of far greater uncertainty due to the rapid fall in oil price. Most of the survey responses were received in the middle of quarter 4 2014 when the Brent price was in the $70-80/bbl range. As such, the results in this survey should be taken as a high watermark. Where possible, the survey results have been modified to reflect latest best estimates based on a data reconciliation process undertaken in January 2015.

However, the reverberations of the price fall, combined with a significant increase in global competition for capital, mean the results in this section of the report are presented with acknowledgment that there is greater uncertainty than ever. Companies are continuing to constrain their investment plans for 2015 and are pursuing ambitious cost reduction and efficiency improvement programmes. They also await clarity on the proposed changes to the UK fiscal regime, which may help sustain long-term opportunities that may otherwise be lost from company plans.

6.1 Reserves

According to company business plans provided to Oil & Gas UK during quarter 4 2014, up to 10 billion boe of known recoverable reserves could be extracted from the UKCS over the next 40 years. Of the 10 billion boe, 6.3 billion are sanctioned reserves from fields that are already in production or under development on the UKCS. Reserves of 2.6 billion boe sit in 36 potential new (greenfield) developments that are yet to secure investment. A further 1.1 billion boe are reported in around 100 incremental (brownfield) opportunities that companies are considering, but again are yet to secure investment.

Figure 7: Build-Up of the Reserves Base



Source: Oil & Gas UK

A year ago, it was anticipated that a total of 9.4 billion boe had a greater than 50 per cent chance of being recovered from the UKCS (>P50 confidence level), 6.6 billion boe of which were already sanctioned. However, the P50 outlook has now fallen to 8.3 billion boe, 6.3 billion boe of which are sanctioned. Even when accounting for the 0.52 billion boe of production in 2014, there is still a 0.6 billion boe shortfall in P50 reserves. This shortfall sits within opportunities that were considered 'probable' near-term developments 12 months ago (>P50), but are now only considered 'possible' developments that are unlikely to proceed in current market conditions.

Brownfields

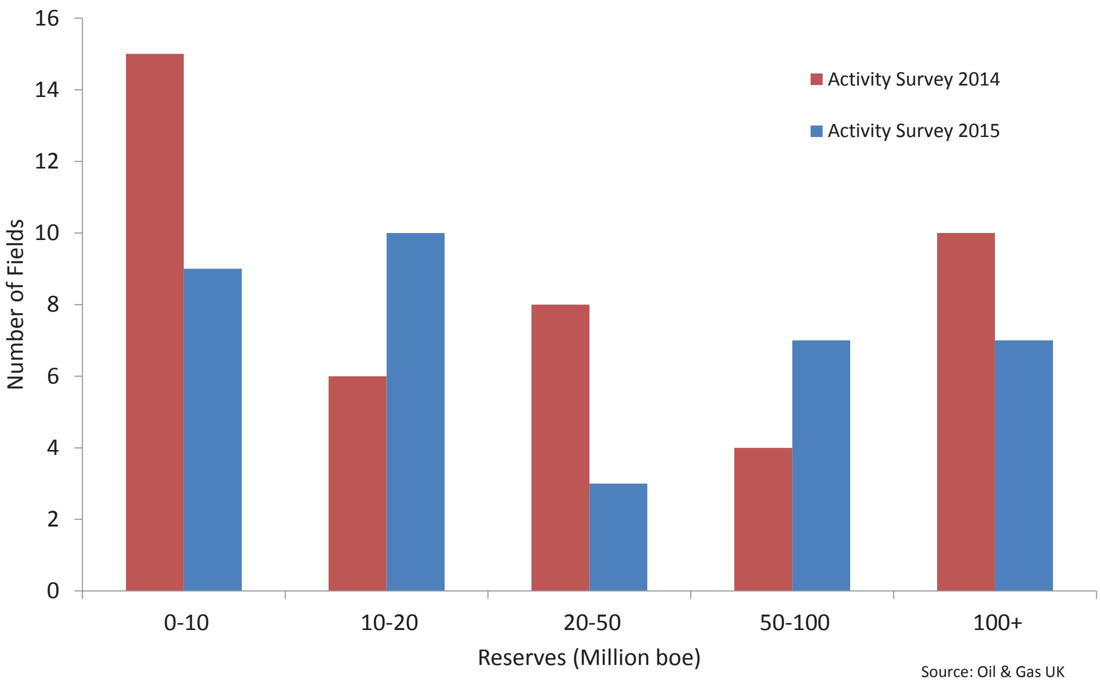
Total volumes associated with potential brownfield projects have decreased by around 200 million boe over the last 12 months to 1.1 billion boe. Whilst some projects have proceeded to sanction over that time, a number of projects are now seen as unviable against the backdrop of the falling oil price, high costs and fiscal uncertainty. Around two thirds of these reserves that still feature in company plans are now considered less than 50 per cent likely to proceed, a concerning increase compared to less than a quarter reported as such last year.

New Fields

The size distribution of potential new field developments has also shifted noticeably over the last 12 months as these investments are being re-evaluated at lower prices. The development concepts behind a number of large potential new projects on the UKCS have been re-assessed and, in a number of cases, the end result has been to downgrade the volumes of initially targeted reserves. Figure 8 illustrates this trend.

The overall sample of new development opportunities has fallen from 43 to 36. Whilst eight fields were sanctioned over the last year, some of the smaller developments do not feature in the 2015 sample as they are no longer seen as viable investments and so have been completely removed from company plans. On the other hand, there are some recent discoveries or new opportunities that feature in the survey for the first time as they have now sufficiently matured to appear in operators' plans.

Figure 8: Distribution of Undeveloped Reserves



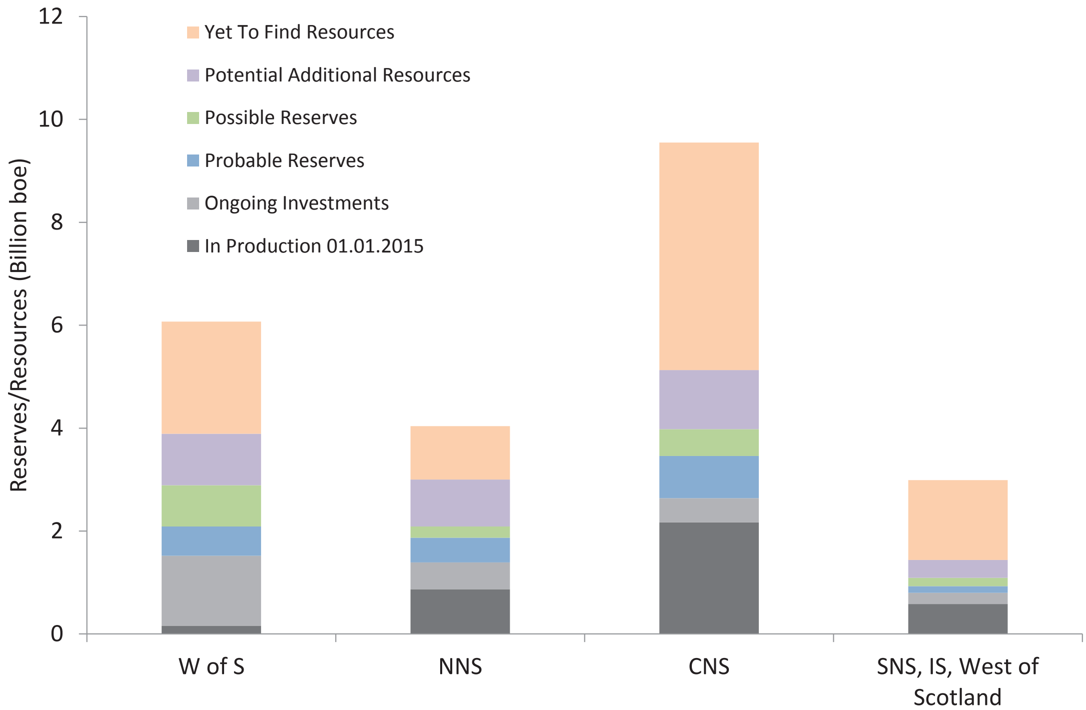
Source: Oil & Gas UK

Comparison by Region

Whilst projections of recoverable reserves should be treated with an even greater inherent level of uncertainty at a time of high price volatility, Figure 9 gives an estimate of the potential of each geographic region of the UKCS. The CNS is the area with the largest reserve base in current company plans at almost four billion boe, over 2.5 billion boe of which are already sanctioned. Significant exploration potential is considered to remain in the CNS, particularly in the very technically challenging HPHT plays.

The relatively immature W of S area is also a region considered to have great potential, but over 95 per cent of resources here are yet to come onstream and exploration plays are still largely untested. The SNS and Irish Sea (IS), the most mature areas of the UKCS, still have the potential to deliver a further three billion boe over time, and that number could increase if unproven exploration plays become commercially viable in the future.

Figure 9: Reserves and Resources Growth by Region



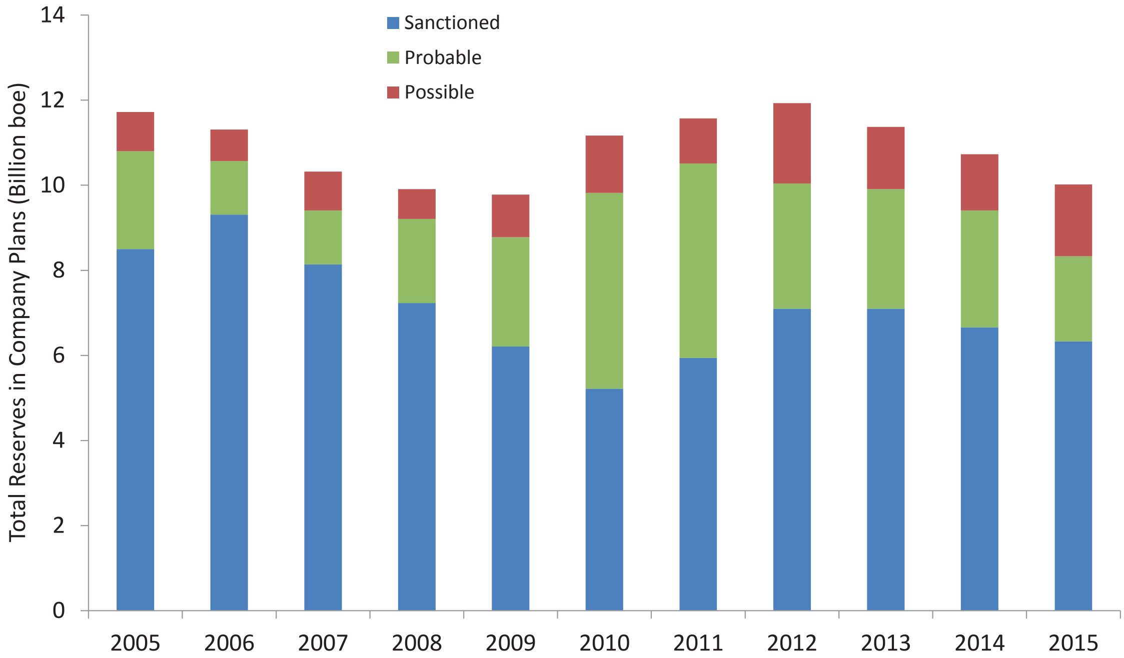
Source: Oil & Gas UK, DECC

Changes in the Reserves Base

Figure 10 shows how the reserves base in company plans consistently grew between 2009 and 2012, before falling in each of the last three years as a lack of exploration activity has curtailed the rate of new volumes being discovered, leading to a fall in the overall reserves portfolio.

The change in sanctioned reserves reported in the survey has followed a similar pattern as reserve maturation through to sanction has also slowed down after some big fields were approved at the start of the decade, many of which were incentivised by targeted field allowances.

Figure 10: Reserves by Probability of Proceeding



Source: Oil & Gas UK

In 2014, 519 million boe were extracted from the UKCS, but only 160 million boe were progressed to sanction and around 50 million boe of potentially commercial reserves were discovered through exploration activity. The current reserves replacement ratio must improve if the UKCS is to have a long-term future. Both industry and government are aware of the size of the prize at stake and the competitive pressures on the UKCS in the current business environment.

Investment Required

The remaining reserves will require significant outlay if they are to be developed and, as such, current estimates show that around £64 billion of capital must be invested to realise the P50 potential in current company plans. Almost £38 billion of that has already been committed, but even some of that investment is being re-assessed at a time when capital is highly constrained and potential revenues are falling rapidly.

The UK must be globally competitive if it is to safeguard existing projects and attract the additional £26 billion of investment that is required to develop the P50 reserves in company plans. The need for this investment is time sensitive as these projects can only proceed while key pieces of UKCS infrastructure remain in place. A further £30 billion of investment will be needed to develop the ‘possible’ reserve base in company plans, although there is little sign of this occurring currently.

An affordable cost base, a competitive fiscal regime and a regulator that will ably facilitate the swift development of these reserves are all essential for ‘probable’ and ‘possible’ projects to mature to certain projects. Extracting these reserves over time will not only provide security of primary energy supply and balance of payments benefits for the UK economy, but it will help ensure that the UK’s world-class supply chain remains a provider of hundreds of thousands of highly skilled and well-paid jobs throughout the country.

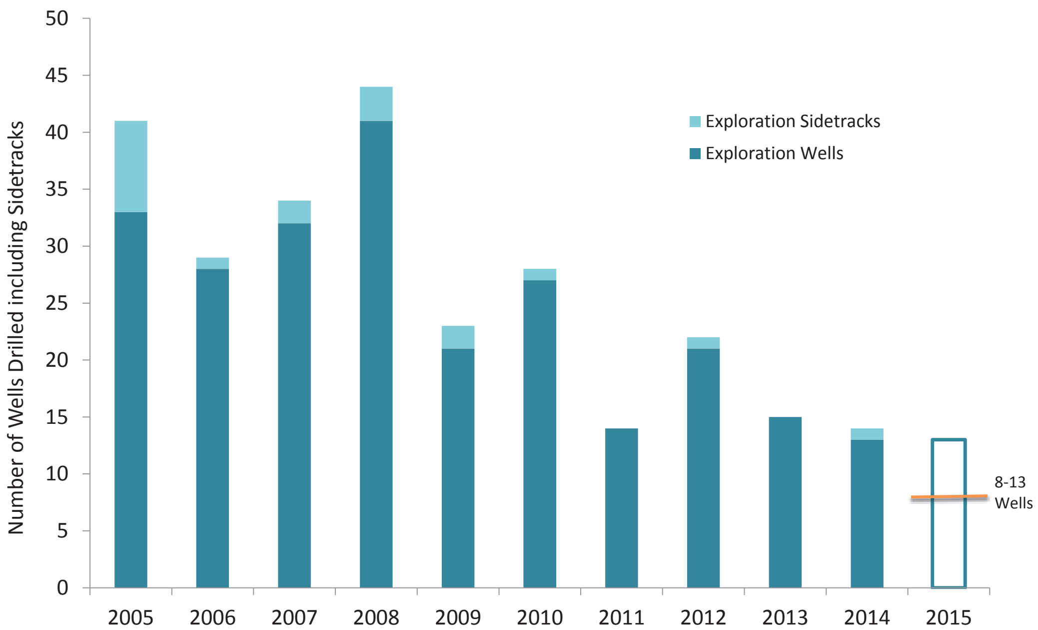
6.2 Drilling Activity

Exploration Drilling

Over recent years exploration activity on the UKCS has collapsed. This trend continued in 2014 with just 14 exploration wells[4] drilled, reflecting the lowest rate of exploration drilling since 1965. Given uncertainty of capital and affordable rig availability, the indications are that the situation is unlikely to improve in 2015 with only eight to 13 exploration wells anticipated.

This trend is of fundamental concern to all stakeholders and raises questions about the UKCS' sustainability. It will require concerted effort by all parties to both understand the drivers that have depressed exploration activity and assess the factors that can most effectively lead to an improvement in the outlook.

Figure 11: Exploration Well Count and Forecast



Source: Oil & Gas UK, DECC

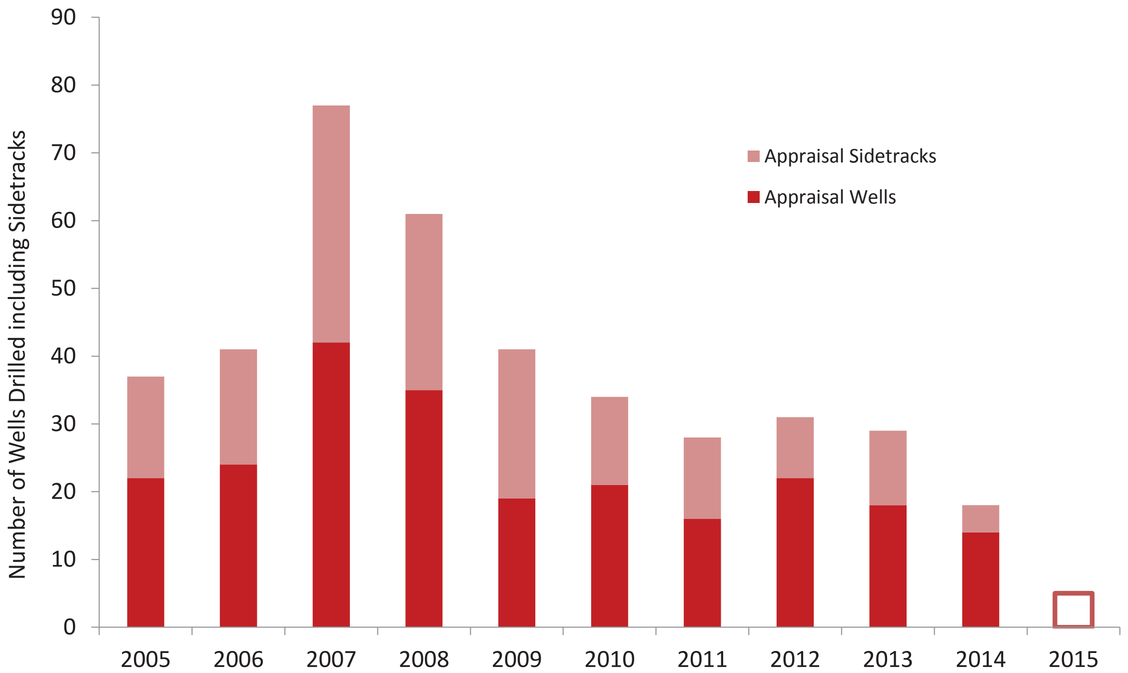
[4] Throughout the report well numbers include geological sidetracks unless stated otherwise. Drilling numbers are counted by spud date unless stated otherwise.

Appraisal Drilling

An average of over 50 appraisal wells per year were drilled on the UKCS from 2005 to 2008, driven by a steady growth in exploration activity over the preceding decade. Appraisal activity fell thereafter to an average of around 30 wells per annum between 2009 and 2013, before falling sharply in 2014 with just 18 appraisal wells drilled. Many of these recent wells were targeting old discoveries made in previous decades.

At this point, the outlook for 2015 is bleak with just five appraisal wells forecast for the year. It appears that this trend is driven by the relatively poor rate of exploration over the last four years, leading to fewer discoveries and hence fewer appraisal opportunities. It is also the case that small discoveries, typical of those seen in recent years, are less able to bear the costs of an appraisal well, further suppressing activity. Appraisal drilling will only pick up when it becomes a more attractive option both as well costs fall and the post-tax value of the discovery is improved. However, without appraisal, many discoveries will fail to meet investment screening criteria and will not progress to development.

Figure 12: Appraisal Well Count and Forecast

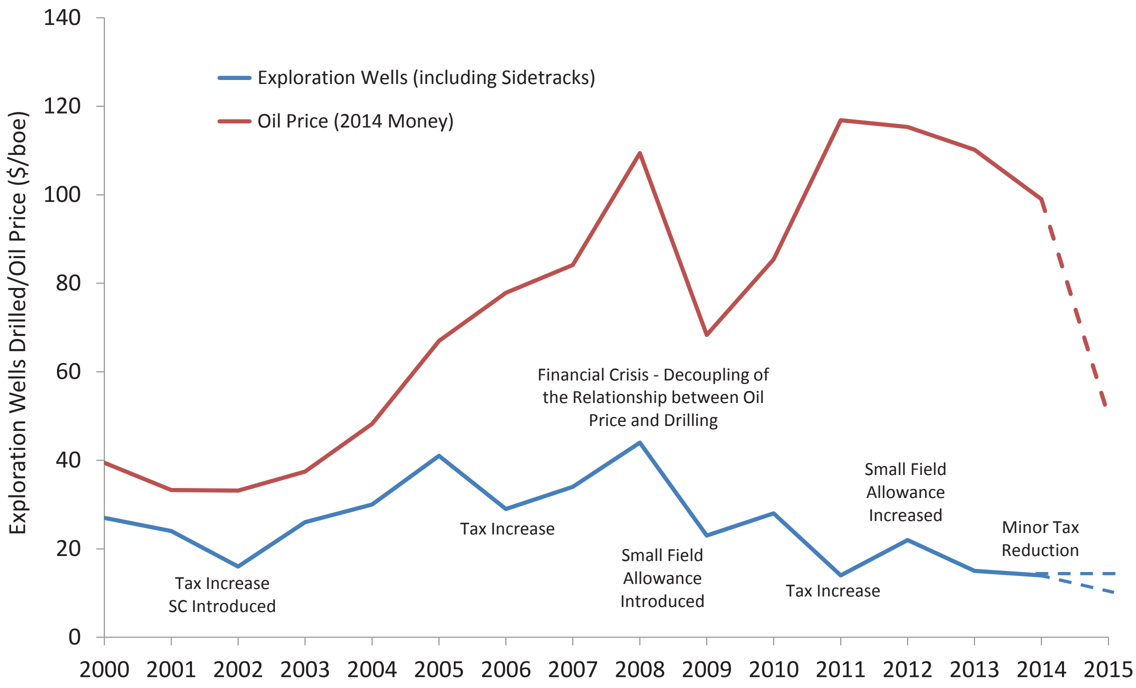


Source: Oil & Gas UK, DECC

Constraints in Exploration and Appraisal Activity

A rising oil price is conventionally seen as a strong driver of exploration activity and this had been the case until 2009 when there was a notable disconnect between the two. The aftermath of the financial crisis restricted access to capital, leaving many companies unable to finance exploration wells even in a time of high oil price. Whilst there was a short-lived recovery in 2010, the unexpected tax increase in 2011 (a 12 per cent rise in the supplementary charge (SC)) halted that recovery. This, combined with the difficulty in attracting finance, has led to exploration on the UKCS falling to an all-time low.

Figure 13: Exploration Drilling versus Oil Price



Source: Oil & Gas UK, DECC, EIA

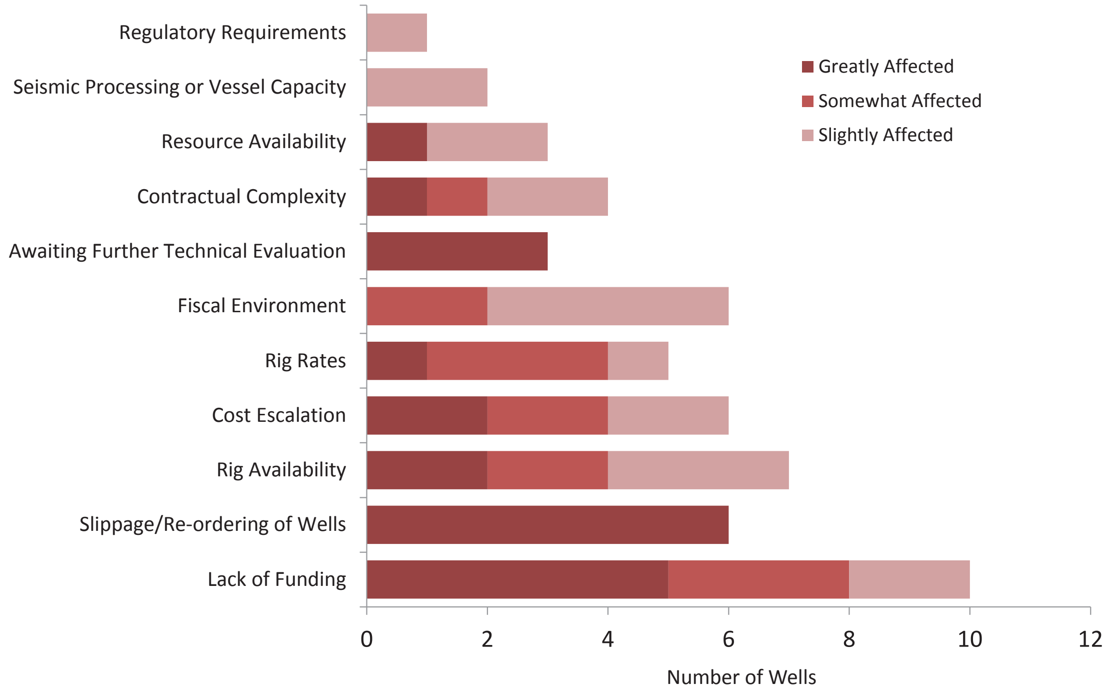
On a positive note, there is no indication that the collapse in exploration activity is driven by a lack of prospectivity. However, it is clear that post-tax returns on exploration drilling in the UK are just not competitive. Even at an oil price of over $100/bbl, the UKCS has struggled to attract funds. Drastic action is required to address this challenge. The Wood Review suggested a range of non-fiscal measures to encourage exploration, including improved access to seismic data and a more flexible licensing regime, but it concluded that fiscal changes are also required to enhance the post-tax value of exploration drilling and to attract new sources of finance. Without such measures, it is very unlikely that even the lower range of yet-to-find (YTF) estimates, of around two to three billion boe reported by DECC[5], are likely to be discovered.

Over the last year, companies postponed 17 wells and cancelled a further four that were initially scheduled to be drilled from 2014 to 2016. Operational factors such as access to rigs, the cost of drilling wells and competition for resources are seen to be significant constraints on E&A activity in recent years. Operators have indicated that the situation will not improve unless these operational problems are addressed. Furthermore, as the survey shows, falling oil price, inability to access finance and the fiscal environment are also seen as significant barriers to activity.

[5] See www.gov.uk/oil-and-gas-uk-field-data#uk-oil-and-gas-reserves-and-resources

It also appears that operators prioritised the drilling of development wells rather than E&A activity last year, reflecting the drive to monetise opportunities at a time of high oil prices. As oil prices fall, E&A becomes even less attractive for many companies as there is less free cash, further exacerbating the problem.

Figure 14: Constraints on Exploration and Appraisal Drilling in 2014



Source: Oil & Gas UK

Exploration and Appraisal Activity by Company and Region

The survey has examined companies that have chosen to operate E&A wells on the UKCS in recent years, considering them in four categories: majors, large companies, small/medium companies and utilities.

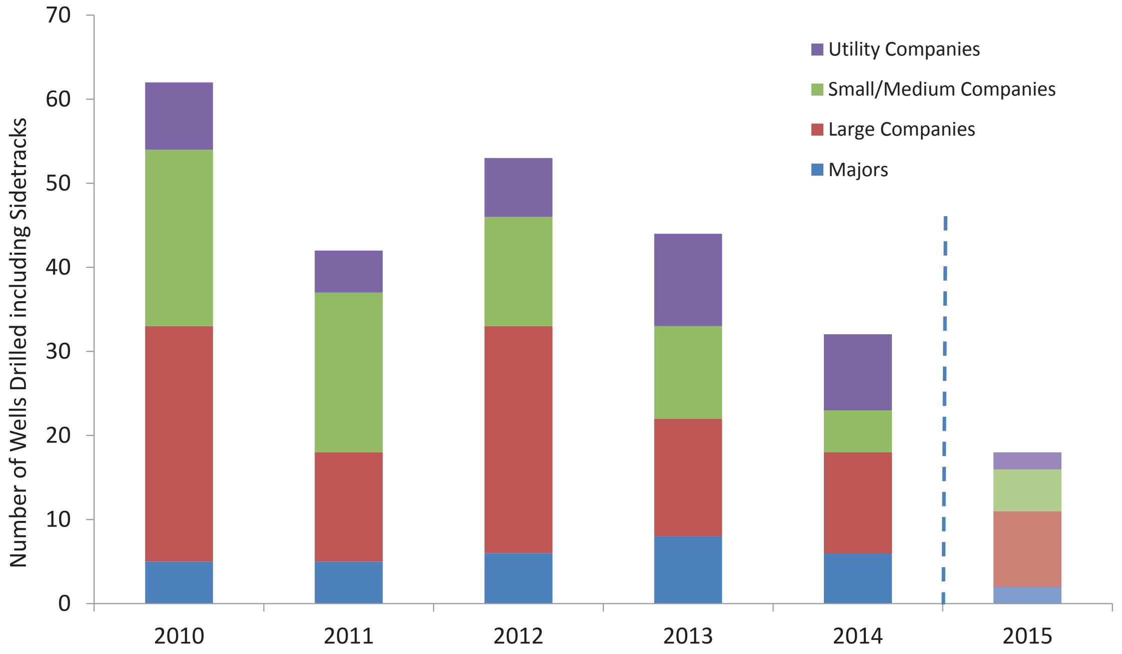
Of the 32 E&A wells drilled during 2014, 12 were drilled by large companies, nine by utility companies, six by the majors and five by small to medium sized companies. Whilst this suggests that the whole of the exploration community is engaged in E&A activity on the UKCS, it masks some important trends.

Taking a broader perspective, drilling activity by smaller companies has declined over the last five years and a greater proportion of wells have been drilled by larger companies. In part, this is due to smaller companies struggling to raise capital, as access to finance has become more constrained following the financial crisis in 2009, and due to general perceptions of the UKCS' competitiveness. Meanwhile, larger companies that have been less capitally constrained (until now at least) have chosen to target some of the more technically challenging opportunities on the UKCS, such as deepwater, heavy oil and ultra-HPHT targets that are beyond the commercial reach of smaller investors.

Smaller companies often seek to take a commercial interest in wells drilled by other, often larger, companies rather than drilling the well themselves as the main operator on a licence. However, difficulty in accessing finance by such companies is also proving to be a barrier to this business model, delaying the commercial consortium and slowing down well drilling.

Although the number of E&A wells drilled by the majors has remained relatively stable over the period 2010 to 2014, the proportion of exploration wells drilled by majors has declined and it is anticipated that such companies will only drill two exploration wells in 2015.

Figure 15: Exploration and Appraisal Drilling by Company Size

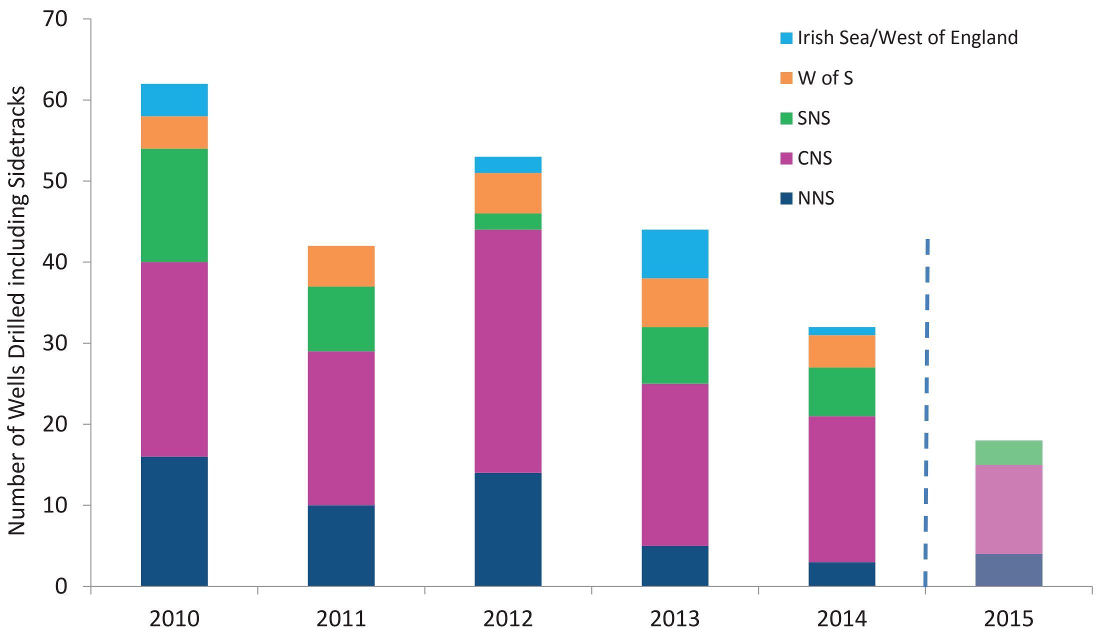


Source: Oil & Gas UK, DECC

Following recent trends, the CNS was again the most active region for E&A activity in 2014, where over half of the E&A wells were drilled. This confirms the prevailing view that the CNS area is one of the most prospective regions of the UKCS. The SNS remained the second most active region with six wells drilled as companies targeted near-field opportunities; whereas activity in the IS region decreased to only one well in 2014, after a high point of six wells in 2013. There are no E&A wells planned in the IS region for 2015.

Although four appraisal wells were drilled in the W of S region in 2014, there was no capital to fund exploration activity in the area. Despite estimates that there could be in excess of two billion boe of YTF resources in the W of S region, the high costs associated with drilling in the area and recent lower success rates may be contributing to a decline in activity.

Figure 16: Exploration and Appraisal Drilling by Region



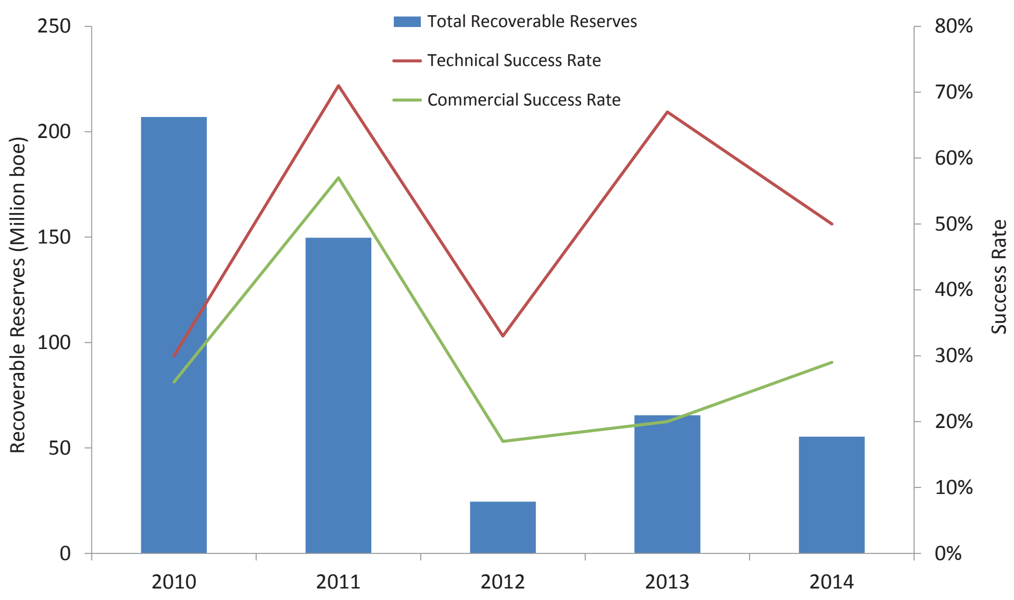
Source: Oil & Gas UK, DECC

Discoveries from Exploration and Appraisal Activity

Survey results from operators suggest that only 55 million boe of technically recoverable reserves were discovered in 2014, with seven of the 14 exploration wells drilled encountering hydrocarbons. Although a 50 per cent technical success rate[6] is in line with the average of the last five years, three of these wells discovered just five million boe in total, materially smaller accumulations than were originally targeted. The other four wells found 50 million boe in total. These could be considered commercially viable opportunities and ultimately lead to development under the right circumstances, giving a commercial success rate[7] of just under 30 per cent, slightly below the average of the last five years.

It should be noted, though, that these numbers are subject to further revision as opportunities are appraised. However, by any measure, 2014 is unlikely to be a remarkable year for hydrocarbon discoveries. It appears that less than 150 million boe in total have been discovered over the last three years, the lowest in the history of the UKCS.

Figure 17: Recoverable Reserves and Associated Success Rates

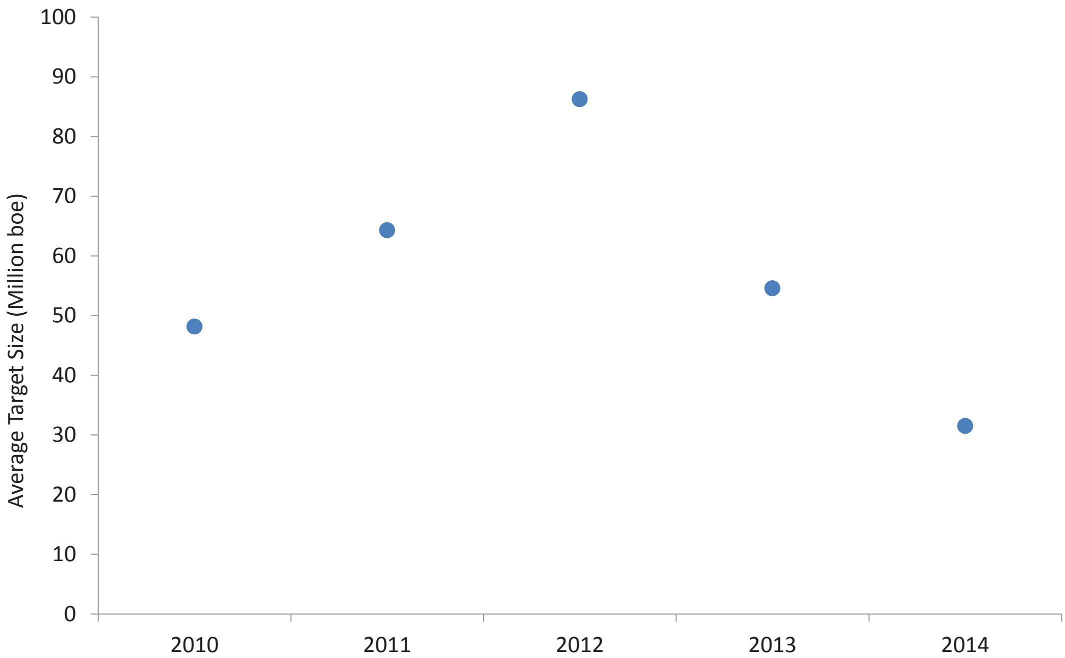


Source: Oil & Gas UK, Wood Mackenzie

[6] Technical success – encountering hydrocarbons that may or may not attract commercial development.
[7] Commercial success – encountering hydrocarbons that stand a reasonable chance of development.

The size of the average exploration target[8] in 2014 was just over 30 million boe, the lowest seen over the last five years. Whilst a small number of wells targeted accumulations of over 50 million boe, with one of 100 million boe, the majority of exploration wells drilled targeted accumulations of less than 20 million boe. This suggests that exploration in 2014 was focused around near-field opportunities using existing infrastructure for their development.

Figure 18: Average Size of Reserves Targeted



Source: Oil & Gas UK

Since the last UKCS discovery of more than 100 million boe (Culzean in 2008), there have been relatively few wells drilled targeting true wildcat opportunities expected to be greater than 100 million boe. Of those that have been drilled, most have been dry wells. Even in wells that did encounter oil and gas, the volumes discovered have been materially smaller than anticipated, with little prospect of being commercially developed.

It is an inevitable conclusion that the current rate of exploration will not deliver the potential resources from the UKCS. Even now, exploration is constrained by the imminent decommissioning of critical infrastructure that will permanently damage the ability to recover the UK's remaining oil and gas resources.

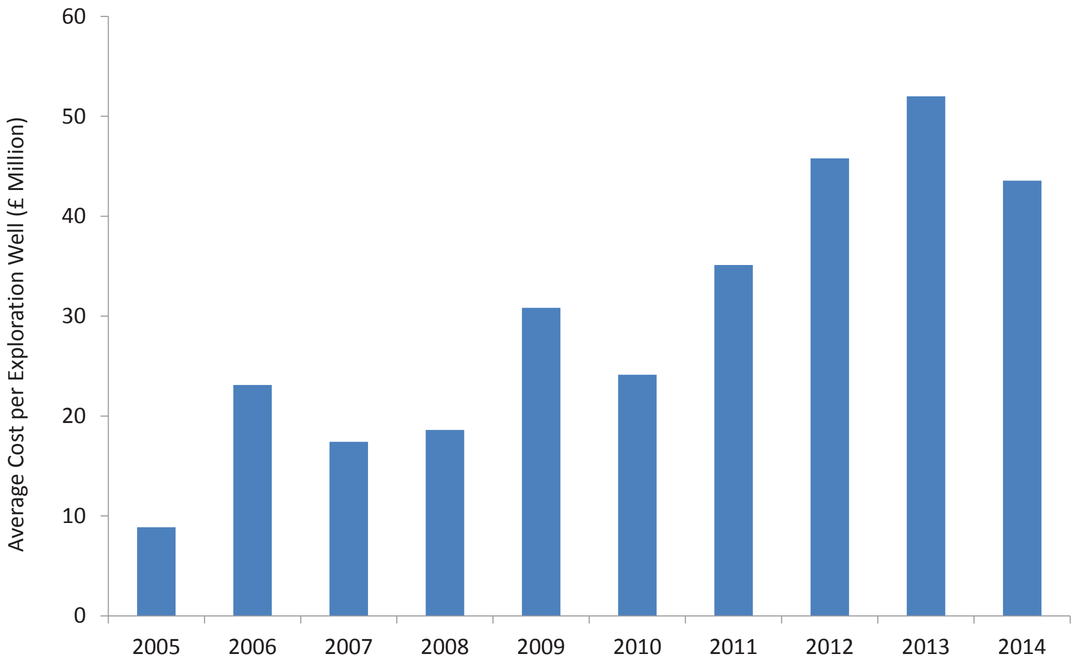
[8] Exploration target taken as the mean success volume (million boe).

Exploration and Appraisal Drilling Expenditure

Just over £1.1 billion was spent on E&A and seismic activity in 2014, compared with £1.6 billion in 2013. Expenditure on exploration drilling decreased from £780 million in 2013 to £610 million in 2014, while expenditure on appraisal drilling declined from £630 million to £440 million. Operators' expenditure on acquiring seismic data decreased to £95 million in 2014 from £150 million in 2013. Just over £40 million of this was spent on new seismic acquisitions, while £55 million was spent on seismic purchase and reprocessing. Operators forecast that they will spend £130 million on seismic acquisition and interpretation in 2015, around £50 million of which is planned to be spent on new broadband seismic acquisitions.

In 2014, the average cost per exploration well was just under £44 million. Although this is lower than the peak average cost of £52 million in 2013, exploration drilling costs have risen sharply in recent years from an average of £23 million per well from 2007 to 2010 to an average of £44 million from 2011 to 2014. The high cost per well in 2013 was due to the number of technically challenging HPHT wells in the CNS region, which are more complex and therefore expensive to drill.

Figure 19: Average Cost per Exploration Well Drilled



Source: Oil & Gas UK, DECC

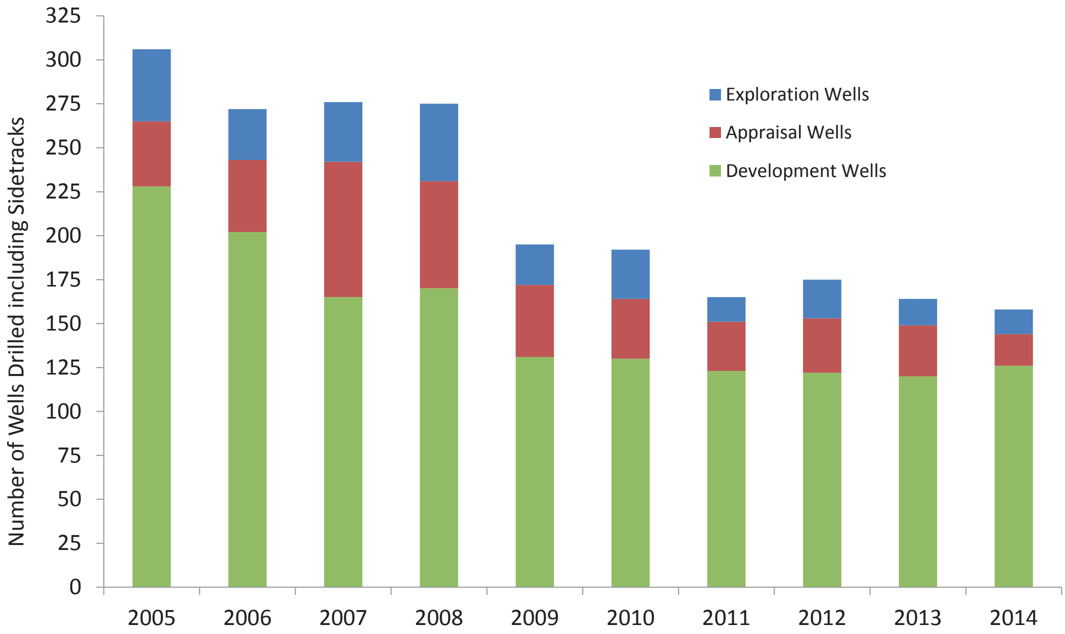
Although the average cost per well drilled has risen over the past three years, the cost of finding commercially recoverable reserves on the UKCS has increased far more significantly. The yearly average cost of finding commercial recoverable reserves has risen from £4/boe from 2009 to 2011 to £22/boe from 2012 to 2014. The finding cost is a very volatile metric and can be skewed by one big discovery within one year. The rise over the last three years has been caused more by a fundamental lack of exploration success rather than excessive growth in exploration spend.

Development Drilling

In 2014, a total of 126 development wells were drilled on the UKCS. Whilst this shows a slight increase of six wells on the total for 2013 (120 wells), development drilling has been on a long-term downward trend over the last decade and is now less than half of what it was at its peak of 298 wells in 1998. This trend mirrors the decline in production over recent years. As the oil price has fallen over the last six months and the pace of investment falters, the concern is that development drilling may decline further and continue to drive down production on the UKCS.

Looking at the total number of wells (exploration, appraisal and development) drilled over the last four years, there appears to have been a ceiling on activity of around 175 wells per annum. It is apparent that rig capacity now exceeds the demand for drilling on the UKCS in the current business environment, and whilst rig rates are adjusting to the fall in demand, there is a concern that drilling rigs will either be stacked or leave the UKCS, permanently destroying domestic drilling capability.

Figure 20: Drilling Activity by Well Type

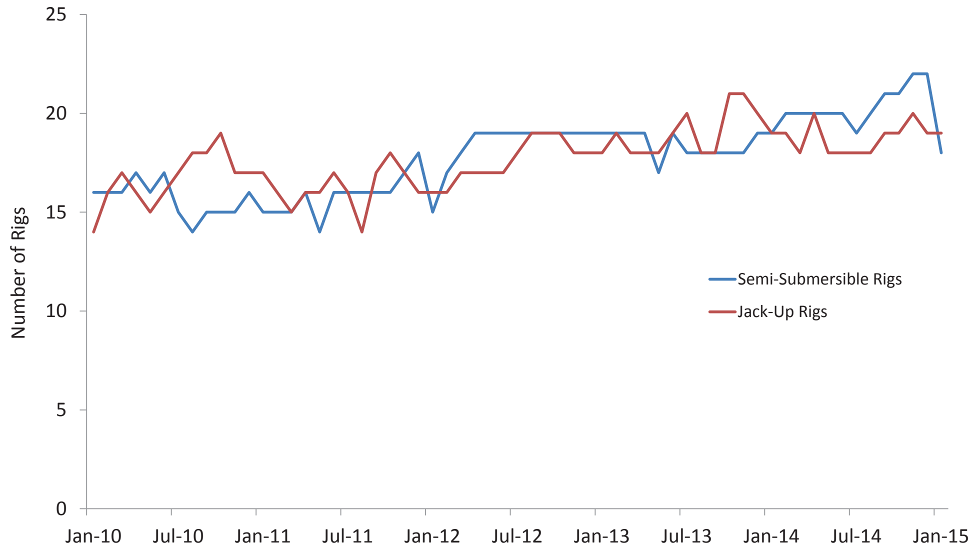


Source: DECC

Mobile Drilling Rig Market

The number of semi-submersible drilling rigs deployed in the UK fell to 18 rigs in January 2015. While the number of jack-up drilling rigs remained relatively stable over 2014 (19 jack-ups on average over the year), a fall is anticipated this year in response to reduced demand.

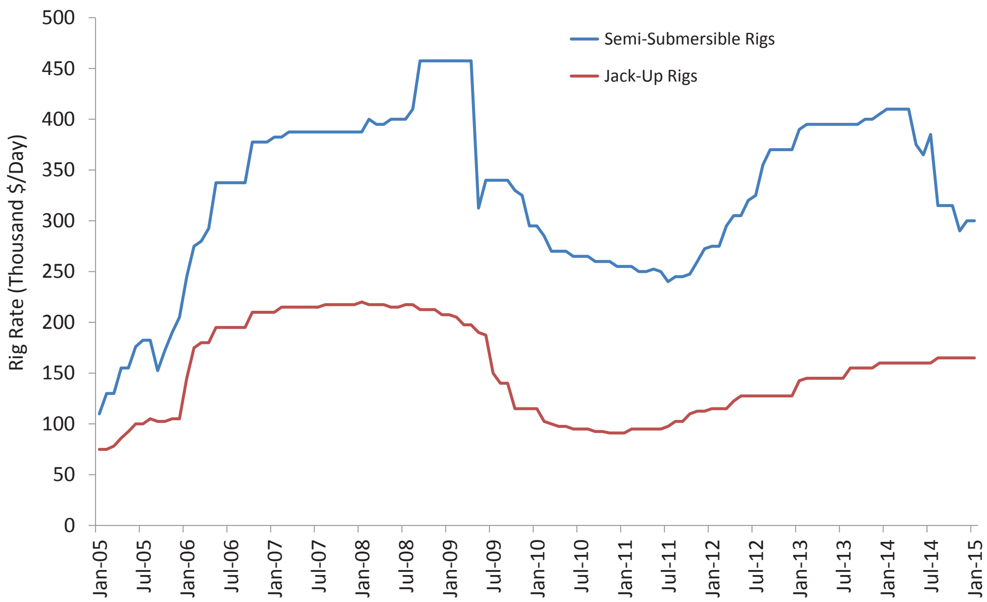
Figure 21: Number of Rigs on the UK Continental Shelf



Source: North Sea Reporter

In response to market pressure, the daily rig rate for semi-submersibles started to decline in 2014, indicating a change in the market following three years of increasing daily rates. Whilst the daily rates for jack-up rigs appeared to increase in 2014, it is expected that the demand for jack-up rigs will reduce, driving down day rates this year.

Figure 22: Daily Rig Rates Based on Reported Contract Awards for Mobile Units



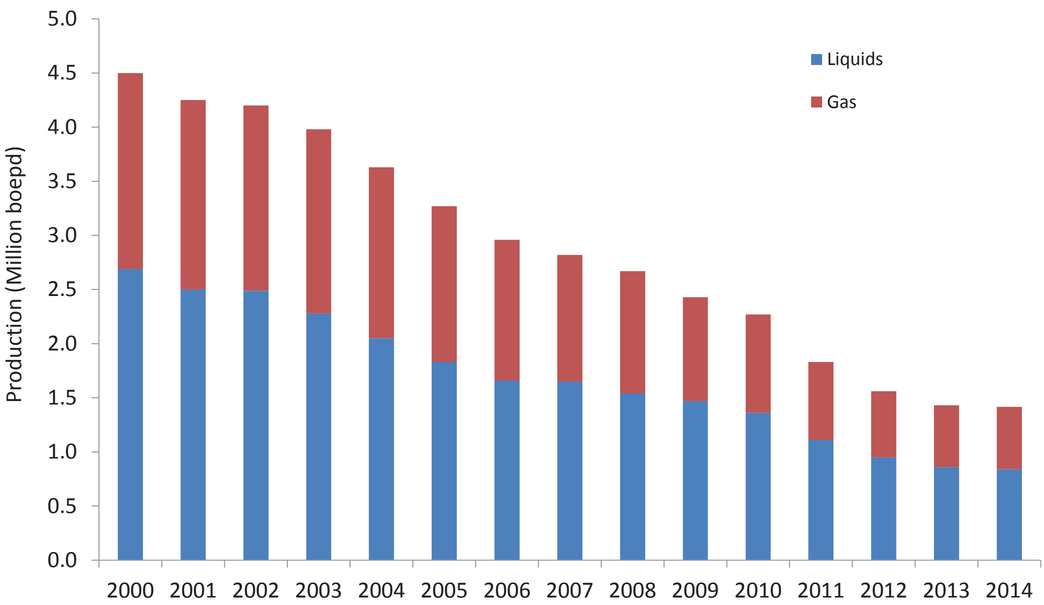
Source: North Sea Reporter

6.3 Production

The UKCS produced 1.42 million boepd (519 million boe) in 2014, representing just a 1.1 per cent year-on-year fall. This is the smallest decline since UK production peaked in 2000, giving the strongest indication to date that the problems leading to previous poor performance are finally being overcome. Investment in new production and improved output from existing facilities have been the key drivers.

Liquids production (oil/natural gas liquids) was down about 2.6 per cent on last year to 0.84 million boepd, but net gas production (less that used by producers offshore) was up 1.1 per cent to 34.7 bcm, which partially offset the overall decline.

Figure 23: Liquids and Gas Production

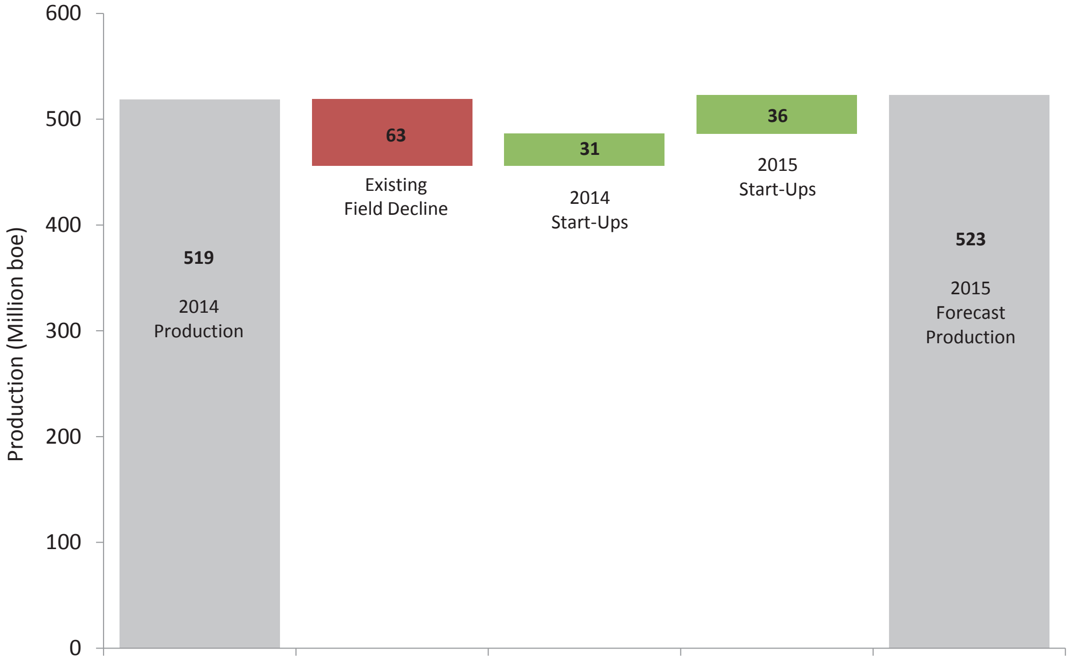


Source: Oil & Gas UK

Production Outlook

Looking ahead to 2015, Oil & Gas UK anticipates that the 1.1 per cent production decline seen this year is likely to be almost entirely recovered and the UKCS should see its first annual production increase in 15 years to around 1.43 million boepd (523 million boe).

Figure 24: Forecast Production from 2014 to 2015

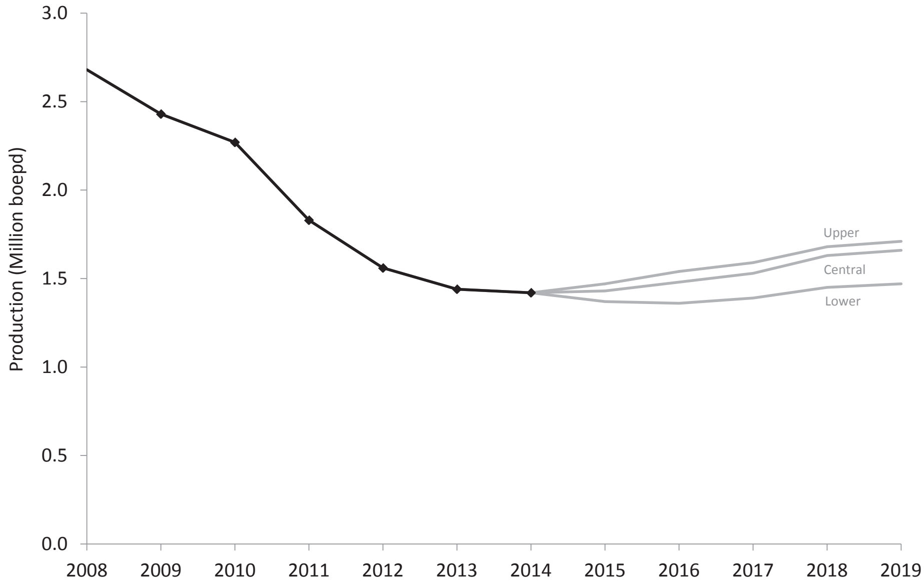


Source: Oil & Gas UK

There are two major components to this forecast – production from existing assets and production from new field start-ups. Output from fields that were already in production prior to 2014, the large majority of fields that represent 'the base', is expected to decline by around 12 per cent. This is a slight increase in the decline rate from last year as many fields advance through the later stages of production and anticipates a drop-off in brownfield investment as competition for limited investment funds intensifies.

That loss of production will be offset by around 67 million boe from new fields, split equally between those that commenced production in 2014 and those expected to start in 2015. Whilst there is reasonable confidence in the output from 2014 start-ups, there is greater uncertainty around a further 15 fields scheduled to come onstream this year. If first production on these new start-ups is delayed, then the central forecast may not be realised. Our low case forecast for 2015, which accommodates significant project slippage for new start-ups, is 1.37 million boepd.

Figure 25: Production Forecast for the UK Continental Shelf

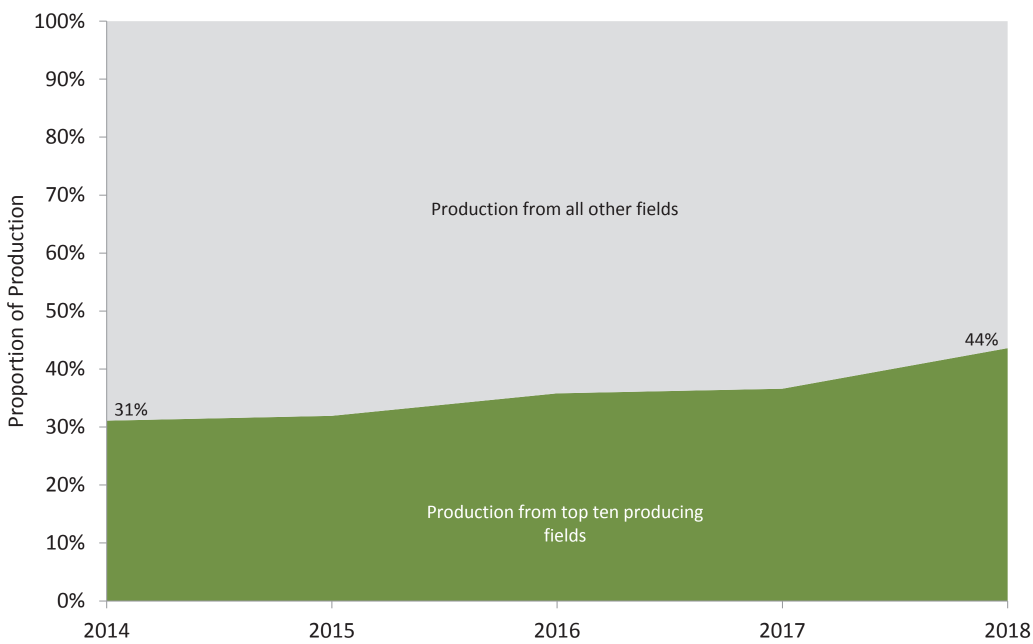


Source: Oil & Gas UK

As we look further into the future, the UKCS' production performance becomes even more uncertain. There are still a number of significant ongoing developments yet to produce first oil or gas that will offer a significant boost to production towards the end of the decade. As a result, even our most cautious production estimate still shows an upturn by 2017.

The top ten producing fields currently account for just under one third of total production. In just four years' time, the top ten fields are expected to make up around 44 per cent of production as the likes of Clair Ridge, Schiehallion, Mariner, the Greater Catcher Area and Laggan Tormore, none of which are currently onstream, become major contributors.

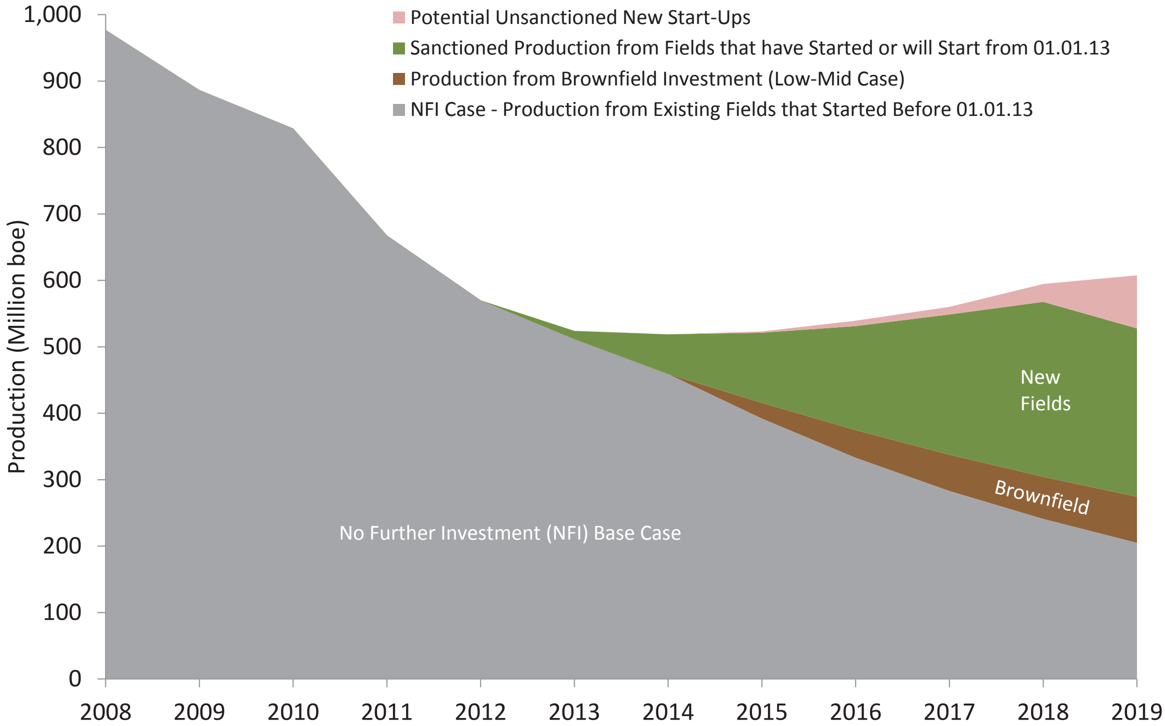
Figure 26: Forecast Proportion of Production from Top Ten Producing Fields



Source: Oil & Gas UK

As illustrated in Figure 27, by 2019, more than half of UKCS production is likely to come from fields that started production since the end of 2012, some of which commenced investment before 2011.

Figure 27: Production Forecast by Category



Source: Oil & Gas UK

However, the industry challenge to slow the decline rate of base production becomes much harder at a lower oil price given the lack of free cash, international competition for investment funds and the maturity of the basin. As a consequence, the primary focus turns to the management of operating costs rather than the drive to invest. It is inevitable that some fields in the UK will be decommissioned over the remainder of this decade as their reservoirs are depleted, but if the high cost base under which this industry currently operates can be addressed, the life of many fields can still be extended through brownfield investment.

With no further investment, the existing fields on the UKCS are likely to decline at around 15 per cent per annum. If sufficient brownfield investment is secured to reduce the decline rate to 10 per cent, an additional 250 million boe would be delivered over the next five years. Whilst a reduction in the operating costs of the assets are essential and must be delivered, a reduction in the headline rate of tax rate would be the most effective way of attracting brownfield capital as post-tax investment returns are enhanced.

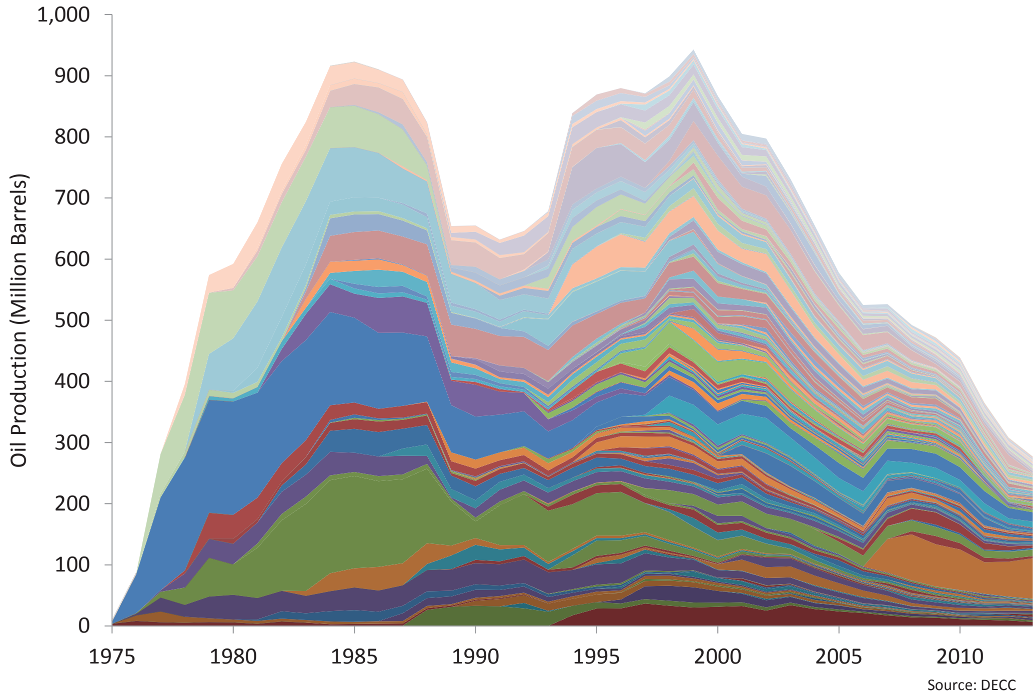
Industry is actively tackling the issue of cost (see the section on Operating Expenditure) but the government also has a crucial role to play in ensuring that the fiscal regime encourages brownfield investment in some of the older assets on the UKCS. Unless industry and government collaborate to make the UK an attractive place to invest, at a time when capital is extremely scarce, many fields will face premature decommissioning and technically recoverable oil and gas will be deemed uncommercial and will be left in the ground.

A well-resourced regulator with a sharp focus on maximising economic recovery, a sustainable cost base and a predictable and competitive fiscal regime all need to be in place to exert control over the UK's base production decline, as shown in Figure 27. If even one of these three is not in place, the UKCS will face further erosion in production, similar to that experienced in 2011.

The complexity of the UKCS has grown dramatically over the last 50 years. Figure 28, showing oil production by field, illustrates that dynamic. In the UKCS' early years, production was dominated by a small number of large fields. Now, in 2015, production is made up of hundreds of fields, typically much smaller in size. There is far greater inter-dependency between these fields and there is a need to consider joint developments or subsea tieback solutions as smaller fields often mean standalone development is not commercially attractive.

This does make UKCS production vulnerable to a 'knock-on effect' if important pieces of infrastructure are shut-in, particularly if that shut-in is unplanned. The Production Efficiency Task Force, set up as part of the government-industry forum PILOT, is working to ensure that operators co-ordinate planned shutdowns so that they are carried out as efficiently as possible.

Figure 28: Production by Oil Field since 1975



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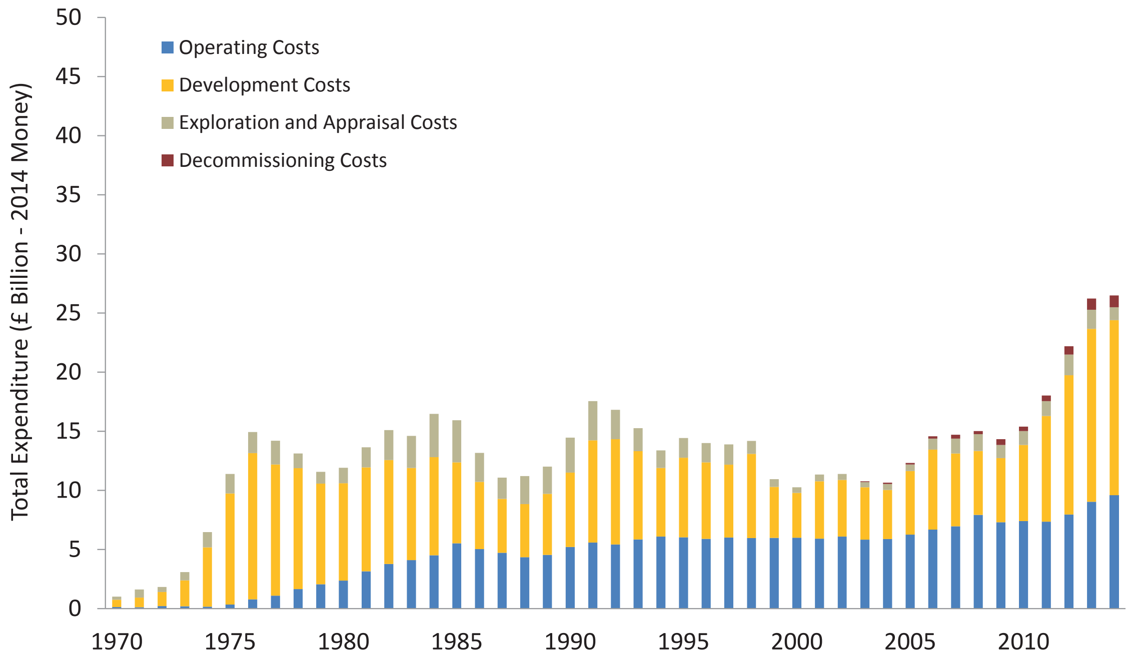
6.4 Total Expenditure

Total expenditure on the UKCS reached £26.5 billion in 2014, the highest on record for the fourth successive year. The biggest component was £14.8 billion of capital investment in developing greenfield and brownfield projects. The cost associated with operating the basin was £9.6 billion, almost an eight per cent increase on 2013 (£8.9 billion). Spend on E&A activity, including seismic data acquisition and interpretation, was £1.1 billion and decommissioning activity reached £1 billion for the first time. Further growth in decommissioning expenditure is anticipated in the years ahead. In addition to the £26.5 billion of total expenditure, around £3.2 billion was paid in corporate production taxes in 2014[9].

Figure 29: Total Expenditure on the UK Continental Shelf



Source: Oil & Gas UK, DECC

The decline in oil price over the last quarter of 2014 meant production revenues for the year were £24.4 billion, their lowest since 1998 when the average oil price for the year was just $18.20/bbl in 2014 money. Given that total expenditure plus production taxes was £29.7 billion, the industry generated a negative cash flow for the second consecutive year in 2014. This time the deficit was far greater at -£5.3 billion compared to -£0.4 billion in 2013. The last time industry experienced such a negative cash flow was 40 years ago when many of the UKCS' flagship assets were being developed.

It is anticipated that the cash flow picture for 2015 will look far worse. Although total expenditure is expected to fall for the first time since the recession in the late 2000s, revenues are also likely to fall to little more than £17 billion[10]. The recent heavy development cycle almost certainly peaked in 2014 and it is anticipated that capital investment will fall by at least £3.5 billion in 2015. There is already evidence that the cost of operating on the UKCS is falling as cost reduction initiatives are being implemented quickly. Additionally, much of the E&A spend is under

[9] Calendar-year figure based on weighted average of £4.7 billion for 2013/14 and £2.8 billion for 2014/15, according to the *Autumn Statement 2014.*

[10] Based on Oil & Gas UK's central production forecast, a UKCS output price of $50/boe and a US Dollar/Great British Pound exchange rate of 1.5.

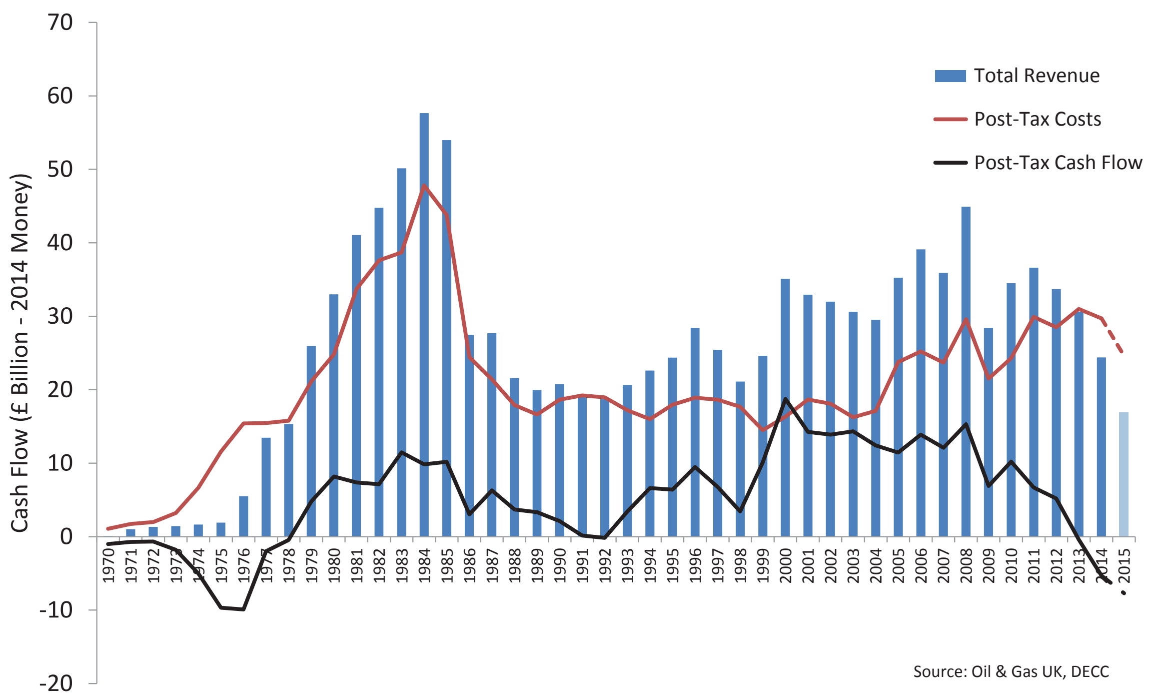
threat as companies re-assess their discretionary investment budget amid the falling oil price. However, even if expenditure falls by as much as £5 billion in 2015, it is unlikely to match the rate at which revenues are falling, as shown by Figure 30 below.

It must be acknowledged that much of the money currently spent on the UKCS is capital investment in developments that will yield revenues in the future. Such investment today is crucial as it will secure future production for the next 20 years and beyond.

When the UKCS was initially developed, funds for investment were typically generated from shareholders as there was no productive base to generate revenues. As the UKCS grew, funds were raised through production revenues and re-invested in the basin. The current dynamic of a negative cash flow places great pressure on shareholders and is likely to restrict the near-term rate of investment in new projects.

The cost base under which the industry operates must reduce further, E&A spend must be more efficient, and decommissioning activity must be delayed through brownfield investment. These actions will serve to improve the present cash flow picture, not just for next year, but for the rest of the UKCS' life.

Figure 30: Revenues and Cash Flows on the UK Continental Shelf

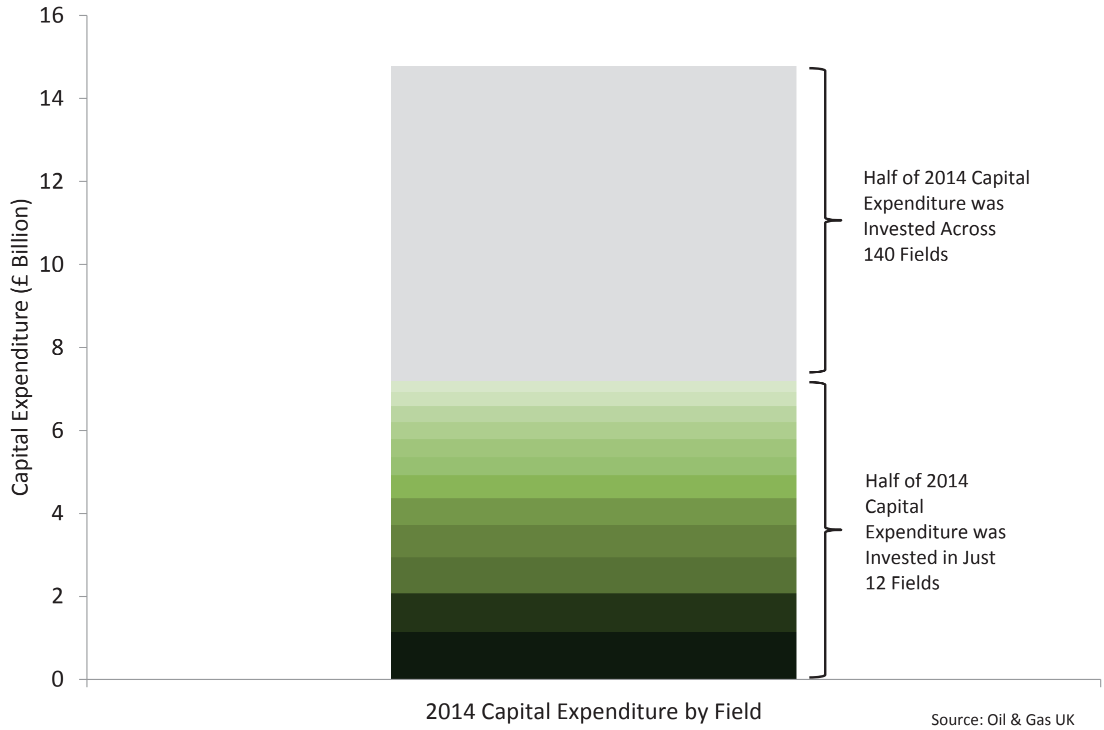


Source: Oil & Gas UK, DECC

6.5 Capital Investment

Capital investment in the UKCS reached £14.8 billion in 2014, surpassing the forecast for this year of £13 billion and the record breaking £14.4 billion spend of 2013. With little new activity sanctioned last year, this rise was primarily a result of cost over-runs and project slippage on ongoing new developments. This effect is clearly shown by the fact that around half of total capital investment last year was spent on just 12 fields, all of which were sanctioned prior to 2014.

Figure 31: Capital Investment by Field in 2014



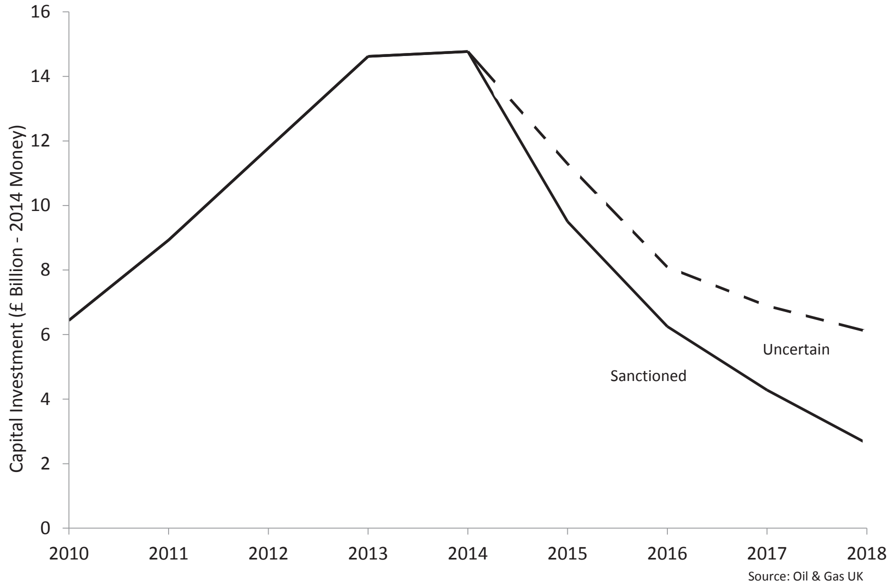
Source: Oil & Gas UK

Investment Outlook

The surge in investment seen from 2010 to 2014 was largely driven by the high oil price and bespoke field allowances. Over the next two years, sanctioned investment is set to halve as many of the high spend fields reach development completion and move into production, unless new investment can be encouraged.

Capital investment is expected to be no more than £11.3 billion in 2015 and is predicted to fall to less than £8 billion in 2016. Whilst investment over the next two to three years will be held up by the ongoing development of previously sanctioned projects, the current cost and price base facing the industry, alongside an outdated fiscal regime, could lead to capital investment falling to as low as £2.5 billion by 2018 if no new investment is sanctioned in the meantime. There must be swift action to secure new investment for the long term.

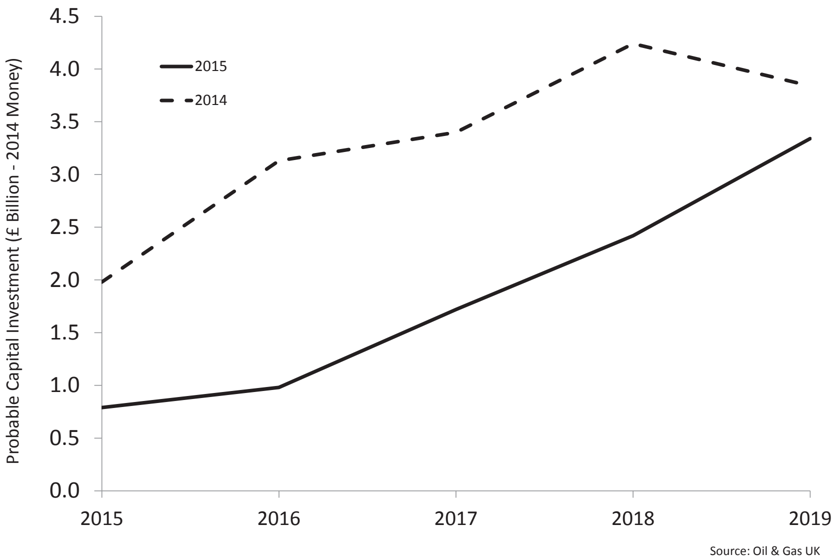
Figure 32: Capital Investment Outlook for the UK Continental Shelf



Quarter 4 2014 data indicate that only £38 billion in total is currently committed for spend on the UKCS and some of this may be at risk as the oil price continues to fall. In the right environment, a further £26 billion of probable investment could see the development of an additional two billion boe. Sustaining and growing this investment is vital to the long-term future of the UKCS, but without cost and tax reductions, future investment, particularly brownfield, is at significant risk as companies compete for capital globally.

A significant change in new investment intentions can already be seen as fresh projects have slipped in time and been reduced in scope. Figure 33 shows investment plans that are yet to receive sanction as of quarter 4 2014 versus the same time last year. A maximum of £3.5 billion of new expenditure will be sanctioned over the next three years, a noteworthy decline from the anticipated £8.5 billion over the same period last year. Looking further ahead, current poor exploration success could further damage longer term investment in the UKCS as few new development opportunities arise.

Figure 33: Comparison of Probable New Capital Investment Outlook



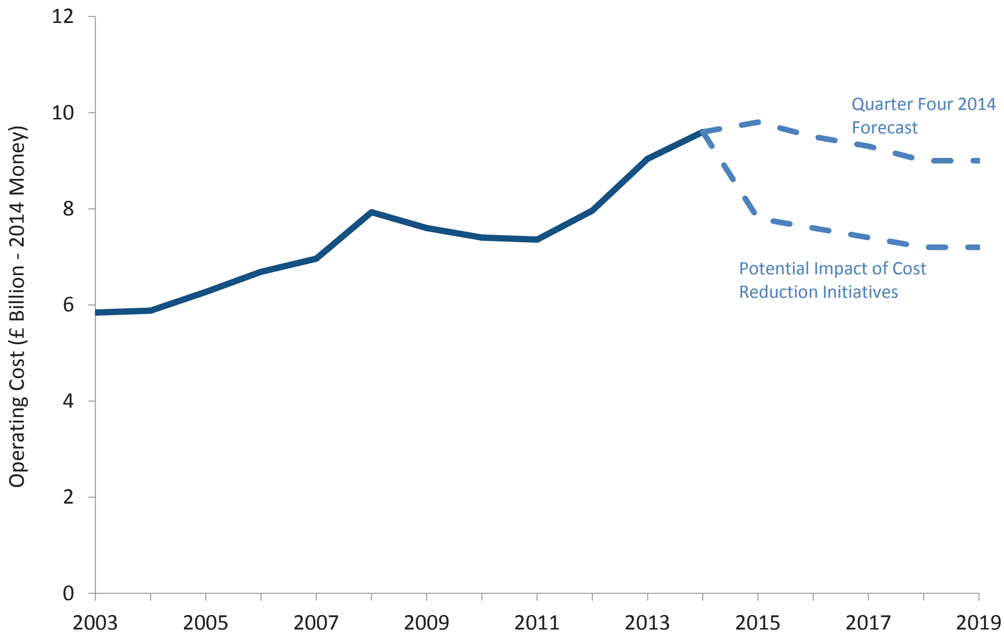
6.6 Operating Expenditure

The cost of operating the UKCS has again risen from £8.9 billion in 2013 to a record £9.6 billion in 2014. However, the rate of increase has slowed from 15.5 per cent in 2013 to almost eight per cent. Around half of the operating expenditure growth is attributable to new assets on the UKCS, whilst the other half has come as a result of cost increases on existing assets.

In real terms, operating costs had been largely contained until 2010 but have since escalated at an average rate of nine per cent per year. Alongside this, the rate of production decline accelerated, placing additional cost pressure on the UKCS. Cost control had already become a major theme of the industry even before the precipitous fall in oil price. The slowing of the cost growth rate in 2014 may reflect early signs that the ongoing cost reduction initiatives across the UKCS are starting to take effect.

As production revenues fall, companies will need to reduce further their operating expenditure in response to the new business outlook. Whilst plans from quarter 4 2014 still indicate there could be further short-term growth in operating expenditure, it is clear that significant work to reduce the UKCS cost base has accelerated in the early part of 2015. Operators are setting themselves demanding targets for cost reduction ranging from 20 to 40 per cent. If a cost reduction of 20 per cent were to be achieved, this would take costs back to a level last seen between 2008 and 2012.

Figure 34: The Cost of Operating the UK Continental Shelf



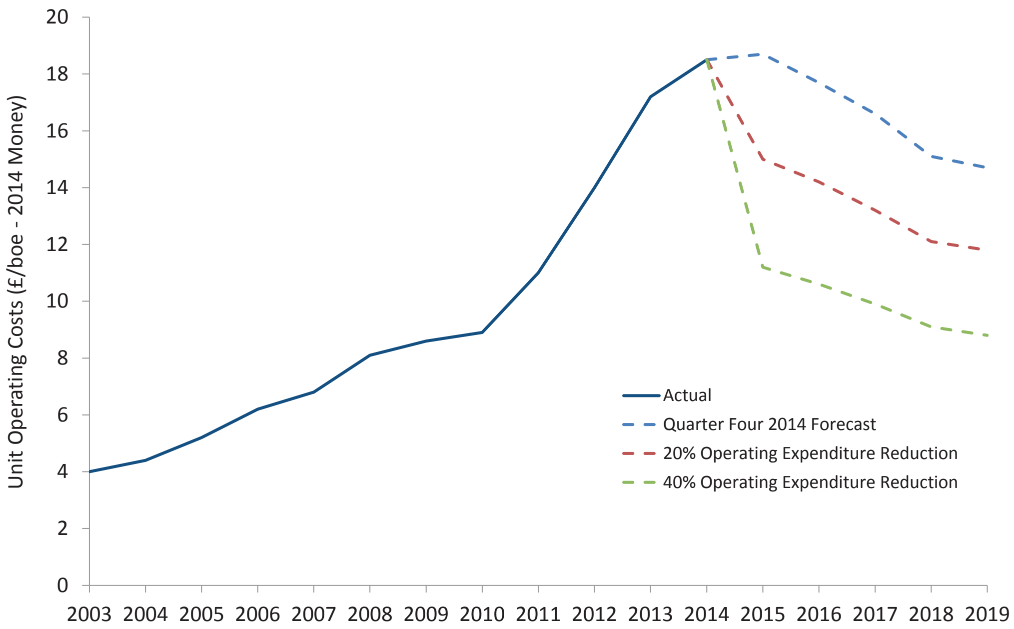
Source: Oil & Gas UK

Unit Operating Costs

As anticipated, the average UOC has risen again to £18.50/boe in 2014. It must decline towards the end of the decade if the UKCS is to have a long-term future. Caused by both a fall in production and growing costs, the average UOC on the UKCS increased in real terms by an average of 13 per cent per year from 2003 until 2011, a figure that accelerated to an average of 19 per cent from 2011 to 2014.

To maintain the sustainability and competitiveness of producing on the UKCS in the current oil price environment, there needs to be a 40 per cent reduction in UOC to offset the fall in production seen since 2011. Realising this will require a combination of both cost reduction and increased production efficiency from existing assets, combined with more investment in new production.

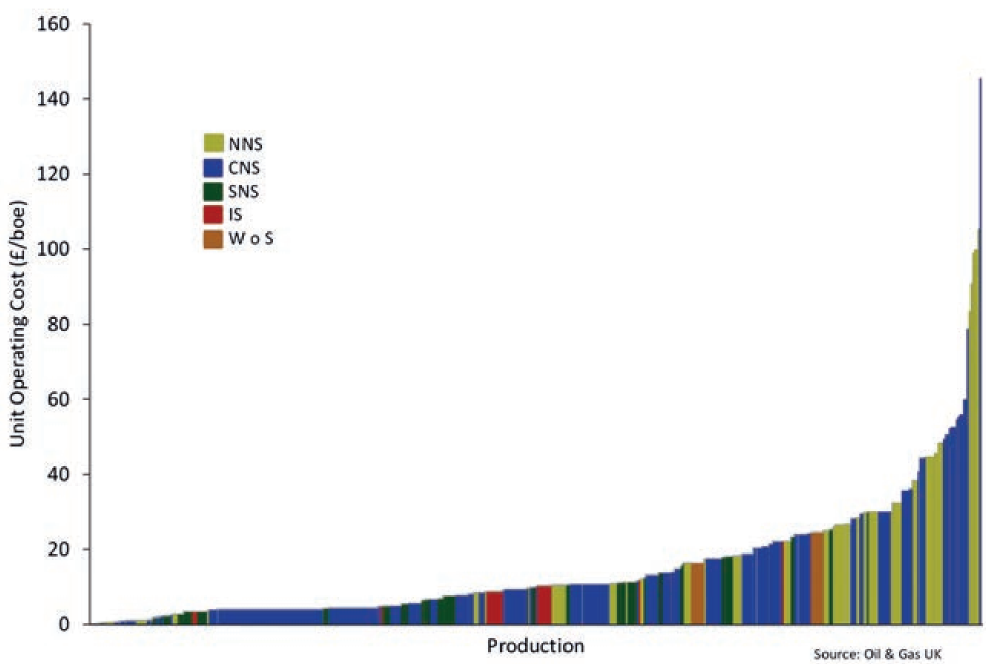
Figure 35: Average Unit Operating Costs



Source: Oil & Gas UK

Figure 36 shows the UOCs in 2014 for fields producing half a million barrels or greater, split by area (the bar width represents associated production). Of the 158 fields, 21 report a UOC greater than £30/boe. Some of the most expensive fields have little associated production, but are key hubs containing critical infrastructure and are therefore vital to the future of the basin.

Figure 36: Unit Operating Costs and Associated Production Volumes by Field and Area in 2014



Source: Oil & Gas UK

There is room for both efficiency improvements and cost reductions in all areas of the UKCS, but under all circumstances safety of operations will continue to be the first priority.

Many of the most expensive fields are located in the mature NNS region, where production peaked at 1.65 million boepd in 1985. Many assets in the region are large steel structures that carry significant fixed operating costs. The area now produces just one sixth of what it did at its peak, yet much of the cost remains, causing it to be the most expensive region to operate on a unit basis. Around one third of fields in the NNS had a UOC of greater than £30/boe in 2014 and the weighted average UOC for the area was £27/boe.

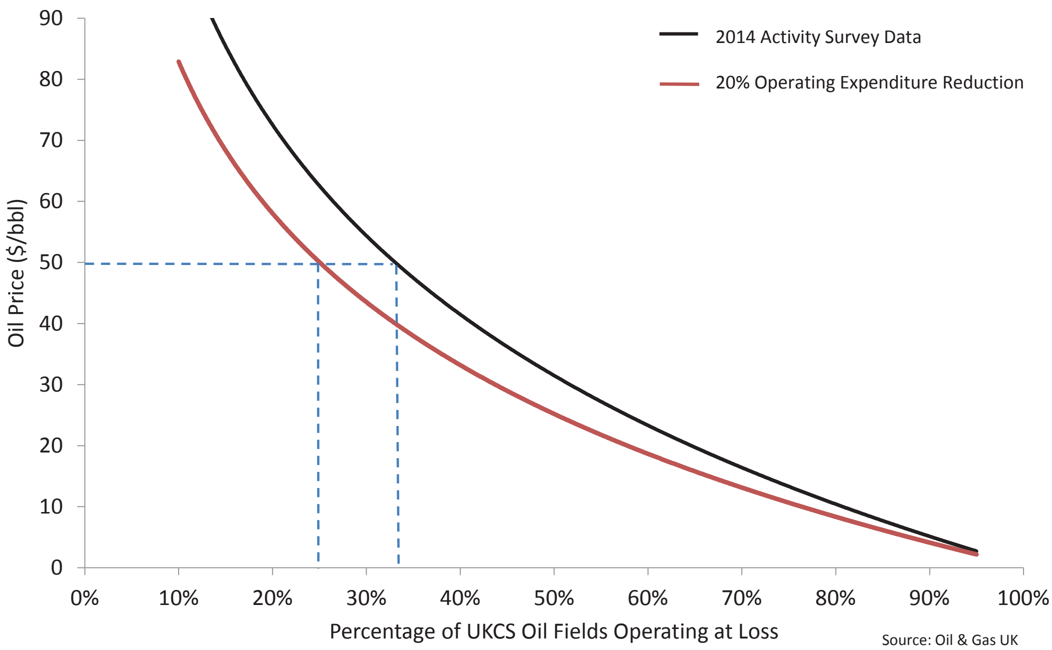
The second most expensive region to operate on the UKCS is the CNS, with a far lower weighted average UOC of £17/boe. Although the CNS has a number of very high cost fields, the biggest producing assets have much lower costs.

The SNS is the least expensive region of the UK to operate at £13/boe, and has seen relatively little cost growth over the last decade. This must, in part, be driven by the need to control costs to maintain profit margins as the gas producing region has not enjoyed the same high revenues as other areas of the UKCS that are rich in liquids.

Taking a baseline of 2014 costs and production, it was anticipated that at $50/bbl, 20 per cent of oil production and one third of oil fields were making a loss on a cash basis. Whilst this does not mean these fields are going to cease production immediately, operating at a loss is clearly not sustainable over the long term. If operating costs were reduced by 20 per cent across the board, the number of oil fields in a loss making position would reduce to around one quarter, 12 per cent of total production. This 20 per cent reduction is equivalent to a $10 increase in oil price. However, some fields require even greater action, and others have depleted their reserves to such an extent that decommissioning in the near term is inevitable.

Although some of the most expensive fields to operate on a unit basis now yield little production, the infrastructure is crucial to the wider operations of the UKCS. Work continues to ensure these hubs are not prematurely decommissioned, but it will take concerted effort by all involved to avoid this happening.

Figure 37: Potential Impact of Operating Expenditure Reductions at Various Oil Prices



Source: Oil & Gas UK

Cost Reduction

Whilst it is true that the falling oil price has placed additional attention on the costs of operating UKCS assets and developing new opportunities, the industry had already acknowledged cost as a major concern in the late spring of 2014 and subsequently began work on a number of pan-industry cost reduction initiatives. These recognised that significant cost benefit can be delivered by tackling the fundamental behaviours driving cost escalation on the UKCS.

The initiatives cross four thematic areas outlined below, prioritised by the size of potential impact. Alongside a revised fiscal regime and the swift implementation of the recommendations of the Wood Review, successful cost reduction initiatives will undoubtedly extend the productive life of the UKCS and deliver a more internationally competitive and sustainable basin.

The proposals for cost reduction initiatives are still being rolled out across the wider industry and will take time to gain traction.

Figure 38: Cost Reduction Initiatives

1. People	Benchmark Contractor Rates
	Offshore Partnership Agreement
	Optimise Offshore Rotas
2. Offshore Efficiency	Increase Wrench Time
	Share Best Practice
	Seek Efficiency Driving Technologies
3. Logistics Planning	Establish Rig Clubs
	Establish Support Vessel/Helicopter Clubs
	Sharing of Spares with Inventory Visibility
	Crew Sharing
4. Standardisation and Simplification	Stop Gold Plating
	Look Back Analysis/Reset of Cost Base
	New Entrant Low Cost Standard/Transformational Ideas Forum

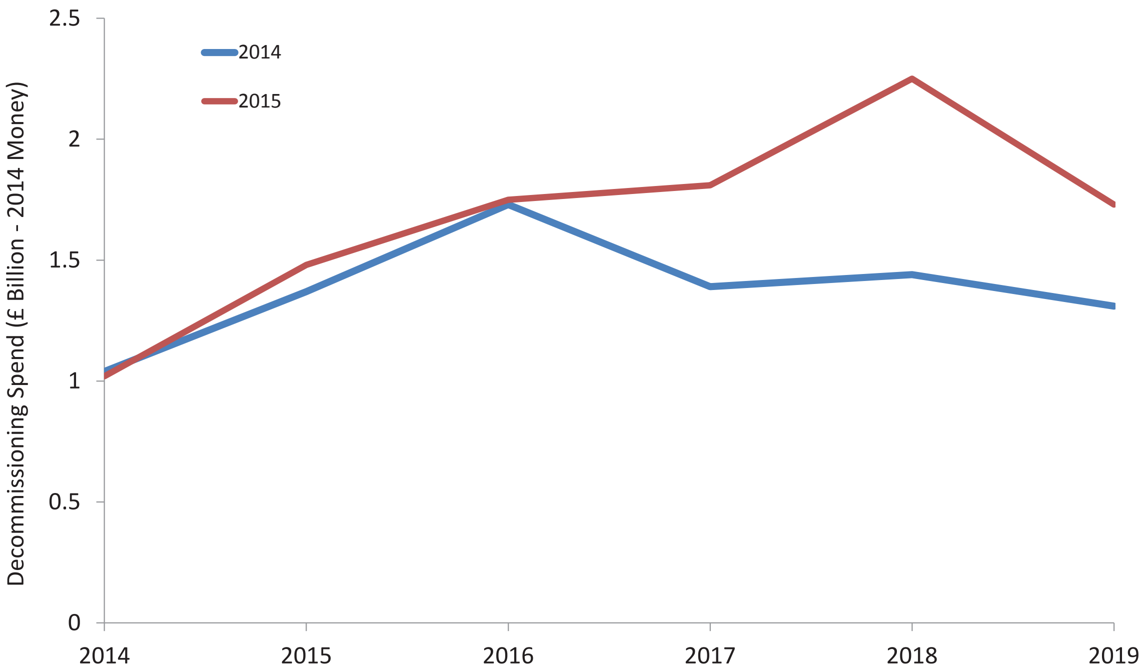
Source: Oil & Gas UK

6.7 Decommissioning

At £1 billion, decommissioning accounted for nearly four per cent of total UKCS expenditure in 2014. This is set to rise significantly over the next five years and could surpass £2 billion in 2018.

Expected average annual spend over the second half of the decade has risen from £1.5 billion in 2014 to £1.8 billion. This increase is driven by a combination of cost escalation and acceleration of decommissioning activity caused by a reduction in future revenue estimates. In contrast, there have also been some examples where decommissioning expenditure has been pushed back, contributing to the increase over 2017 and 2018. The fast implementation of a decommissioning strategy will be a priority for the OGA as they seek to ensure maximum economic extension of field life whilst also achieving macro-level cost reductions in decommissioning.

Figure 39: Forecast Decommissioning Expenditure on the UK Continental Shelf

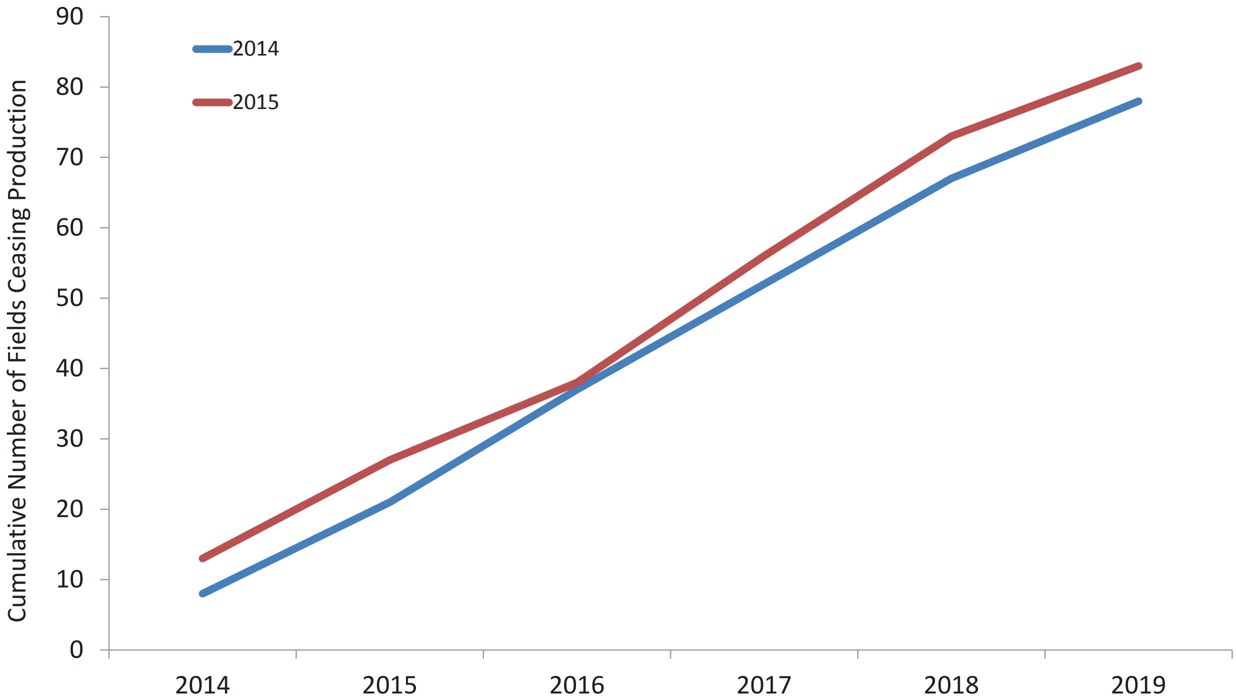


Source: Oil & Gas UK

Looking out to 2040, the forecast for total decommissioning spend has risen from £41.3 billion to £46 billion in 2014 money. £43 billion of this will be spent on decommissioning existing and sanctioned projects, and a further £3 billion will be spent on decommissioning projects that are yet to be developed. Although it is crucial to maintain the infrastructure of the UKCS for as long as economically possible, the undoubted future growth in the decommissioning market will present an excellent opportunity for the UK supply chain to establish world-class expertise in this area.

Comparison of 2014 and 2015 cessation of production forecasts suggests a six per cent rise in the total number of fields planning to cease production over the next five years. This increase is primarily due to fields ceasing production earlier than previously anticipated as higher costs and lower revenues mean they reach their economic limit sooner. As the data were collected in quarter 4 2014, the full impact of the oil price fall is yet to be felt. It is anticipated that without fresh intervention the number of fields reaching cessation of production over the remainder of the decade may rise significantly.

Figure 40: Forecast Number of Fields Ceasing Production



Source: Oil & Gas UK

7. Supply Chain Perspective

Thousands of businesses across the UK provide goods and services to the exploration and production (E&P) companies operating offshore, which has enabled the extraction of more than 43 billion barrels of oil and gas over the last five decades. These companies provide highly skilled, well-paid employment for hundreds of thousands of people across the UK and rely on a stable home market to provide a foundation for their international businesses. As a measure of its success, the UK supply chain achieved a turnover of more than £35 billion in 2012, 40 per cent of which was in the export of goods and services around the world, accessing a global energy market. This is an achievement the UK should be proud of.

Over the last four years, rapid growth in expenditure on the UKCS has placed considerable demand-side pressures on the supply chain. This has been exacerbated as the recent record investment comes after a prolonged period of much lower expenditure over the last decade, when previous tax increases had deterred much needed investment in the UKCS and reduced the productive capacity of the supply chain. In the last year, awareness of cost pressures became more widespread and has resulted in the introduction of cost reduction initiatives outlined in section 6.6.

Lower oil prices have now sharply reduced production revenues and both operators and their supply chain have had to adjust quickly to the new market conditions. The supply chain will inevitably have to reappraise its UK business and, in many cases, seek to accommodate lower domestic demand as well as downward pressure on costs. This may encourage many in the supply chain to place a greater priority on their export markets to provide some protection against a declining local market.

In what is inevitably a cyclical business, given the volatility in oil and gas prices, fiscal and regulatory stability on the UKCS are as important for the wider supply chain as for the E&P companies. The ability to sustain investment on the UKCS throughout the cycle is crucial and has at times been made harder by the impact of policy changes by successive governments. If spending on the UKCS declines over the coming years, as is currently anticipated, there will be consequences for the wider supply chain and it is inevitable that many companies will migrate overseas in search of new markets, diminishing the value of their contribution to the UK economy.

The UK upstream oil and gas supply chain can be split into five broad areas of activity: reservoirs, wells, facilities, marine and subsea, and support and services.

Figure 41: UK Upstream Oil and Gas Supply Chain Sub-Sectors

Tier 1: E&P Companies (End User)	Integrated Majors	Large/Small Independents	Energy Utility 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/pipe lay 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	

Source: EY

The following considers some of the broader impacts of current market conditions on each of these sectors. Clearly, many companies are already adjusting their businesses to accommodate the current outlook; many are looking to make operating efficiencies, reduce headcount or, at the least, rebalance the mix between staff and contractors within their workforce. Whilst this has led to concerns about the risk of losing skilled personnel, employers are seeking to balance near-term action with mid-term expectations for the UKCS. Supply chain confidence in the sustainability of the UKCS and its ability to attract new investment funds in the current environment will be crucial. In the meantime, for those companies that can do so, geographic and technical diversifications are being used to offset the impact of reduced business from the UK offshore oil and gas industry.

Reservoirs

This is a small, but nonetheless critical, segment of the industry. Activity within this sector is dominated by demand for their services from E&P companies, particularly from the UKCS and North Sea, which are their core markets. The need to deploy high quality seismic data using the latest 3D techniques is crucial both to improve recovery from existing fields as well as to promote fresh exploration activity, but demand for services from this sector are under pressure at this time. A number of companies report that they have not yet been affected by the current decline in oil price due to ongoing seismic work. However, these companies anticipate their order books to decline later in 2015, and, in anticipation, have halted all non-essential spending.

Importantly, a number of industry initiatives to mitigate the fall in demand within the sector are being progressed with government. These include the preparation of a 21st Century Exploration Roadmap to encourage fresh exploration and more targeted seismic surveys in under-explored areas of the UKCS.

Wells

Activity within the wells sector is linked to the fortunes of the industry as a whole; a fall in the rate of drilling activity is a leading indicator for an imminent downturn on the UKCS.

This is a capital intensive sector with large drilling rigs and expensive downhole equipment and techniques engaged in much of the work. Normally, companies' rigs and skilled resources are highly mobile and their services are in demand in all of the oil provinces around the world. However, whilst drilling activity is likely to decline globally, the UK is at risk of a bigger fall in activity given the reduced competitiveness of the UKCS at lower oil and gas prices.

Companies are recognising the decline in previously planned drilling activity and the early termination of some drilling projects. Measures to sustain fresh investment in new developments will be particularly important for this sector.

Facilities

This is recognised as the largest segment of activity on the UKCS, contributing around a third of the total supply chain revenue in 2012 and employing nearly 62,000 people[11]. It is a sector that engages with a wide range of companies involved in all aspects of the business from original concept design of platforms through to construction, in-field modifications and facilities maintenance, and eventually onto decommissioning. Companies range from large multinational organisations, employing a wide range of skills and disciplines, to specialised small companies.

The opportunities for diversification within this sector are considerable. The larger organisations in particular are also involved in other forms of energy provision, including nuclear and renewables, plus building and construction, road, rail and air transport. Such diversification can help but does not completely ameliorate the impact of the current business environment.

Some of the smaller companies, however, which are predominantly reliant on work from the oil and gas sector face the biggest pressures to adapt. Whilst a number of these companies are partially protected by their current contract work, others have already noticed a significant drop off in spend on engineering projects and anticipate a further fall in their workload. In addition, with fewer new projects being tendered, there is strong downward pressure on company rates. Most of the businesses in the sector expect a reduction in revenue and, as such, have a keen focus on cost reduction. There is also the expectation that workload will switch from new developments to maintenance and limited brownfield expenditure.

[11] The EY report on the *UK Upstream Oil and Gas Supply Chain* is available to download at www.oilandgasuk.co.uk/knowledgecentre/economic-contribution.cfm

Marine and Subsea

This is the second largest segment of activity and contributed around a quarter of the total supply chain revenue in 2012.

The UK is generally regarded as a global leader in subsea technology, which has stemmed from more than 30 years of application in the North Sea. Subsea technology is a key element that can offer significant advantages over fixed installations, allowing oil and gas to be extracted more cost effectively. This has obvious benefits, especially in areas of deeper water such as in the NNS and W of S regions where several major projects are in production or under development. Here, any downturn in UK investment will have a direct impact on the sector and will result in loss of capability and capacity and risk resource flight to more attractive provinces.

The whole marine sector is under pressure to reduce costs by clients further up the supply chain and many companies are freezing recruitment or cutting headcount as a consequence. The two types of marine vessels currently deployed in the North Sea are:

- General service type boats that are used to transport goods to and from offshore locations. These have business models that assume high utilisation booths to support routine operations and service summer shutdown and construction activity. Whilst there will remain a base load of work, as demand reduces due to lower activity, day rates will decline, often quite significantly.

- Specialist service units that are more likely to be used in a campaign or project-specific mode (such as pipelay, heavy lift, construction support). The specialist units are often booked months or years in advance and are much less vulnerable to short-term fluctuations in oil and gas prices. However, even if investment declines, their services will be under pressure.

Support and Services

This sector of the market has conventionally been dependent on activity on the UKCS and traditionally dominated by domestic business from larger operator and contractor companies. However, there are signs of increasing diversification with, for example, companies that provide IT services, recruitment, catering, consultancies and communications to the oil sector broadening their reach to access other sections of the UK economy. Whilst the support and services sector has some protection through diversification, where oilfield services dominate the local economy, such as in the north east of Scotland, there will be significant pressures to reduce costs and increase operating efficiency in the face of a much more competitive marketplace.

8. Summary of Key Statistics

	2012	2013	2014	2015
Total Production	1.56 mln boepd	1.44 mln boepd	1.42 mln boepd	1.43 mln boepd
Oil/Liquids	0.95 mln boepd	0.86 mln boepd	0.84 mln boepd	~0.85 mln boepd
Gas	0.61 mln boepd 36.7 bcm	0.57 mln boepd 34.4 bcm	0.58 mln boepd 34.7 bcm	~0.58 mln boepd ~35 bcm
Total (£ Billion)	~£21.3 billion	~£25.8 billion	£26.5 billion	~£22 billion
Capital Investment	£11.4 billion	£14.4 billion	£14.8 billion	~£9.5-11.3 billion
Operating Expenditure	£7.7 billion	£8.9 billion	£9.6 billion	~£8-10 billion
Exploration & Appraisal	£1.7 billion	£1.6 billion	£1.1 billion	~£1 billion
Decommissioning	£0.5 billion	£0.9 billion	£1 billion	~£1.5 billion
Unit Technical Cost ($/boe)	41.2	52.6	48.2	~
Unit Dev't Cost ($/boe)[1]	19.7	26.1	20.4	~
Unit Operating Cost ($/boe)	21.5	26.5	27.8	~25-26
Unit Technical Cost (£/boe)	26.6	34.4	32.1	~
Unit Dev't Cost (£/boe)[1]	13.1	17.4	13.6	~
Unit Operating Cost (£/boe)	13.5	17	18.5	~17-18
Oil Price (avge)	$112/bbl	$109/bbl	$99/bbl	~
Gas Price (av'ge – day ahead)	60 p/th	68 p/th	50 p/th	~
Combined Oil and Gas Price	$89/boe	$90/boe	$78/boe	~
Direct N. Sea Tax Revenues (Fiscal Year)	£6.5 billion	£5 billion	£2.8 billion[2]	~ £2.2 billion[2]

Wells Drilled	2012 incl. sidetracks	2012 excl. sidetracks	2013 incl. sidetracks	2013 excl. sidetracks	2014 incl. sidetracks	2014 excl. sidetracks	2015 incl. sidetracks	2015 excl. sidetracks
Exploration	22	21	15	15	14	13	~8-13	~
Appraisal	31	22	29	18	18	15	~ <5	~
Development	122	75	120	69	126	76	~	~
Total	**175**	**118**	**164**	**102**	**158**	**104**		

	2012	2013	2014	2015
New Field Approvals	21	10	8	~
Incremental Projects	8	26	28	~
New Field Start-ups (Excludes incrementals)	9 (146 million boe)	13 (392 million boe)	5 (195 million boe)	~
Exploration Volumes Discovered	20 million boe	80 million boe	~55 million boe	~

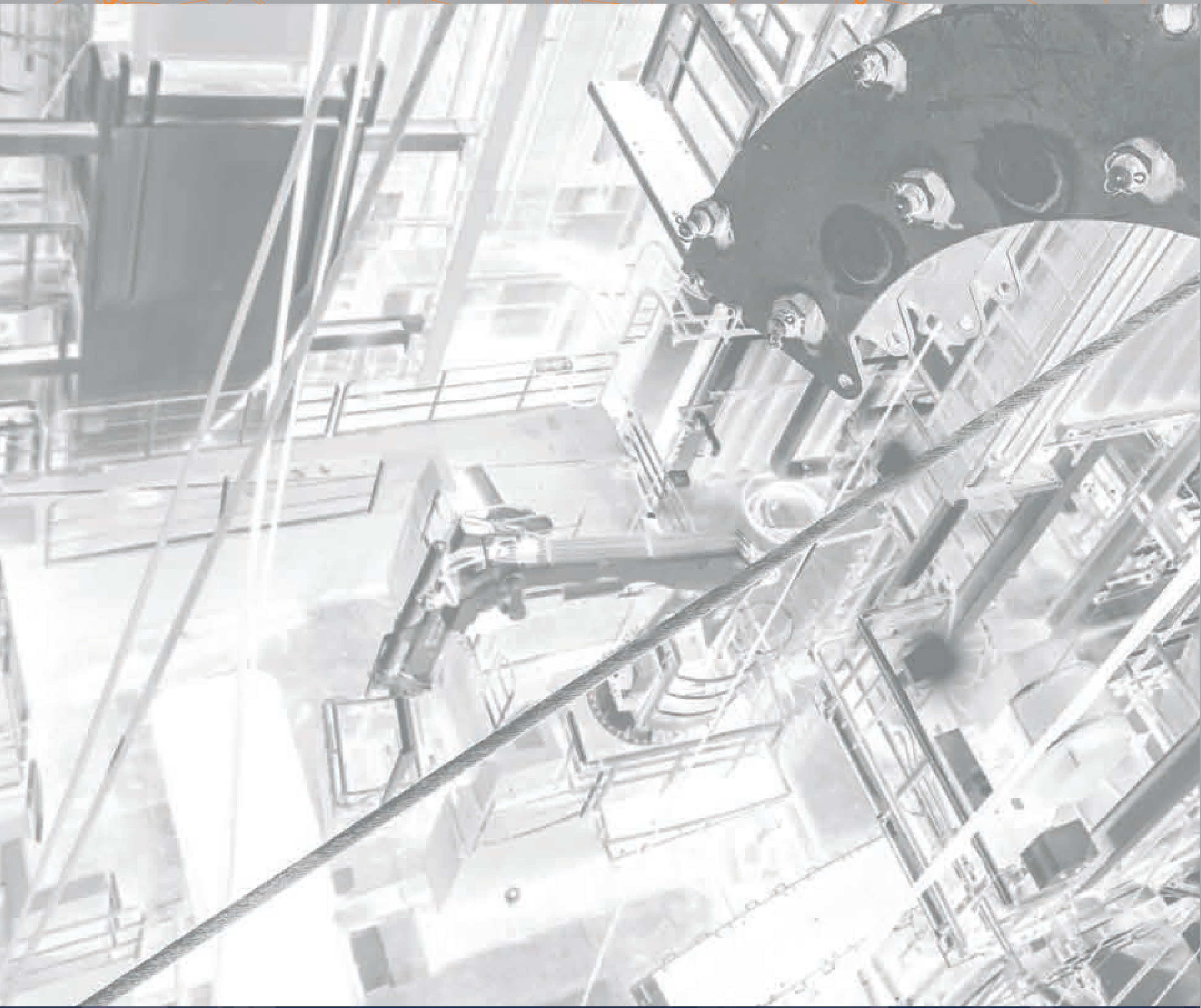
[1]This reflects the average unit development cost of new fields approved in the year

[2]Based on HM Treasury's *Autumn Statement 2014* Forecast

N.B - All expenditures and costs are quoted in money of the day

List of new fields given DECC field approval:

2012		2013	2014
Alma	Solan	Balloch	Alder
Barra	Soitaire	Cladhan	Aviat
Cayley	Stella	Enochdhu	Burgman
Conwy		Kraken	Catcher
Cormorant East		Kraken North	Cawdor
Cygnus		Mariner	Flyndre (UK)
Fionn		Morrone	Varadero
Fram		Orca	Ythan
Gala		Orlando	
Godwin		Tonto	
Harrier			
Harris			
Juliet			
Katy			
Kew			
Leman South			
Rhyl			
Shaw			



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