Department of Energy & Climate Change

Statutory Security of Supply Report

A report produced jointly by DECC and Ofgem

November 2012

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pursuant to section 172 of the Energy Act 2004
as amended by section 80 of the Energy Act 2011

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Executive Summary

Introduction

This report discharges the Government's and Ofgem's obligation under section 172 of the Energy Act 2004[1] as amended by section 80 of the Energy Act 2011 to report annually to Parliament on the availability of electricity and gas for meeting the reasonable demands of consumers in Great Britain; and the Government's obligation under certain EU Directives[2] to monitor gas and electricity security of supply issues and publish reports.

The technical data presented here has been provided jointly by DECC, Ofgem and National Grid. DECC sets out policy considerations relating to security of supply in its Energy Security Strategy[3] which assesses key cross cutting risks to energy security and the characteristics that imply a secure system for each key fuel: adequate capacity, diversity, reliability and demand side responsiveness.

Electricity

Around a fifth of electricity generation capacity available at the start of 2011 has to close by the end of the decade. In addition, National Grid's demand forecasts suggest that over the period to 2030, peak electricity demand will increase. This means that without investment in new generation there will be increased risks to security of supply. Ofgem's Electricity Capacity Assessment published earlier this Autumn sets out the risks associated with closures and possible low levels of investment over the coming years. The report shows that electricity de-rated margins, the amount of spare generation capacity on the system, could fall from 14 per cent today to 4 per cent in winter 2015/16[4].This would lead to increased risks to security of electricity supplies.

The Annex of this report provides the Secretary of State's response to Ofgem's 2012 Electricity Capacity Assessment.

1 Available from http://www.statutelaw.gov.uk/Home.aspx

2 Directive 2009/73/EC of the European Parliament and the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC augmented by Regulation (EU) 994/2010 of the European Parliament and the Council of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC; and Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC augmented by Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment.

3 http://www.decc.gov.uk/en/content/cms/meeting_energy/en_security/en_security.aspx

4 Available at: http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Documents1/Electricity%20Capacity%20Assessment%202012.pdf

The electricity transmission network remains extremely reliable, but significant new investment in both the transmission and distribution networks will be crucial to ensure future security of supply.

Gas

Gas consumption can, broadly speaking, be divided into thirds, split between power generation, domestic and industry use. The UK gas market is currently supplied through a combination of domestic production, pipeline and LNG imports and seasonal and short-range storage.

While it is expected that production from the UKCS will continue to decline, diverse import capacity and flexible storage capacity can help offset supply risks.

There are a wide range of future scenarios, which highlights the uncertainty around future levels of gas supply and demand at both the GB and global levels. For example, global demand is expected to rise dramatically and supply will need to react considerably to meet it. There are also prospects for a continued tightening of LNG markets towards the middle of this decade as demand growth outstrips growth in liquefaction capacity. However, capacity is expected to increase after this with new projects from Australia.

Unconventional gas could potentially enhance security of supply. However, it is still very early days for shale gas outside the US.

Oil

UK oil production peaked in 1999 and is declining. Oil imports are forecast to increase throughout the 2030 timeframe to meet a broadly flat overall demand for oil. Significant demand reductions are not anticipated in the near term.

Oil products play an important role in the UK economy, providing around a third of the primary energy used. The UK is a net exporter of petroleum products, mainly petrol, but is increasingly reliant on imports of diesel road fuel and jet fuel.

Chapter 1: Electricity

Introduction

1.1 This chapter presents scenarios for electricity demand, which are subject to a range of sensitivities. Likely developments on the supply side are also discussed, with expected new build as well as generation closures discussed to give a picture of how the supply side could develop in the future. The chapter also discusses the future need for significant electricity transmission network investment.

1.2 Ofgem's Electricity Capacity Assessment published earlier this Autumn sets out the risks associated with closures and potential low levels of investment over the coming five winters (2012/13 to 2016/17)[5]. Analysis further out is from National Grid. Ofgem's report shows that electricity de-rated margins, the amount of spare generation capacity on the system, could fall from 14 per cent today to 4 per cent in winter 2015/16.

1.3 The Secretary of State's response to Ofgem's Electricity Capacity Assessment can be found in the annex to this document.

Electricity demand

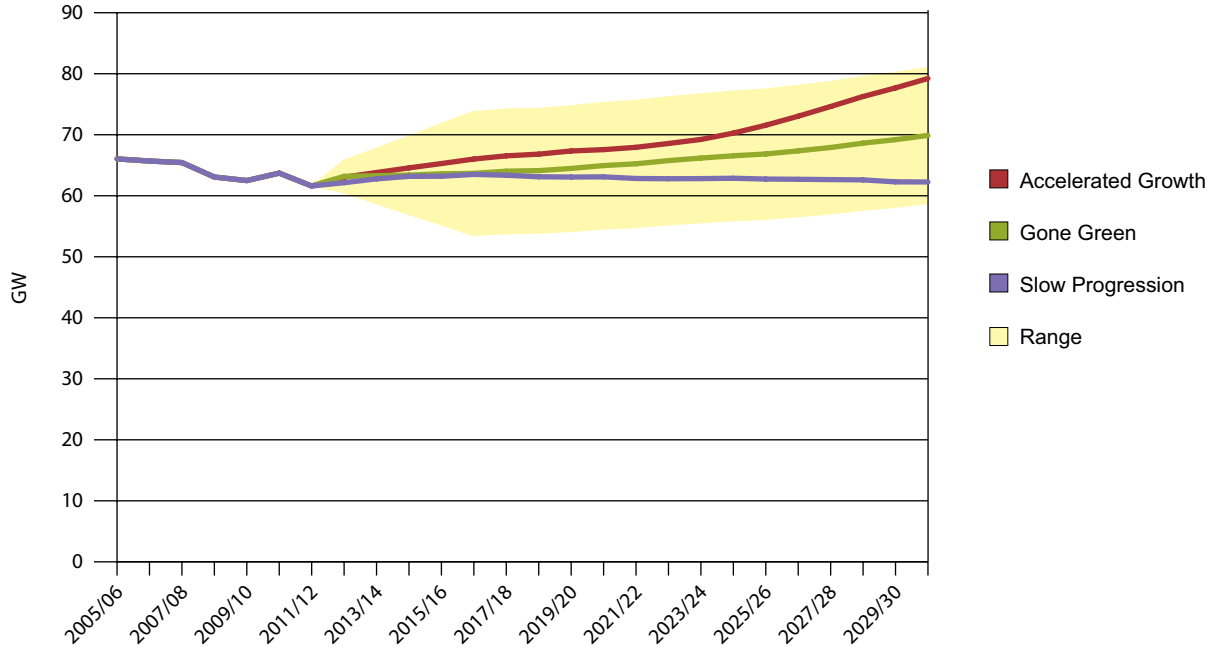
1.4 Chart 1.1 shows projections of future peak electricity demand from National Grid. National Grid's[6] project peak electricity demand to grow from around 63 GW now to around 70 GW in 2030 under their Gone Green scenario. This includes demand met by generation which is connected to the transmission network as well as generation that is connected directly to the distribution network (embedded generation). According to National Grid peak demand met by the transmission system in winter 2011/12 was around 60GW. More detail on the Slow Progression, Gone Green and Accelerated Growth scenarios produced by National Grid can be found in the *Development of Investment scenarios*[7] document.

5 http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Pages/index.aspx

6 Where analysis in this chapter draws on data provided by National Grid, it refers to electricity supply and demand in GB and does not include Northern Ireland unless otherwise stated.

7 http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios/

Chart 1.1: Future development of peak demand



Source: National Grid

Electricity supply

Present capacity

1.5 At the beginning of 2012, the UK as a whole had a total of around 89 GW[8] of electricity capacity, of which around 83 GW[9] was connected to the transmission network. This represents a drop in capacity from 90.4 GW at the end of 2010. In addition, at the start of the year, GB had the capacity to import and export the equivalent of 3.5 GW from and to France, the Netherlands and Ireland; additionally, a new interconnector to Ireland opened in September this year and has the capacity to import and export a further 0.5 GW, raising total interconnection capacity to 4 GW.

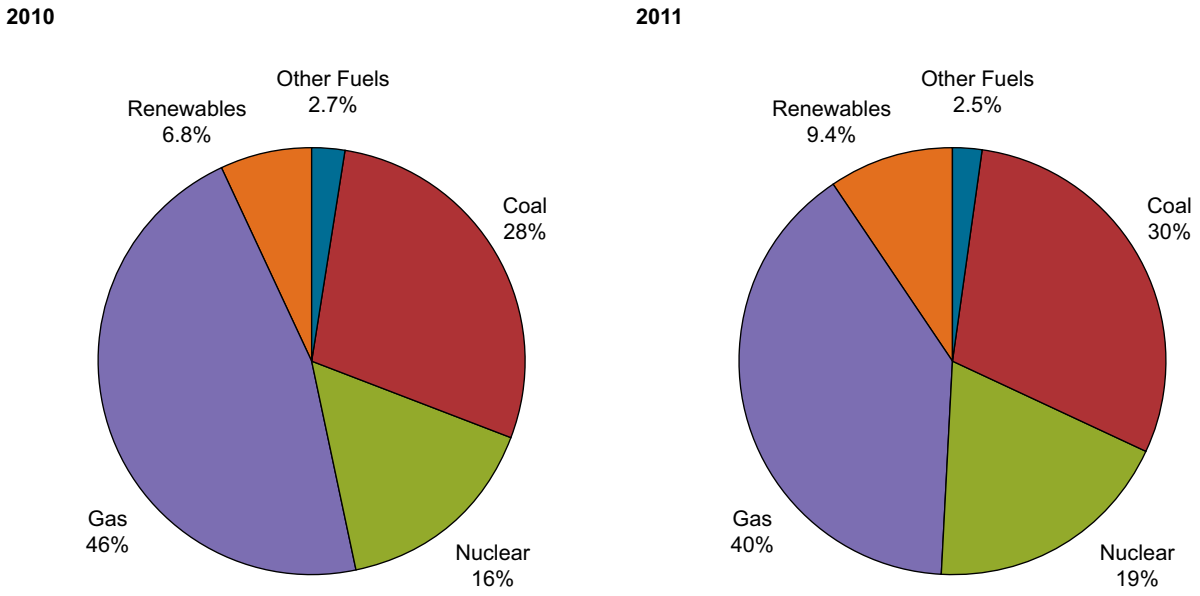
1.6 The proportion of electricity produced by each generating technology is different from the proportion of each technology's total potential capacity. This is because some plant generates more or less continuously (for example nuclear, due to its low marginal costs), some only at times of extremely high prices and/or demand (for example, oil), and some depending upon the intermittency of the power source (wind).

1.7 In 2011, 368 TWh of electricity was generated, down from 381 TWh in 2010. The breakdown of this by technology type is shown in Chart 1.2. Coal increased its share from 28 per cent to 30 per cent, renewables up from 6.8 per cent to 9.4 per cent, and nuclear up from 16 per cent to 19 per cent. The biggest drop was in gas, which saw its production share fall from a record high of 46 per cent to 40 per

8 DECC Digest of UK Energy Statistics 2012. These figures include embedded generation.
9 National Grid data

cent; this has been due to high gas prices relative to coal making it comparably more expensive to generate, as well as greater generation from nuclear and renewables.

Chart 1.2: Shares of electricity generation, by fuel, in 2010 and 2011



Source: DECC, Digest of UK Energy Statistics, Chart 5.2

Plant closures

1.8 Ofgem's Electricity Capacity Assessment published earlier this Autumn sets out the risks associated with plant closures and potential low levels of investment over the period to 2016/17. Box 1.1 at the end of this section provides some detail of the high level results.

1.9 Chart 1.3 below shows National Grid's expectation of the closures of our existing plants. Around 8 GW of coal plants (and 4 GW of oil-fired plant) have to close by the end of 2015 as they have opted out of the EU's Large Combustion Plant Directive (LCPD).

1.10 From 1st January 2016, the LCPD will be replaced by the Industrial Emissions Directive (IED), which places more stringent emission requirements on power plants than the LCPD. This will affect the UK coal capacity that has already complied with the LCPD, as well as some gas capacity. These plants will be required to either 'opt in' to the IED and meet its emission requirements from January 2016, opt in via the Transitional National Plan (which allows a gradual adjustment to the new emission requirements between 2016 and 2020), or (as under the LCPD) they can choose to 'opt out', at which point they will be subject to a limited lifetime derogation (of a maximum of 17,500 running hours), and must close by the end of 2023 at the latest.

Table 1.1: Scheduled Capacity Closures

MW	2013	2014	2016	2018	2019	2023
Gas	218					
Coal[10]	4,175		2,957			
Nuclear		490	2,335	1,081	2,410	2,418
Oil + GT	1,355		2,281			

Source: National Grid

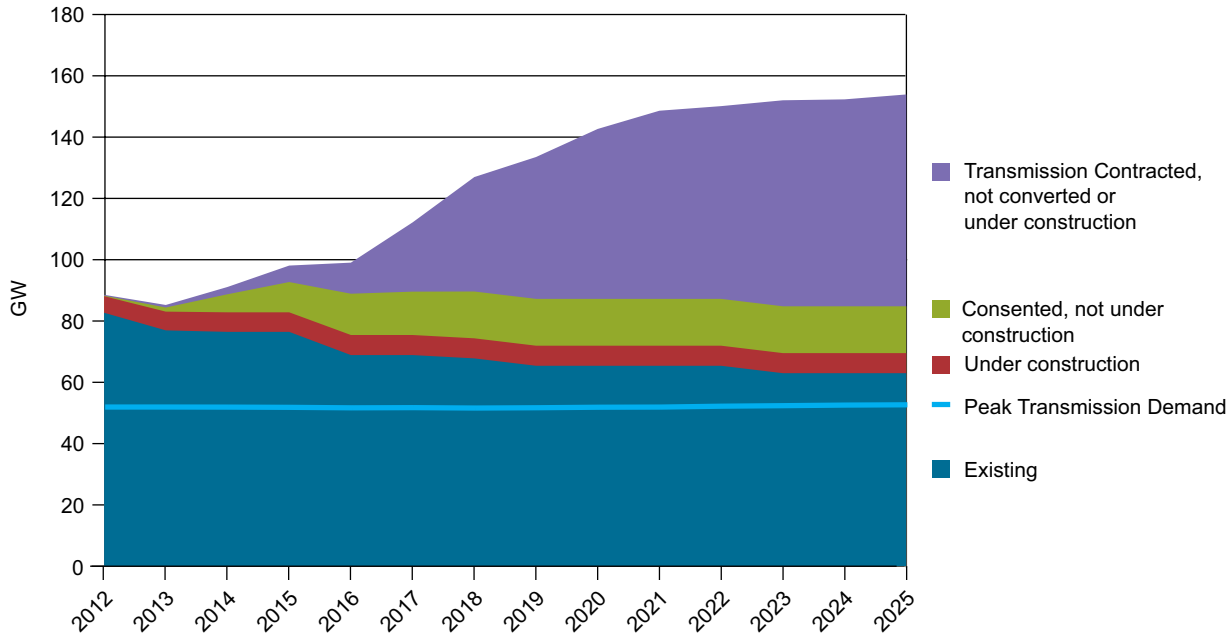
1.11 Nuclear operators, and in particular EDF Energy, have previously published indicative dates that they expect individual nuclear sites to close by. According to current timetables[11], around 6 GW of existing nuclear generation capacity will have closed by end 2020. However, the operating lives of nuclear power plants can be extended, but only with the approval of the Office for Nuclear Regulation (ONR). The decision whether to seek to extend the scheduled closure date is a commercial one for the operators. These decisions will take into account such factors as plant safety and operating costs, as well as supply, demand and price expectations in the electricity market as a whole. On 16 February 2012, as part of their end of year results EDF announced that they intended to undertake a programme of investment that will allow their AGR fleet to run for an average of 7 years beyond their indicative closure dates and the PWR at Sizewell to run for an additional 20 years.

1.12 Chart 1.4 below shows National Grid's timeline of plants that might connect to the transmission network and the various stages that each development has got to.

10 This table does not mention any plants that have closed prior to 2012.
11 http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/nuclear/2027-past-and-present-uk-nuclear-reactors.pdf

New build: quantity

Chart 1.3: Existing and potential GB electricity generating capacity (non-derated)



Source: National Grid

New build: planning

Gas and Coal-fired Generation

1.13 Two new Combined Cycle Gas Turbines (CCGT) will have been built in GB between November 2011 and March 2013, providing around 3 GW of new capacity. In addition, a significant volume of new CCGT capacity is in the pipeline; more than 15 GW of capacity has been consented. Despite the considerable capacity in the pipeline, other than Carrington[12], there is still uncertainty over if and when it will be built.

New build: Nuclear

1.14 EDF anticipate that the first new plant at Hinkley C, if consented, will be operational from 2019. Plans for other sites are on a slower trajectory which means most new plants will only be operational from 2021/22 and thereafter.

12 Carrington Power Ltd (owned by ESB) has recently announced that its power station at Carrington will be built and is expected to open in 2016.

New build: Renewables

1.15 The latest figures from National Grid's Transmission Networks Quarterly Connections Update (TNQCU) show that 2.4 GW of Transmission connected renewable electricity generation projects are under construction. An additional 5.3 GW of projects have been granted planning permission and are awaiting construction. These projects are predominantly offshore and onshore wind and biomass[13].

Box 1.1: Ofgem's Electricity Capacity Assessment

Ofgem's Electricity Capacity Assessment sets out its analysis of de-rated capacity margins that could be delivered by the electricity market over the next four years and the risks to security of supply associated with these.

Ofgem expects demand to remain broadly flat in their Base Case. However, there will be a significant reduction in electricity supplies from coal and oil plants over the period, primarily driven by closures required by European environmental legislation. Reflecting this, estimated de-rated margins decline from around 14 per cent this year to just over 4 per cent by 2015/2016 in the Base Case.

Ofgem has also modeled a range of sensitivities. This includes high and low CCGT scenarios and different assumptions on the level of electricity which will be available from the Continent through interconnection.

These sensitivities show the range of uncertainty in mothballing and new build assumptions. The impact of different assumptions on interconnection is also significant. Assuming full imports from the Continent, de-rated margins decline from around 20 per cent to just over 9 per cent over the four years. In the (highly unlikely) event of full exports to the Continent at times of peak demand, de-rated margins would not be positive in 2015/2016 (see diagram below).

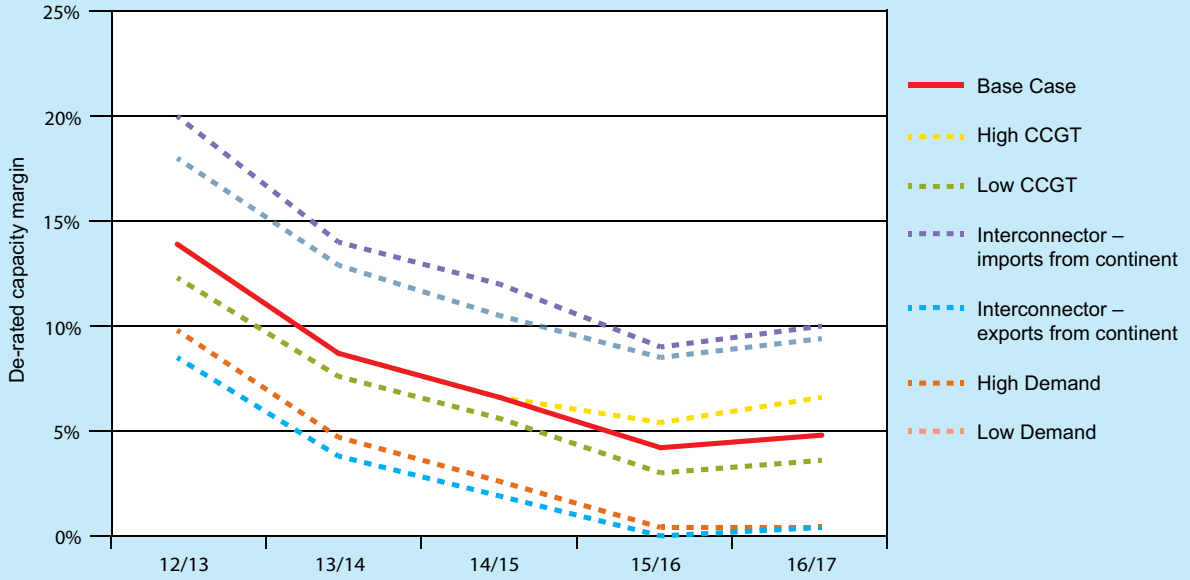
The risk of electricity shortfalls is expected to be highest at the end of the period, in 2015/2016 and 2016/2017, mirroring the declining margins. Under the Base Case, the expected volume of demand that may not be met because of an energy shortfall in 2015/2016 is around 3.4 GWh. The annual loss of supplies arising from transmission and distribution outages is typically more than three times this amount.

Ofgem also estimates the risk of customer disconnections. In their Base Case, Ofgem assumes that, before disconnecting customers, the electricity system operator is able to make use of 2 GW of emergency interconnection services. These services are not taken into account in the calculated de-rated capacity margins. The chance of an event requiring the disconnection of customers (which

13 Latest statistics from the Renewable Energy Planning Database August 2012 (https://restats.decc.gov.uk/app/reporting/decc/datasheet) show that 5GW of renewable electricity projects are under construction. An additional 11GW of projects have planning permission and are awaiting construction and a further 13.3GW have submitted planning applications for consideration. These figures differ from the National Grid's Transmission Networks Quarterly Connections Update (TNQCU) figures due to methological differences in data collection.

would be equivalent to a shortfall exceeding 2.75 GW), is estimated to be around 1 in 12 years under the Base Case in 2015/2016. The equivalent figure for this winter, based on Ofgem's modelling is 1 in 3,300 years.

De-rated Capacity Margins in Ofgem analysis



Electricity Capacity Assessment (Ofgem, 2012)

Demand side response

1.17 Demand side response (DSR) involves electricity users varying demand due to changes in the balance between supply and demand, usually in response to prices. National Grid estimate that around 0.2 GW of their contracted Short Term Operating Reserve (STOR) is demand side response (DSR). In addition, they contract around 0.14 GW from demand side service providers to provide frequency response on the system.

1.18 The proportion of demand side frequency response has fallen in recent years, and changes in fuel type have lead to a reduction in the DSR used in STOR. This may be expected to increase in response to Electricity Market Reform.

Electricity Networks

Current network reliability

1.19 The three transmission owners (TOs) in GB face regulatory incentives and statutory obligations that, amongst other things, create an operating environment designed to minimise energy unsupplied. Historically, the record for the electricity transmission network in GB has been impressive. For instance, for 2011/12, the National Grid transmission network in England and Wales experienced total

estimated unsupplied energy of 791 MWh which equates to overall reliability of supply of 99.99972%[14].

1.20 The operators of electricity distribution networks in GB also face incentives to reduce the number and duration of interruptions to supply over their networks. Since these "quality of service" incentives were introduced, and based on 2010-11 performance, an average distribution service customer in GB would have experienced around seven interruptions over a ten year period[15].

Future development of electricity networks

1.21 There is a significant programme of investment underway in GB electricity networks, which includes network expansion to accommodate new generation projects as well as replacement and maintenance of network assets to ensure continued network reliability. The latest Distribution Price Control (DPCR5) that covers 2010-15 has allowed up to £6.6 billion of new capital investment in the distribution network and Ofgem has already approved up to £5.1 billion under the current transmission price control period that runs until 2013 (TPCR4, originally covering 2007-2012 and extended by one year under TPCR Rollover).

1.22 Ofgem recently reformed its process for carrying out Price Control Reviews. Its new framework, RIIO (Revenue=Incentives+Innovation+Outputs) aims to ensure that transmission and distribution network companies play a full role in the move towards a sustainable low carbon and secure energy system while providing long term value for money for existing and future consumers. The next transmission price control (RIIO-T1) period is 2013-2021 and business planning by the three TOs is well advanced. In April 2012 Ofgem approved up to £6.0 billion (2009-2010 prices) of new investment in the Scottish transmission network[16] and in July 2012 set out its Initial Proposals to allow up to £11.0 billion (2009-2010 prices) of investment in the transmission network in England and Wales[17] for which final proposals are expected in December 2012.

1.23 In addition, in February 2012 the Electricity Networks Strategy Group (ENSG), a high level industry group chaired by DECC and Ofgem, published an update of its 2009 '2020 Vision' report that set out the strategic network investments which may be needed to 2020 to facilitate the achievement of the Government's renewables targets. The report concluded that, provided the identified reinforcements are taken forward on time and the planning consents needed for network development

14 See page 19 of NETS Performance Report 2011-12: http://www.nationalgrid.com/NR/rdonlyres/FB8E72DA-6286-4C0F-AB53-9EB9DD80594C/56380/NationalElectricityTransmissionSystemPerformanceReport20112012.pdf

15 See page 28 of Ofgem 2010/11 Electricity Distribution Quality of Service Report http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/Electricity_Distribution_Annual_Report_for_2010_11.pdf

16 See Ofgem's final proposals for Scottish Power and SSE as part of RIIO-T1 price control http://www.ofgem.gov.uk/Media/PressRel/Documents1/Final%20Proposals%20SP%20SHETL.pdf

17 See Ofgem's report RIIO-T1: Initial Proposals for National Grid Electricity Transmission and National Grid Gas – Overview http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIO%20T1%20Initial%20Proposals%20for%20NGGT%20and%20NGET%20Overview%202707212.pdf

works can be secured in a timely manner, then the reinforcements identified by the TOs in the report can be delivered to required timescales[18].

1.24 Government has put in place a regulatory regime to deliver offshore energy connections in a secure, timely and cost-effective manner. A key element of the regime is the competitive tender process run by Ofgem to appoint Offshore Transmission Owners (OFTOs) to construct (where a generator chooses not to do so itself) and own and operate the offshore transmission assets. Initial analysis by Ofgem suggests that the competitive regime will deliver considerable savings for generators and consumers.

1.25 The offshore transmission regime has also been successful in attracting investor appetite, with new entrants and new sources of finance demonstrating interest in the sector. Funding of almost £4 billion was offered in relation to the first £1.1 billion of assets. So far, five OFTO licences have been granted, and there has been a range of participants in bidder consortia.

1.26 DECC and Ofgem have launched a joint Offshore Transmission Coordination Project to consider whether additional measures might be required to further maximise the opportunity for coordination. The Project conclusions, published in March 2012, suggest that coordinated offshore network development does have the potential to deliver significant savings – coordination in respect of The Crown Estate (TCE) Round 3 Zones has the potential to deliver savings of around 8-15%, or £0.5-3.5 billion, when compared to purely radial configurations – and support an incremental, evolutionary approach to network development rather than the building of a large-scale, meshed network from the outset.

Interconnection

1.27 The UK has a 2 GW link to France and a 500 MW link between Northern Ireland and Scotland (max flow into GB is 295 MW). A 1 GW connection with The Netherlands became operational in April 2011 (this interconnector can run harder (up to 1.2GW) in exceptional circumstances). In addition, the East West Interconnector, a 500 MW link between the GB and Irish electricity grids, went live in September this year.

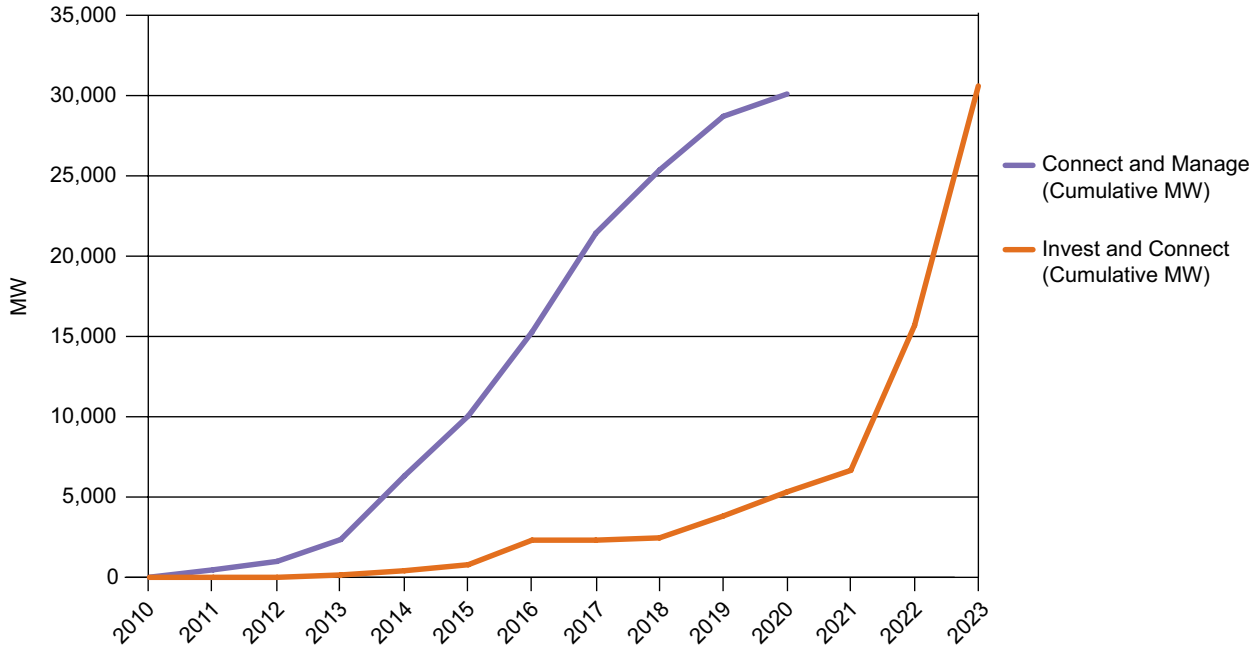
1.28 There are also plans for further links with Belgium, France, Norway, Denmark, Spain and Iceland. Many of these projects are still in the early stages of development. It is not clear which of these links will be realised, but a conservative estimate is that by 2020 an additional 2-3 GW of interconnection may be built.

18 http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/future-elec-network/4264-ensg-summary.pdf

Grid Access

1.29 Timely grid connection for new renewable and other low carbon generation projects will be essential over the next decade if security of supply is to be maintained. Until recently, getting access to transmission network represented a major barrier, with some new generation projects being offered connection dates as late as 2025. To address this, the enduring 'Connect and Manage' grid access regime was introduced in August 2010. This allows new generation projects to connect to the network as soon as their enabling works are completed rather than waiting, as under the previous 'Invest and Connect' regime, for wider network reinforcements to take place. As the following chart shows, 'Connect and Manage' has so far brought forward the connection timescales for 107 large generation projects (renewable and non-renewable with a total capacity of around 30 GW) by an average of six years.

Chart 1.4: Advancement of Connections under Connect and Manage



Source: National Grid

Conclusions

1.30 Forecasts for both the demand for electricity and the level and nature of capacity that will be available to produce it are subject to a range of sensitivities when looking forward over the next decade and beyond.

1.31 There are a number of challenges facing the electricity system today. Ofgem have published an assessment of capacity adequacy over the next five winters[19]. This provides a comprehensive outlook of the impact of changes in both the supply and the demand for electricity generation for the period to 2016/17. The Secretary of State's response to Ofgem's Electricity Capacity Assessment can be found in the annex to this document.

1.32 The electricity transmission network remains extremely reliable but there is a need for a significant amount of new investment in both the transmission and distribution networks to ensure future security of supply. The reforms that both DECC and Ofgem are undertaking aim to ensure that transmission and distribution network companies play a full role in the move towards a sustainable low carbon and secure energy system while providing long term value for money for existing and future consumers.

19 Available at: http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Documents1/Electricity%20Capacity%20Assessment%202012.pdf

Chapter 2: Gas

Introduction

2.1 This chapter sets out the current security of supply situation for gas in the UK. Demand projections can be compared against supply projections to give an indication of the likely capacity margin of UK gas supplies and gas infrastructure going forward. There are large uncertainties inherent in projections of gas supply and demand and for this reason a range of projections are set out below, taken from National Grid's futures modelling as well as DECC's own work.

2.2 In addition, the analysis in this chapter has drawn on Ofgem's assessment of the potential risks to medium and long term gas security of supply in Great Britain. The Secretary of State asked Ofgem in November 2011 to carry out this work and to appraise potential measures which could enhance security of supply beyond the Gas SCR. The report looked at developments in the GB, European and global gas markets and assessed the scale and nature of the risks to security of supply. The final report can be accessed on DECC and Ofgem's websites[20, 21].

Demand

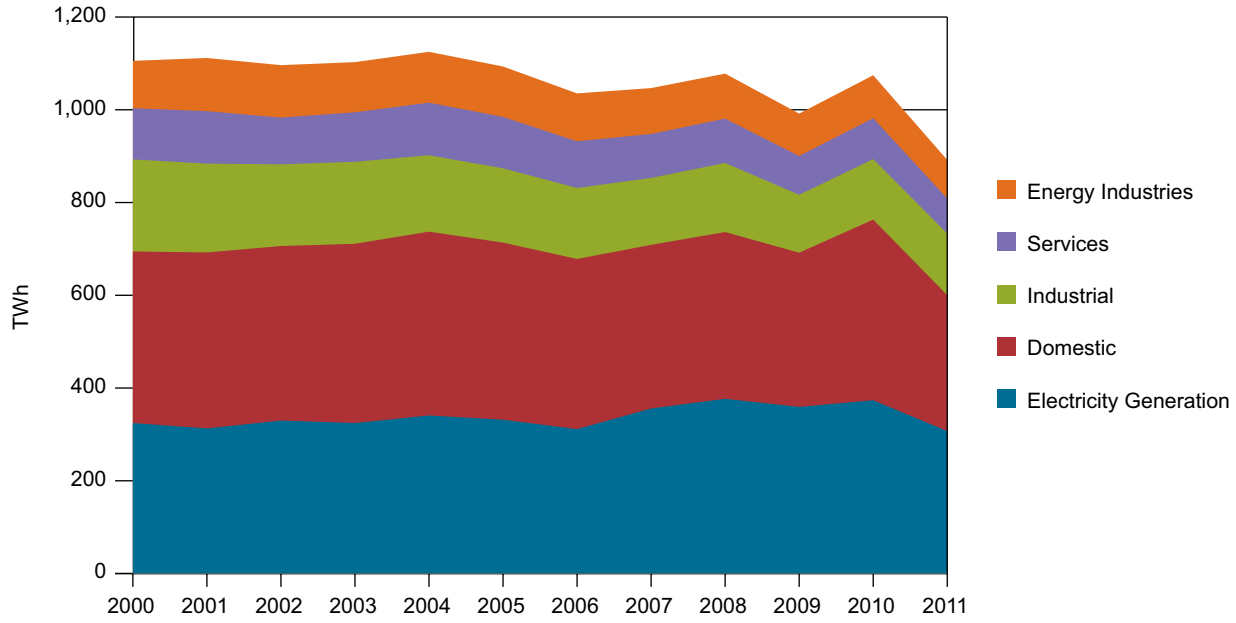
2.3 Chart 2.1 shows how the consumption of gas can be split into generation, domestic and a combination of industrial, services, and energy industries in roughly equal thirds.

2.4 2011 saw a sharp reduction in the consumption of natural gas due to a combination of factors. The continuing slow recovery from the 2008 global financial crisis, a relatively mild winter, and prices favouring coal-burn in the power sector all contributed to a noticeable reduction in demand for gas.

20 The Ofgem report concludes that while it is expected that production from the UKCS will continue to decline, the UK has attracted significant investment in infrastructure and storage. However, the decline in UK continental shelf production has resulted in increased reliance on international gas markets, which exposes Great Britain to a range of additional risks. That said, Ofgem's analysis shows that only very extreme circumstances would result in physical interruption to domestic customers and small businesses. While the likelihood of such events is very low, their impacts would be severe.

21 http://www.decc.gov.uk/en/content/cms/meeting_energy/markets/gas_markets/gas_markets.aspx and http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/gas-security-of-supply-report/Documents1/Gas%20SoS%20Report.pdf

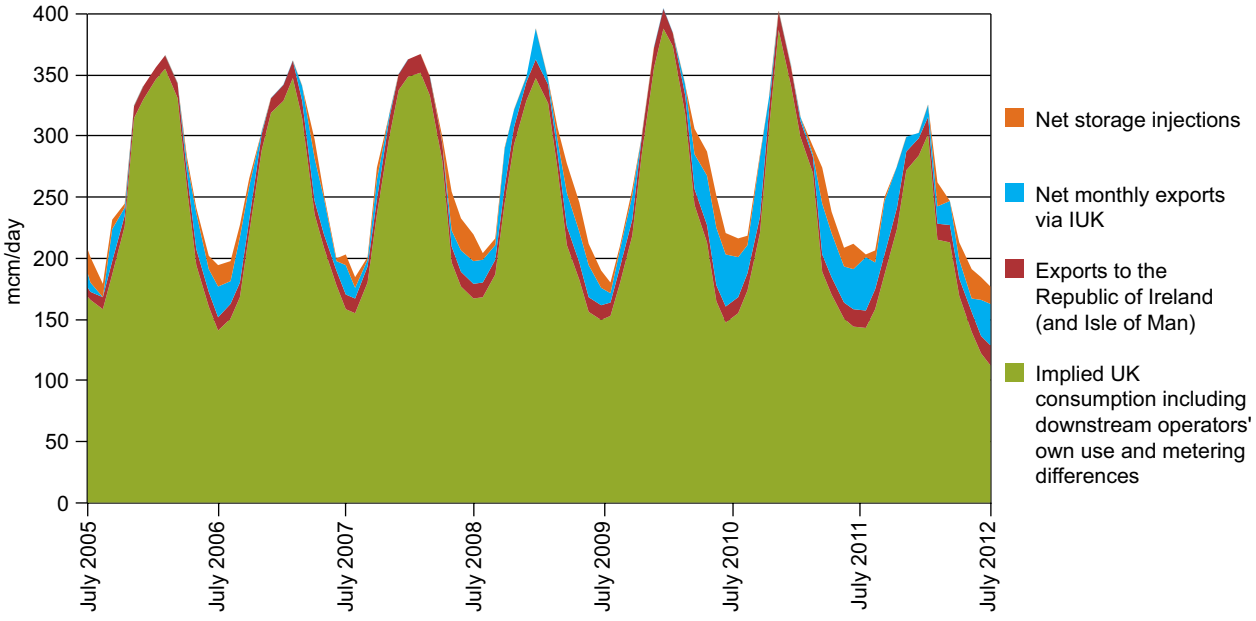
Chart 2.1: Consumption of natural gas 2000 to 2011



Source: DECC, Digest of UK Energy Statistics, Table 4.2

2.5 Demand for gas varies on a daily basis and is generally higher in winter than in summer as shown in chart 2.2. Temperature levels are a large driver behind this difference as they determine how much gas households and businesses require for space heating, creating a noticeable seasonal pattern. Gas demand for electricity generation and industrial purposes tends not to follow this seasonal pattern, but is instead influenced by the price of gas relative to the price of other fuels and the price of electricity.

Chart 2.2: UK Monthly Gas Demand



Source: DECC Energy Statistics, 2012

2.6 Chart 2.3 shows predicted annual gas demand in four scenarios including National Grid's: Slow Progression (SP)[22], Gone Green (GG)[23] and Accelerated Growth (AG)[24] and DECC's Central Scenario (DECC)[25].The underlying assumptions behind National Grid's scenarios have been updated for 2012; more details are published in 2012 Future Energy Scenarios[26].

2.7 A wider range of projections is shown, reflecting the uncertainty over how our future energy mix will evolve. The role of gas in the power generation sector is one of the main drivers behind this uncertainty. This is influenced by electricity demand, environmental legislation, government policy and the role of other fuels such as wind and nuclear. It is also influenced by the future relative price of coal and carbon prices that determine whether coal or gas is used for base load generation. For instance, in AG it is assumed that gas prices are high relative to coal and after 2020 new coal plant is built with CCS, which leads to a steady reduction in demand for gas from 82.7 billion cubic meters (bcm) in 2012 to 44.9 bcm in 2030. In SP, on the other hand, gas is cheaper than coal and no new coal plants are built meaning demand for gas remains relatively static, only decreasing by 5.3 bcm from 2012 to 2030.

2.8 In chart 2.3, it should be noted that the assumptions that relate to each scenario are applied immediately and do not take into consideration current market conditions, so the start point differs for each projection. It should also be noted that the demand projections provided by National Grid are higher than the DECC projections because these include exports to Ireland and exports to the Continent via the Interconnector (IUK).

2.9 The factors that influence gas demand become harder to predict in the future, meaning that the range of possible outcomes increases. In 2012 the difference in the range of predictions is 15.1 bcm, in 2020 this increases to 48.1 bcm and in 2030 is 53.7 bcm.

22 In the "Slow Progression" scenario low economic growth, low fuel prices, a failure of government policy to meet energy efficiency and renewable energy targets and a lack of change in consumer behaviour lead to sustained demand for gas.

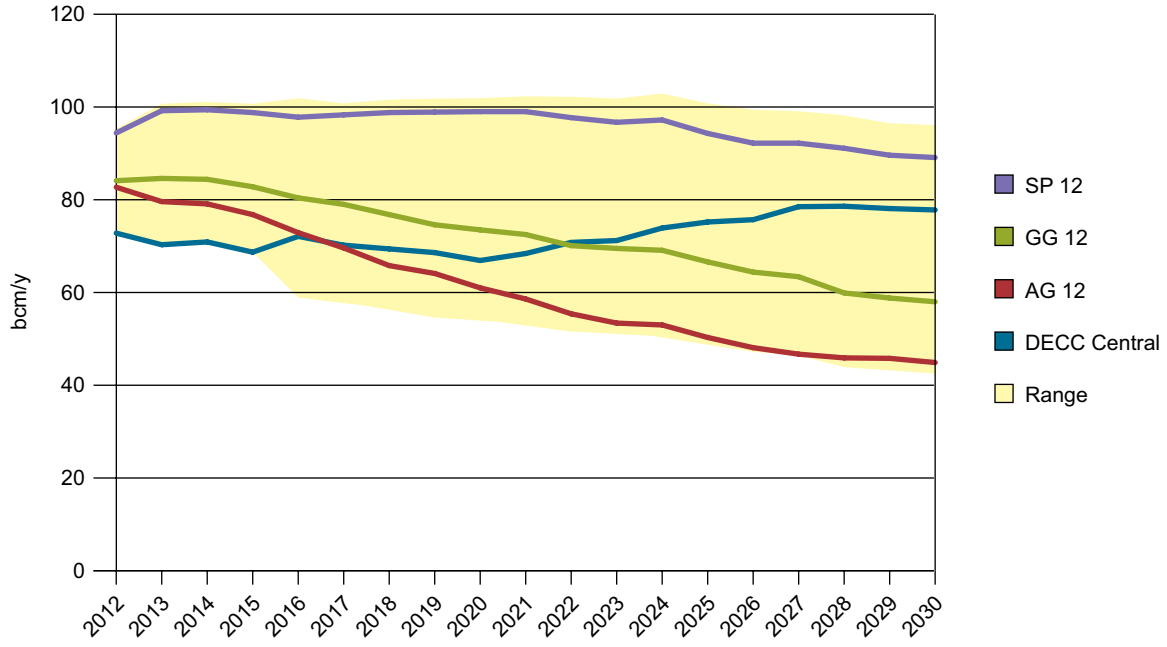
23 In the "Gone Green" scenario it is assumed that renewable energy and carbon targets are met and energy efficiency policy delivers leading to a reduction in demand.

24 The "Accelerated Growth" scenario assumes high gas prices leading to a switch to new-build coal with CCS to replace gas demand for electricity generation. It also assumes that economic growth is high, renewable and carbon targets are met early and energy efficiency policy is successful significantly reducing gas demand.

25 This is the central scenario from Energy & Emissions Projections data, where only the influence of policy that is significantly advanced enough to be modelled is included. For instance, the influence of EMR.

26 http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios/

Chart 2.3: Annual Gas Demand Sensitivity Analysis



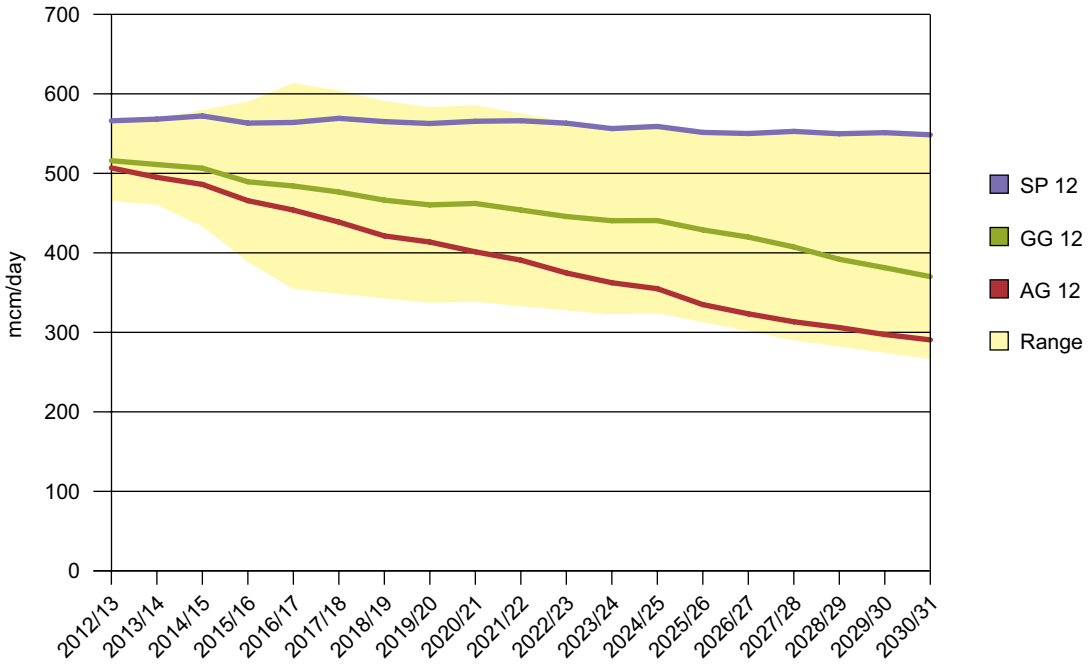
Source: National Grid & DECC (2012)

Peak Demand

2.10 As well as understanding annual demand, analysis of the gas market's ability to meet demand on a 1 in 20 peak day is crucial for security of supply. The analysis shows that on a peak day the grid has to deliver over double the average daily gas demand. Using 2012 figures, in the GG scenario, average demand is forecast to be 230 million cubic meters/day (mcm/day), whereas on a peak day demand could rise to 516 mcm/day.

2.11 A peak day has been modelled in chart 2.4 to represent a 1 in 20 cold peak day for the whole country. In reality there is no single profile of demand across the country due to differences such as temperature and population density. Chart 2.4 uses National Grid's three projections as in chart 2.3. In SP gas is used for base load, whereas in the GG and AG scenarios the influence of increased wind generation, heat pumps and electricity interconnection show a reduced reliance on gas during a peak day.

Chart 2.4: Peak Demand Sensitivity Analysis



Source: National Grid

2.12 It is not only temperature and the relative costs of other fuels that will impact demand into the future, but also the role of gas in the UK energy mix. Increasing amounts of variable and relatively unpredictable wind generation may increase the volatility of gas demand, as gas-fired generators are used to balance the electricity market. In addition, the amount of nuclear capacity that is built will influence the extent to which gas generation is used to meet baseload demand. In the coming years the gas market will need to respond to this by becoming increasingly flexible; for example by increasing the rate at which gas can flow around the network (see box 2.1), or through greater demand side response.

2.13 The increased volatility in gas demand coincides with the closure of 12 GW of coal and oil generation capacity in the middle of the decade due to the Large Combustion Plant Directive (LCPD), increasing the reliance on gas for electricity generation.

Box 2.1: RIIO-T1 Uncertainty Mechanism

In its RIIO-T1 submission, National Grid Gas has asked Ofgem to clear some capital expenditure to address changing gas transmission network flow patterns required by its users. This includes expenditure to 1) reverse flows to support diminishing UKCS flows from St. Fergus; 2) provide additional compression capacity in the South West; 3) deal with the dynamic nature of future flows (wind intermittency, central corridor congestion); and 4) fund initial projects to investigate future requirements.

At this stage, Ofgem believes only the funding for projects 1) and 4) are deemed appropriate, namely to enable reversal of flows towards Scotland to support peak demand and a contribution towards the future requirements projects. Instead Ofgem has set out in its Initial Proposals, published 27 July, to have a mid-period re-opener to give NGG a chance to build a more detailed case for specific investments. In addition, Ofgem will develop an uncertainty mechanism to allow NGG scope to acquire additional funding during the price control if it becomes apparent that it is required.

Gas Security of Supply Report (Ofgem, 2012)

Demand side response

2.14 DSR is a mechanism used to ensure that in times of market tightness, supply and demand can be balanced. The power-generation sector provides the greatest opportunity for switching demand away from gas to coal or oil generation, although this will decline as coal and oil plants close towards the end of the decade. At times where coal is relatively less expensive and gas is already the marginal source there is also limited to no opportunity for switching in the power generation sector.

2.15 GB has a liquid wholesale gas market, so, at times of market tightness price signals generally bring about effective DSR. Consumers (and producers) that are exposed to these price signals have incentives to respond and where technically feasible can switch to alternative fuel or scale back or cease production. Non-daily metered consumers (domestic consumers and small businesses) are not exposed to these fluctuations in wholesale prices and therefore have no signal to reduce demand. In the future, through smart metering, consumers will have near real-time information about energy consumption to help them control energy use, save money and reduce emissions.

2.16 Ofgem's Gas Security of Supply Significant Code Review (Gas SCR) attempts to sharpen the incentives on gas market participants in order that they invest in measures to enhance security of supply by reforming the gas cash-out mechanism. In the event of a Gas Deficit Emergency (GDE), the cash-out price will be set at £20/therm to reflect the value that consumers place on uninterrupted gas supplies, termed 'Value of Lost Load' (VoLL)[27]. It is expected that the proposals will provide a strong incentive to shippers to undertake actions which reduce the risk of a GDE occurring, such as encouraging gas market participants to invest in new infrastructure (e.g. storage). The proposals should also encourage suppliers to sign more interruptible contracts with daily metered customers, increasing the opportunities for DSR. However, the proposed arrangements will only fund payments to customers affected by a network isolation for the first day of the interruption. It is recognised that this leaves a gap in the incentives for shippers to provide security of supply, even after cash-out reform.

2.17 Under exit reform the previous transporter interruptible contracts have been replaced by an off-peak product with the scope for transporter interruption with at least 4 hours notice. The new arrangements came into force on 1 October 2012.

2.18 For winter 2012/13, the relative gas and coal prices strongly favour coal as base load, reducing demand for gas. As a result, National Grid estimates that the DSR from power generation will be very limited. DSR from other sources could be up to 10 mcm/d (e.g. large industrial consumers), if the price was high enough and sustained. This continues the trend from 2011/12.

Supply

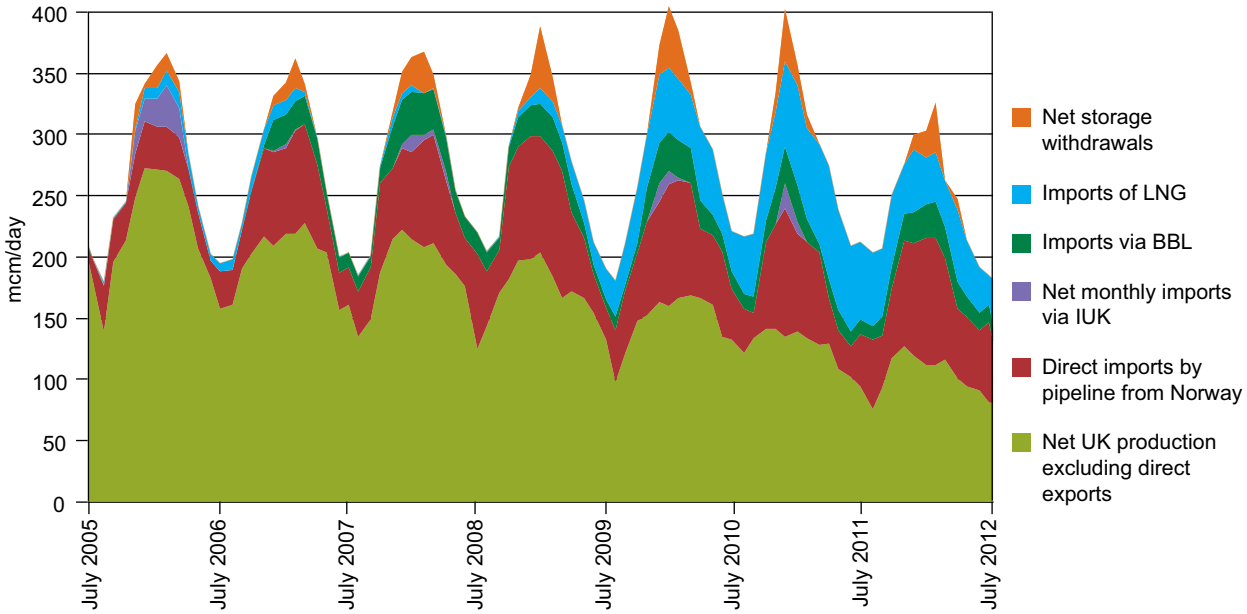
UK Production

2.19 Chart 2.5 shows how production of gas from the UK Continental Shelf (UKCS) has been steadily declining. The seasonal variation in supply from UK production, termed 'swing supply', has also reduced. This reduction reflects a greater share of production from associated gas fields and less from dry gas fields[28] with producers being reluctant to reduce production from oil fields and also because a declining share of production is sold under buyer-nomination contracts which allowed production to be varied in line with demand.

27 Ofgem is proposing to reform the gas cash-out mechanism so that the cash-out price would be set at £20/therm in a GDE for: all days of firm load shedding (where individual large customers are required to reduce their gas demand) and the first day of any network isolation. Ofgem are also proposing that a proportion of the cash-out payments from shippers would be used to fund payments for involuntary demand-side response services to those consumers whose gas supply has been interrupted. Firm customers would be paid £20/therm for each day they are without gas. If network isolation occurs, firm customers that are interrupted would be paid £20/therm for the first day of an interruption only.

28 Associated gas fields hold both oil and gas, and gas is produced as a joint-product with oil. Since oil is the higher value product, production tends to be governed by conditions in the oil market. Dry gas fields contain only natural gas and so their production is influenced but not determined by short term supply and demand conditions in the gas market.

Chart 2.5: UK Monthly Gas Supply

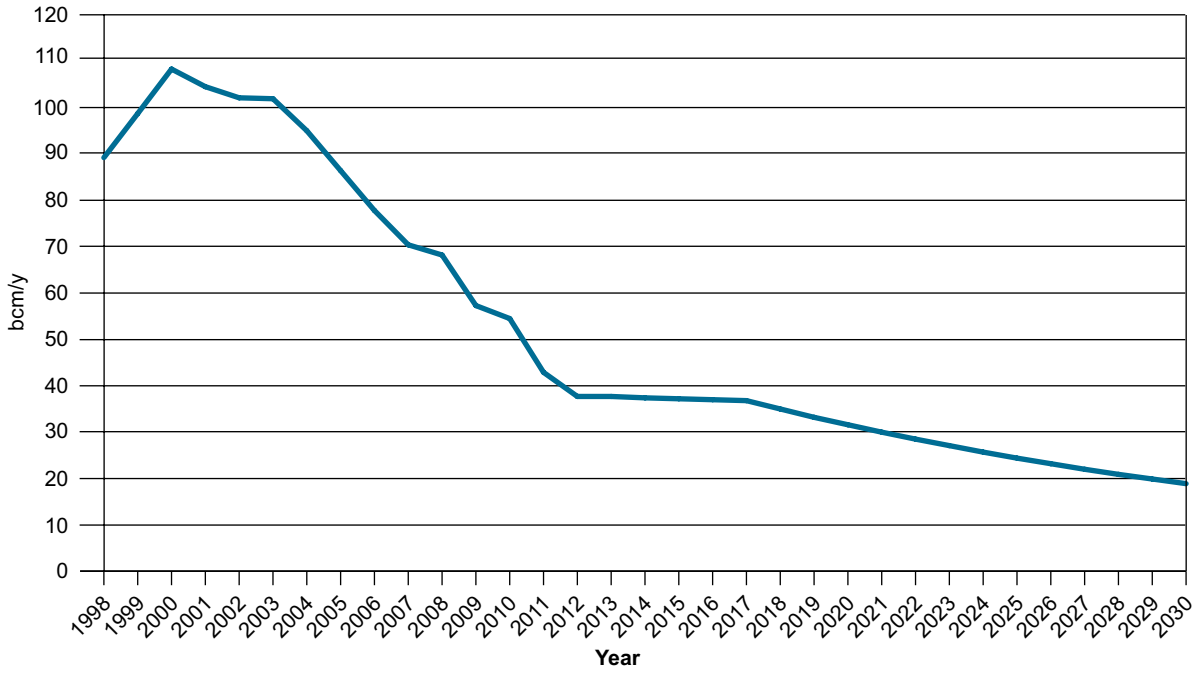


Source: DECC Energy Statistics, 2012

2.20 Roughly half of UK gas demand is still supplied through UK production. Chart 2.6 shows that UK gas production has been declining since 2000 and that this decline is expected to continue. As with projections of demand, due to the inherent uncertainties involved, projections of UK gas production should be treated as indicative rather than definitive.

2.21 There are small scale plans for gas production from unconventional sources including biomethane and coal-bed methane. The potential for unconventional gas should be explored because of the additional security of supply it could provide. However, it is important to stress that it is still very early days for shale gas in the UK. Given the uncertainties, for the present, it is prudent to take a cautious view of its implications for security of supply and contribution to the UK energy mix.

Chart 2.6: Actual and Projected UK net gas production



Source: DECC, October 2012

Imports

2.22 Imports via pipeline from Norway and the Continent and liquefied natural gas (LNG) are becoming more important sources of supply, not only in times of peak demand but throughout the year.

2.23 Since 2004 the UK has been a net importer of gas. In 2011, net imports of gas decreased relative to 2010 levels because UK demand fell even more than UK production but, when separated out in more detail in Table 2.1 below, we can see imports of LNG increased, notably from Qatar. Increased reliance on imports brings additional challenges. This section considers the UK's projected demand for imports, capacity to receive imports, potential sources and the risks associated with delivery.

Table 2.1: Natural Gas imports and exports

	2007	2008	2009	2010	GWh 2011
Imports:					
Pipeline from:					
Belgium	6,471	12,174	7,945	13,568	4,032
Netherlands	76,602	90,563	69,529	87,120	69,001
Norway	225,764	283,722	260,438	276,807	234,194
LNG	14,903	8,912	110,579	203,789	270,733
of which:					
Algeria	*6,605*	*3,113*	*19,392*	*11,524*	*2,647*
Australia	-	-	*812*	-	-
Egypt	*1,751*	-	*5,804*	*1,263*	*877*
Nigeria	-	-	-	*3,674*	*12,833*
Norway	-	-	*1,862*	*8,904*	*9,965*
Qatar	*2,693*	-	*61,159*	*159,984*	*230,618*
Trinidad & Tobago	*3,854*	*5,799*	*21,550*	*16,646*	*5,816*
USA	-	-	-	-	*1,552*
Yemen	-	-	-	*1,794*	*6,425*
Total Imports	**323,740**	**395,371**	**448,491**	**581,284**	**577,960**
Exports to:					
Belgium	51,390	45,949	62,084	95,932	101,526
Netherlands	6,358	10,389	13,094	15,830	17,544
Norway	153	389	266	158	125
Republic of Ireland	50,972	54,260	54,357	56,266	58,041
Total Exports	**108,873**	**110,987**	**129,801**	**168,186**	**177,236**
Net Imports	**214,867**	**284,384**	**318,690**	**413,098**	**400,724**

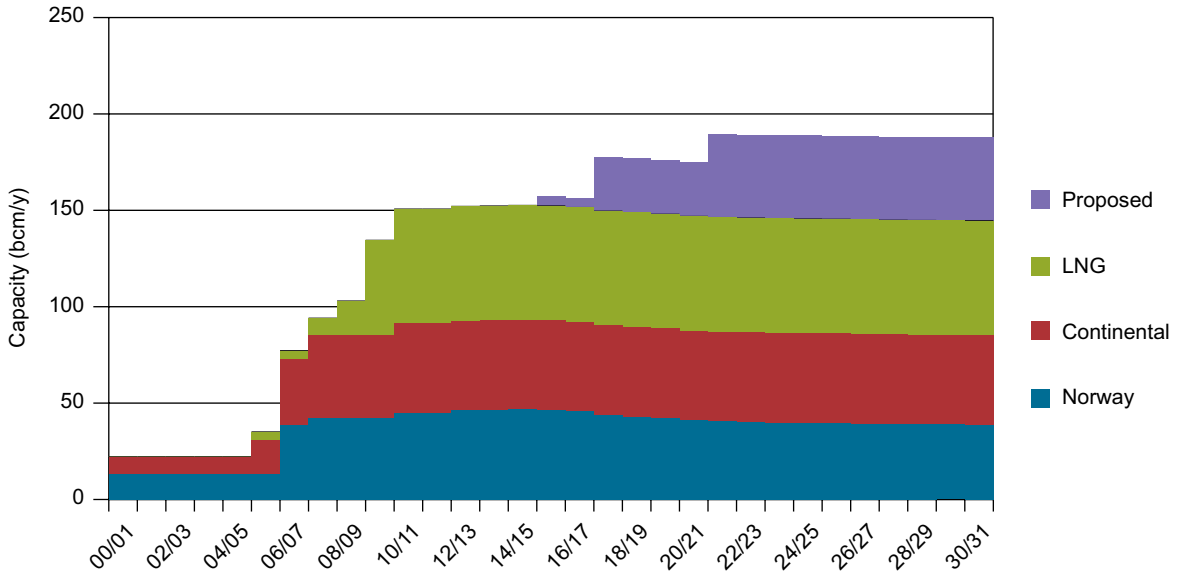
Source: DECC, Digest of UK Energy Statistics, 2012 (Table 4.5)

Import Capacity

2.24 The UK has a diverse range of sources of gas supply, including domestic production, pipeline imports from Norway and the EU, LNG from global markets and storage. There is also a degree of DSR response as some large loads (such as power plant) can reduce demand in response to short term increases in gas price. Gas shippers can draw on all of these sources to ensure they meet overall demand. Import capacity and diversity also allows the UK to react to price signals, importing marginal volumes of gas from whichever is the cheapest source.

2.25 Chart 2.7 shows that currently the UK has an import deliverability of ~46 bcm/y from pipelines connecting to Norway, ~46 bcm/y from capacity connected to the Continent, ~59 bcm/y from LNG import terminals and that 43.3 bcm/y import capacity has been proposed. It is important to note however that capacity is not a measure of utilisation.

Chart 2.7: Possible evolution of UK gas import deliverability (total)

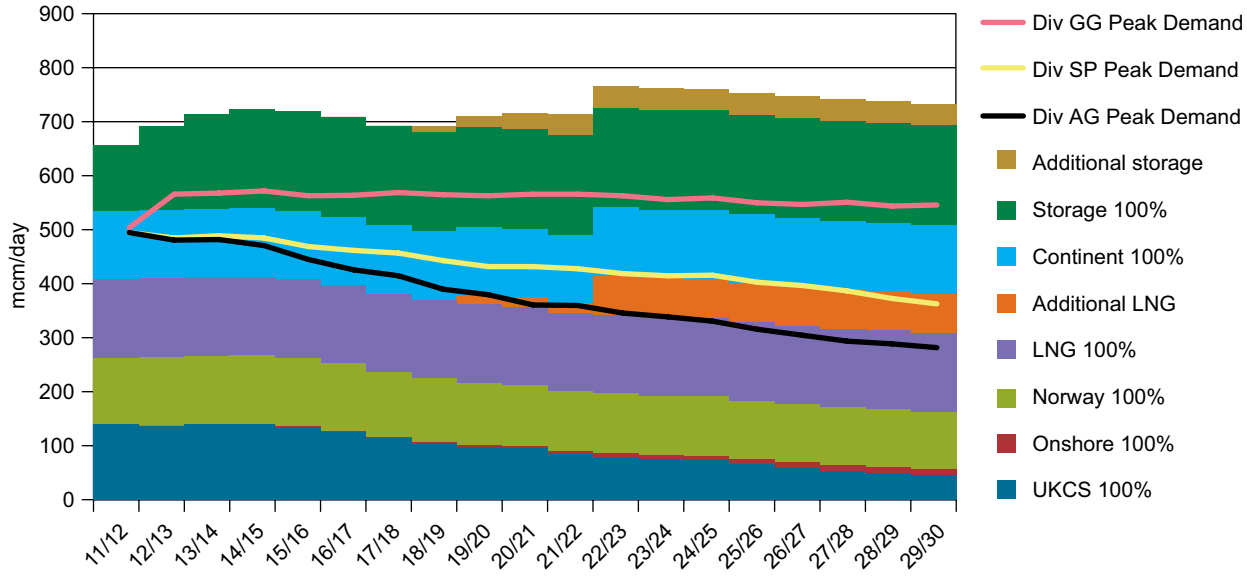


Source: National Grid (September 2012)

2.26 Chart 2.8 shows three different winter peak scenarios[29] overlaid on supply capacity in the SP supply scenario. This supply capacity includes physical import pipeline capacities, peak storage deliverability and capacity of the UKCS to supply at 100% availability. The projection suggests that the capacity of the infrastructure would be able to meet demand on a peak day out to 2030.

29 National Grid's AG, GG and SP scenarios.

Chart 2.8: Peak Daily Supply Availability with additional LNG and storage infrastructure (Based on SP Supply)

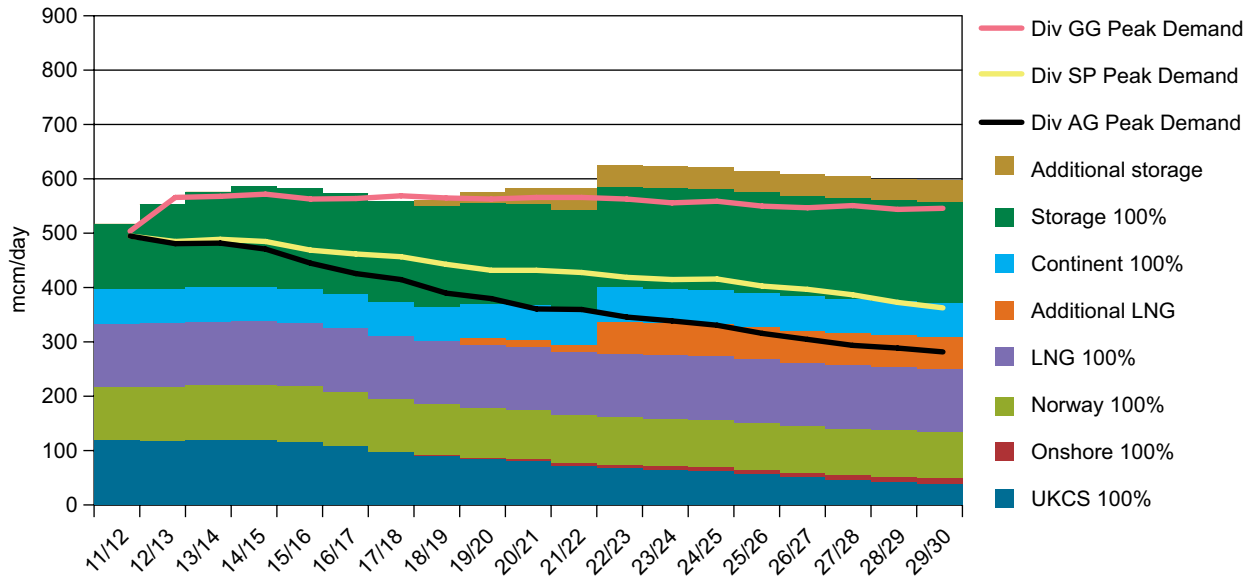


Source: National Grid September 2012

2.27 In reality, these levels of availability would not be expected due to availability of supply and any planned or unexpected maintenance to the infrastructure. Chart 2.9 shows the same build up of supply but at 'de-rated' capacity values to reflect typical operational winter characteristics. With de-rated capacity values, the supply picture is somewhat tighter, particularly in the SP demand scenario. While using de-rated values can be useful to reflect expected flow rates at times of peak demand, caution must be exercised as there are a number of factors that influence the availability of gas throughout the supply chain[30]. If demand outstrips supply using de-rated capacities it doesn't necessarily mean that the infrastructure would not be able to deliver as real capacity utilisation could be higher or lower than indicated. Still, everything being equal, due to the liquidity of the UK wholesale gas market, in the event of peak demand, it is likely that more gas would become available as gas prices increase.

30 For example, the availability of gas in Europe for export through the IUK or the availability of LNG that can be delivered to import terminals.

Chart 2.9: Peak Daily Supply Availability with additional LNG and storage infrastructure, de-rated values (Based on SP Supply)



Source: National Grid September 2012

Norway

2.28 Norway is a crucial gas supplier to the UK, supplying around a quarter of our total gas demand in 2011. Norway currently has the infrastructure capacity to export 53.8 bcm a year to the UK. Infrastructure built to supply the UK this decade includes the 25.3 bcm Langeled pipeline commissioned in 2006 (supplying gas to Easington), the Tampen link (9.1 bcm, commissioned in 2007) and the Gjoa link (6.2 bcm, commissioned in 2010), which feed into the FLAGS pipeline terminating at St Fergus. The Vesterled pipeline was commissioned in 1978 and can supply 13.1 bcm to St Fergus. Norwegian gas production is currently about 100 bcm annually and is projected to remain stable or rise by around 20% this decade. There is greater uncertainty beyond 2020 due to on-going seismic studies and new discoveries in the Arctic (Barents Sea and Norwegian Sea). Consequently, Norway is considering options for new infrastructure to transport these potential new volumes of gas to European customers (including the UK) via pipeline, or to wider international markets via expanded LNG capacity.

The Continent

2.29 The UK gained its first interconnection to Continental Europe in 1998. Today, import capacity through Interconnector UK is around 27 bcm/y and 20 bcm/y through the Balgzand Bacton Line (BBL).

2.30 With the UK being increasingly import-dependent, access to mainland European gas markets is important. However, on the one hand greater interconnection with mainland Europe gives the UK some measure of increased security of supply as it can access a wider pool of gas, on the other hand the UK may be more exposed if there are significant gas supply disruptions. For example, the EU as a whole is dependent on Russia for over 30% of its gas imports. Norway and Algeria are also significant suppliers to Europe. Disruptions in any of these sources, depending on the severity, will affect the available pool of gas and therefore may, in some limited circumstances, have an impact on the UK market, particularly since mainland Europe's market is still considerably less liquid than the UK's.

2.31 In winter 2011/12, the IUK interconnector acted as a flexible supply source and was seen to respond to market dynamics including prices, UK and Continental demand and storage flows and stocks. However, analysis undertaken by Ofgem shows that, in general, gas flows through interconnectors are not always responsive to price and that not all available capacity is utilised[31]. Lower market liquidity in Europe also means that in a gas supply emergency, when it is vital that gas is flowing through interconnectors, economic access to European gas may be difficult. To understand whether further steps are required to improve the responsiveness of interconnectors, Ofgem has published an open letter, in collaboration with the Belgian and Dutch regulators, calling for evidence on the economic efficiency of cross-border interconnector flows between GB and the continent[32].

2.32 Measures introduced through the EU Third Package incentivise investment in cross-border infrastructure and facilitate cross-border trading. A suite of technical regulations are being developed to underpin this. Investments in physical infrastructure are also being made to enable gas to flow more freely around the EU. Furthermore, measures and obligations laid out in the Gas Security of Supply Regulation will enhance EU security of supply.

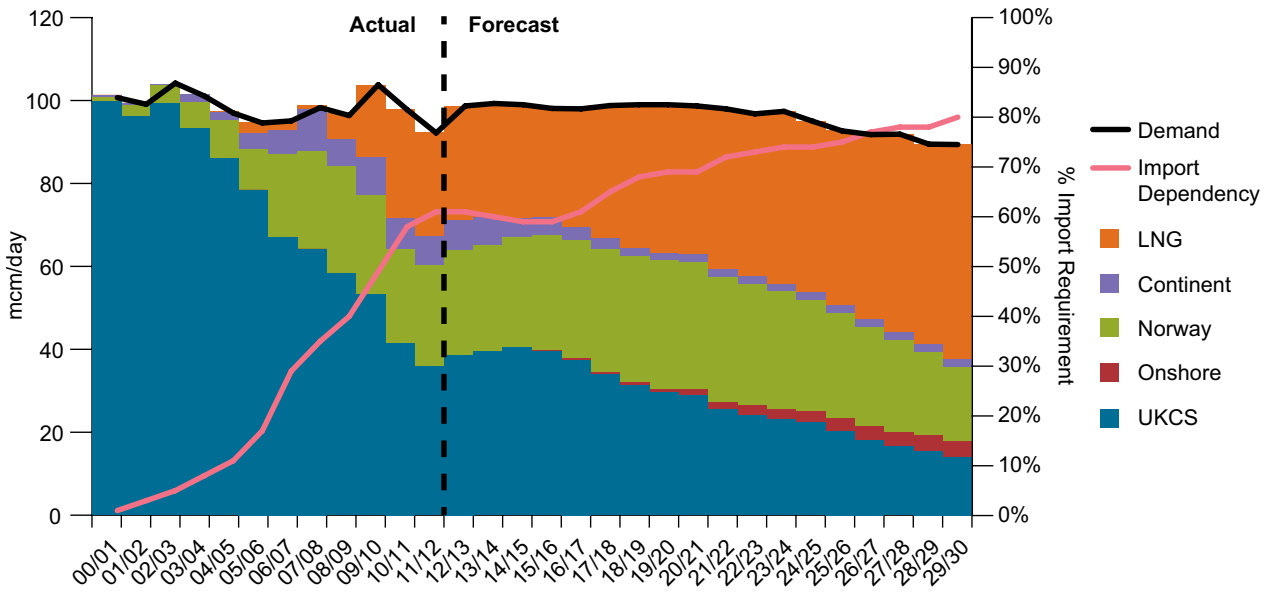
Imports from the rest of the world

2.33 In 2011 our largest international gas suppliers were Norway (41% of imports), Qatar (40%), and the Netherlands (12%). Chart 2.10 shows that currently ~50% of demand is met through imports and out to 2030 this could increase to ~80%. Diverse supply sources make the UK gas supply infrastructure more resilient to supply shocks.

31 For example, large price differentials are often associated with utilisation below maximum levels, and gas flows can flow in the opposite direction than expected. According to initial Ofgem analysis, aggregate daily utilisation levels on IUK and BBL are typically below 50% of maximum capacity.

32 http://www.ofgem.gov.uk/Europe/Documents1/120928_Interconnector_Open%20Letter%20Final.pdf

Chart 2.10: National Grid Annual Supply-Demand Match (SP Scenario)



Source: National Grid, 2012

2.34 In recent years the UK's LNG regasification capacity has increased significantly. The UK now has two import terminals at Milford Haven, one on the Isle of Grain, and the Teesside GasPort facility, which in total provide for around 56 bcm of annual capacity. This increase has enabled LNG imports to rise from less than 5% of total imports in 2005 to almost half of the UK's total imports of gas in 2011. With the decline of domestic production, this means the UK is increasingly affected by developments within the global gas supply and demand balance.

2.35 Global gas markets have traditionally been regional with three, loosely interconnected markets; North America, Europe and Asia. However a more global gas market continues to develop[33] as the LNG market continues to grow and gas trading becomes increasingly flexible, driven by market liberalisation, especially in Continental Europe.

2.36 The IEA has described the global gas resource base as "vast and widely dispersed geographically", and have estimated remaining recoverable reserves of conventional gas as equivalent to 130 years of current consumption, and those of unconventional gas potentially equivalent to a further 125 years.

33 The IEA forecast inter–regional trade (excluding trade with regions such as Europe) will grow from 21% of global demand to 23% between 2008 and 2020, with LNG making up an increasing proportion. Source: IEA WEO 2010 (p.193)

2.37 However the global supply outlook is highly uncertain. It is particularly unclear whether the US shale gas experience will be replicated elsewhere in the world, and if so, when this will happen. The US boom in unconventional production was supported by favourable geology, low population density, a competitive supply industry which has developed significant advantages of scale, variable levels of environmental regulation, and strong development incentives for landowners. With the possible exception of the geology, these factors do not, at least for the time being, exist elsewhere. Although there is considerable potential particularly in Australia and China, the extent, timing and costs of production remain subject to considerable uncertainty. It is unlikely that significant production of unconventional gas will occur in Europe in this decade.

2.38 Global gas demand is also forecast to rise dramatically, by 55% by 2035 according to IEA[34], driven especially by demand growth in Asian economies. A global move away from nuclear power could add to this rising demand. Some commentators have forecast that rising demand could continue to tighten global LNG markets towards the middle years of this decade, before significant new LNG export infrastructure projects are expected to be complete (especially in Australia).

2.39 Additionally, Ofgem's Gas Security of Supply Report highlights the risks associated with the closure of critical LNG shipping lanes, and makes the point that the destination of LNG cargoes can go against price signals. Going forward, it is important that market arrangements properly reflect the importance of security of supply and its value to consumers.

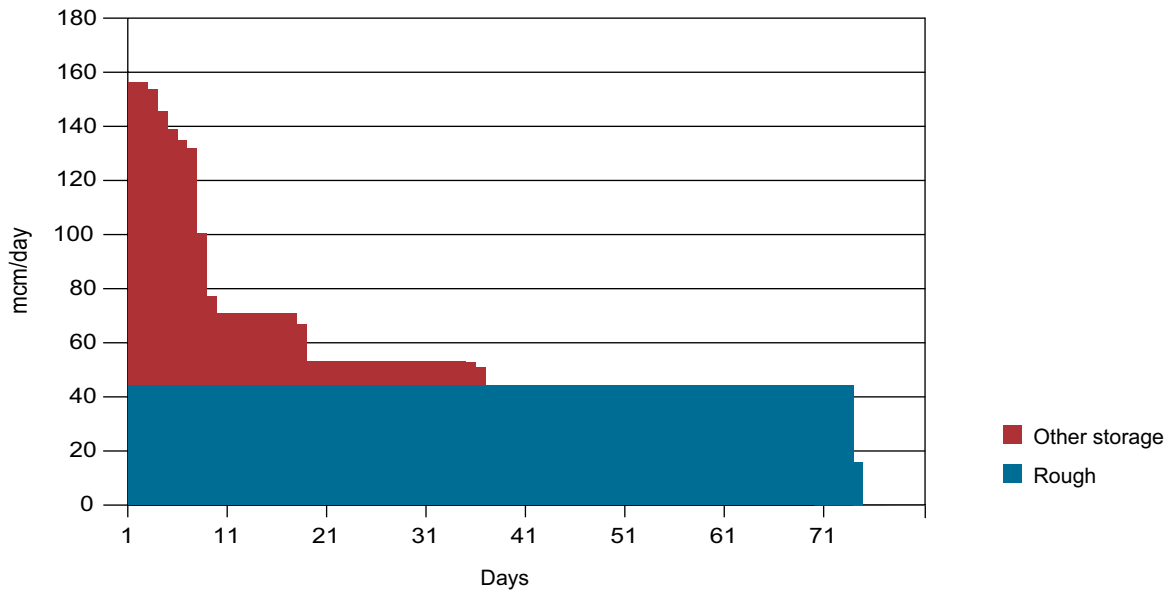
Storage

2.40 Storage facilities are a means to effectively manage seasonal demand fluctuations for gas. Facilities are filled during summer months, when gas is cheap and in abundance in order to meet increased demand in winter when prices are higher. In addition, many of the more flexible storage facilities are able to replenish their stocks during winter months. Storage is also a useful means to mitigate against supply disruptions, which is a growing risk as the UK becomes increasingly import dependent.

2.41 The Energy Act 2011 gives Ofgem power to implement measures to sharpen the incentives on gas market participants to prepare for and respond to a gas supply emergency. Such measures would help underpin commercial demand for the range of supply infrastructure we are likely to need in the future, including gas storage. These changes will come about as part of Ofgem's Gas Security of Supply Significant Code Review.

34 IEA New policies scenario

Chart 2.11: Nominal Storage Supply Capacity in Mcm/d



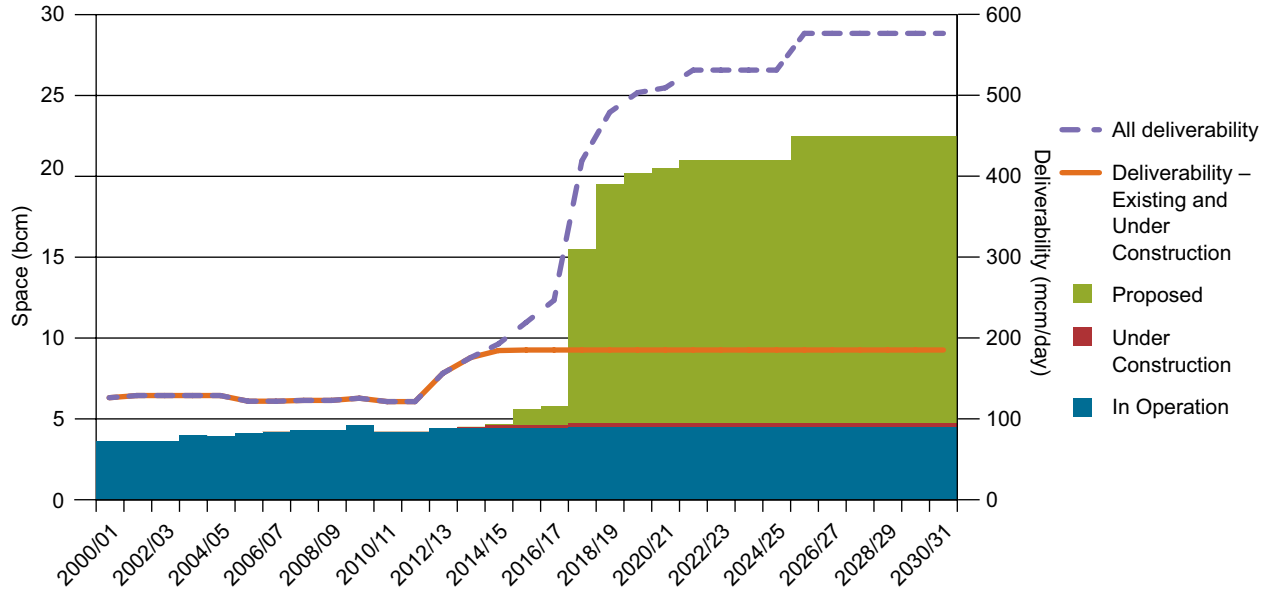
Source: National Grid (2012)

2.42 Describing the UK's storage capacity in terms of the number of days of demand that it could meet is not meaningful, as in reality, gas from storage is not the only source that is used to meet demand. Chart 2.11 shows the aggregate storage deliverability (with Rough, the UK's largest storage facility shown separately).

2.43 Maximum deliverability for 2012/13 has increased to 108 mcm/day (National Grid's assumed deliverability figure from the Winter Outlook Report 2012, the name plate capacity is far higher as shown in chart 2.11) as the storage facilities Aldbrough, Holford and Hill Top Farm become available.

2.44 Chart 2.12 shows current and proposed gas storage capacity, although the number of proposed storage sites that will become operational is uncertain. The capacities shown represent the storage developers' views, in reality the proven capacity may be much lower.

Chart 2.12: GB Gas Storage Capacity



Source: National Grid (information as of September 2012)

Network reliability

2.45 The UK gas transmission network achieved 100% reliability in 2011/12. System reliability is assessed as no supply losses to firm supply points. During winter 2011/12, there was no requirement to interrupt any customers supplied directly from the NTS on any occasion. No other Transporter or Emergency interruption to customers supplied directly from the NTS was required. In the future the network will need to be able to react to the complications of greater gas demand volatility as gas is used as a back-up fuel for increased wind-power generation capacity.

Conclusion

2.46 Analysis shows that in the near term the UK gas market has capacity to meet demand. Into the future, projections show a wide range of scenarios, highlighting the uncertainty around future levels of gas supply and demand at both the GB and global levels. These are affected by factors such as the impact of government policy, changes in consumer behaviour, economic growth and the future profile of the UK energy mix.

2.47 While it is expected that production from the UKCS will continue to decline, the UK has attracted significant investment in infrastructure and storage, and we now import gas from a diverse range of sources. Notwithstanding that, increased dependence on international markets exposes the UK to a range of additional risks to security of supply. Ofgem's Gas SCR, if implemented as expected by winter 2013/14, should strengthen the incentives on gas shippers to ensure they can balance their contractual supply obligations.

2.48 Even so, there are prospects for a continued tightening of LNG markets towards the middle of this decade as demand growth outstrips supply growth. After this, the tightness is expected to recede with planned capacity expected to increase, in particular with new projects from Australia. Unconventional gas could potentially enhance security of supply. However, it is still very early days for shale gas outside the US.

Chapter 3: Oil

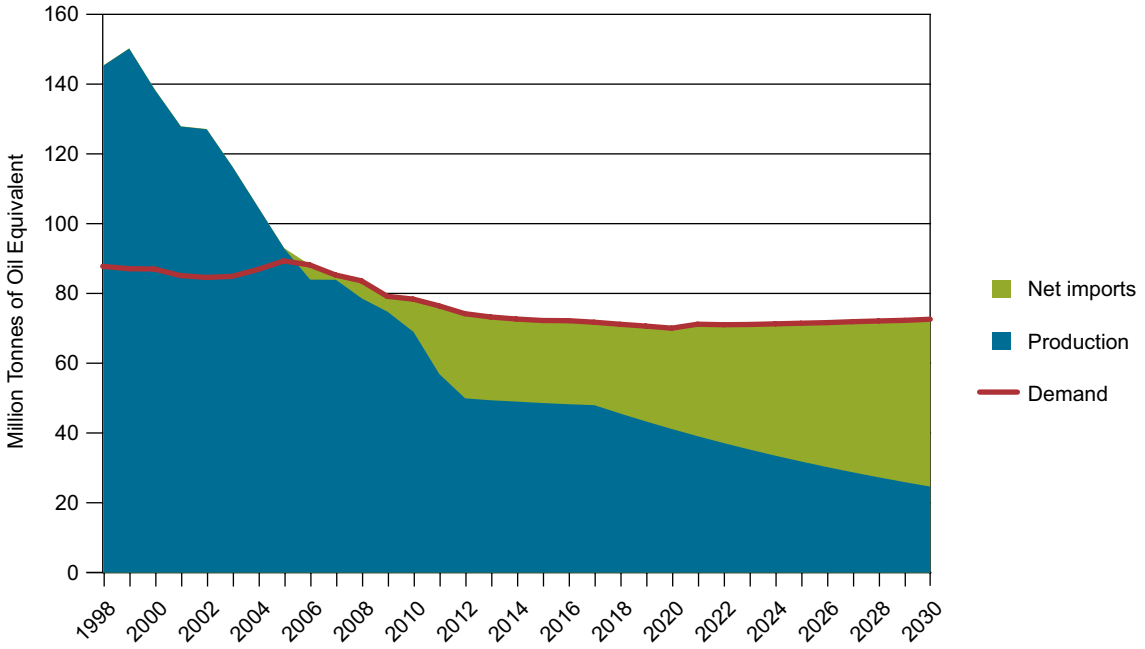
Introduction

3.1 This chapter presents a brief summary of key facts on UK oil production and demand, using DECC data to the end of 2011 and forecasts to 2030. As with all scenarios, a wide margin of uncertainty is inherent in the projections and future supply and demand will depend on a range of factors.

UK Oil Production

3.2 Oil production from the UKCS peaked in 1999 and declined at an average rate of around 7 per cent per year until 2010. A number of unexpected slowdowns in oil production saw a reduction of around 17 per cent in 2011. For the first time since production peaked in 1999, gross crude oil imports exceeded domestic production. DECC's latest central projection indicates UK production (including Natural Gas Liquids) will fall to 49 million tonnes of oil equivalent in 2015, down from 57 million tonnes in 2011, though there is a wide margin of uncertainty with such projections. The actual rate of future decline will depend on the level of investment and the success of further exploration. Chart 3.1 shows the declining production profile, and how net imports will be increasingly important in meeting a broadly flat demand profile.

Chart 3.1: UK Oil Demand, Production & Imports



Source: DECC Projections of UK Oil Production and Updated Energy Projections (both October 2012)

3.3 Since 2005, the UK has consistently been a net importer of crude oil, as production from the UKCS has declined. Whilst the UK's production would be sufficient to meet over two thirds of refinery demand, there is an active trade in oil. The UK imports crude oil for various commercial reasons, a principal element of which is the oil's sulphur content. North Sea type crude contains a high proportion of the lighter hydrocarbon fuels resulting in higher yields of products such as motor spirit.

3.4 Most of the UK's crude imports come from Norway, given not only its proximity to the UK but also the similarity in its crude types with the remainder largely supplied from Russia and the OPEC countries. Although supplies tend to be sourced nearby in order to minimise transport costs, the UK imports from a diverse range of sources which reduces the impact of a disruption to any one source of supply.

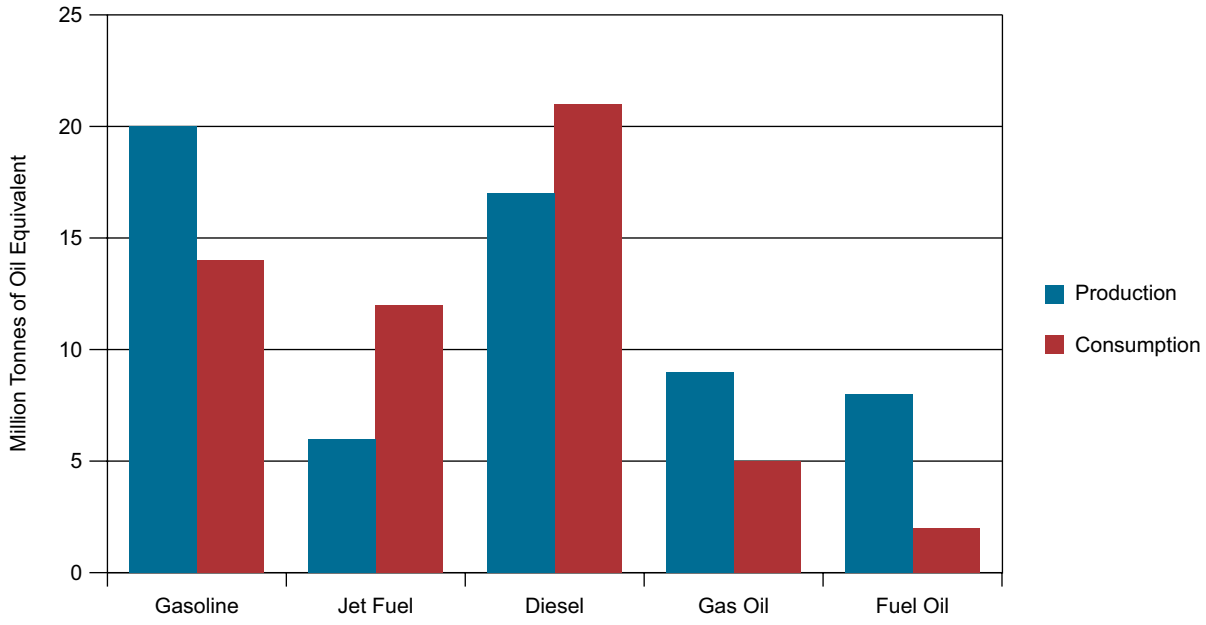
UK Oil Demand

3.5 Oil products play an important role in the UK economy, providing around a third of the primary energy used in 2011. We currently rely on oil for almost all of our road and air transport needs. Transport accounted for over 75 per cent of final consumption of oil products in the UK in 2011, (almost 49 million tonnes of oil).

3.6 The UK demand for oil products has changed over the last 10 to 15 years, driven by growth in the aviation sector, the increased proportion of diesel vehicles in the car fleet, and a reduction in the use of oil for power generation. Although aggregate demand has fallen (from 81 million tonnes in 2005 to 69 million tonnes in 2011) there has been a more significant shift in the mix of products consumed.

3.7 UK refineries have not matched the changing pattern of demand, as shown by Chart 3.2. Compared to the current UK demand, they produce a surplus of petrol and fuel oil and relatively little middle distillates (such as diesel and jet fuel), as they remain configured to meet the historically higher levels of petrol demand. For refineries to reconfigure their processes to produce more middle distillate would require substantial investment in new processing/conversion units.

Chart 3.2: Production and consumption of key petroleum products 2011

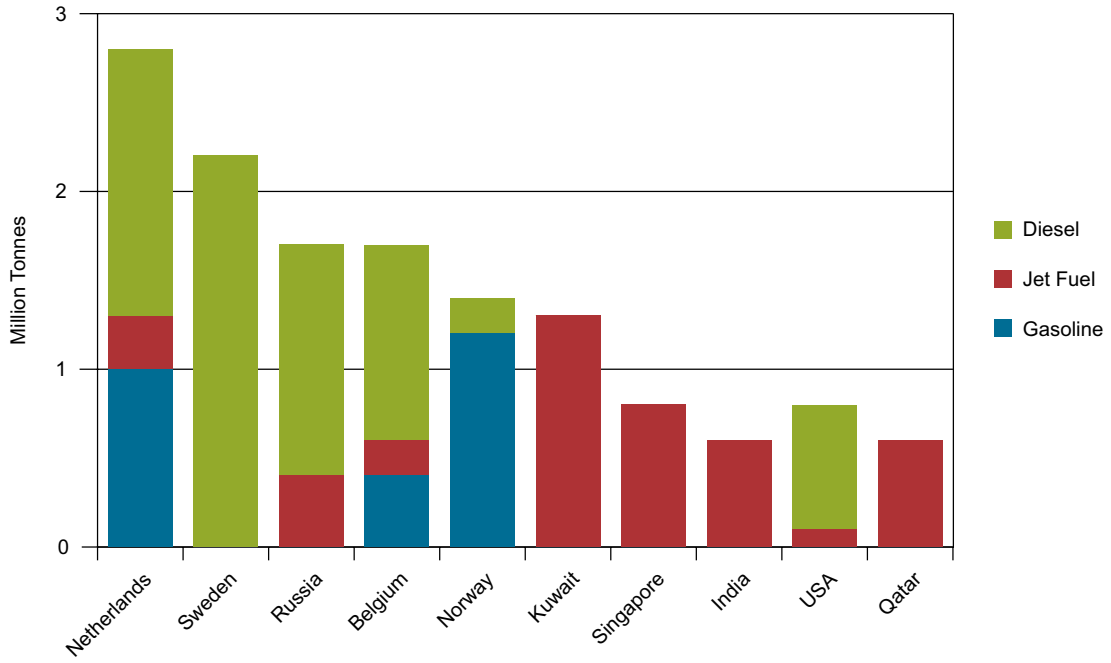


Source: Digest of United Kingdom Energy Statistics 2012

3.8 The mismatch between refinery output and demand leads to significant trade. The UK is a net exporter of petroleum products (around 28 million tonnes of exports in 2011, a third of which is gasoline) but is increasingly reliant on importing diesel road fuel and jet fuel to meet demand (net imports of over 4.5 million tonnes and 5.5 million tonnes respectively).

3.9 Chart 3.3 illustrates that the UK sources its petroleum products from a diverse range of countries. The bulk of the products come via the Netherlands, which acts as a major trading hub: the fuel might have originated from elsewhere in Europe or beyond. Imports from European countries are mainly transport diesel whilst imports from Asia are mainly jet fuel.

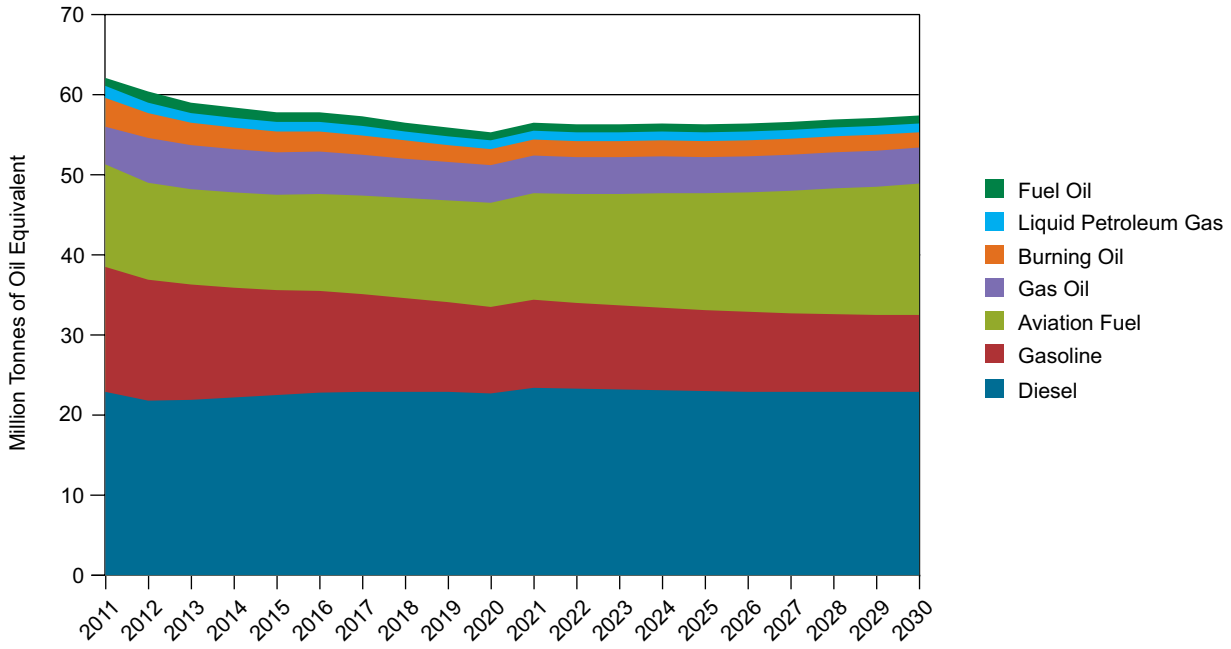
Chart 3.3: UK Oil Product Imports



Source: Digest of United Kingdom Energy Statistics 2012

3.10 Demand for oil in the UK will decrease slightly to 2030 but oil will continue to be the dominant fuel for road and air transport. As Chart 3.4 shows, demand for diesel road fuel and aviation fuel will remain robust whilst demand for gasoline will continue to decrease reflecting the continuing dieselisation of the car fleet. The use of oil for heating will continue to be important but declining, and oil will also remain an important source of feedstock for petrochemical, industrial and construction products.

Chart 3.4: Forecast UK oil demand by petroleum product type



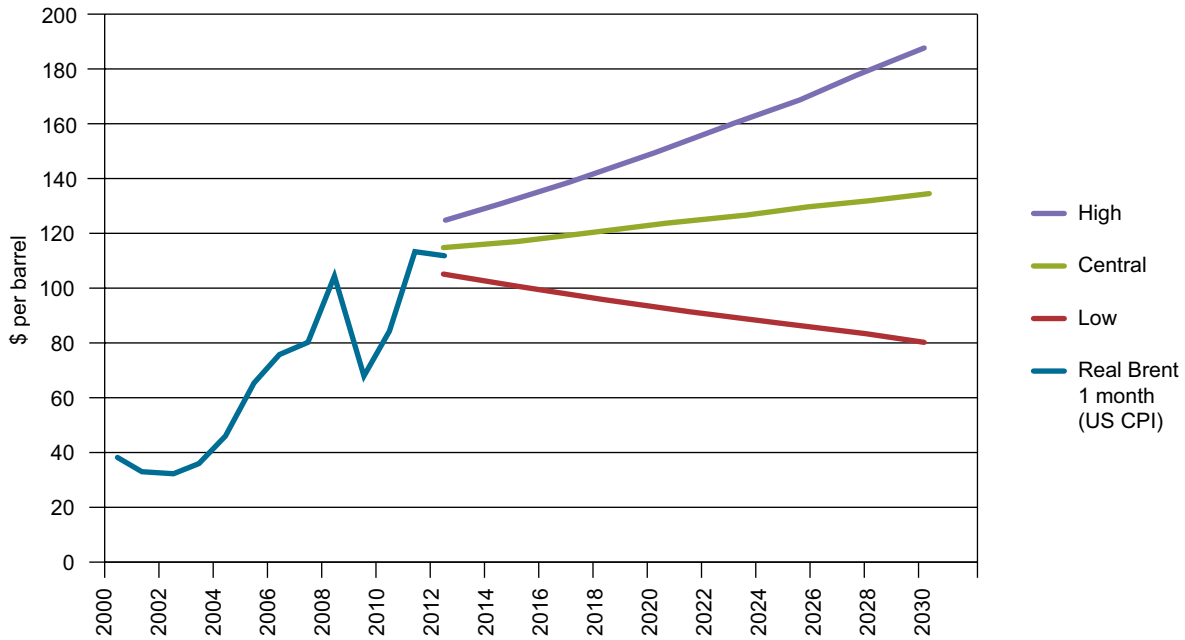
Source: DECC Updated Energy Projections (October 2012)

Global oil outlook

3.11 Global oil demand is projected to increase by around 14 per cent by 2035 compared to 2011 levels (IEA WEO 2012 analysis – New Policies Scenario), driven by the emerging economies of China and India.

3.12 The oil market is a global one so, even when the UK was a net exporter of oil, it has always been exposed to the risk of global events driving higher and more volatile oil prices, leading to significant impacts on the economy. The volatility of the oil market is illustrated in Chart 3.5, which shows that the price of crude increased in the 2000's due to growing demand specifically from Asian economies. The financial crisis in 2008 saw a collapse of the price, which has subsequently recovered.

Chart 3.5: Brent oil price 2000 onwards & DECC fossil fuel projections, $ per barrel (2012 prices)



Source: Adapted from Bloomberg and DECC fossil fuel price

3.13 Higher crude oil prices make affordable energy harder to achieve and have negative implications for economic growth. Whilst there are considerable uncertainties with such forecasts, Chart 3.5 shows the central estimate is for an increase in per barrel prices over the next twenty years. The chart also shows DECC's low and high assumptions for per barrel prices.

3.14 Key drivers for price volatility this year have been strong demand, growth in emerging economies, and concern over developments in the Middle East/North Africa, including Iran and the impact of sanctions.

Emergency oil stocks – the UK's international obligations

3.15 The UK is required to hold several million tonnes of oil stocks as part of international obligations arising from membership of both the EU and the International Energy Agency (IEA). These emergency stocks can be released onto the market to maintain supply in the event of a significant disruption to global oil supplies.

3.16 EU and IEA obligations are currently on slightly different bases although the same stocks can be used to meet both obligations. The UK is currently obliged to hold 67.5 days of final consumption as its EU obligation and 90 days of net imports as its IEA obligation. As UK production declines, the IEA's requirement to hold stock will become more important, but work is in progress to align the stock-holding requirements between the EU and the IEA.

3.17 The UK held just under 12 million tonnes of petroleum products (equivalent to about 79 days of consumption) towards its EU obligation at the end of 2011, about

1 million tonnes less than the previous year. The lower stock levels observed in 2011 were, in part, a result from the international stock release coordinated by the IEA as a result of the disruption to Libyan oil production.

Conclusion

3.18 Oil products play an important role in the UK economy, providing around a third of the primary energy used. Transport accounted for over 75 per cent of final consumption of oil products in the UK in 2011.

3.19 Whilst still the largest oil producer in the EU, the UK's production of crude oil and Natural Gas Liquids decreased by nearly a fifth during 2011 due to maintenance work and a number of unexpected events. This is the largest decrease since oil production peaked in 1999. Whilst the decline in oil production was sharper than expected in 2011, the long term trend is for a continuing but slower rate of decline in production over the next 20 years.

3.20 The UK remains a significant producer of refined products, though the closure of the Coryton oil refinery in June 2012 could reduce this capacity by around 10 per cent. Despite significant refining capacity within the UK, refinery output does not match demand: the UK exports gasoline but needs to import diesel road fuel and jet fuel to meet domestic demand.

3.21 Oil demand is expected to stay relatively constant in the UK in the short to medium term. Over time, technology changes, including electric vehicles and the generation of more heat from renewables, together with Government energy policies, should reduce demand for oil.

3.22 Globally, oil demand is anticipated to increase by 14 per cent in the run up to 2035, largely given growth in demand for transport in the Asian economies. Over the same period, global production is expected to become more challenging. As our requirements for imports increase,the UK will become increasingly exposed to the global oil market.

Annex – Response to Ofgem's Electricity Capacity Assessment 2012

Context

A.1 The Electricity Act 1989 was amended by the Energy Act 2011 to oblige Ofgem[35] to provide the Secretary of State with a report assessing demand for, and supply of, electricity in Great Britain, including an assessment of the different possible capacity margins for that supply and the degree of protection that each would provide against the risk of shortfalls in supply. Section 47ZA of the Electricity Act 1989 requires the Authority to provide the report by 1 September 2012 and before that date in every subsequent calendar year. This is the first year that a report has been required and Ofgem delivered its report to the Secretary of State on 28 August 2012. The report covers the period from winter 2012/13 to winter 2016/17.

A.2 Section 172 of the Energy Act 2004 (annual report by Secretary of State on security of energy supplies) also now obliges the Secretary of State to make an assessment of the amount of capacity required to meet the demands of electricity consumers including a spare capacity to account for unexpected demand or unexpected loss of capacity over the periods. This document fulfils this obligation.

A.3 Ofgem's report can be found online at:

http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Documents1/Electricity%20Capacity%20Assessment%202012.pdf

Executive Summary

A.4 Ofgem has submitted its first annual Electricity Capacity Assessment to the Secretary of State for Energy and Climate Change. It provides a comprehensive analysis of the security of electricity supply outlook over the forthcoming five winters. The Assessment estimates that electricity capacity margins will tighten significantly over the period to winter 2016/17.

35 The terms "the Authority" and "Ofgem" are used interchangeably in this document. Ofgem is the Office of the Gas and Electricity Markets Authority.

A.5 Ofgem's Assessment broadly supports DECC's own analysis of the security of supply outlook and has provided crucial evidence to inform decisions on the timing for initiating a Capacity Market.

A.6 Although there are some differences between the two organisations' projections of capacity margins, these are principally due to reasonable differences in assumptions on the future outlook for electricity demand and interconnection. Both sets of analysis point to a strong likelihood of capacity margins falling over the coming years.

A.7 The Government will take powers in the Energy Bill to run a Capacity Market. The Capacity Market, if required, will incentivise sufficient reliable capacity (both supply and demand side) to ensure a secure electricity supply even at times of peak demand.

A.8 The Government is minded to run the first auction in 2014, for delivery of capacity in the year beginning in the winter of 2018/19. If implementing the Capacity Market the Government also intends to run pilot auctions for delivery of DSR and storage from 2015–18, to provide additional capacity during this period.

A.9 A final decision will be taken subject to evidence of need. This will be informed by updated advice from Ofgem and National Grid which will consider economic growth, recent investment decisions, the role of interconnection and energy efficiency, as well as consideration of the outcome of the review of the 4th Carbon Budget.

A.10 As well as a Capacity Market, the Government is also working to improve security of supply by reducing the demand for electricity and thus reducing the need for additional capacity. The recently published Energy Efficiency Strategy sets out our mission to seize the energy efficiency opportunity.

Summary of Ofgem Analysis

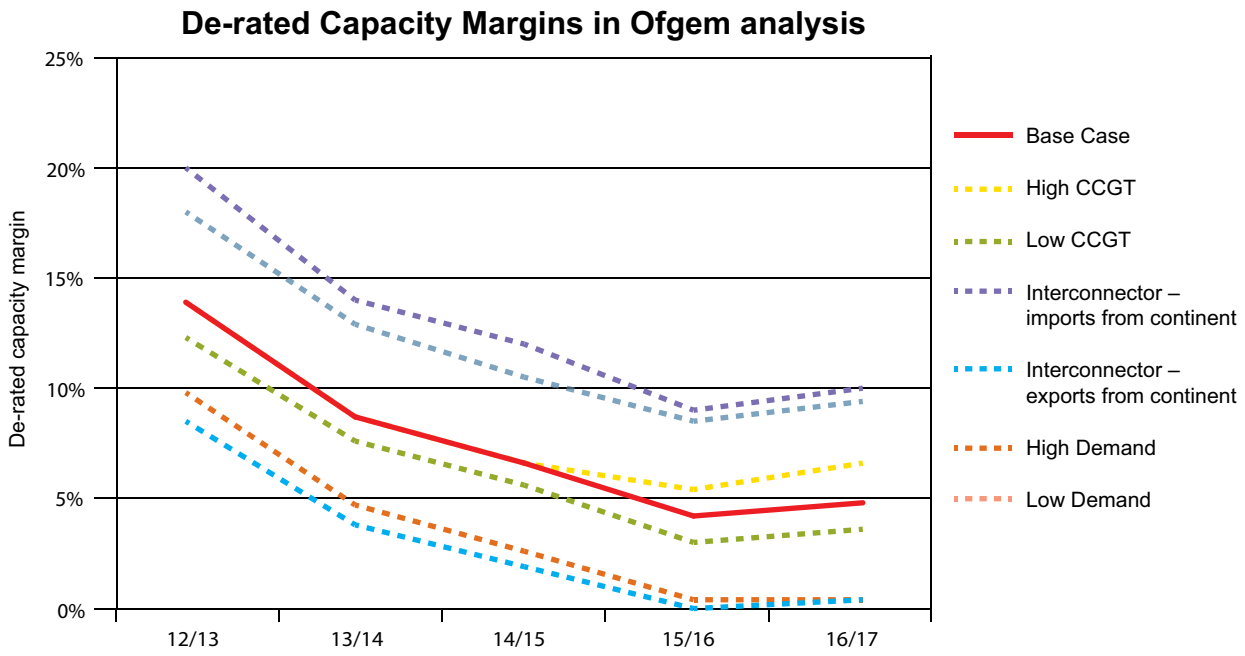
A.11 The methodology and assumptions underlying Ofgem's Electricity Capacity Assessment are set out in detail in their report.

A.12 Ofgem's Electricity Capacity Assessment suggests that the current capacity excess is likely to reduce significantly over the period covered by the report. The key driver for declining capacity margins is the retirement of coal and oil plant under the European Union's Large Combustion Plant Directive as well as low levels of new investment in conventional generation. According to the Base Case presented in Ofgem's report, de-rated[36] capacity margins are expected to fall from their current level of around 14% this coming winter to around 4% in 2015/16.

36 The de-rated capacity margin is the capacity margin adjusted to take account of the availability of generating capacity, specific to each type of generation technology. It reflects the expected proportion of a source of electricity which is likely to be technically available to generate (even though a company may choose not to utilise this capacity for commercial reasons).

A.13 Given the range of input assumptions to consider, Ofgem has developed a number of different scenarios for de-rated capacity margins. A full list of these scenarios and the assumptions which underpin them can be found in their report. Figure 1 shows a chart with de-rated capacity margins for a selection of the scenarios that Ofgem examined.

Figure 1: De-rated Capacity Margins in Ofgem analysis[37]



A.14 In addition to capacity margin analysis, Ofgem sets out the risks to security of supply associated with these capacity margins using a variety of metrics including statistical measures of risk such as the loss of load expectation and the expected energy unserved. These results are set out in detail in the report. The report also considers the actions that National Grid may be able to take to mitigate potential security of supply events before it is necessary to disconnect customers. The mitigation measures include: voltage reductions; instructing generators to increase their output to maximum; calling on emergency services from interconnectors. Ofgem assumes that the mitigation measures would be deployed in the order that they are listed above. Once all assumed mitigation measures were exhausted, it could be necessary to disconnect some customers, starting with industrial demand and then if supplies were unavailable moving to domestic demand. Ofgem's Base Case estimates that the likelihood of customer disconnections occurring in 2015/16 is 1 in 12 years compared to the situation this winter where the likelihood of experiencing customer disconnections is estimated to be around 1 in 3300. Table 1 sets out Ofgem's assessment of the likelihood that customers would be disconnected in a range of scenarios. These estimates assume that all mitigating measures have been exhausted.

37 The figures in this table have been recreated by DECC from the Ofgem report.

Table 1: Likelihood of electricity customers being disconnected[38]

Sensitivity	Probability of controlled disconnections for some electricity customers in 2015/16 (1-in-x years)
Base Case	1-in-12
High CCGT	1-in-22
Low CCGT	1-in-7
Interconnector – full exports to continent	1-in-4
Interconnector – full imports from continent	1-in-52
High demand	1-in-2.4
Low demand	1-in-102

A.15 It is difficult to determine precisely the impact of disconnections on domestic customers as this would depend on the size and duration of the outage. It would also depend on whether industrial demand could be disconnected first and the size of industrial demand. Table 1 sets out the probability of disconnection of any consumer (including industrial) and therefore the probability of disconnection for domestic consumers is likely to be lower than the figures shown.

DECC Analysis[39]

A.16 DECC uses a Dynamic Dispatch Model (DDM) to make projections of future developments in the electricity sector including future capacity margins reflecting a set of assumptions on fossil fuel and carbon prices and costs. The DDM is a comprehensive fully integrated power market model covering the GB power market over the medium to long term. The model enables analysis of electricity dispatch from GB power generators and investment decisions in generating capacity from 2010 through to 2050. It considers electricity demand and supply on a half hourly basis for sample days. Investment decisions are based on projected revenue and cashflows allowing for policy impacts and changes in the generation mix. For example as capacity margins are expected to tighten, the modelled investors will expect higher prices in the wholesale market. All other things remaining equal, this would increase the likelihood of them investing in new capacity, or keeping existing capacity on the system for longer. The full lifecycle of power generation plant is modelled, from construction through to decommissioning.

A.17 No matter what modelling approach taken, the future outlook for electricity security of supply is very difficult to project with confidence because marginal changes in

38 The figures in this table have been recreated by DECC from the Ofgem report.
39 DECC's analysis in this document is consistent with the analysis for Electricity Market Reform.

input assumptions which affect either supply or demand can have large impacts on capacity margins.

A.18 The key uncertainties are focussed on the following variables.

a) Demand for electricity. The key drivers of electricity demand growth are GDP growth, population growth and changes in electricity efficiency over time. There is uncertainty around how each of these variables will develop over time.

b) The capacity contribution of interconnectors: GB currently has around 4GW of interconnection with its European neighbours. As long as prices accurately reflect scarcity conditions, then the flow of electricity on an interconnector ought to be in the direction in which it is most needed, although we note that this is not necessarily the case yet under existing market arrangements. There is also little empirical evidence of the behaviour of interconnectors when the electricity systems on each side of the interconnector are both experiencing scarcity conditions therefore it is difficult to form a view based on historical flows. For this reason it is difficult to forecast with confidence in which direction the electricity will flow. In addition it is difficult to take a view on how tight capacity will be in neighbouring countries.

c) Supply of generation: The amount and reliability of capacity expected to be on the system. Key uncertainties relating to the supply of generation are:

   i. Mothballing of existing plant: A significant quantity of CCGT plant is unavailable to National Grid this Winter and could therefore be considered to be mothballed. It is difficult to form an accurate view of how much of this plant will return to the market if capacity margins tighten. That will depend on the individual commercial decisions of the companies involved.

   ii. New build: There is little conventional thermal capacity that could come on the system between now and 2015/16 because of the lead times involved in making a final investment decision and being built. The earliest new thermal plant,if delivered on time, is likely to be operational in 2016.

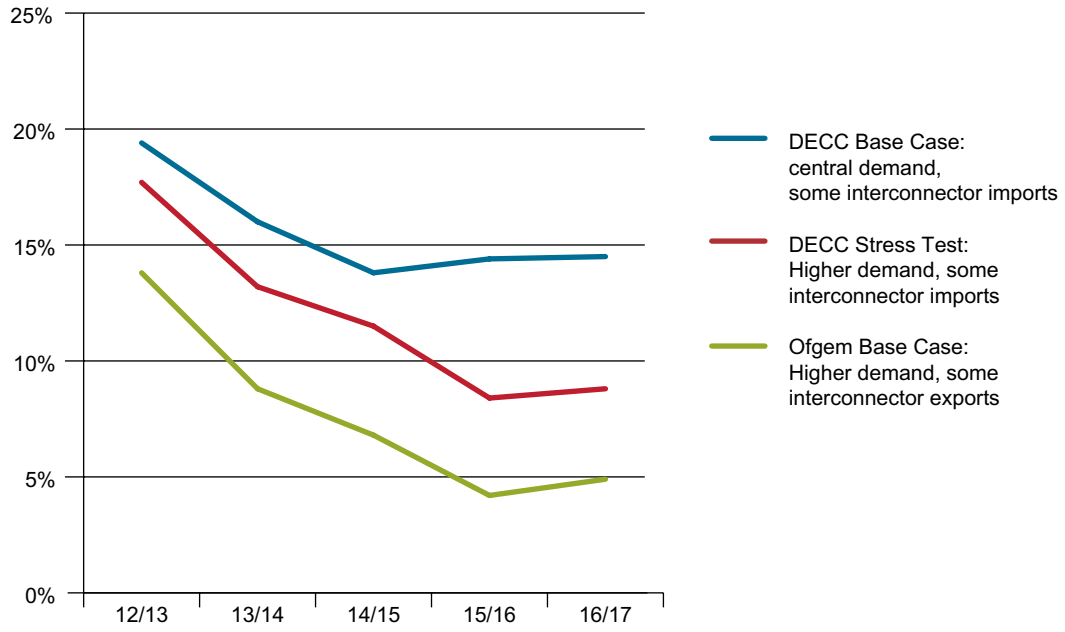
   iii. There is more uncertainty around the level of renewable capacity that might become operational since many renewable technologies can be built on shorter timescales than conventional thermal generation and for many of the embedded projects there is no need for the developer to notify National Grid. However, since the availability factors for most of the major renewable technologies are quite low, the consequences of this uncertainty are not as severe as i. or ii.

A.19 DECC has modelled the security of supply outlook. The full analysis goes out to 2030, but only the outputs to winter 2016/17 are shown below to mirror the scope of the Ofgem Assessment. This includes a central case (DECC Base Case) and a plausible stress test which includes among other things, higher levels of demand. The de-rated capacity margins from these scenarios are shown in Figure 2 below

along with the Ofgem Base Case and one of their least secure sensitivities which uses higher demand. The full DECC analysis out to 2030 has been included in the Impact Assessment for the introduction of a Capacity Market.

A.20 It is important to note that the DECC analysis and the Ofgem analysis are different and are derived from separate models. However, we have tried to minimise the differences between the two approaches as far as possible. For example, DECC assumes that the same level of reserve is held back to cover the single largest loss on the system as Ofgem. DECC also assumes that the availabilities of different technologies at times of peak are the same as those that have been used by Ofgem in their analysis (with the important exception of interconnection flows). However, it is not possible to completely align assumptions and indeed it would not be desirable to do so, as looking at results from different models provides a richer analysis.

Figure 2: DECC and Ofgem estimates of de-rated margins



A.21 As well as differences between the modelling approach, any assessment of future security margins is highly sensitive to changes in the supply or demand either assumed or modelled. The most important differences in assumptions between the different scenarios in the DECC analysis and the Ofgem analysis are as follows:

a) Demand: The DECC Base Case uses demand figures based on the Updated Energy Projections published in October 2012 on the DECC website[40]. The central demand projection sees annual demand falling over the period to 2016/17 particularly in the domestic sector. The DDM derives peak demand from these annual demand figures. DECC projects a reduction in expected peak demand, largely as a result of improved energy efficiency; the DECC stress test and Ofgem Base Case use higher levels of demand, based largely on National Grid's Gone Green projections which form a part of their Future Energy Scenarios[41]; and the Ofgem high demand scenario contains even higher demand forecasts based on the inner range of demand sensitivities included in DECC and Ofgem's Statutory Security of Supply Report 2011.

b) Contribution of interconnection: The DECC Base Case and stress test assume 1.5GW of net imports through interconnectors; the Ofgem scenarios assume 0.95GW of net exports[42]. As discussed previously, this is a key area of uncertainty.

c) Supply: The DECC scenarios assume no new CCGT built between now and 2016/2017 other than what will be online this year. The Ofgem scenarios assume that nearly 1 GW of new build CCGT comes online between now and 2015/16. In addition DECC's Base Case analysis assumes that more CCGT plant will mothball than in Ofgem's scenarios primarily as a reaction to falling demand.

A.22 It is clear from both the Ofgem analysis and DECC's own analysis that 2015/16 presents the most severe challenge when all of the plant that must close under the LCPD will have come off the system.

40 http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/analytic_projs.aspx
41 http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios/
42 Both the Ofgem Base Case and the DECC Base Case assume that the Irish Interconnectors will be fully exporting. The differences are due to our different assumptions on the behaviour of our continental interconnectors. Ofgem assume that our continental interconnectors will be at float, i.e. neither importing nor exporting. DECC assume that we will be importing around 2.5 GW from the continent at times of system peak.

Potential impacts in 2015/16

Table 2 sets out the potential impacts from the four alternative scenarios.

Table 2: Security of Electricity supply in 2015/16

	Derated capacity margin (%)	Likelihood of some customer disconnections (years and %)	Typical amount of energy unserved (GWh)	Loss of load expectation (number of hours per year in which demand not met)
DECC Base Case[40]	14.4	~>1 in 3000 (0%)	Negligible	Negligible
DECC Stress	8.4	~1 in 50 (2%)	~0.5	~0.25
Ofgem Base Case	4.2	1 in 12 (8%)	3.4	2.7
Ofgem High Demand	0.3	1 in 2 (50%)	21	13.9

Note: ~ information in cells containing this symbol has not been estimated from DECC modelling but has been inferred from similar results in Ofgem's modelling.

Note: The likelihood of some customer disconnections gives the probability of some customers facing disconnection after the system operator has made full use of the mitigating measures available to it, including the provision of emergency services from Britain's interconnectors. Industrial customers would be disconnected before households.

A.23 Both are based on judgements by the different organisations on the level of interconnector flows at times of peak demand. Ofgem take a cautious approach while DECC's view is that interconnection with the continent is likely to improve security of supply at times of system peak.

A.24 In the Ofgem Base Case, it is likely that any energy unserved would lead to small, occasional shortfalls which could be dealt with by National Grid through demand side action (such as voltage reduction ("brownouts")), with little or no impact on customers. Involuntary disconnection of some customers ("blackouts") would be likely to occur in a small minority of years – 1 in 12 (or 8% chance) in the Ofgem Base Case, and 1 in 50 years (or 2% chance) in the DECC stress test. These could, in the worst case, affect domestic households, but industrial customers would be disconnected first where possible. Ofgem has stated that the estimated de-rated capacity margins in their Base Case are similar with those that GB experienced in the middle of the last decade. However, the risks associated with

43 We have inferred the risks to security of supply in the DECC analysis using the relationship between Capacity Margins and risk measures, contained in Ofgem's Electricity Capacity Assessment. Note that this is therefore not a modelled output from the DECC model. We note that the relationship between the capacity margin and the risk measures is not one for one as it depends on the exact generation mix. Therefore the estimates of risk in the DECC scenarios are illustrative.

this margin are likely to be different because of the different composition of the generation fleet.

Additional Capacity

A.25 Section 172 of the Energy Act 2004 was amended by the Energy Act 2011 to oblige the Secretary of State to make an assessment of the amount of capacity required to meet the demands of electricity consumers including a spare margin to account for unexpected demand or unexpected loss of capacity. As part of the introduction of a Capacity Market it is expected that Government will set a reliability standard to guide the amount of capacity to contract for. The reliability standard will express the desired trade off between the costs of additional security of supply as a result of additional capacity, and the benefits as a result of reduced lost load. We would expect that the reliability standard will be expressed in terms of loss of load expectation (LOLE) although this is not certain. This is the metric that is used for many other countries which use reliability standards. For example France assesses its capacity to be adequate if it is expected that there will be no more than three hours a year in which there is unmet demand. We intend to consult on options for the GB reliability standard in the draft EMR delivery plan, in Summer 2013.

A.26 At present, the GB market does not have an explicit reliability standard and therefore we must use alternative methods to determine the amount of additional capacity required.

A.27 Despite not having a standard, we do have some illustrative examples which can underpin an estimate of the amount of capacity that is required. It is very important to note however, that until GB has an explicit reliability standard based on robust analysis of the costs and benefits of additional reliability, it is not possible to be provide a firm recommendation about the amount of additional capacity required. As a result, we present two alternative standards as the basis for determining the additional capacity required. Neither of these illustrative standards should be though to prejudge any future reliability standard.

a) A 10% de-rated capacity margin: This is the standard that DECC has used in the Impact Assessment of a Capacity Market. In particular, we have assumed that this standard guides the level of capacity to procure. This is an informal standard used which is based on the amount of capacity that the energy only market has typically delivered in the past.

b) A loss of load expectation (LOLE) of 3 hours a year: This is the reliability standard that is used by the RTE, the French System Operator to guide their assessment of whether additional capacity is required.

10% De-rated Margin

A.28 If the reliability standard were to meet a 10% de-rated capacity margin in any year, then the amount of additional de-rated capacity required to meet demand including a spare margin is shown in Table 3. In Ofgem's low demand scenario (see Ofgem's report referenced in paragraph A3), in 2015/16, the estimated capacity margin is less than 10% and this leads to a less than a 1% chance of customer interruptions.

Table 3: Additional Capacity required to meet a 10% de-rated capacity margin

Additional de-rated capacity required to meet a 10% de-rated capacity Margin[36] (GW)	2012/13	2013/14	2014/15	2015/16	2016/17
DDM Base Case[41]	0	0	0	0	0
DECC Stress Test	0	0	0	0.8	0.7
Ofgem Capacity Assessment Base Case	0	0.8	2	3	3

3 hours per year Loss of Load Expectation

A.29 If the reliability standard were to have enough capacity to have no more than 3 hours loss of load expectation in any year, then the amount of additional de-rated capacity required to meet demand including a margin is set out in Table 4.

Table 4: Additional Capacity required to meet a 3 hour per year loss of load expectation

Additional Capacity Required to meet a 3 hour LOLE level of reliability (de-rated GW)	2012/13	2013/14	2014/15	2015/16	2016/17
DDM Base Case	0	0	0	0	0
DECC Stress Test	0	0	0	0	0
Ofgem Capacity Assessment Base Case	0	0	0	0	0

Conclusion

A.30 Ofgem's report suggests capacity margins will tighten significantly over the coming five winters. This supports DECC's own analysis of the security of supply outlook.

44 All numbers are presented to 1 significant figure

A.31 Given the likelihood of capacity margins falling over the coming years and the need to tackle the underlying failures in the electricity market to bring forward sufficient investment, Government is minded to run the first capacity auction in 2014, for delivery of capacity in the year beginning in the winter of 2018/19. A four year lead time between the auction and delivery year will allow new capacity to compete against existing capacity helping to ensure a competitive auction.

A.32 A final decision will be taken subject to evidence of need. This will be informed by updated advice from Ofgem and National Grid which will consider economic growth, recent investment decisions, the role of interconnection and energy efficiency, as well as consideration of the outcome of the review of the 4th Carbon Budget.

A.33 If implementing the Capacity Market the Government also intends to run pilot auctions for delivery of DSR and storage from 2015–18, to provide additional capacity during this period. This will provide additional capacity and security of supply benefits. DECC will also continue to monitor the security of supply outlook and will respond to an earlier problem if necessary.

A.34 Further analysis can be found in the Capacity Market Impact Assessment and the EMR Overview Document and Annexes.

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