Energy Security

- Oil and gas provides some 73 per cent of the UK's total primary energy.
- Production from the UK's continental shelf (UKCS) satisfied 49 per cent of the country's primary energy demand in 2011:
  - 68 per cent of oil demand
  - 58 per cent of gas demand
- In 2020, 70 per cent of primary energy in the UK will still come from oil and gas, even if the 15 per cent target for renewable energy is met.
- The UKCS has the potential to satisfy close to 50 per cent of the UK's oil and gas demand in 2020 if the current rate of investment is sustained.
- A total of 41 billion barrels of oil equivalent (boe) has so far been recovered from the UKCS, with further overall recovery estimated at 15-24 billion boe.

UK Employment

- The industry supported at least 440,000 jobs across the UK in 2011.
- Employment is spread across the UK:
  - Scotland – 45 per cent
  - South East England – 21 per cent
  - North West England – 6 per cent
  - West Midlands – 5 per cent

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Economic Contribution

- Over £300 billion in production related corporate tax has been paid to the Exchequer in over 40 years since production began.
- The industry paid £11.2 billion in corporate tax on production in 2011-12, almost 25 per cent of total corporation tax received by the Exchequer.
- The wider supply chain is estimated to have contributed another £6 billion in corporation and payroll taxes.
- Production of oil and gas boosted the balance of payments by some £40 billion.
- The supply chain added another £6 billion in exports of goods and services.
- The UK offshore oil and gas industry remains the largest investor and the largest contributor to national gross value added among the industrial sectors of the economy.
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1. Foreword

Oil & Gas UK’s Economic Report 2013 is the definitive guide to the performance of the offshore oil and gas industry in the UK, regarding its investment, production and overall economic contribution. Working with data from our wide and growing membership – currently over 370 companies, including all the leading players in the industry – and the Department of Energy and Climate Change (DECC), this report provides insights into the current health and future prospects of this crucial sector of Britain’s economy.

2013 marks 25 years since the Piper Alpha tragedy, an anniversary which prompts us to reflect on and rededicate ourselves to the cause of safety. The Cullen Inquiry and consequent report transformed the approach to oil and gas safety in the UK’s waters. However, at the Piper 25 Conference held in June of this year, at which Lord Cullen gave the keynote speech, we reminded ourselves that there is absolutely no room for complacency, that very important challenges still remain and that we must dedicate ourselves to continually improve the safety performance of this industry.

I believe that the same can be said of our operational goals. In this report you will find evidence of a renewed commitment by the government and the industry to the extraction of oil and gas from the UK’s Continental Shelf (UKCS). The Coalition Government has taken some significant and positive steps over the past two years. New and much needed tax allowances have boosted investment in oil and gas production by £6 billion over 2012 and 2013; total investment is expected to reach an all-time record of £13.5 billion this year. Furthermore, the much needed certainty provided on decommissioning tax relief will release additional funds for future investment. Partly due to these fiscal improvements, exploration activity is now also increasing which, in turn, boosts the prospect of more discoveries and hence more indigenous production of oil and gas. But the improving business environment needs to be sustained and enhanced over the coming decades so that this industry can support the economic wellbeing of this country and its energy security.

Both the British and Scottish governments have recognised the substantial contribution made by our industry’s world class supply chain and its great potential for growth in domestic and overseas markets. This supply chain now contributes £27 billion a year to the economy, about £7 billion being in exports. The UK is a world leader in subsea engineering, capturing 45 per cent of the global market, and the well services companies are generating the highest gross revenues since records began in 1996. Britain’s fabricators have meanwhile been integral to the construction of around 6.5 million tonnes of concrete and steel structures installed on the UKCS to date.

The industrial strategies launched by both governments set a strong framework for increased investment, improved application of new technology, growth in exports of goods and services and, as a result of all of these, yet more jobs to add to the 450,000 which this sector already supports throughout the economy.

There is indeed much more that needs to be done. Despite impressive investment in new developments, the production efficiency of existing assets has been in worrying decline, with a number of fields failing to produce as expected. DECC and the industry are working to tackle this serious concern through a joint task group. We were also encouraged when, in June, Edward Davey, the Secretary of State for Energy and Climate Change, commissioned an independently led review of the recovery of the UK’s offshore oil and gas. We very much look forward to seeing the recommendations of the Wood Review early in 2014. Unlocking the full economic potential of the UKCS will require both the industry and government to play their respective parts to the full.

Malcolm Webb
Chief Executive, Oil & Gas UK
July 2013
2.
2. Industry at a Glance

The following summarises the key findings of Oil & Gas UK’s Economic Report 2013. Figures below refer to 2012, unless otherwise stated.

Security of Supply
• Currently, oil and gas provide some 73 per cent of the UK’s total primary energy, with oil for transport and gas for heating being dominant in these markets.
• In 2030, 70 per cent of primary energy in the UK will still come from oil and gas, according to the Department of Energy and Climate Change’s (DECC) latest projections.
• If the current rate of investment is sustained, the UK’s Continental Shelf (UKCS) has the potential to satisfy close to 50 per cent of the UK’s oil and gas demand in 2020 (>50 per cent for oil, <50 per cent for gas).

Economic Contribution
• Production of oil and gas boosted the balance of payments by some £32 billion.
• The supply chain in the UK generated more than £20 billion of sales from the UKCS.
• Another £7 billion of supply chain sales were in the export of goods and services.
• Offshore oil and gas remained the largest investing sector and the largest contributor to national gross value added (GVA) among the industrial sectors of the economy.

Oil and Gas Prices
• The price for Brent oil averaged $112 per barrel, less than 50 cents higher than 2011’s average.
• The oil price peaked at $128 per barrel in March 2012, before slipping to a minimum of $89 per barrel at the end of June and then recovering again.
• The day-ahead gas price at the National Balancing Point (NBP) was relatively stable throughout the year, averaging 60 pence per therm, although it did spike to almost £1 per therm on 7 February 2012 because of supply constraints in mainland Europe caused by extremely cold weather.
• The combined oil and gas price for UKCS production was, on average, $89 per barrel of oil equivalent (boe).

Production
• Production declined by 14.5 per cent from 2011 to 567 million boe, or 1.54 million boe per day.
• The UK remained the third largest producer of gas, and second largest producer of oil in Europe. The UK also remained in the top 25 global producers of both oil (20th) and gas (23rd) despite the sharp decline in production over the last two years.
Total Expenditure (in 2012 money)

- Total expenditure on the UKCS was over £20 billion for the first time in its history.
- Since 1970, the industry has spent over £500 billion by:
  - Investing £317 billion in exploration drilling and field developments
  - Spending £183 billion on production operations
  - Spending £2 billion on decommissioning assets that have ceased production

Taxation

- The industry paid £6.5 billion in corporation taxes on production in 2012-13.
- Whilst subdued production and record investment have driven tax revenues down in the short-term, the contribution from oil and gas production was still over 15 per cent of the Exchequer’s total receipts of corporation tax.
- The wider oil and gas supply chain is estimated to have paid an additional £5 billion in corporation and payroll taxes.

Capital Investment on Developments

- Capital investment reached £11.4 billion as the development of a number of large projects continued and other smaller opportunities were incentivised by field allowances.
- Oil & Gas UK predicts that capital investment will reach a record of £13.5 billion in 2013.
- Over 2011 and 2012, 45 projects have been approved by DECC which require capital expenditure of the order of £22 billion, yielding over two billion boe of production over time.
- Total capital investment committed to projects already in production or under development totalled £44 billion at the start of 2013, £13 billion higher than 12 months earlier.

Operating Costs

- Total operating expenditure was ten per cent higher than in 2011, at £7.7 billion.
- Unit operating costs continued to rise to an average of £13.50 ($21.50) per barrel as production continued to fall and spending on asset integrity and rejuvenation increased.

Reserves

- Almost 42 billion boe has been recovered from the UKCS so far.
- Further overall recovery is forecast to be in the range of 15 to 24 billion boe.
- Considering the full range of opportunities available, current investment plans have the potential to deliver 11.4 billion boe in total, as follows:
  - 7.4 billion boe from existing fields or those currently under development
  - Four billion boe from incremental and new field developments (not yet approved)
- Total expenditure of up to £1,000 billion (in 2012 money) will be required over the remaining life of the UKCS, if recovery is to reach the upper end of the forecast.
New Developments

• Nine new fields came on-stream, bringing 146 million boe into production.
• DECC approved 21 new projects, as well as eight substantial, incremental redevelopments.
• 55 per cent of fields approved in the last five years have been or will be developed as subsea tie-backs to existing infrastructure.

Drilling Activity

• The number of wells drilled (including sidetracks) was:
  o 26 exploration wells
  o 25 appraisal wells
  o 122 development wells
• Whilst drilling figures improved from 2011, they are still below the average for the last ten years. They need to rise further to avoid losing substantial potential reserves from the UKCS as infrastructure starts to be decommissioned.
• Exploration drilling is expected to pick up further in 2013 with 37 wells planned for the year.
• Appraisal drilling of 18 to 20 wells is expected in 2013.

Employment

• The industry supported some 450,000 jobs, many highly skilled, across the whole economy, with:
  o 36,000 employed by operating companies (12,500 of whom worked offshore)
  o 200,000 employed in the supply chain (45,000 of whom worked offshore)
  o 112,000 in jobs induced by the economic activity of the above employees
  o 100,000 in the export of goods and services

Decommissioning

• Some 475 installations, 10,000 kilometres of pipelines, 15 onshore terminals and 5,000 wells will eventually have to be decommissioned.
• Decommissioning expenditure was around £500 million and that is likely to rise to an average of £800-1,000 million per year during the rest of this decade.
• From 2013 through to 2040, £31.5 billion is forecast to be spent on decommissioning of existing assets.
• New investment in probable developments would add £3.5 billion to the total, although much of this will be incurred after 2040.

Editorial Notes:

• A Glossary of Terms and Abbreviations is included in the Appendix.
• The drafting of this report was undertaken during June and July 2013.
3. Oil and Gas Markets

**Oil Markets**

Oil prices in 2012 were characterised by a short-term peak followed by an even shorter trough during the first half of the year and steadiness for the second half of the year. Overall, although world demand for oil edged upwards, with demand in OECD\(^1\) countries falling and non-OECD rising, there has been notable consistency during the past two years in the price of Brent crude oil, the main ‘marker’ price in the Atlantic basin (see figure 1).

The average price was $112 per barrel in 2012 (versus $111 in 2011), to the nearest whole numbers. However, if measured with greater precision, the difference between the two was even smaller: less than 50 cents per barrel. The maximum was $128 per barrel in March and the minimum $89 in June. Since the beginning of 2013, the price has fallen by about ten per cent and, in recent months, has largely oscillated in the range of $100 to $105 per barrel, but with a slight increase evident at the time of writing, in June and July, owing to renewed political turmoil in Egypt.

Worth noting is the comparison of oil priced in dollars and pounds sterling which obviously reflects movements in exchange rates (see figure 2). In particular, the price of Brent in sterling has been largely constant over most of the past two years, apart from the brief excursions in March and June 2012 mentioned above, at a time when worldwide demand has been creeping steadily upwards (to an average of 90 million barrels per day (bpd) in 2012. For comparison, it was 80 million bpd in 2003).

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\(^1\) The mission of the Organisation for Economic Co-operation and Development (OECD) is to promote policies that will improve the economic and social well-being of people around the world. Thirty-four countries are members of the organisation. More information can be found at: [http://www.oecd.org](http://www.oecd.org)
Meanwhile, the gap between Brent and lower priced West Texas Intermediate (WTI) crude oils has narrowed from its range of $10 to $20 per barrel in recent years to less than $10 per barrel. Various new projects are diverting supplies away from Cushing, Oklahoma, where the price of WTI is set, with WTI rising towards Brent and the difference narrowing to as little as $3 per barrel in July 2013.

Notwithstanding the above, several significant trends are becoming established in oil markets:

- In OECD countries demand is falling, while it continues to rise in non-OECD countries.
- As a result of shale oil and oil sands, production in North America is rising, reversing a previous, long term decline.
- Middle Eastern oil is increasingly serving the Asia-Pacific region, with less going to the Atlantic basin.

Gas Markets

The consequences of Japan’s Fukushima disaster, following an earthquake in March 2011, continue to be felt in Europe’s gas markets. Demand for liquefied natural gas (LNG) remains high in Japan as a result of most of its nuclear power stations being closed (although its current government has indicated that it wishes to re-open a number of them). This led to a reduction of LNG cargoes arriving in western Europe during the winter of 2012-13, when it was not only cooler than in the previous winter, but was characterised by a particularly cold ending, with demand for gas at mid-winter rates throughout March and into early April. This raised gas prices at Britain’s National Balancing Point (NBP) and other trading hubs in the EU, such as the Netherlands, Belgium and Germany.

Figure 3: Wholesale Gas Price at the NBP in Great Britain, January 2008 to July 2013
Figure 3 shows how day-ahead prices rose at the NBP in late 2012 and into 2013, having been steady throughout 2011 and much of 2012, as winter’s higher demand and the arrival of fewer LNG cargoes took effect. The cold end to the winter 2012-13 put considerable strain on storage stocks and caused the largest flows ever through the Inter-Connector pipeline between Belgium and Britain, with more than 70 million cubic metres per day flowing on a number of days. This clearly demonstrated the value of an open and competitive market at the NBP and how important the liberalisation of the EU’s market in gas is. It would be difficult to imagine such flows occurring at short notice without the benefits of liberalisation.

In contrast, US gas prices, while rising slightly, have remained at a substantial discount to those in Europe, with all the competitive advantages this entails for the USA’s economy. Within mainland Europe, several buyers have successfully challenged the operation of the oil indexation of prices under long-term contracts and obtained discounts as a result. Nonetheless, it would appear as though the underlying pricing structures mostly remain in place, albeit with the formula having been adjusted to reflect more closely open market conditions at the trading hubs. However, it is understood that many long-term Norwegian gas supply contracts have been re-negotiated to reflect market conditions.

According to the European Commission, about half of the EU’s gas consumption in 2012 was supplied under oil indexed contracts, with north-west Europe being considerably more liberal (about 70 per cent open market pricing) than central Europe (less than 40 per cent). The story of oil indexation and its expected decline in the EU would appear to have further to run, therefore.
4. The UK’s Continental Shelf

Development of the UK Continental Shelf

In the 1960s, the discovery of natural gas in the southern North Sea (SNS) was the first step in the development of an offshore oil and gas industry in the UK. Over the past 45 years, 42 billion barrels of oil equivalent (boe) have been recovered from the UK’s Continental Shelf (UKCS).

As a result of the early discoveries, production of gas began in 1967 from the West Sole field and other gas resources were developed rapidly in the late 1960s and early 1970s, with various large fields such as Leman, Indefatigable and Hewett being quickly brought on-stream. It was not until December 1969 that oil was discovered further north in the central North Sea (CNS) and shortly afterwards in the northern North Sea (NNS). The first oil was produced from the Argyll field in June 1975. Large, iconic oil fields such as Forties (also in 1975), Brent and Beryl (1976), and Ninian (1978) commenced production over the next few years.

After the first exploration successes, the ensuing surge in activity led to more than 25 billion boe being discovered by the mid-1970s and, to date, almost 55 billion boe have been discovered in more than 400 fields across the UKCS. Just under 300 of these are in production today, including the first, West Sole, leaving about 100 not yet developed, some of which may never be so for technical and commercial reasons. Whilst it is anticipated that production from the Brent field will cease in about the middle of this decade, many of these early large fields remain in production and there are even plans afoot to redevelop smaller, old fields such as Argyll, which ceased production in 1992 and is now renamed Alma.

The industry has three main goals in the coming years. These are to: continue to explore for and make new discoveries, increase the rate of recovery from existing fields and extend the productive life of the existing infrastructure, all in a safe and environmentally responsible manner.

Figure 4 overleaf shows that, as the UKCS has matured, the rate of discovering new resources has slowed, yet significant volumes continue to be found. Even since the turn of the century when production peaked, 4.1 billion boe of recoverable reserves have been discovered. These discoveries vary in size with some, such as the Buzzard field discovered in 2001, now believed to contain more than 700 million boe of recoverable reserves. However, finds such as Buzzard are rare and discoveries have typically been much smaller since 2000, with the median size being just ten million boe.

The region to the west of Shetland is the latest to be developed, with production only beginning in 1997. Already, seven fields of 100 million boe or more in size have been discovered; it is the area of the UKCS that is believed to have the most undeveloped resources.

The gap between the volumes discovered and produced (see figure 4) has converged in recent years as production from the early, large fields continues, albeit at declining rates, and new discoveries are being developed with the benefit of the extensive infrastructure available throughout the North Sea.
However, there are still a significant number of discoveries which have taken a long time to be developed, either because of limitations in prevailing technologies, a lack of local infrastructure or marginal economics. Clair and Mariner are examples of fields that were first discovered in the late 1970s and early 1980s, but were not developed until more than two decades later, after new technologies became available.

The dynamics of the UKCS in the early days of production were very different from today. Throughout the 1970s and 1980s, a small number of very large fields dominated UKCS production, whereas today’s production comes from a much larger number of fields, most of which are considerably smaller in size.

Figure 5 demonstrates this effect for oil since production began in 1975. This is not unusual for a maturing oil and gas province. The biggest and easiest reservoirs are found and developed first, with later and smaller discoveries often being tied back to existing infrastructure. While this is often an enabling factor because it makes the new field economic, it means that tie-backs are dependent on the performance of an older, host installation, thereby adding a degree of complexity to the operation.

Targeted policies drive the pace of development

Much of the newer resources are to be found in high pressure high temperature (HPHT), heavy oil, and deep water fields. However, many of the technologies required to recover these resources are still under development. If technology continues to advance at the rate experienced over the last 40 years and if commodity prices remain high, the share of production from such demanding reservoirs is expected to increase in future.
As well as the rate of technical change and oil and gas prices, government policy, particularly fiscal policy, has also affected the pace of development. Figure 6 shows how industry and government are working together, under the auspices of the task force, PILOT. The overall intention is to ensure that the right policies are in place and are being implemented to achieve maximum economic recovery of oil and gas from the UKCS.

For more information about PILOT and its work, please refer to the sub-section below entitled ‘The Road to 2040’.

**Remaining Resources and Reserves**

Oil and gas extraction from the UKCS has provided the economy with energy supplies, highly skilled and paid jobs, and more than £300 billion (in 2012 money) to the Exchequer in production taxes over the past 45 years. During this period, 42 billion boe of oil and gas have been produced, but there is still a significant resource of some 15 to 24 billion boe left to be developed. This will require further exploration activity and increased investment, in both existing and new fields.

About 7.4 billion boe should be produced from existing fields and new projects that have already been sanctioned. This can be seen as the lowest likely figure for reserves, that is the oil and gas which have a greater than 90 per cent chance of being recovered. In reality, it is highly likely that there will be further investment on the UKCS and, therefore, more reserves recovered.

**Figure 6: Policies to Increase Recoverable Resources**

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<tr>
<th>Aim</th>
<th>Policy</th>
<th>Work Group</th>
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<tr>
<td>Increase Reserves Discovered</td>
<td>Small Field Allowance</td>
<td>Oil &amp; Gas UK Economic &amp; Fiscal Forum</td>
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<td>PILOT Exploration Task Force</td>
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<tr>
<td>Increase Recovery from Existing Assets</td>
<td>Brown Field Allowance</td>
<td>Oil &amp; Gas UK Economic &amp; Fiscal Forum</td>
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<td>PILOT IOR and EOR Work Groups</td>
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<tr>
<td>Commercialisation of Marginal Discoveries</td>
<td>All Field Allowances</td>
<td>Oil &amp; Gas UK Economic &amp; Fiscal Forum</td>
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<tr>
<td>Extending the Life of Infrastructure</td>
<td>Infrastructure Code of Practice (ICoP)</td>
<td>PILOT Infrastructure Access Group</td>
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<tr>
<td>Increase Production Efficiency</td>
<td>Asset Stewardship</td>
<td>PILOT Production Efficiency Task Force</td>
</tr>
<tr>
<td>Promoting Investment and Postponing Decommissioning</td>
<td>Fiscal Certainty on Decommissioning Relief</td>
<td>Oil &amp; Gas UK Economic &amp; Fiscal Forum</td>
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If companies invest in projects which they deem to have a greater than 50 per cent chance of being developed ('probable reserves'), as is reasonably expected with the passage of time, a further 2.5 billion boe of oil and gas will be recovered. Additionally, there are resources with, currently, a less than 50 per cent chance of being developed ('possible reserves'). These account for a further 1.5 billion boe, although many of these projects are technically difficult and/or marginal in commercial terms, hence their classification as 'possible'. The total resources in companies' plans, ranging from producing fields to possible new or brownfield developments, is 11.4 billion boe.

The latest figures from the Department of Energy and Climate Change (DECC) show a range for potential additional resources (PARs) of 1.5 to seven billion boe and yet-to-find resources (YTF) of six to 17 billion boe. However, Oil & Gas UK has taken a more conservative position, reflecting the uncertainties in these ranges, and believes it is more prudent to consider PARs in the range of one to four billion boe and YTF resources of three to nine billion boe. The forecast of total UKCS reserves and resources, as at the end of 2012, is depicted in figure 7. While it indicates the potential range in each category, caution is required in its interpretation and it should not be assumed that the top of each range will be achieved.

None of these can be realised without substantial expenditure. If the 11.4 billion boe in companies’ current plans are to be realised, around £300 billion (in today's money) will be required:

- £100 billion of capital investment to develop both green- and brown-fields.
- £160 billion to operate these assets throughout their productive lives.
- £35-40 billion to decommission them after production has ceased.

Significant additional investment will be required if PARs and YTF resources are to be recovered from the UKCS. This is because of the need for further extensive exploration and the fact that unit costs of development and operation are now approaching £30/boe as reserves become more difficult to extract.

**Figure 7: Forecast of UKCS Reserves and Resources (as at the end of 2012)**
Oil & Gas UK estimates that total expenditure of £600-1,000 billion (in 2012 money) will be required over the life of the UKCS, if recovery is to reach the higher figures in the forecasts.

However, investment is not the only factor that will influence the longevity of the UKCS. Whilst sanctioned investments already guarantee the industry will be active for another 15 to 20 years, the future to 2050 and beyond is reliant on a number of determinants, such as commodity prices, cost inflation, rate of technical improvement, access to infrastructure, fiscal policy, and supply chain capacity and capability. As long as the UKCS continues to be a competitive oil and gas province in which to invest, Oil & Gas UK believes that up to some 24 billion boe of resources remain to be recovered (towards the higher end of these various projections) and the industry will be active beyond 2050.

Production

In 2012, 1.54 million boe per day (boepd) were produced from the UKCS, 14.5 per cent less than in 2011. This compares unfavourably with an average annual reduction of about nine per cent a year over the previous decade (shown in figure 8).

Furthermore, the 14 per cent reduction in 2012 followed one of 19 per cent in 2011, resulting in a 30 per cent reduction over the course of the last two years and the lowest production since 1977. Figure 9 illustrates how numerous fields have contributed to this decline.

The 19 per cent decline during 2011 was the largest recorded for the UKCS since production peaked at the turn of the century, with 230 fields accounting for a 542,000 boepd reduction. Many of these are natural declines on account of ageing, but ten large fields made up 37 per cent of the reduction: of the ten, Buzzard, North Morecambe and
Brent had lengthy maintenance shutdowns, Goldeneye ceased production in preparation for its role in a carbon capture and storage project, Rhum had been shut for geopolitical reasons (and remains so) and Gryphon’s floating production, storage and offloading (FPSO) vessel had to undergo substantial repairs following damage in bad weather. Fortunately, 93 fields increased their output relative to 2010, which meant that the net decline for 2011 was 413,000 boepd.

In 2012, 239 fields produced 470,000 boepd less than in 2011. This decline was dominated by ten fields which eclipsed the positive contributions made by the 82 fields that increased their output. A gas leak at Elgin in the central North Sea (CNS) during March and the subsequent closure of the SEAL pipeline had a substantial effect on production for the year; the seven fields feeding into the SEAL pipeline, including Shearwater, produced 126,000 boepd less than in 2011, or 41 per cent of the net decline between 2011 and 2012.

The fields that increased production were a mixture of existing and new ones. Nine fields started production in 2012, although with relatively modest total reserves of 146 million boe. These included Islay, Wingate, Bacchus and Devenick, but their impact was too small to offset the decline from existing fields. This offsetting effect would have been larger had the dates for the start of production not been later than anticipated for some fields. The likely reasons underlying the limited reserves brought on-stream in 2012 are the poor results from exploration drilling in recent years and an unexpected tax increase in 2006, with its adverse effects on investment.

Some key fields, such as Buzzard, emerged from lengthy, planned maintenance periods and provided a timely boost to production in 2012. Meanwhile, the Sean gas field increased its output as it came to the end of its production contract which had previously kept it in a reserve role.

In 2013, there are 15 fields anticipated to come on-stream (with combined reserves of 470 million boe). As Oil & Gas UK forecast in February, production in 2013 has continued to decline and, using the latest available data (to the end of May), the indications are that it is towards the bottom of our predicted range, namely 1.4 million boepd. If this rate were maintained for the rest of the year, production would be 8.5 per cent lower than in 2012.

However, maintenance is concentrated in the summer months and so, although the decline will be offset in part by the return to production of the Elgin and Franklin fields and Banff and Gryphon FPSOs and by new production coming on-stream, notably the Jasmine field in the fourth quarter of the year, Oil & Gas UK’s updated forecast is for production to be in the range of 1.2 to 1.4 million boepd for 2013 overall (see figure 10 opposite).
Looking to the mid-term future, production is expected to be similar in 2014 before improving again, potentially rising towards two million boepd in 2017. This potential reinforces the need to improve production efficiency (see below) and the significance of the work of the government-industry task force, PILOT (see ‘The Road to 2040’ on page 31) and the Wood Review mentioned in the Foreword.

Production Efficiency

Production efficiency – the ratio of actual production to the maximum potential – fell to 63 per cent in 2011, with a further fall to about 60 per cent expected in 2012 when all data are available. Paradoxically, this came against a backdrop of high oil prices, record capital investment and man-hours expended offshore.

Average production efficiency of the UKCS was in the high 70s of per cent just four years ago and around 80 per cent seven to eight years ago. The recent decline has resulted from deteriorating reliability, with extended maintenance shutdowns, compounded by several major production outages mentioned above.

Had such efficiencies been maintained in 2012, production would have been almost half a million boepd higher. The government and industry are working together to combat the various issues affecting production and are charting a course to return to such overall efficiencies.
Expenditure and Investment

In 2012, total expenditure exceeded £20 billion for the first time in the history of the industry in the UK (measured in 2012 money, that is adjusted for inflation). After a reasonably flat period during the 1990s and early 2000s, expenditure has now risen by an average of 16 per cent a year for the last four years. While expenditure on operations (opex) and exploration and appraisal (E&A) drilling have risen steadily over that time, it is capital investment (capex) that is responsible for the majority of the increase.

The offshore oil and gas exploration and production industry continues to be the largest investing sector and contributor to national gross value added (GVA) among the industrial sectors of Britain’s economy.

Capital Expenditure

Figure 13 opposite shows a time series of capital investment over the life of the UKCS since 1970, adjusted for inflation (based on general inflation across the economy²). In today’s money, £270 billion of capital has been invested in developing fields over the past 45 years.

Having started in the shallow waters of the southern gas basin, large amounts of capital were spent as the industry found and developed oil fields in the deeper waters of the CNS and NNS during the 1970s, reaching over £11 billion in 1976. A number of very large fields were brought rapidly into production, but the pace of development then slowed through the 1980s, reflecting the technical and economic challenges arising from the building

Figure 12: Total Expenditure on the UKCS

2 In reality, the industry’s inflation has been greater than inflation in the wider economy over the last 40 years. However there are insufficient data collected to present a reliable deflator for the industry on its own.
and commissioning of the first generation of deep water platforms, high marginal tax rates and, subsequently, falling oil prices, with capex declining sharply to around £4 billion in 1987.

There was another surge of investment at the end of the 1980s and into the early 1990s, as the industry responded to meet more stringent health and safety regulations in the aftermath of the Piper Alpha disaster. Several new fields were also developed and some early, large fields underwent re-development. However, with low oil prices and high costs, capital investment declined again in the late 1990s and early 2000s, as many investors considered the UKCS to be a less attractive destination for their capital compared with other opportunities around the world. Despite the oil price trebling between 2003 and 2008, investment on the UKCS continued to remain relatively flat until 2009.

In 2012, capital expenditure rose to £11.4 billion, and Oil & Gas UK believes that it will increase by a further £2 billion, reaching £13.5 billion in 2013. This rate of investment has not been seen since the mid-1970s and capital expenditure this year is almost certain to be an all-time record (but subject to the caveat in footnote 2). This represents a step-change in activity for an oil and gas province that had not previously seen capital investment above £7 billion since the early 1990s. Five main reasons have identified behind this recent increase:

a. A new wave of investment in a small number of large fields – 30 per cent of the capital in 2012 (almost £3.5 billion) was spent in just four fields. Eight developments approved by DECC since the beginning of 2010 have a projected capital investment of over £1 billion each (see figure 14). Capital in such projects is typically spent over a three to five year period and Oil & Gas UK’s analysis suggests
that the year-by-year expenditure on these developments peaks in 2013.

As well as these large developments, there has been investment in a stream of smaller, new projects in recent years and many more incremental developments have been approved in 2012 and 2013 as a result of the newly introduced Brown Field Allowance.

b. **Renewed confidence on the UKCS among the major companies** – the amount of capital that the majors\(^3\) have invested on the UKCS has more than trebled from 2009 to 2013 (see figure 15 opposite). This represents a significant change of attitude. The companies had previously been rationalising and reducing their commitments, but, having streamlined their portfolios, they are now investing heavily again in large, new and brownfield developments on the UKCS, especially to the west of Shetland.

c. **The impact of field allowances** – to the benefit of the wider industry and the Exchequer, field allowances are now making many marginal investments possible following their introduction in 2009 and subsequent expansion (for details, please refer to figure 48 in the Appendix). During 2012 and 2013, Oil & Gas UK expects more than £6 billion of capital to be spent on fields that are in receipt of field allowances. For many of these fields, an allowance has enabled investment that would not otherwise have happened under prevailing market conditions.

d. **Asset integrity and rejuvenation** – Oil & Gas UK has noted that companies are adopting a more risk averse attitude to operations since the Macondo incident in the Gulf of Mexico in April 2010. Around £1 billion was spent on asset integrity work in 2012 and the same is expected in 2013. Although this expenditure does not immediately yield additional barrels of oil or gas, companies can expect these assets to be more reliable and, therefore, experience less downtime over the remainder of their productive lives, which may well have been extended as a result.

e. **The extraction of more technically challenging reserves leading to increased capital intensity** – as the UKCS has matured, the reserves which were easiest to recover have already been extracted. More recently, advances in technology, higher prices and an evolving fiscal regime have enabled companies to develop oil and gas in more technically challenging fields. A wide variety of HPHT, heavy oil and very deep reservoirs, as well as difficult shallow water gas fields, have begun to be developed.

The consequences of this activity for unit costs are shown in figure 16. Over time, projects approved by DECC are becoming significantly more expensive to develop per barrel recovered. Each pound of capital invested on the UKCS now yields only one fifth of the oil and/or gas it did in 2002. Therefore, investment would have to be five times higher than in 2002 to achieve the same outcome, as a result of inflation of capital costs and the complexity of the reservoirs. This concept of capital intensity is becoming a crucial measure for the future health of the province.

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\(^3\) For this purpose, Oil & Gas UK has defined majors as BP, Chevron, ConocoPhillips, ExxonMobil, Shell and Total.
Figure 15: Investment in Assets Operated by the Majors as a Proportion of Total Investment

Figure 16: Average Annual Unit Development Costs for Projects Approved since 2005
After this current wave of investment, it is anticipated that capital investment may fall to around £8-10 billion a year from 2015 (in 2012 money). However, were the rate of investment to be below this, at around £6-8 billion per annum, it would probably be insufficient to sustain current rates of production and the programme of works on asset integrity. On the other hand, if investment were to rise significantly above its current rate, it would apply additional inflationary pressure, as the capacity of the supply chain would become yet more stretched.

It is expected that a number of large new field developments of at least 100 million boe of recoverable reserves will materialise in the coming years, including Rosebank, Bressay and further development of the Clair field. Additionally, there is a renewed drive to recover more from existing fields which should ensure the UKCS remains healthy. This is being achieved through improved reservoir management, enhanced oil recovery (EOR) and other such techniques, together with continued investment in many smaller opportunities. All this will need to be supported by the necessary investment to extend the life of critical infrastructure.

Operating Expenditure

The costs of operating the fields and their assets across the UKCS totalled £7.7 billion in 2012, an increase of ten per cent from the previous year. A further ten per cent increase is expected in 2013, such that Oil & Gas UK estimates that total operating expenditure will reach £8.5 billion for the year.

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*Figure 17: Rise in UKCS Operating Costs*
Operating costs have risen by around 90 per cent since 2000. Adjusting for inflation, the increase is only around 50 per cent over the last 13 years, or about 3.5 per cent a year, representing good cost control from an overall perspective. This increase has been consistent over the last decade, excluding a dip after the financial crisis in 2008 and 2009. Keeping operating costs under control is a considerable achievement for the industry, given the need to maintain ageing assets to satisfactory standards and the worldwide competition for resources, especially skilled people.

While growth in operating costs has been fairly well contained, the unit cost per barrel produced has risen much more, particularly in recent years as production has declined. The unit operating cost (UOC) has risen four-fold over the past decade, a worrying trend that could have a major influence on the longevity of the UKCS. Lower production is providing constant upward pressure on UOCs, alongside the recent increase in expenditure on asset integrity.

The range of UOCs for individual fields on the UKCS is very wide, from less than £5/boe all the way up to around £70/boe. There are several fields on the UKCS that now cost more than £40/boe to operate. Oil & Gas UK has found that much of the cost escalation is concentrated in a small number of fields, but the general trend for UOCs is rising markedly and this will not change unless the decline in production is reversed. If there were to be a fall in commodity prices, the more expensive assets would have to be shut down and could face premature decommissioning.

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4 More information about asset integrity and the Health & Safety Executive’s Key Performance 4 (KP4) programme can be found at: http://www.oilandgasuk.co.uk/assetintegrity.cfm
Licensing and Drilling

a) Exploration
An active exploration market remains crucial to the success of the UKCS; without it, there can be no long-term future for oil and gas production. Since 2000, 358 exploration wells have been drilled, resulting in 4.1 billion boe of reserves being discovered with a median discovery size of ten million boe.

Despite the high volume of reserves already recovered, the UKCS still has substantial oil and gas resources and exploration potential. Oil & Gas UK believes that between three and nine billion boe have yet to be discovered (see figure 7 on page 18). At the current rate of drilling, it is estimated that it will take some 20 years and 250 to 500 wells to explore for and find these resources, the recovery of which will rely, to a large extent, on the availability of existing infrastructure.

Exploration and appraisal (E&A) drilling increased overall in 2012, with 24 exploration (14 in 2011) and 19 appraisal (16 in 2011) wells being drilled, together costing £1.7 billion. These numbers exclude sidetracks of which there were two exploration and six appraisal wells in 2012. Despite this increase in E&A drilling, the industry is struggling to reach the rates of 2007 and 2008.

Exploration drilling activity, averaged over the past four years, has been the lowest for a decade, with 2011 being notably low. This can partly be blamed on the economic crisis and limited access to finance for smaller exploration companies.

Figure 19: Forecast Distribution of Yet-to-Find Resources

Source: DECC
Figures 20 and 21: Exploration and Appraisal Wells Drilled, including Sidetracks, 2003 to 2012

Source: Oil & Gas UK / DECC
Furthermore, the period 2009 to 2012 saw a decoupling of the relationship between the oil price and the number of exploration wells drilled. During this period, the number of wells drilled was consistently below average, despite a generally high oil price. It is evident that exploration drilling is responsive to both oil price and fiscal shocks. Figure 22 shows that there was almost no time lag between the sudden increases in tax rates of 2002, 2006 and 2011 and the fall in drilling figures; exploration capital is very mobile and so can be quickly moved to other parts of the world.

Encouragingly, surveys conducted by Oil & Gas UK indicate a positive outlook for 2013 to 2015, with operators forecasting a potential of 37 exploration wells to be drilled in 2013. Despite a tightening rig market, roughly 85 per cent of exploration wells and 100 per cent of appraisal wells to be drilled this year have secured firm rig slots, providing additional confidence in the forecast. Exploration activity is expected to peak in 2014, with 53 wells forecast to be drilled. Even if 80 per cent of these are drilled, 2014 would see the highest rate of exploration since 2008.

b) Exploration and Appraisal Expenditure
E&A expenditure typically corresponds to the number of wells drilled, but is also directly linked to the rise and fall of the international drilling rig market (see figure 24 opposite).

In 2009 and 2010, a similar number of wells were drilled to 2006, but the amount spent was nearly double, demonstrating an escalation in costs. Then, in 2011, the number of wells drilled decreased, despite a further increase in expenditure. The rise in expenditure in 2012, though, was mainly due to an increase in exploration drilling compared with 2011. It is anticipated that there will be a further increase in expenditure in 2014 to nearly three times as much as was spent in 2011.
c) Licensing
Over the past 49 years, there have been 27 Licensing Rounds with the 28th Round expected to be launched in January 2014. DECC issued a total of 167 new licences covering 330 UKCS blocks in the 27th Round of October 2012. This was the largest number in the history of offshore exploration in the UK and it is anticipated that the increased interest in Licensing Rounds will help stimulate exploration activity in the years to come.

Seventy per cent of all E&A wells drilled in 2012 were in acreage that was awarded in Licensing Rounds 22 to 26 (of 2004 to 2010), yet only four per cent were in acreage awarded in Rounds 17 to 21 (of 1996 to 2003). This contrast could be a direct result of the changes to licensing terms in 2002, which increased pressure on operators to fulfil certain drilling requirements within a four year time-frame.

Around 17 per cent of wells drilled were in acreage obtained in Rounds 1 to 4 (of 1964 to 1972), demonstrating that companies are revisiting old and previously explored acreage using improved seismic imaging and/or prospects have become commercial because of the proximity of surrounding infrastructure. Constraints on access to finance for smaller companies and a tight drilling rig market have heightened uncertainty and pushed companies to develop lower risk opportunities that have a number of infrastructure options.

Only nine per cent of wells drilled in 2012 were in acreage awarded in Rounds 5 to 16 (of 1976-1995), raising the question of whether or not the acreage awarded in those Rounds has been fully exploited to date.

The Road to 2040
Since production peaked in the year 2000, the offshore oil and gas industry in the UK has entered a mature phase and its outlook has changed. In
recent years, most new developments have not involved the construction of large, new production platforms with their own pipelines to shore. Instead, the tendency has been to use existing infrastructure for new developments which has two main benefits: it extends the infrastructure’s life and allows smaller fields to be developed economically.

Today, most new fields are small when compared with the early giants such as Leman, Forties and Brent. Also, remaining reserves are increasingly difficult and costly to extract. As a result, there has been a drive to make the industry more cost effective, without compromising safety or the environment, so that the UKCS can continue to win investment for new projects.

PILOT, the government and industry task force, was formed in early 2000 to develop an appropriate strategy for delivering a sustainable, long-term future for the UKCS. It was born out of a crisis. As oil prices fell to $10 a barrel at the end of 1998, all stakeholders in the offshore oil and gas industry realised that powerful factors outside their control could jeopardise the contribution that it makes to the economy.

PILOT is a unique arrangement between the industry and government, uniting senior management in operators, contractors, suppliers and relevant government departments who are working co-operatively to deliver quicker and smarter solutions aimed at securing the maximum economic recovery of the country’s oil and gas resources. This was and remains PILOT’s overall objective. It meets twice a year and is chaired by the Secretary of State for Energy and Climate Change and includes around 13 industry representatives, as well as representatives of government.

Now in its 14th year, PILOT covers matters relating to all phases of the oil and gas life cycle, from exploration, development and production through to decommissioning. The task force promotes initiatives to reduce costs, eliminate un-necessary barriers and maximise the effectiveness of resources. The goal is to bring about a future that could still see the industry meeting approximately half of the nation’s oil and gas needs in 2020.

Through its various initiatives, PILOT has been extremely influential in advising and supporting both government policy and industry practices and has had various successes as a result of its innovative and co-operative work. These include:

- **Attracting new players and global investment** – a diverse range of new players has entered the province which has led to more small fields being developed and the introduction of new technologies.
- **Stimulating activity** – the Fallow initiative has placed still prospective acreage into the hands of companies that want to develop it.
- **Enabling access to infrastructure** – companies are able to negotiate with owners for access to production facilities and pipelines for processing and transport of oil and gas. This has typically enabled subsea tie-backs of small fields to established infrastructure hubs, although there are still various challenges in this regard.
- **Improving stewardship** – an ability to analyse thoroughly the potential of producing fields has been created, through techniques such as infill and near-field drilling, together with a more transparent mechanism for the sharing of infrastructure data.
- **Facilitating new technology** – the Industry Technology Facilitator (ITF) has been established to foster innovation and promote the development and use of new technologies.
- **Training and skills** – the industry workforce has increased by 100 per cent throughout the life of PILOT, and the oil and gas academy, OPITO, was established.
• **Exports** – there have been more exports by the industry than anticipated and the UK’s subsea sector is renowned for its excellence around the world

• **Investment** – investment has exceeded expectations in recent years, because of higher oil prices and the remaining potential of the UKCS.

The matters addressed by PILOT are aimed at the overall objective of recovering the maximum amount of the UK’s oil and gas resources that can be economically achieved. However, the specific matters being addressed do change as the years go by. Currently these are:

• **Decline in exploration**
  In response to the sharp decline in exploration drilling in 2011 (see page 28), PILOT’s Exploration Task Force was created to identify the main obstacles to exploration drilling and to determine what government and industry could do to increase activity.

• **Improved/enhanced oil recovery (IOR/EOR)**
  As oil and gas become more difficult and costly to extract, the industry is investing in improved methods of extraction. As a result, IOR and EOR work groups were created to undertake a formal analysis of the benefits of using new technologies to increase recovery from the UKCS.

• **Infrastructure access**
  PILOT’s Infrastructure Access Group was formed in 2012 and has three areas of work: the Infrastructure Code of Practice\(^5\) (ICoP), criticality of infrastructure and transformational options for critical infrastructure.

One of the recommendations of this group was to establish areas of ‘special economic interest’ on the UKCS to encourage greater co-operation between parties, targeting critical infrastructure hubs to promote maximum economic recovery. Work groups have been established that are looking at specific infrastructure issues in the northern and central North Sea.

• **Production efficiency**
  As a result of the rapid decline in production efficiency (see page 21), PILOT has launched a Production Efficiency Task Force that is challenging the industry to increase efficiency from 60 per cent to nearer 80 per cent.

• **Technology**
  Technical innovation and application can and will play a major part in enhancing the future of the UKCS by improving exploration success, increasing recovery and safely extending the lives of fields. The range of technologies required is broad with the required funding, policy and supply mechanisms complex. Therefore, PILOT has commissioned the creation of a Technology Strategy to help establish the UK as a leader in selected areas of oil and gas technology, thereby strengthening the supply chain.

The success of past PILOT initiatives has demonstrated the willingness of government and the industry to find solutions to difficulties in a co-operative manner. There will be a continuing need to work together to ensure that the productive life of the UKCS stretches to at least 2050.

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\(^5\) To ensure that new and smaller companies can develop and bring on-stream discoveries which require use of others’ infrastructure, the industry developed a Code of Practice for third party access to infrastructure, known as ICoP. Adopted in 2004 and updated since, the ICoP outlines the best practice and expected behaviour of those who conduct negotiations for access to infrastructure. More information about ICoP may be found at [http://www.oilandgasuk.co.uk/knowledgecentre/InfrastructureCodeofPractice.cfm](http://www.oilandgasuk.co.uk/knowledgecentre/InfrastructureCodeofPractice.cfm)
5.
5. Case Studies of New Investment: Cygnus and Montrose-Arbroath Fields

Introduction

The special tax regime which applies to the UKCS has undergone many changes since its inception in the mid-1970s, not least in March 2011. It is clear that the regime will have to be refined further in the years to come to ensure that the overall objective, shared by government and the industry, of recovering as much oil and gas as is economically possible from the UKCS is achieved. Since the shock of 2011’s tax rises, much work has been done by both HM Treasury (HMT) and the industry to find ways of helping to stimulate investment in technically difficult and economically marginal fields; investment that would not otherwise happen.

Two such projects which have benefited from newly introduced tax reliefs, called field allowances, are outlined below, the first being a greenfield development (Cygnus) and the second brownfield (Montrose-Arbroath). It should be emphasised that field allowances only ease the tax burden; they do not remove it. An explanation of how UKCS production is taxed and how these allowances are applied is given in Section 6.

GDF SUEZ E&P UK’s Cygnus Development

GDF SUEZ E&P UK Ltd is becoming one of the leading, new operators in oil and gas exploration and production on the UKCS and is focused on growth in three core areas: the central and southern North Sea and west of Shetland.

Since entering the UK in 1997, the company has built a substantial portfolio of assets in these areas, comprising almost 50 licences, 18 as operator. With more than 300 staff and contractors based in London and Aberdeen, the operator recently underlined its commitment to the UKCS by taking a 15-year lease on a new building in Aberdeen which will be completed in 2014.

GDF SUEZ E&P UK is operator of the Cygnus development, with partners Centrica and Bayerngas UK. Cygnus is one of the most significant undeveloped gas fields in the southern North Sea (SNS) and the sixth largest field in the UKCS by remaining gas reserves. The company is also operator of the Juliet gas field in the SNS, a subsea tie-back development with first gas due in late 2013, and has an exciting portfolio of discoveries and exploration projects in the central North Sea and west of Shetland.
Cygnus is the largest gas discovery in the SNS during the last 25 years. The project has reached development thanks to innovative geological and technical thinking by operator GDF SUEZ E&P UK and also because of a tax relief for large, shallow water gas fields announced by the government in July 2012.

The partners are investing approximately £1.4 billion in the project, of which more than 80 per cent is being spent in the UK with the creation of 4,000 direct and indirect jobs. First gas from the field is expected to be produced in late 2015. It will meet the demand of nearly one and a half million homes at the plateau of its production in 2016, when it will be the second largest gas producing field and account for around five per cent of the UK’s gas production.

The development concept comprises two drilling centres. The central production, processing and accommodation facilities consist of three bridge linked platforms (Alpha Production and Utilities (PU), Alpha Quarters and Utilities (QU) and Alpha Wellhead Platform (WHP)) located on Cygnus East. The second drilling centre will be a satellite WHP (Bravo WHP) located approximately seven kilometres north-west of Alpha on Cygnus West and will be tied back to the Alpha PU via a 12 inch pipeline.

There will be compression facilities situated on Alpha PU in order to meet the field’s full production potential. The Bravo WHP will be a ‘normally unattended installation’ and the gas export route will be via a 24 inch, 55 kilometre pipeline connected to the Esmond Transmission System and through to the onshore gas terminal at Bacton in Norfolk.

GDF SUEZ E&P UK is aligned with Oil & Gas UK in the industry body’s constructive engagement with HMT and DECC. This dialogue has resulted in a range of tax measures, such as the small

*Figure 26: Field Layout of the Cygnus Development*
fields and high pressure, high temperature field allowances, which have enabled investors to take a fresh look at the economic viability of projects on the UKCS.

The tax relief to support large shallow water gas fields provided the Cygnus partners with the certainty and confidence to proceed with the project which was sanctioned in August 2012. In due course, production from Cygnus will generate substantial tax revenues for the Exchequer, as well as contributing significantly to the balance of payments, security of supply and job creation. GDF SUEZ E&P UK believes that it is important that the right investment and fiscal regime exists to help move potential new projects through to their development.

Leading edge geophysics and a successful appraisal programme have been central to the progress of Cygnus since GDF SUEZ E&P UK became operator in 2002. The company has transformed a small discovery into the largest gas development in the SNS during the last 25 years. Cygnus also faces technical challenges because of its shallow water location. This limits the number of vessels that can work in such water depths which in turn affects the weight and size of the platforms. In deeper water, a number of these platforms could be combined. The large areal extent means that a minimum of ten long wells (up to 18,000 feet) with horizontal sections (up to 3,500 feet) have to be drilled to reach the multiple reservoirs.

By drawing on international knowledge within the organisation, applying bespoke drilling techniques and revitalising existing infrastructure, GDF SUEZ E&P UK aims to ensure that Cygnus is a North Sea success story set to secure future energy supplies.

**Figure 27: Cygnus Milestones**

<table>
<thead>
<tr>
<th>Year</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1988 and 1989</td>
<td>Blocks including the Cygnus field were drilled by other operators, but were not pursued because initial evaluation suggested a poor quality reservoir</td>
</tr>
<tr>
<td>2002</td>
<td>GDF SUEZ E&amp;P UK acquired the licence for the blocks</td>
</tr>
<tr>
<td>2003</td>
<td>The appraisal programme began with the first 3D seismic survey in the SNS using what was then new long cable technology</td>
</tr>
<tr>
<td>2006</td>
<td>First appraisal well drilled</td>
</tr>
<tr>
<td>2009</td>
<td>Plans were drawn up for a relatively simple development; however, other parts of the field showed much better reservoir quality. Two further appraisal wells were drilled.</td>
</tr>
<tr>
<td>2010</td>
<td>Another two appraisal wells drilled, confirming a westerly extension with good quality reservoir delivering high flow rates</td>
</tr>
<tr>
<td>2011</td>
<td>Extended development concept for Cygnus selected</td>
</tr>
<tr>
<td>July 2012</td>
<td>Shallow water gas field tax allowance introduced by HM Treasury</td>
</tr>
<tr>
<td>August 2012</td>
<td>Project sanctioned</td>
</tr>
<tr>
<td>September 2012</td>
<td>The Chancellor of the Exchequer, George Osborne, visited Heerema yard in Hartlepool for ceremonial contract signing</td>
</tr>
<tr>
<td>December 2012</td>
<td>First steel for the project cut at Heerema, Hartlepool</td>
</tr>
<tr>
<td>May 2013</td>
<td>First steel cut for the four jackets at Burntisland Fabricators, Fife</td>
</tr>
</tbody>
</table>
Factors for Success

- Innovative geological thinking combined with leading edge geophysics
- A long-term perspective on E&A activity
- Subsurface knowledge sharing between GDF SUEZ E&P affiliates in the UK, the Netherlands and Germany
- Application of high-tech 3D seismic technology to capture previously unseen images
- Application of drilling techniques for fine grained reservoirs
- Revitalisation of existing transport infrastructure

Key Facts

- Cygnus is located in the southern North Sea, 150 kilometres off the coast of Lincolnshire
- £1.4 billion will be invested by the partners, more than 80 per cent of which will be spent in the UK, creating around 4,000 jobs
- First gas is due in fourth quarter of 2015
- Gas will be landed at the terminal at Bacton on the coast in north-east Norfolk
- It has reserves (with at least a 50 per cent probability of recovery) of approximately 18 billion standard cubic metres of natural gas
- It is the UK’s sixth largest gas field by remaining reserves
- At plateau production in 2016, it will be the second largest source of gas on the UKCS
- The partnership is led by operator GDF SUEZ E&P UK (38.75 per cent), with Centrica (48.75 per cent) and Bayerngas UK (12.5 per cent)

Major contracts awarded in the UK

Companies that are already benefiting from contracts awarded for the Cygnus project include:

- Heerema Fabrication Group’s Hartlepool yard – for the fabrication and commissioning of the Alpha WHP and PU platform topsides
- Burntisland Fabrication (BiFab) – for the engineering, procurement and construction of the Cygnus jackets and piles, as well as construction of the QU platform. This work will be undertaken at their facilities in Methil and Burntisland in Fife on the Scottish mainland and Arnish on the Isle of Lewis in the Outer Hebrides
- AMEC Group in London – for the detailed engineering design contract
- Saipem in London – for the diving works and the installation of the main 55 kilometre export pipeline from the platform to the Esmond pipeline and the seven kilometre infield line from the Bravo WHP to the Alpha Complex.
- Ensco in London – for the Ensco 80 rig to drill the ten horizontal wells.
- Isleburn in Invergordon – for the fabrication of the structures for the subsea ‘Y’ manifold and subsea isolation valves (SSIVs)
- Genesis in Aberdeen – which completed the subsea detailed design and remains involved in follow-up engineering

Figure 28: Cygnus Project – Locations of Principal Contractors
Talisman Sinopec Energy UK’s Montrose Area Redevelopment

Talisman Sinopec Energy UK (TSE UK) is one of the newest and most dynamic companies exploring for and producing oil and gas in the North Sea. TSE UK, based in Aberdeen, was created in 2012 as a joint venture between Talisman Energy Inc and Addax Petroleum UK Limited, a wholly-owned subsidiary of China Petrochemical Corporation (Sinopec Group). TSE UK is one of the largest operators on the UKCS, with 26 fields, 11 offshore installations and one onshore terminal.

The main purpose of the organisation is to unlock opportunities in the North Sea and build a safe, profitable and sustainable business. The most recent effort to realise this potential is the £1.6 billion Montrose Area Redevelopment (MAR) project which will extend the life of one of the UK’s oldest platforms – inaugurated in 1976 – to at least 2030.

The Montrose platform will undergo significant modifications, including the development of a new bridge linked platform (BLP) which is planned to be installed in 2015. Two currently undeveloped fields, Cayley and Shaw, will also be brought into production by being tied back to the BLP.

The MAR project will unlock 100 million barrels of reserves when it comes on-stream in 2016 and will create or sustain more than 2,000 jobs during construction, fabrication, installation, subsea engineering and drilling. The government has recognised its value to the economy by making it the first project to benefit from a Brown Field Allowance (BFA), a tax relief introduced in 2012 to encourage the renewal and life extension of existing fields (see section 6 for more information about this allowance).

Figure 29: MAR Milestones

- **1969**: Arbroath reservoir discovered, the first oil field on the UKCS
- **1971**: Montrose reservoir discovered
- **1976**: First oil from Montrose Field
- **1990**: First oil from Arbroath Field
- **1996**: Arkwright Field developed via a subsea tie-back to Arbroath
- **2005**: Brechin Field developed as a subsea tie-back to Arbroath
- **2007**: Wood Field developed as a subsea tie-back to Montrose
- **2007 to 2009**: A successful exploration campaign resulted in the discovery of the Cayley, Godwin and Shaw Fields
- **2011**: Sanction of the Godwin Field development
- **2012**: Sanction of integrated Montrose Area Redevelopment programme to develop Cayley and Shaw via a bridge-linked platform at Montrose and to carry out further infill drilling in the Montrose field
- **2013 to 2014**: Godwin Field development by drilling extended reach well from Arbroath
- **Quarter 1 2016**: First expected oil from Cayley and Shaw Fields
The project will create new infrastructure in the Montrose field and comprises the following:

- The development of about 100 million boe of reserves, with 40 per cent coming from the Shaw oil field, 30 per cent from the Cayley gas-condensate field and the balance from infill drilling on and life extension of the Montrose field
- Life extension of the MAR infrastructure from 2017 to beyond 2030
- Subsea tie-back of 17 to 18 kilometres of the Shaw field to the BLP via rigid subsea pipelines
- Subsea tie-back of ten kilometres of the Cayley field to the BLP via two pipeline bundles
- A modular rig to be installed on Montrose to allow drilling of infill wells starting in 2016
- Modifications on the existing Montrose platform requiring over 200,000 direct hours of offshore construction work. Additional living quarters for 30 personnel are being installed on Montrose, together with a new central control room with associated integrated control and safety system and new office spaces. Various modifications are also required to support the new BLP interfaces, along with life extension upgrades

Major Contracts Awarded in the UK

- **Subsea 7 Ltd in Aberdeen** – provision of engineering, procurement and installation of two five-kilometre pipeline bundles complete with towing heads; procurement, installation, trenching and pre-commissioning of 17.5 kilometre production and gas lift pipelines and an 18.5 kilometre water Injection pipeline; and installation of four subsea umbilical lines, production manifold and gas export SSIV structure. Offshore installation will take place during 2014 and 2015 seasons. Contract value: £178 million.
- **AMEC Group in Aberdeen** – engineering, procurement, construction and commissioning services on the Montrose platform. Contract value: £67 million
- **CB&I UK in London** – engineering design of jacket and topsides. Contract value: £62 million
- **OGN North Sea in Newcastle** – engineering, procurement and construction of the Montrose BLP jacket and piles. Contract value: £55 million
- **Saipem in London** – transportation and installation services. Contract value: £37 million
- **Proserv Controls in Great Yarmouth** – engineering, procurement, manufacture and testing of the subsea control system. Contract value: £10 million
- **Duco Ltd in Newcastle** – engineering, procurement, manufacture and testing of six subsea umbilical lines. Contract value: £10 million
- **Invensys Systems (UK) in London** – new integrated control and safety systems for Arbroath, Montrose and the new BLP. Contract value: £5 million
- **Hertel in Middlesbrough** – engineering and construction of additional living quarters for 30 personnel on Montrose. Contract value: £6 million

**Figure 30: MAR Project – Locations of Principal Contractors in the UK**

Source: Talisman Sinopec
• Construction works to be completed over a three-year period from 2013 to 2015. A flotel (floating hotel) will be on location for ten months to provide additional accommodation over the various phases of construction. At their peak, the upgraded facilities are expected to produce 55,000 boepd from the MAR fields and the annual average will be some 35,000 boepd.

The BLP has four significant elements (jacket, deck, bridge and flare), requiring the design, procurement, construction and commissioning of over 17,000 tonnes of materials and equipment. The jacket includes three caisson riser systems to facilitate the tie-in of the Cayley and Shaw pipelines and umbilical lines, whilst providing spare risers and a J-tube for future developments. The deck houses state-of-the-art process facilities for separating the hydrocarbon streams from Cayley (gas condensate) and Shaw (oil and associated gas), produced water treatment and water injection. The development uses existing oil and gas export subsea facilities, although gas will now be exported through a new rigid caisson riser system located on the BLP.

Subsea isolation valves (SSIVs) are being installed on all new production and gas lift pipelines and will be contained within a single structure to the north-west of the BLP.

The subsea field developments of Cayley and Shaw require 100 kilometres of pipelines to be procured, assembled and installed to tie-back seven subsea wells from three drilling centres. Some 600 kilometres of control hoses and tubing will be manufactured into umbilical lines contained within pipeline bundles to distribute hydraulic fluids and chemicals across the fields.

\[\text{Figure 31: Layout of the Montrose-Arbroath Project}\]

\[\text{Key Facts}\]

- TSE UK and its co-venturer, Marubeni, will invest £1.6 billion in the MAR project
- MAR encompasses four fields in Palaeocene-aged reservoirs (Montrose, Arbroath, Arkwright and Brechin), four fields in Jurassic-aged reservoirs (Wood, Godwin, Cayley and Shaw) and a Zechstein-aged reservoir (Carnoustie)
- The fields are located approximately 210 kilometres north-east of Aberdeen
- Since production started in 1976, over 270 million boe of oil and associated gas have been produced
- The MAR project will unlock 100 million barrels of reserves when it comes on-stream in 2016 and will create or sustain more than 2,000 jobs during construction, fabrication, installation, subsea engineering and drilling
- Oil is exported via the Forties Production System (FPS) to Cruden Bay and then on to Grangemouth
- Gas is exported via the Central Area Transmission System (CATS) to Teesside
- The project was the first to be awarded a BFA
6. Fiscal Policy

Introduction

The production of oil and gas from the UKCS is the most highly taxed business activity in the country, with three separate corporate taxes which generate substantial revenues for the Exchequer.

Over the past decade or so, the UKCS has been subject to considerable fiscal instability, with the most recent tax change, in March 2011, increasing overall tax rates to between 62 per cent and 81 per cent. To ensure that the remaining development opportunities on the UKCS are internationally competitive, the government has had to build on existing field allowances (FAs), first introduced in 2009, providing targeted relief from the scope of the Supplementary Charge (SC).

These allowances have contributed to a greater diversity of marginal tax rates which reflect the varying commercial opportunities available on the UKCS. Since the introduction of the Brown Field Allowance (BFA) in September 2012 and with the security to be provided by Decommissioning Relief Deeds (DRDs), the government now has the ability to influence all phases of the development cycle through the fiscal regime. This should help ensure that the full economic potential of the UKCS is realised over the coming years.

The Fiscal Regime for Oil and Gas

The production of oil and gas from the UKCS is subject to a ‘ring fence’ tax regime\(^6\) comprising:

- **Ring Fence Corporation Tax (RFCT)** – this is computed in a similar way to normal Corporation Tax (CT), but with different rules for the treatment of losses, 100 per cent first year capital allowances and a higher rate of 30 per cent on all profits. The oil and gas industry has not benefitted from reductions in the rate of CT seen elsewhere in the economy in recent years.

- **Supplementary Charge (SC)** – this is an additional corporation tax, levied on all profits at the rate of 32 per cent (was 20 per cent before March 2011). Profits are computed in the same way as for RFCT, but finance costs are not deductible for SC purposes.

- **Petroleum Revenue Tax (PRT)** – this is a field-based tax on profits in the regime and only applies to fields given development consent by DECC before March 1993. PRT is levied at a rate of 50 per cent and is deductible for the purposes of computing profits charged to RFCT and SC. Immediate relief is given for all capital and revenue expenses.

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\(^6\) The ‘ring fence’ ensures that the profits from oil and gas production are taxed separately from any other activities within a company and any losses made by those other activities cannot be used by the company to offset the profits from the production of oil and gas.
Marginal tax rates therefore vary across the UKCS as follows:

- Fields subject to PRT, SC and RFCT pay 81 per cent of their profits in tax, comprising PRT at 50 per cent, plus 30 per cent RFCT and 32 per cent SC of the remaining 50 per cent
- Fields not paying PRT (either because they are not liable to this tax, or by virtue of a relief called Oil Allowance\(^7\)) are subject to tax at a marginal rate of 62 per cent (30 per cent RFCT plus 32 per cent SC)
- Fields which benefit from a FA – a relief against SC – pay tax at a rate between 30 per cent (that is only paying RFCT at 30 per cent) and 62 per cent (on profits once the field allowance has been used).

As the oil and gas fiscal regime taxes profits at a minimum rate of 30 per cent which is considerably higher than for companies in all other parts of industry and commerce, the Oil Allowance within the PRT regime and field allowances for SC purposes only ever reduce the tax burden from very high rates to one that is closer to, but still higher than that for other companies. Therefore, these allowances cannot be said to represent a subsidy for the industry as they only partially alleviate the tax burden.

Furthermore, some companies are also subject to both the RFCT regime in respect of their upstream oil and gas production activities and the normal CT regime for their downstream refining and marketing activities. Companies cannot offset their profits or losses between the two regimes to reduce their overall tax liability, as upstream profits are always taxed separately under the ring fence regime.

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\(^7\) Oil Allowance is a relief to ensure that PRT is only levied on the largest, most productive fields. The allowance gives each field liable to PRT amounts of oil and gas which can be produced free of PRT per tax period and for the life of the field. Any production above these amounts is subject to PRT at the prevailing rate.
Recent Developments with Field Allowances

During 2012, there were a number of extensions to the FAs, as follows:

- A new class of FA was introduced in March 2012 for deep water oil fields with a pre-tax value of £3,000 million. This enabled a consortium led by Chevron to continue with its development of the Rosebank field to the west of Shetland.
- Also in March 2012, the Small Field Allowance was increased in value to £150 million pre-tax and in scope to cover fields up to 50 million boe of recoverable reserves.
- In July 2012, another new FA was introduced with a £500 million pre-tax value for large, shallow water gas fields.

The most significant change occurred in September 2012, when the FA concept, which had only previously been applied to new fields, was extended to cover incremental investment projects in fields already in production. The resulting BFA was the culmination of over 12 months of work, led by Oil & Gas UK, with the government and industry.

It introduced a capital cost based allowance per project, scaled with its size. As long as the capital costs exceed £60 per tonne of recoverable oil (approximately $12/bbl), the allowance is available for each tonne that the project is expected to recover. The BFA is calculated on estimated capital expenditure and estimated reserves to be recovered at the time the project is granted development consent.

**Figure 33: The Brownfield Allowance**
Oil & Gas UK believes that the BFA is essential in enabling maximum recovery of the UKCS’ resources and ensuring that projects are competitive in attracting international capital investment. Since the BFA was introduced, more than £3 billion of capital expenditure has been allocated to some of the oldest and most mature fields on the UKCS, unlocking around 300 million boe of reserves.

However, as mentioned above in Section 4, it is clear that the taxation of the UKCS will have to be refined further in the years to come to ensure that the overall objective, shared by government and the industry, of recovering as much oil and gas as is economically possible is achieved.

A table explaining the various field allowances can be found in the Appendix of this report.

**Decommissioning Tax Relief**

Operators are under an obligation to decommission their wells, platforms, pipelines and other facilities once production from a field has ceased (there are strict regulatory requirements in place). Clearly, this is an expensive process which is currently forecast to cost the order of £35-40 billion for the whole UKCS (in 2012 money). As with the original investment, it is a cost which is allowable for tax purposes. However, profits have been taxed year by year without any provisions being allowed for future decommissioning expenditure and, furthermore, there has never been any certainty that tax relief on decommissioning costs will be available as and when the expenditure is incurred.
This has been a substantial and long standing concern for the industry, which was exacerbated in the Budget of March 2011 when a restriction was introduced on the rate of relief allowed. Since then, Oil & Gas UK has led the industry in working with the government to secure the necessary tax reliefs for the whole of the UKCS. Subsequently, the Finance Act 2013 legislates for the introduction of Decommissioning Relief Deeds (DRDs), which will provide contractual certainty that costs arising from decommissioning activities can be offset against tax previously paid by companies (for RFCT and SC purposes) and fields (for PRT).

Securing certainty for tax relief on decommissioning is a seminal moment for the industry. It will mean that the current barriers to the trading of assets are lifted, enabling these assets to be transferred to those companies most likely to develop them. In turn, this should unlock a significant amount of new investment to extend the productive lives of a wide variety of fields. All this has been achieved at no cost to the government and without requiring any pre-funding from the industry.
7. The Supply Chain, Employment and Skills

A healthy supply chain is integral to the success of the UKCS. Industry and government recognise that supporting the domestic supply chain has positive effects on employment, Gross Domestic Product (GDP), taxes, the development of technology, exports and, ultimately, the recovery of oil and gas reserves.

**Industrial Strategies**

Both the Scottish and British governments have published oil and gas sector strategies, the former in the summer of 2012\(^8\) and the latter in the spring of 2013\(^9\) jointly by the Department for Business, Innovation and Skills (BIS) and DECC. Both documents cover similar themes, focus on the upstream oil and gas supply chain and are jointly owned by government and industry.

BIS and DECC’s strategy has three underpinning aims:

- To maximise the economic production of the UK’s offshore oil and gas resources
- To sustain and promote the growth of the industry’s supply chain, in both domestic and international markets
- To promote purposeful collaboration across industry and between industry and government

An industry council has been formed to advise BIS and DECC. Of the 42 actions that have come from the council, mapping the supply chain represents one of the biggest challenges. Once complete, the map will identify where best to promote growth and further expand the oil and gas supply chain’s capabilities, both domestically and internationally.

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Many of these actions are underway, each being led by more than one council champion. As part of the council’s work, the government has agreed to consider its role in improving the public’s perception of the industry. A pilot project, ‘Energising the Nation’s Future’, has been initiated by Oil & Gas UK to raise awareness of the industry and the positive case studies from the sector. Other actions underway include co-operative work by government and industry to help stimulate student demand for engineering careers and mapping of the work carried out by BIS to address the uptake of STEM (Science, Technology, Engineering, and Mathematics) subjects.

All actions arising from both the Scottish and British strategies are in place to help work towards the ultimate goal of maximising economic recovery of oil and gas from the UKCS.

Ernst & Young’s Oil Field Services Report 2012

The supply chain supports the industry across all its requirements, from the seismic acquisition of reservoir data, through exploration and appraisal drilling, field developments and production operations, to decommissioning at the end of field life. According to Ernst & Young’s 2012 Oil Field Services Report for the UK, the combined activity of 390 companies generated £27 billion of revenues in 2011 for their goods and services; this was 17 per cent more than the previous year. In terms of jobs, these companies provided direct employment for almost 93,000 people in 2011, a seven per cent increase on 2010, reflecting the increased activity in the industry and its supply chain.

Figure 34 suggests that revenues have risen steadily since data were first collected in 2008.

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10 See [http://www.energisingthenationsfuture.co.uk](http://www.energisingthenationsfuture.co.uk)

11 Ernst & Young only include companies where at least 50 per cent of their turnover is in the oil and gas sector, are UK registered and have annual revenues exceeding £10 million. E&Y identified another 720 companies involved in the sector, but with annual revenues of less than £10 million.
However, pre-tax profits actually fell in 2009 and 2010, before rising by 27 per cent in 2011. The failure to translate increased revenues into increased profits suggests that the supply chain struggled to contain its costs in 2009 and 2010. Rising labour costs, resulting from a tight market for highly skilled people, are the likely cause of these increased costs.

Ernst & Young’s report splits the supply chain into four broad categories: reservoir and seismic, exploration and production drilling, operations (comprising production and maintenance), and engineering, fabrication and installation. The relative turnovers of these are shown in Figure 35 and their profitability in Figure 36.

Engineering, fabrication and installation is the largest sector in terms of revenue, accounting for some 40 per cent of total UK supply chain turnover in 2011 and employing some 32,000 people. Operations (production and maintenance) comprise the second biggest sector in terms of revenue with a 30 per cent share and it is the largest sector in terms of employment, with 38,000 employees in 2011. Exploration and production drilling typically make up a quarter of supply chain revenues and employs some 19,000 people, while the smallest sector in terms of revenue and employment is reservoir and seismic, which typically captures less than five per cent of revenues and employs around 4,000 people.

The 26 per cent growth in revenues for the UK’s engineering, fabrication and installation sector in 2011 was driven by the international success of subsea engineering businesses and the demand for engineering and design work.

Operations’ (production and maintenance) revenues recorded a healthy increase for a third consecutive year. This segment is made up of production processes, including a broad range of operations and maintenance work.
and activities associated with increasing oil recovery. Given the ageing infrastructure present on the UKCS and the number of brownfield projects, it is not surprising to see such a rise in revenues from operations.

Revenues in exploration and production drilling grew slightly in 2011, but overall its market share in the UK has been decreasing. Revenues are consistently lower than those seen in the equivalent Norwegian sector, but costs in Norway are also consistently higher.

Reservoir and seismic is a growing sector in the UK, but from a relatively small base. Profitability fell by 54 per cent in 2010, which was probably caused by the six month drilling moratorium in the Gulf of Mexico (GoM) between May and November, releasing spare seismic vessels from the GoM to the UKCS and depressing day rates. The supply of these vessels in the UK tightened in 2011 after the moratorium in the GoM was lifted, helping both revenues and profits to recover in 2011.

Scottish Council for Development and Industry’s Report – Exports

The Scottish Council for Development and Industry’s 2011-12 Survey of International Activity in Scotland’s Oil and Gas Sector indicates that the Scottish supply chain’s revenues totalled £17.2 billion in 2011, growing by 5.8 per cent from 2010. International sales increased by 8.4 per cent to £8.2 billion in 2011, with North America remaining the main export market. Scottish exports to Norway, Angola, Nigeria and the UAE are also strong.

Subsea Engineering

A particular strength of the UK’s supply chain is subsea engineering which generates £8.9 billion in revenue for the economy according to Subsea UK. Subsea technology has become increasingly important, both in producing oil and gas reserves from the UKCS and in expanding exports.

More than 800 companies are active in the UK’s subsea sector, with SMEs making up the largest proportion. Of that total number, seven per cent each generate more than £100 million of turnover a year, with the median turnover being £2.6 million. The 36 largest companies and their subsidiaries produce 70 per cent of subsea turnover in the UK and 77 per cent of the sector’s total output.

The companies involved are spread across the country, although three quarters of the total revenue is generated in the north-east of Scotland (£6.7 billion). Around £614 million of output is concentrated in the east of England and £400 million and £126 million in the north-east and south-east of England, respectively. The remainder is spread across the east Midlands, the north-west and south-west of England, Wales and the rest of Scotland.

The export of subsea goods and services from the UK is valued at £4.4 billion. Key markets are Norway, West Africa, North America and Asia. Engineering and manufacturing companies generate a substantial share of this revenue, as do service providers in disciplines such as diving, remotely operated vehicle inspection, underwater construction, installation and surveying.

On the back of this strong performance, 16,000 new jobs have been created since 2010, bringing the total number of people directly employed in the subsea sector to 53,000, with another 13,000 employed indirectly. Engineering, construction and diving roles account for 48 per cent of the workforce, with manufacturing accounting for 19 per cent of the total.

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The future prospects of the subsea sector are positive and, if companies’ growth forecasts are achieved, over £11 billion of revenues could be achieved by 2016. Future growth in exports is anticipated to come primarily from North and South America and Asia.

**Well Services**

The state of the well services’ sector is a good indicator of current and future activity on the UKCS, because of its involvement in the exploration for and appraisal and development of oil and gas reservoirs. In 2012, companies delivering drilling, completion, testing and maintenance services for oil and gas wells generated the highest gross revenue since records began in 1996, at £1.9 billion. This higher than expected revenue can be attributed to the growing number of technically complex wells which require the specialist skills and knowledge of well services’ contractors.

This success has in turn boosted employment, as the number of highly skilled jobs in the UK supported by the sector also rose by ten per cent in 2012 to 13,000, including 2,200 graduate engineers and 1,700 technicians.

The sector’s future prospects are good with companies forecasting a further five per cent increase in revenues in 2013. Technical innovation is a priority for well services’ contractors with some companies spending up to 90 per cent of their annual capital investment on developing new technologies. Indeed, their overall investment in future capacity increased by 20 per cent in 2012 to £111 million, half of which was in capital equipment, the other half in new technology.

**Fabrication**

Since the discovery of oil and gas on the UKCS more than 40 years ago, the industry has developed an indigenous fabrication supply chain with expertise in the design and construction of offshore platforms and a broad range of associated structures.

Britain’s fabricators have been involved in much of the construction of around 6.5 million tonnes of concrete and steel structures installed on the UKCS to date. The sector has demonstrated it has the capacity to design and fabricate:

- Jackets (the steel substructures which support platforms)
- Decks and modules comprising the topsides facilities (above the jackets), such as drilling, production, process, utilities and accommodation units
- Flare booms and towers
- Subsea manifolds and pipeline bundles

While the requirement for very large, integrated offshore platforms is no longer as it was in the 1970s, 1980s and 1990s, there still remains substantial demand for fabrication services, especially associated with fields developed as subsea tie-backs to existing production platforms. The existing infrastructure often requires modification and upgrading to accommodate new flows of oil and/or gas (55 per cent of fields approved in the last five years have been or will be developed as subsea tie-backs).

An illustration of a pair of bridge linked, offshore platforms is depicted in Figure 37 overleaf (note that it is not unusual for all the topsides facilities to be accommodated in a single, integrated platform).
a) Distribution of Fabricators in the UK
Fabrication firms tend to be located along the coasts, often in regions with a strong heritage in heavy engineering industries, such as ship-building, mining or power generation. Over the past 40 years, the bigger fabrication yards have also encouraged the emergence of a diverse, often local, supply chain in which SMEs have evolved to support fabricators by delivering more specialised goods and services, such as pipework fabrication, painting and insulation, asset integrity consultancy and other technical services.

b) Fabrication Work for Field Developments on the UKCS, 2008 to 2013
Oil & Gas UK recently conducted a survey covering the five year period 2008 to mid-2013 to assess the volume and location of fabrication activity taking place in the UK associated with UKCS developments and to identify where fabrication for these projects is undertaken by firms overseas.

DECC approved more than 60 field developments from 2008 to mid-2013 which

**Figure 37: Typical Offshore Platforms**
Oil & Gas UK has categorised into five different types for fabrication purposes:

- **Subsea**
- **Floating Production Storage and Offloading vessels (FPSOs)**
- **Steel structures within three main weight ranges:**
  - Under 4,000 tonnes
  - Between 4,000 tonnes and 20,000 tonnes
  - Greater than 20,000 tonnes

The number of projects in each category over this five-year period can be seen in figure 39 (overleaf) and, as mentioned above, the majority in this time-frame are subsea tie-backs. For this type of development, the survey results show that most of the structures are fabricated in the UK. Larger platform structures are being built in both the UK and overseas, but fabrication of FPSOs is invariably contracted to ship yards located in Korea and China for commercial and capacity reasons.
In BIS and DECC’s industrial strategy for oil and gas, referred to above, fabrication has been identified as requiring specific attention. While there are several British fabrication yards that actively tender for substantial offshore projects, a number of recent major fabrication contracts have been awarded to overseas yards that are apparently more competitive than those at home. The government is working with the industry, without compromising the competitiveness of projects, to ensure that fabricators in this country are given every opportunity to bid for all UKCS contracts.

**Technology**

The development and production of oil and gas from the UKCS has a history of great technical innovation to find and develop a wide variety of oil and gas reservoirs in varying water depths, often with a high degree of geological uncertainty and in demanding maritime conditions.

Historically, much of the research and development (R&D) has taken place within the international oil companies (IOCs) and larger service companies who have significant R&D capability. The government’s 2010 scoreboard showed that, of the top 1,000 UK companies investing in R&D, 16 invested some £1.2 billion in oil and gas R&D in this country.

Meanwhile, direct government funding of R&D for the oil and gas industry has been fairly low (about £7 million between 2006 and 2011) with no thematic oil and gas research area within Research Councils UK\(^\text{14}\). The majority of research council funding has been indirect via projects in areas of relevant science (such as advanced materials) and other related subjects (such as carbon capture and storage). This has raised the total of £7 million mentioned above to nearer £10 million between 2006 and 2011, or about two per cent of the total public sector funding of energy research.

\(^{14}\) See [http://www.rcuk.ac.uk/Pages/Home.aspx](http://www.rcuk.ac.uk/Pages/Home.aspx)
In addition, the Technology Strategy Board has funded some £22 million of oil and gas related projects since 2007 (11 per cent of its energy funding).

Looking to the future, it is clear that the prosperity of the UKCS will be significantly influenced by successful development and implementation of new technologies. In recent years, the number of operators has increased, while the role of the major IOCs has decreased. As a consequence, the ability of operators to undertake R&D in-house has declined. This means that, more than ever, an efficient, industry-wide system of research through to deployment in the field is required.

The technical challenges facing this diverse range of operators are becoming greater, as outlined below:

- Current exploration success rate is low compared with other oil and gas provinces. The exploration targets are small and geologically complex and sometimes with high pressures and temperatures.
- Current oil field recovery factors in the central and northern North Sea are just over 40 per cent. IOR and EOR technologies will be required to increase the average recovery factor to above 50 per cent.
- Much of the infrastructure is beyond its design life, requiring comprehensive plans to extend its life and increase recovery (note the Health and Safety Executive’s Key Programme 4 on asset integrity referenced in footnote 4).
- Cessation of production from critical fields could constrain access to new resources.
- The remaining reservoirs hold resources which are increasingly difficult to recover.
- Long and/or complex subsea tie-backs are necessary for many new developments.
- Decommissioning is a growing activity across the UKCS.

However, the above challenges represent an enormous opportunity for the companies involved and for Scotland and the UK as a whole, hence the work of the task force, PILOT, in addressing these matters (see ‘The Road to 2040’ in Section 4) and the two industrial strategies discussed earlier in this section.

**Figure 40: New Technology – the Treatment of Injected Water for EOR Purposes in the Clair Field**

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15 See [http://www.innovateuk.org](http://www.innovateuk.org)
Employment

The industry is a major source of employment throughout the UK. The most recent figures available show that direct employment by companies exploring for and producing oil and gas from the UKCS has grown by 12 per cent to 36,000 compared with the previous study conducted in 2010.

Over the same period, it is estimated that the number in indirect employment (in supply chain companies contracted for work by operators) has remained fairly stable at around 200,000, in part because of gains in efficiency, but also due to increased competition for labour internationally and the awarding of some contracts overseas. However, induced employment is estimated to have grown from 100,000 to 112,000. Overall, therefore, the composition of the upstream oil and gas workforce in the UK during 2012 was:

- 36,000 directly employed by operating companies (12,500 of whom worked offshore)
- 200,000 employed in the wider supply chain (45,000 of whom worked offshore)
- 112,000 in jobs induced by the economic activity of the above employees
- 100,000 in jobs in exporting goods and services

This suggests that the industry supported some 450,000 jobs within Britain’s economy in 2012, about half of which are in Scotland, with the other half spread across the rest of the UK. However, this is likely to be an underestimate, given that total expenditure by the industry has risen by more than 15 per cent in the last year alone (although some of this will be spent abroad). The industry has sizeable employment multipliers. It is estimated that 13 jobs are supported by every £1 million of operational expenditure on the UKCS and 15 jobs are supported by every £1 million of capital expenditure.

Figure 41: Offshore Employment by Home Address
Skills

The past year has seen frequent reports in the media of the skills shortages facing the industry and it is acknowledged as one of the biggest challenges. The limited data available about the labour market (which was tested at Oil & Gas UK’s skills conference in September 2012) show that the critical areas of shortage are in a number of mid-career, onshore roles, including design engineering, subsea and drilling engineering, project management and geosciences. Technicians and skilled craftsmen are also in short supply because of the high volume of activity.

The shortages are partly due to reductions implemented when the oil price has been low in the past, as in the 1990s, but they are also very much a consequence of the current success of the industry. The skills, expertise and technology developed on the UKCS are highly sought after by other oil and gas provinces around the world; competition for skills is truly international.

Supply chain companies have highlighted the mid-career gap and have been working with the Chartered Institute of Purchasing and Supply to develop accredited courses. However, the large number of applicants for the Upstream Oil and Gas Industry Technician Training Scheme and companies’ graduate schemes indicates that the industry is attracting new entrants straight from school and university.

During the past year, Oil & Gas UK has been working with industry to identify where and to what extent co-operation across the industry can help tackle the demand for skills. A number of actions have been identified, including:

- **Establishing a high level industry relationship with the Ministry of Defence (MoD)** – 18-20,000 men and women will leave the armed forces in each of the next three years and many of them will have transferable skills. The industry’s training organisation, OPITO16, is working with the MoD to map and identify skills in both industry and military roles to facilitate the matching of skills and the development of appropriate transition training.

- **Discipline work groups in areas of shortage have been established to explore the feasibility of transition training/accelerated development.**

- **Creating smarter training solutions** – for example, through possible development of facilities that could be used as assessment or proving centres for skilled workers from other industries and to reduce the offshore training time required. A feasibility study is underway for this initiative.

- **Lobbying the government on immigration policy to facilitate recruitment of skilled personnel from non-EU countries.**

- **Education** – pooling of resources and effort under the auspices of OPITO so the industry can reach more schools throughout the country, more often, and with consistent messages about the importance of and opportunities afforded by studying STEM subjects.

Though the sector has no difficulties in attracting new entrants to the industry, it is important for the longer term to sustain a flow of school leavers and university graduates with STEM qualifications, not just for this industry, but for the economy as a whole.

16 See [http://www.opito.com](http://www.opito.com)

The world’s energy landscape continues to spring its surprises. Just a few years ago, who would have considered that North America may well return to self-sufficiency in oil by the end of the current decade or shortly thereafter, just as ten years ago who foresaw its coming self-sufficiency in gas, with the likelihood of future exports of LNG rather than imports?

These dramatic changes in one of the world’s largest markets, driven entirely by technical advances, have turned many assumptions about energy policy on their head. Instead of ever rising prices for fossil fuels, as often assumed, the price of gas has been low for the past four years in North America and this, in turn, has driven down the price of coal around the world, as surplus American coal has been exported.

In Europe and Germany in particular, this has led to a significant increase in coal consumption for power generation purposes, thus threatening the EU’s projected reductions in greenhouse gas (GHG) emissions, at least in the short term.

Elsewhere, coal’s use in power generation has meant that almost half of the rise in energy demand worldwide over the past ten years has been met by coal, expanding faster than all renewable energies combined, with China king of the coal consumers and India following on a similar trajectory, but from a lower starting point. In end use terms, electricity demand is growing the fastest, hence the increase in coal consumption, and this is likely to continue as non-OECD countries continue to develop rapidly. The contrast between the energy requirements of OECD and non-OECD countries is illustrated vividly in Figure 42.

Figure 42: A Tale of Two Worlds – Energy Demand in OECD and Non-OECD Countries

![Figure 42: A Tale of Two Worlds – Energy Demand in OECD and Non-OECD Countries](source: ExxonMobil 2013 Outlook for Energy)
In terms of investment, however, the rise in non-OECD demand is paralleled by the need for OECD countries to renew much of their energy, particularly electricity, infrastructure. Most of this infrastructure was either built or rebuilt during the great economic recovery following the Second World War and so is now reaching the end of its expected life. This provides both an opportunity to rebuild so as to accommodate new technologies and sources of supply, but also poses a threat, as the necessary financial and other, especially human, resources stretch both the investing companies and the supply chain beyond what is deliverable within the time-frame envisaged. This point has been raised in these Economic Reports for several years.

Gas is currently the fuel of choice for power generation in North America, sharply reducing emissions of GHGs while lowering electricity costs for consumers including, importantly, for heavy industry, making it more competitive internationally.

Gas is also starting to be used in medium to heavy commercial road transport in the USA and in buses in various parts of the world, offering both cost and environmental benefits. In the International Energy Agency’s (IEA) most recent World Energy Outlook17, published in November 2012, gas remains the only fossil fuel whose demand is forecast to grow in all three of the IEA’s policy scenarios (new, current and 450).

Within Europe, gas is primarily a fuel for heat, although it has a significant presence in electricity generation as well, albeit this has been reduced of late by the resurgence of coal. Nonetheless, looking ahead to 2030, gas is likely to gain market share in Europe and elsewhere for power generation purposes, as demand in non-OECD countries and environmental pressures almost everywhere keep on rising. New nuclear power is delayed or, in some countries, rejected, and large scale renewable electricity projects are struggling for funding, notably in the EU.

**Evolution of the UK’s Energy Policy**

It should not be forgotten that the UK’s energy consumption divides broadly into three similarly sized parts: electricity, heat and transport. Gas dominates heat supply; more than 80 per cent of Britain’s homes are heated by gas, together with much of the smaller commercial sector and significant parts of the larger commercial and industrial sectors. Meanwhile, oil products supply transport to an overwhelming extent, as is the case around the world, with electricity holding a share of the rail market where traffic densities make investment in the necessary infrastructure sensible.

Almost all the policy debate in the EU and UK continues to concentrate on electricity, although DECC published a heat strategy in March 2013. It is clear from this strategy how difficult and expensive reforming heating throughout the country is going to be. At its highest level, policy is governed by the energy and climate change triangle, depicted in figure 43 opposite. As has been commented on before in these reports, it is Oil & Gas UK’s view that far more attention has so far been paid to reducing emissions than on security of energy supplies and their affordability with which comes economic competitiveness.

However, the consequences of the recession in much of the EU have moved the debate perceptibly towards security of supply and affordability. This is understandable, given that the public at large are likely to react adversely to any threat to supplies and/or the affordability of energy.

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In some analysis undertaken for Oil & Gas UK, London Energy Consulting examined the energy use and carbon intensities of various OECD, but mainly European countries and compared these, as shown in Figure 44. The UK’s Carbon Budgets (carbon emissions’ targets) are superimposed as green lines, together with the 2050 target. Interestingly, the UK is better placed than several comparable economies such as the Netherlands, Germany, Japan and Denmark, but it is behind France (due to the effects of nuclear power) and Italy and Spain (due to their warmer climates).

Above all, though, this chart demonstrates clearly the magnitude of the task if the 2050 target is to be met by almost any Member State of the EU, given that major energy investments such as large power stations and oil and gas fields typically last for 45 to 50 years and that 2050 is only 37 years away.

a) Electricity
At the time of writing (July 2013), an Energy Bill is being debated in parliament. It seeks to reform the electricity market and stimulate the very large investment in low carbon power generation, especially new nuclear and offshore wind, to meet the government’s own targets as well as its European obligations. Within the Bill, the main instruments being proposed are:

• **Contracts for Difference (CfDs)** – a means to support the incomes of generators who invest in low carbon technologies where generation costs are above market prices.

• **A Capacity Mechanism** – a payment to encourage the provision of the generating capacity that will be required to back up intermittent renewable power and stabilise the grid.

• **An Emissions Performance Standard** – a mechanism to prevent the building of unabated coal fired power stations, but not gas, although in future the standard could be adjusted so as to affect all unabated fossil fuel power.
In addition there is already another, relevant instrument:

- **A Carbon Price Floor** – legislated by HM Treasury through the Finance Act 2011, this sets a minimum price to be paid for carbon emissions through the Climate Change Levy and is intended to encourage power generation by low carbon means. It took effect on 1 April 2013, but only applies in the UK, raising our power prices relative to those in other Member States of the EU.

It is difficult to reach any conclusion which does not recognise the inherent complexity that these measures will engender. Indeed, it has to be a matter of concern that such complex measures underpin the whole strategy for low carbon generation. Furthermore, much of the decision making in power generation will be moved from companies and markets to government departments and ministers. As stated in the last of six conclusions of Oil & Gas UK’s response in March 2011 to DECC’s consultation on its proposals for electricity market reform: “A greater degree of realism is called for. Policies should be simplified and de-risked; they would have a better chance of success.”

However, Oil & Gas UK was pleased when DECC announced and, in late 2012, released its gas generation strategy. This recognises the necessary role that gas fired power generation will to have to play over the next 15 to 20 years and probably for many years thereafter, if carbon capture and storage (CCS) can be made to work at power station scale.

Under the Large Combustion Plant Directive (LCPD), whose effects are already being felt, some 12 giga-watts (GW) of coal and oil fired power generation capacity will be closed by the end of 2015. In addition, under the Industrial Emissions Directive (IED), up to 18.5GW of coal and 18GW of early gas fired generating capacity will be closed by the end of 2023, when most of the coal fired plants will be 50 years old anyhow (although some of it is being converted to burn biomass). In aggregate, these represent a very substantial share of the country’s total power generating capacity, to which must also be added the progressive closure of 9.5GW of nuclear capacity within the same time-frame, because of old age, and premature closure of some early gas power plants which are now uneconomic, owing to the low price of coal mentioned above.

Meanwhile, construction of the first of the planned new nuclear power stations, at Hinkley Point in Somerset, is slipping further, through a combination of difficulties in raising the necessary finance, continuing negotiations about the ‘strike price’ under a CfD (that is the size of the subsidy to be paid by customers), and concerns about the cost and complexity of the reactor’s design. A potential rival type of nuclear reactor, meanwhile, still needs to go through its Generic Design Approval for use in the UK (a procedure likely to take two to three years) and it needs to gain planning permission before construction can begin. This means that it is now unlikely that any new nuclear power plant will start operation in Britain much before the mid-2020s and there will be less nuclear generating capacity throughout most of the 2020s than there is today.

It is therefore inevitable that a fleet of new gas fired power stations (mainly combined cycle gas turbines (CCGTs)) will have to be built to cover the considerable shortfall in base-load generating capacity and to provide back-up for intermittent renewable power, especially offshore wind, where substantial expansion of capacity is planned. There is no other technology available that can fulfil these needs on this scale, with the necessary reliability and within the time-frame mentioned above.
London Energy Consulting also compared the economics of offshore wind generation and a CCGT power plant running at 90 percent load factor. The results are shown in Figure 45. Over the range of prices considered, Round 2 offshore wind only becomes economic with a gas price above 90p/therm (p/th) and a CO₂ price of £120/tonne; with a gas price of 120p/th, offshore wind power becomes economic above a CO₂ price of £70/tonne (the envisaged price in 2030 under the UK’s Carbon Price Floor).

Such prices for CO₂ are beyond the realms of current contemplation under the EU’s Emissions Trading Scheme and these two gas prices are of the order of 50 and 100 percent above current prices. Even under the reference conditions used by DECC (80p/therm for gas and £80/tonne of CO₂), it is not economic to invest in offshore wind and, as Figure 45 also shows, Round 3 offshore wind is even more difficult than Round 2.

At the time of writing, DECC had just published its draft proposals for ‘strike prices’ for renewable generation associated with CFDs. Per mega-watt hour (MWhr) of electricity produced, the proposals include £155 for offshore wind, £100 for onshore wind, £125 for large scale, solar photo-voltaic (PV) and £305 for either wave or tidal power. These compare with a current market price of £50 to 55/MWhr and, if confirmed, would mean that the subsidies which consumers will have to fund through their future bills are of the order of 100 and 200 per cent for on- and off-shore wind, respectively, 150 per cent for large scale solar PV and 500 per cent for marine technologies. The sustainability of subsidies on this scale has to be questionable.

![Figure 45: The Economics of Gas and Offshore Wind Generation](image)

<table>
<thead>
<tr>
<th>Carbon Price (£/tonne)</th>
<th>120</th>
<th>110</th>
<th>100</th>
<th>90</th>
<th>80</th>
<th>70</th>
<th>60</th>
<th>50</th>
<th>40</th>
<th>30</th>
<th>20</th>
<th>10</th>
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</thead>
<tbody>
<tr>
<td>Gas Price in p/therm</td>
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<td>7.5</td>
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<td>10.8</td>
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<td>8.7</td>
<td>9.3</td>
<td>9.3</td>
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</tr>
</tbody>
</table>

Generation projects, starting in 2018, using 10% discount rate. Gas at load factor of 100%.

Source: London Energy Consulting using data from DECC October 2012
b) Heat

It still remains notable how little of the energy debate, in public at least, is about heat, especially given the size of the heat sector in this country. Gas dominates heating in Britain, most particularly in the domestic and small commercial sectors where individual boilers are the preferred choice of providing heat. According to National Grid’s Future Energy Scenarios\(^\text{18}\) published in September 2012, gas demand for these purposes is declining as a result of better insulated buildings and higher efficiency boilers. These changes, while not rapid, accumulate steadily as the years go by.

DECC published its heat strategy, The Future of Heating: meeting the challenge\(^\text{19}\), in March 2013, having consulted on the matter during the spring of 2012. It has divided its strategy for this large subject into four main categories:

- Efficient low carbon heat in industry
- Heat networks
- Heat and cooling for buildings
- Grids and infrastructure

The most important characteristic of heat is the extent of the change in demand between summer and winter. While industrial demand for heat used in various production processes is reasonably constant and predictable, seasonal demand for heating (and cooling) in domestic and commercial premises is almost wholly weather dependent. During the winter peak, demand for heat – mostly supplied by gas in Britain – is about five times the demand for electricity.

This simple multiplier gives a clear indication of the scale of the transformation which the government foresees, especially when DECC’s strategy envisages the spread of heat networks in towns and cities and greater use of electricity in heating through air and ground source heat pumps; in this regard, it is worth noting that heat pumps perform best in thermally efficient buildings. Furthermore, increasing requirements for air conditioning in commercial and, probably, domestic premises in future will add to the demand for electricity for heating and cooling.

The biggest difficulty lies in the lack of energy efficiency in much of this country’s buildings stock. Modern buildings to the latest standards are part of the answer, but in the domestic sector the turnover is slow (100+ years), whereas in the large commercial sector it is much faster and the opportunities to invest in the latest technologies considerably greater.

According to National Grid’s Future Energy Scenarios, the domestic insulation market will start to saturate in the next ten years, with the residual housing stock being much harder and more expensive to treat. In like manner, the replacement of older gas boilers with modern, high efficiency ones – one of the simplest and most beneficial changes which is being made now – will have largely run its course by the mid-2020s. Nonetheless, it is almost impossible for an upgraded, older building to reach the thermal efficiency standards of a new building.

It is likely, in our opinion, that effecting the changes in the nation’s heat supplies implicit in the four main categories listed above will require substantial investment and will only happen slowly. Therefore, gas will continue to play a substantial role in providing heat for several decades to come.

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c) Transport
Oil products continue to dominate fuels for transport throughout the world (>90 per cent share). Apart from the electrification of railway lines with high traffic densities, the inherent properties of oil products – availability, portability and energy density – make them uniquely suitable for land, sea and air transport, especially over long distances. As mentioned previously, however, gas is now being tried on a modest scale in medium to heavy commercial road transport in the USA and in buses in various parts of the world.

While some of the new technologies being developed demonstrate applicability for road transport over shorter distances, such as for cars, buses and vans in and around towns and cities, none so far shows signs of replacing oil products for longer distances on land, never mind at sea or in the air. And thus far, neither hybrid nor purely electric vehicles have captured the public’s imagination.

Meanwhile, under a combination of more stringent regulatory requirements, high prices and competitive pressures, manufacturers have already made considerable progress in improving the fuel efficiency of petrol and diesel vehicles during the past ten years and there is the likely prospect of more advances in technology improving efficiency yet further during the coming years.

In the air, new technologies such as are evident in Boeing’s 787, which entered service in October 2011, and Airbus’s A350, which flew for the first time in June 2013, are creating step changes in fuel efficiency. Even with long established airframes, such as the popular 737 and A320 families of aircraft, the relentless demands of competition are delivering ever better performance and lower fuel consumption.

It seems inevitable that oil’s products will remain the dominant fuels for transport until 2030 and probably beyond.

Gas from Shale
As a result of the extraordinary developments in the USA in the past few years, one of the most openly debated subjects in Britain and the EU has been shale gas and the hydraulic fracturing (or ‘fracking’) of wells, a technique which has existed in oil and gas exploration and production for more than 60 years, long before shale gas exploration started20.

A wide variety of reports has been published, but a joint publication by the Royal Society and the Royal Academy of Engineering in June 201221 was among the more keenly awaited in this country. It had been commissioned by the government’s Chief Scientific Adviser in the aftermath of two small tremors following hydraulic fracturing of a well by Cuadrilla Resources in Lancashire during spring 2011. DECC lifted the temporary moratorium on shale gas drilling in mid-December 2012, together with imposing some additional controls on operators to mitigate the risks of a recurrence.

In June 2013, DECC released the latest assessment by the British Geological Survey22 of the potential shale gas resources in the Bowland Shale across the north midlands and northern England (most of Lancashire, Yorkshire, Cheshire, Staffordshire, Derbyshire and Nottinghamshire plus parts

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20 There are understood to be more than a million wells worldwide which have been hydraulically fractured; such wells already exist both onshore and offshore the UK.
22 See https://www.gov.uk/government/publications/bowland-shale-gas-study
of Leicestershire and Lincolnshire). The size of the resources in place is much larger than previously forecast, with a central case of 37.6 trillion cubic metres (tcm). For comparison, current consumption in the UK is about 85 billion cubic metres (bcm) per year and so, even if only ten per cent of the resource were to be recovered, this would still equal more than 40 years of supply at today’s rate of consumption.

However, it is not possible at this stage to forecast how much will be technically and economically recoverable. This will only become apparent when many more wells have been drilled and tested. As data are accumulated, it will gradually be possible to forecast the potential size of the prize.

Nonetheless, the signs are encouraging. Shale gas is most unlikely to induce the degree of change in the UK (or EU) which has occurred in the USA because of very different circumstances, but there is the potential for a new arm of the oil and gas industry to develop in Britain, providing investment, jobs, new gas supplies and tax revenues, while reducing imports. A report published by the Institute of Directors in May 2013 examines the possibilities. In addition, everything else being equal, any new supplies of gas will tend to exert downward pressure on prices relative to what they would otherwise be.

As drafting of this report was being completed, the government announced new tax arrangements for the production of shale gas, modelled on the FA concept which applies to the UKCS (see Section 6 for more details of the tax regime as applies to the UKCS).

Further information about shale gas may be found at the following three websites especially established by the industry in Europe:

http://www.ngsfacts.org
http://www.shalegas-europe.eu/en
http://www.europeunconventionalgas.org

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Energy Flow Chart 2012
(million tonnes of oil equivalent)

Figure 46: DECC’s Energy Flow Chart, 2012

- **Primary Supply**: 213.9
- **Primary Demand**: 214.3

**Footnotes**:
1. Coal imports include imports of manufactured fuels, which accounted for 0.1 million tonnes of oil equivalent in 2012.
2. Bioenergy is renewable energy made from materials of recent biological origin derived from plant or animal matter, known as biomass.
3. Includes non-energy use.
4. Includes heat sold.

**Imports**:
- **Crude Oil and NGL**: 49.4
- **Refined Products**: 1.2
- **Iron & Steel**: 72
- **Transport**: 63.2
- **Domestic**: 42.2
- **Exports and Marine Bunkers**: 83.6

**Non-Energy Use**:
- **7.6**

**Conversion Losses**:
- **49.4**

**ENERGY INDUSTRY USE AND DISTRIBUTION**
- **7.1**

**TOTAL FINAL CONSUMPTION**
- **148.2**

** Primary Supply**

** Primary Demand**

**FOOTNOTES**:
- 1. Coal imports include imports of manufactured fuels, which accounted for 0.1 million tonnes of oil equivalent in 2012.
- 2. Bioenergy is renewable energy made from materials of recent biological origin derived from plant or animal matter, known as biomass.
- 3. Includes non-energy use.
- 4. Includes heat sold.

This flowchart has been produced using the style of balance and figures in the 2013 Digest of UK Energy Statistics, Table 1.1.
9. Appendix

a) Oil & Gas UK’s Membership

Much of the data used in this publication have been collected from Oil & Gas UK’s membership, the composition of which can be seen below in Figure 47. The membership has changed dramatically since 2007, from consisting of almost entirely larger operators to encompassing all parts of the industry. The influx of smaller independent operators, contractors, suppliers and associated service businesses is a reflection of Oil & Gas UK’s objective of welcoming a broader, more representative membership. The increase of smaller, independent operators is a result of the changing nature of the companies that operate on the UKCS compared with earlier years.

Figure 47: Composition of Oil & Gas UK’s Membership

- Contractor / Supply Chain: 80%
- Operator: 16%
- Associate Member: 4%
b) Field Allowances

*Figure 48: Field Allowances Available for the UKCS*

<table>
<thead>
<tr>
<th>Name</th>
<th>Pre-Tax Value</th>
<th>Qualification Criteria (as per Field Development Plan consent)</th>
<th>Effective Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Fields</td>
<td>Up to £75 million</td>
<td>Central case recoverable reserves of up to 3.5 million tonnes (circa 25 million boe)</td>
<td>March 2009</td>
</tr>
<tr>
<td>Ultra High Pressure/High Temperature (HPHT)</td>
<td>Up to £800 million</td>
<td>Reservoir conditions exceeding pressures of 862 bar and temperature of 166 degrees Celsius</td>
<td>March 2009</td>
</tr>
<tr>
<td>Ultra Heavy Oil</td>
<td>£800 million</td>
<td>Oil at API gravity below 18 degrees and viscosity exceeding 50 centipoise at reservoir temperature and pressure</td>
<td>March 2009</td>
</tr>
<tr>
<td>Deep Water Gas</td>
<td>Up to £800 million</td>
<td>• The field is in water depths exceeding 300 metres</td>
<td>January 2010</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• More than 75 per cent of the reserves comprise gas</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Gas is to be transported for more than 60 kilometres along a new pipeline to relevant infrastructure</td>
<td></td>
</tr>
<tr>
<td>Small Fields (amended)</td>
<td>Up to £150 million</td>
<td>Central case recoverable reserves of up to seven million tonnes (circa 50 million boe)</td>
<td>March 2012</td>
</tr>
<tr>
<td>Large Deep Water Oil</td>
<td>Up to £3,000 million</td>
<td>• Central case recoverable reserves of between 25 million and 55 million tonnes (circa 187.5 – 412.5 million boe)</td>
<td>March 2012</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• The field is in water depths exceeding 1,000 metres</td>
<td></td>
</tr>
<tr>
<td>Large Shallow Water Gas</td>
<td>Up to £500 million</td>
<td>• Central case recoverable reserves of between 10 and 25 billion cubic metres</td>
<td>July 2012</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• More than 95 per cent of the field’s reserves comprise gas</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• The field is in water depths less than 30 metres</td>
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<tr>
<td>Brown Field Allowance</td>
<td>Up to £50/tonne, up to a cap of £250 million (£500 million if PRT paying) per project</td>
<td>Authorised project capital costs exceed £60 per incremental tonne of oil and gas produced</td>
<td>September 2012</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Project has been granted consent by the Department of Energy and Climate Change after 7 September 2012 by way of Field Development Plan Addendum (see main text for further details)</td>
<td></td>
</tr>
</tbody>
</table>

Notes.

1. If a field qualifies for more than one field allowance then it can only claim the more valuable one, with the exception of fields that subsequently qualify for a Brown Field Allowance, which is available in addition to any of the other categories of field allowance.

2. The conversion of oil from tonnes into barrels varies depending on the density of the crude from each reservoir. For illustrative purposes only, a light sweet crude is around 0.132 tonnes. For gas the conversion is set at 1,100 cubic metres to equal one tonne.
c) Glossary of Terms and Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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</thead>
<tbody>
<tr>
<td>API</td>
<td>American Petroleum Institute</td>
</tr>
<tr>
<td>bbl</td>
<td>barrel of oil (one barrel = 0.16 m³ and 7.55 barrels = one tonne)</td>
</tr>
<tr>
<td>BBL</td>
<td>Balgzand (in the Netherlands) to Bacton (in Norfolk, England) gas pipeline</td>
</tr>
<tr>
<td>bcm</td>
<td>billion cubic metres (one metre³ = 35.3 cubic feet)</td>
</tr>
<tr>
<td>bcm/y</td>
<td>billion cubic metres per year (of gas)</td>
</tr>
<tr>
<td>BFA</td>
<td>Brown Field Allowance</td>
</tr>
<tr>
<td>BIS</td>
<td>Department for Business, Innovation and Skills</td>
</tr>
<tr>
<td>billion</td>
<td>one thousand million or 1⁰</td>
</tr>
<tr>
<td>boe</td>
<td>barrel of oil equivalent: this includes oil, gas and other hydrocarbons and equates all of these with oil, in energy equivalent terms, so that a common measure can be made of any of them (one boe = 164 m³ or 5.8 thousand cubic feet of gas) barrels per day</td>
</tr>
<tr>
<td>boepd</td>
<td>barrel of oil equivalent per day</td>
</tr>
<tr>
<td>brownfield</td>
<td>an oil or gas field already in production</td>
</tr>
<tr>
<td>BTU</td>
<td>British Thermal Unit (of energy)</td>
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<tr>
<td>capex</td>
<td>capital expenditure</td>
</tr>
<tr>
<td>CATS</td>
<td>Central Area Transmission System</td>
</tr>
<tr>
<td>CCGT</td>
<td>combined cycle (gas + steam) gas turbine</td>
</tr>
<tr>
<td>CCS</td>
<td>carbon capture and storage</td>
</tr>
<tr>
<td>CDA</td>
<td>Common Data Access (a subsidiary of Oil &amp; Gas UK)</td>
</tr>
<tr>
<td>CFD</td>
<td>contract for difference</td>
</tr>
<tr>
<td>CHP</td>
<td>combined heat and power</td>
</tr>
<tr>
<td>CNG</td>
<td>compressed natural gas</td>
</tr>
<tr>
<td>CNS</td>
<td>Central North Sea</td>
</tr>
<tr>
<td>CO₂</td>
<td>carbon dioxide (one of the six ‘greenhouse gases’ under the Kyoto protocol)</td>
</tr>
<tr>
<td>condensate</td>
<td>low density, liquid hydrocarbon usually associated with natural gas which, depending on temperature and pressure, can be gaseous</td>
</tr>
<tr>
<td>CoP</td>
<td>Cessation of Production (from a field)</td>
</tr>
<tr>
<td>CT</td>
<td>Corporation Tax (see also RFCT)</td>
</tr>
<tr>
<td>DEAL</td>
<td>Digital Energy Atlas &amp; Library</td>
</tr>
<tr>
<td>DECC</td>
<td>Department of Energy and Climate Change</td>
</tr>
<tr>
<td>DRD</td>
<td>Decommissioning Relief Deed</td>
</tr>
<tr>
<td>E&amp;A</td>
<td>exploration and appraisal (drilling)</td>
</tr>
<tr>
<td>EEA</td>
<td>European Economic Area (the EU plus Norway, Iceland and Liechtenstein)</td>
</tr>
<tr>
<td>EIA</td>
<td>Energy Information Administration (of the USA)</td>
</tr>
<tr>
<td>EMR</td>
<td>electricity market reform (by DECC)</td>
</tr>
<tr>
<td>EOR</td>
<td>enhanced oil recovery</td>
</tr>
<tr>
<td>E&amp;P</td>
<td>exploration and production (of oil and/or gas)</td>
</tr>
<tr>
<td>EU</td>
<td>European Union (the 28 member states)</td>
</tr>
<tr>
<td>EU ETS</td>
<td>European Union’s Emissions Trading Scheme</td>
</tr>
<tr>
<td>FA</td>
<td>Field Allowance, a tax relief for certain categories of field</td>
</tr>
<tr>
<td>FDP</td>
<td>Field Development Plan</td>
</tr>
<tr>
<td>FIT</td>
<td>Feed-in Tariff (for electricity)</td>
</tr>
<tr>
<td>FPAL</td>
<td>First Point Assessment Ltd, an organisation providing a registration, qualification and performance monitoring system of the industry’s suppliers and contractors</td>
</tr>
<tr>
<td>FPSO</td>
<td>floating production, storage and offloading (vessel)</td>
</tr>
<tr>
<td>GDP</td>
<td>Gross Domestic Product (the main measure of domestic economic output)</td>
</tr>
<tr>
<td>GHG</td>
<td>greenhouse gas (of which there are six under the Kyoto protocol)</td>
</tr>
<tr>
<td>GtL</td>
<td>gas to liquids</td>
</tr>
<tr>
<td>GVA</td>
<td>Gross Value Added</td>
</tr>
<tr>
<td>GW</td>
<td>Giga Watt (of electricity): one billion watts</td>
</tr>
<tr>
<td>HH</td>
<td>Henry Hub (the principal trading point for gas in the USA)</td>
</tr>
<tr>
<td>HMRC</td>
<td>Her Majesty’s Revenue and Customs (sometimes known as ‘the Exchequer’)</td>
</tr>
<tr>
<td>HMT</td>
<td>Her Majesty’s Treasury</td>
</tr>
<tr>
<td>HPHT</td>
<td>high pressure, high temperature (of reservoirs)</td>
</tr>
<tr>
<td>HSE</td>
<td>Health and Safety Executive</td>
</tr>
<tr>
<td>ICO</td>
<td>Infrastructure Code of Practice (for third party access to platforms, pipelines etc)</td>
</tr>
<tr>
<td>IEA</td>
<td>International Energy Agency (part of the OECD)</td>
</tr>
<tr>
<td>IOC</td>
<td>International Oil Company</td>
</tr>
<tr>
<td>IOR</td>
<td>increased oil recovery</td>
</tr>
</tbody>
</table>
|ITF| Industry Technology Facilitator, a not-for-profit, industry owned body
JOA  Joint Operating Agreement  
(~~between partners in a field~~)

kms  kilometres

KW  Kilo Watt (of electricity) – unit of power: one thousand watts

KWh  Kilo Watt hour – unit of energy

LNG  liquefied natural gas

mboepd  million barrels of oil equivalent per day

mbopd  million barrels of oil per day

mcm/d  million cubic metres per day (of gas)

mtoe  million tonnes of oil equivalent

MW  Mega Watt (of electricity) – unit of power: one million watts

MWhr  Mega-Watt Hour

NBP  National Balancing Point (fictional location in Britain where the NTS is notionally in balance and at which the trading of gas takes place)

NGL  natural gas liquid (e.g. butane, propane)

NNS  northern North Sea

NTS  National Transmission System (high pressure gas transmission system in Britain operated by National Grid – the ‘motorway’ network for gas)

OCGT  open cycle gas turbine

OECD  Organisation of Economic Co-operation and Development

OGP  International Association of Oil and Gas Producers

ONS  Office of National Statistics

OPEC  Organisation of Petroleum Exporting Countries

opex  operating expenditure

OPITO  the upstream oil and gas industry’s training organisation

OTC  over the counter

PAR  potential additional resources

PILOT  joint oil and gas industry – government task force chaired by the Secretary of State of DECC

PRT  Petroleum Revenue Tax

p/th  pence per therm (for gas)

R&D  research and development

RFCT  ‘Ring Fence’ Corporation Tax

(~~as applied to upstream oil and gas production~~)

ROV  remotely operated vehicle (subsea)

SC  Supplementary Charge (a corporate tax applied to upstream oil and gas production in addition to RFCT)

SCDI  Scottish Council for Development and Industry

SIC  Standard Industrial Classification

(~~ref ONS~~)

sidetrack  description of a well that is started from the bore of an existing well, but is then deviated to create a new well

SME  small to medium (sized) enterprise

SNS  southern North Sea

STEM  Science, Technology, Engineering and Maths

trillion  one million million or $10^{12}$

tcm  trillion cubic metres

UKCS  United Kingdom Continental Shelf

UKTI  UK Trade & Investment

UDC  unit development cost

UOC  unit operating cost

WoS  west of Shetland

(~~sometimes referred to as ‘Atlantic margin’~~)

YTF  yet-to-find resources

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**Editorial Note:**

- The drafting of this report was undertaken during June and July 2013.