Department
of Energy &
Climate Change

Gas Generation Strategy

December 2012

Gas Generation Strategy

Presented to Parliament
by the Secretary of State for Energy and Climate Change
by Command of Her Majesty

December 2012

Cm 8407 £16.00

Any enquiries regarding this publication should be sent to us at correspondence@decc.gsi.gov.uk

This publication is also available for download at www.official-documents.gov.uk This document is also available from our website at www.decc.gov.uk

ISBN: 9780101840729

URL: http://www.decc.gov.uk/en/content/cms/meeting_energy/oil_gas/gasgenstrat/gasgenstrat.aspx

Printed in the UK by The Stationery Office Limited
on behalf of the Controller of Her Majesty's Stationery Office

ID P002517650 12/12 25333 19585

Printed on paper containing 75% recycled fibre minimum content.

Ministerial Foreword

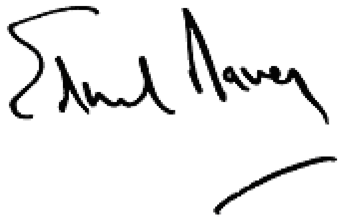
The UK faces a threefold energy challenge: how to keep the lights on, at affordable prices, while moving towards a sustainable low-carbon future. I firmly believe the best way to meet these goals is with a competitive, diverse, low-carbon energy mix. A mix where gas continues to play a vital role.

As we put the UK on course to meet our ambitious emissions reduction targets, existing and ageing power plants will close, large amounts of it through the next decade. Gas – as a flexible source of generation, which emits half the CO_2 of coal – will be needed to help balance the relatively inflexible and intermittent low-carbon generation our policies will bring forward. It will provide crucial capacity to keep the lights on and the economy working.

New gas plants, which are relatively cheap and quick to build, will be needed to support the system during this period, providing significant power while greater amounts of renewables technologies are deployed. Gas will also continue to play a significant role in heat, where, as we set out in *The Future of Heating*, we expect gas to remain the dominant fuel in 2030.

Responses to the Call for Evidence that we issued on gas generation highlighted a number of barriers and obstacles to investors in new gas plants. This Gas Generation Strategy sets out our response to those concerns and how we will address those barriers to help build investor confidence and encourage the new capacity we will need over the coming years. It sets out our work to maintain the security of our gas supply, and ensure we make the best use of our natural resources.

We have set out our view on the important role we expect unabated gas to have in a changing electricity market. In the longer term, gas with Carbon Capture and Storage (CCS) can be a significant part of our low-carbon generation mix. We have a £1 billion fund to support Carbon Capture and Storage (CCS) projects to drive the technological innovation necessary to make CCS a commercial reality over the next two decades, allowing gas to play a significant long-term role in the UK energy mix as a form of flexible low-carbon generation.



Edward Davey

Secretary of State for Energy and Climate Change

Contents

Executive Summary

Gas currently forms an integral part of the UK's generation mix and is a reliable, flexible source of electricity. Using gas as a fuel in our power stations currently provides a significant proportion of our electricity generation (around 40% in 2011). Gas sets the electricity price for most of the year, as generation from gas is used to meet the peaks in our electricity demand. The Government expects that gas will continue to play a major role in our electricity mix over the coming decades, alongside low-carbon technologies as we decarbonise our electricity system.

The role gas plays will be determined by the market, while keeping emissions within the limits set by the Carbon Budgets and consistent with a least-cost approach to the UK's binding 2050 carbon target. Both now and in the future, we need a diverse generation mix that balances risks and uncertainties of different technology options, including uncertainty on future gas prices. However, we are likely to need significant investment in new gas plant. Modelling by DECC suggests that up to 26 GW of new gas plant could be required by 2030 (in part to replace older coal, gas and nuclear plant as it retires from the system). It also indicates that, in 2030, we could need more overall gas capacity than we have today, although operating at lower load factors. The modelling shows that gas could play a more extensive role, with higher load factors, should the 4th Carbon Budget be revised upwards.

A key role for gas is also consistent with the need to decarbonise our economy. It is the cleanest fossil fuel, and much of the new gas capacity needed would effectively be replacing ageing coal capacity. Gas is also important for balancing out the increasing levels of intermittent and inflexible low-carbon energy on the system. Unabated gas generation will continue to play a crucial role in our generation mix for many years to come, and the amount of gas capacity we will need to call on at times of peak demand will remain high. In the long term, the development of cost-competitive Carbon Capture and Storage should ensure gas (and coal) can continue to play a full role in a decarbonised electricity sector.

Gas-fired power stations are relatively cheap and quick to build, and investment in new gas plant will offer employment opportunities throughout the country. Much of the new gas investment needed is likely to be in the 2020s but, under some circumstances, there could be a need for up to 9 GW of capacity this decade.

Given the importance of gas to our energy mix, the Government issued "A call for evidence on the role of gas in the electricity market" on 2nd May 2012, and has engaged with industry and stakeholders to identify whether there are any barriers to investment in gas generation, and if so, what we can do to remove them.

Respondents identified a number of different barriers to investment. The most widespread response to this question was that, from an economic perspective, the current profitability of gas plant (represented by the clean spark spreads[1]) is low and that there is uncertainty on their future profitability. Historically, developers have been able to look beyond low spreads and invest in new plant in anticipation that spreads will rise in the future. However, there is concern

[1] The theoretical gross margin of typical Combined Cycle Gas Turbine (CCGT) gas plant, a measure frequently used to assess the profitability of gas plant. A new CCGT will tend to have a higher efficiency than existing plants and hence obtain higher margins.

that in practice prices in the electricity market may not rise high enough at times of scarcity to provide the correct signals to ensure investment does come forward. Investors are therefore faced with uncertainty on load factors for their plant, when and how often it will run, and the prices that can be achieved when it does run.

Further, some respondents stated that uncertainty related to the detailed implementation of Electricity Market Reform (particularly around the Capacity Market), is making it more difficult for developers to anticipate the future power market conditions under which gas plants will operate. In addition, many investors suggested that the pace and extent of the low-carbon generation roll-out is difficult to predict, and thus the extent to which gas generation will operate in a low-carbon electricity market is difficult to gauge. This makes the investment case for new gas plant more challenging.

There were a number of other factors that developers and financiers considered currently act to constrain investment in gas generation assets, including credit, access to finance and planning procedures.

The objective of this strategy is to reduce the uncertainty around gas generation for investors. The Government recognises that support for other forms of generation could undermine certainty for gas investors. We are therefore seeking to provide certainty for investors in both low-carbon energy sources and gas. To this end, we are setting a sustainable and affordable cap on the Levy Control Framework out to 2020. We are also reiterating that our approach to decarbonisation trajectories will continue to stay in step with other EU countries throughout the 2020s and consistent with a least-cost approach to our legally-binding 2050 decarbonisation objective and the 4th Carbon Budget.

In addition, and in response to the Call for Evidence, to ensure we have the gas generation plant we need, we have:

- **Provided clarity on Electricity Market Reform** including that we are legislating for the introduction of a Capacity Market. 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. 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. Any generators that begin construction between May 2012 and the first capacity auction will be eligible to participate in the Capacity Market as new plant, should new and existing plants be treated differently in the capacity auction. We are also supportive of Ofgem's decision to conduct a Significant Code Review (SCR) on electricity cash out arrangements.
- **Introduced powers in the Energy Bill[2] that will enable Government to act in order to improve wholesale electricity market liquidity if necessary.**
- **Brought forward proposals to improve the planning regime in each part of Great Britain** by introducing greater flexibility for existing consents, and have committed to

[2] Energy Bill: http://www.decc.gov.uk/en/content/cms/legislation/energybill2012/energybill2012.aspx

consider improvements to front-loading requirements and provide more clarity on flexibility available for new applications under the Planning Act 2008.[3]

To ensure the development and commercialisation of Carbon Capture and Storage, which will potentially enable both gas and coal fitted with CCS to have a significant role as a low-carbon technology, we have:

- **Developed a world leading support package for CCS** including capital funding; operational support through Contracts for Difference (CfDs) £125m for research and development; and a well-developed regulatory environment.
- **Shortlisted four CCS projects** to bring forward into a period of intense negotiations in our £1bn Commercialisation Competition.
- **Set up a CCS Cost Reduction Task Force** to advise Government and Industry how best to ensure CCS can be cost competitive with other low-carbon technologies.

To ensure the security of our gas supply we:

- **Support Ofgem's intention to work with industry to consider the case for interventions to enhance gas supply security through improving the operation of the market**, via increased transparency and measures to promote the standardisation of interruptible contracts, and their investigation into the price responsiveness of interconnector flows.
- **Will consider whether there is a case for further measures to encourage gas storage**, and will publish our findings in Spring 2013.

To ensure we make the best use of our natural resources, we have:

- **Announced that DECC will establish an Office for Unconventional Gas and Oil** that, working with Defra[4] and other Government departments, will join up responsibilities across Government, provide a single point of contact for investors and ensure a simplified and streamlined regulatory process.
- **Announced our plans to** consult on an appropriate fiscal regime for shale activities, on the terms and durations of licenses, and on an updated Strategic Environmental Assessment with a view to further onshore licensing.

Together, these measures should ensure that:

- adequate gas generation capacity is available, including ensuring we maintain an appropriate capacity margin to maintain security of electricity supply;
- there is competition in the electricity generation market and opportunities for investors in gas generation plant;
- flexible plant is available to meet the intermittency associated with renewables, providing back-up energy particularly in times of peak demand and low renewable generation; and,
- the necessary gas supply infrastructure is in place to support the role of gas in generation.

[3] In Scotland, planning is a devolved function where planning and consenting processes have been streamlined and the Scottish Government delivers onshore spatial planning through the Scottish National Planning framework. Please see: http://www.scotland.gov.uk/Publications/2009/07/02105627/0
[4] Department for Environment, Food & Rural Affairs

Chapter 1 – Current Role of Gas Generation

Chapter Summary

- **Gas generation has formed a major part of the UK's generation landscape for around 20 years.**
- **Since the early 1990s, the use of gas to meet electricity demand has grown significantly.**
- **Between 2000 and 2011, investment in gas generation capacity accounted for nearly 70% of all new generation capacity.**
- **By 2011, gas was providing around 40% of electricity, and gas power stations accounted for around a third of UK capacity.**
- **In 2012, however, given the relative price of coal and the low carbon price, use of gas for generation has fallen.**

Introduction

1.1. Gas currently forms an integral part of the UK's generation mix, playing a critical role in maintaining energy security, affordability and decreasing carbon emissions in the UK. This is true for both the GB electricity market, and in Northern Ireland (which is part of the Single Electricity Market).[5] It is one of the most flexible sources of generation, able to provide baseload,[6] mid-merit and peaking services, as well as a number of ancillary services. Gas generation has proved an attractive prospect to UK developers because it is a proven technology with moderately low capital costs. Since the early 1990s, investment in gas generation infrastructure has been a key component of investment in the energy sector, accounting for nearly 70% of new capacity coming online between 2000 and 2011, and there is now around 32 GW of CCGT gas capacity.[7]

1.2. Gas generation is, in general, an efficient form of thermal generation, meaning that more electricity can be produced from less fuel than is the case with other fossil fuel technologies. This is particularly so with Combined Cycle Gas Turbines (CCGTs), which recover heat to deliver more generation.[8] Where plants are located close to heat demand

[5] Northern Ireland has a separate regulator and planning regime.
[6] 'Baseload' is understood here to generation from plant that—if available—will generate continuously at its design rating.
[7] DUKES, 2012
[8] The other main form of gas plant are Open Cycle Gas Turbines, which do not recover heat. They, therefore, have lower efficiencies and higher carbon intensity, but are much quicker to start and ramp-up.

sites, gas generation can be implemented as Combined Heat & Power (CHP), utilising fuel energy even more effectively.

1.3. While development times for new gas plants will vary between projects, they are generally relatively quick to build,[9] meaning that development can respond quite rapidly to changes in market conditions, such as closures of other generating plants announced at relatively short notice or delays in delivery of other planned projects. The relatively low capital cost of CCGTs means that they have also been fairly easy to finance historically, and as a proven and well-documented technology, they carry less risk than many other forms of generation.

1.4. The use of gas for generation rose significantly between 1991 (when the first CCGT was built, and before which natural gas was not permitted for use in electricity generation) and 2000. The market conditions for investment in that new capacity has been relatively attractive over that period. However, current market conditions, coupled with a number of significant barriers, has made investment in gas more difficult. While this should not be of concern in the current market given our very high capacity margins, older coal and nuclear plants are expected to close over the coming decade and those margins are expected to tighten. Alongside renewables and nuclear as we decarbonise, new unabated gas plant will therefore be needed to replace that capacity as it closes. It is essential that we are not complacent to ensure that security of supply is maintained. Addressing obstacles to future investment is therefore a key objective for the Government in order to ensure the market can deliver the new gas generation capacity that we will need. Chapter 3 provides more details on the barriers to investment and actions we are taking to address them.

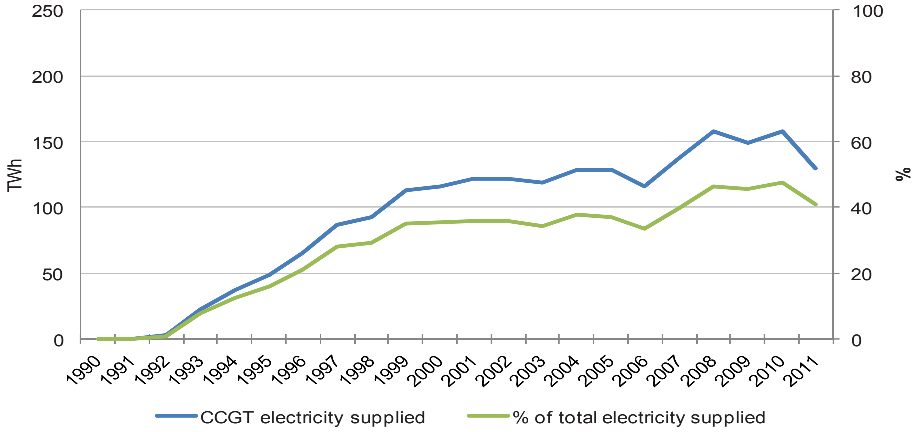
The Growth of Gas Generation

1.5. The first CCGT power station in the UK was commissioned in 1991, and the role of CCGTs in the UK's generation mix has steadily grown through the 1990s and 2000s. The 'dash for gas' in the 1990s saw newly-privatised electricity companies moving towards natural gas for generation, with around 20 GW of new CCGTs coming online as plans for coal and nuclear power plants were put on hold.

1.6. From the early 2000s, gas plants have been providing over a third of the UK's generation, with the remainder provided predominantly by coal and nuclear, although the share of renewables has been growing and will continue to do so. The growth in gas generation has been met with a corresponding fall in generation from other fossil fuels, mainly coal. Coal has, however, remained an important part of the energy mix, with around 28 GW of capacity providing a substantial portion of the energy mix. For the first six months of this year, for example, with high gas prices, coal supplied around 40% of the UK's electricity.[10]

[9] Estimated to be between 1.8 and 2.5 years construction time. See Electricity generation cost model: PB Power update (2011): www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/gen_costs/gen_costs.aspx
[10] Table et5.1

Figure 1A: CCGT Generation Supply, 1990-2011



Source: DECC - Historical electricity data: 1920 to 2011

1.7. In the mid-2000s, the case for investment in new CCGT plant was strong because of the forecast tightening of the market due to the constrained running hours, and eventual retirement of around 12 GW of old coal and oil plants under the Large Plant Combustion Directive (LPCD). As a result, the profit margins of CCGT plants were expected to grow, and since 2009 around 9 GW of CCGT capacity has, or is shortly set to, come online. This includes RWE's Pembroke plant, which was formally opened on 19th September 2012 and EDF's West Burton, which is currently being commissioned and will be fully operational in early 2013. In addition, ESB have recently announced that they will begin the construction of an 880 MW CCGT in Carrington, Greater Manchester, which is due to open in early 2016.[11]

1.8. Average gas plant (CCGT) load factors[12] over the past five years have generally been above 60%, peaking at 71% in 2008. However, this fell in 2011, partially in response to the large amounts of new capacity coming online at that time and relative coal and gas prices.[13] Average load factors are expected to have fallen again in 2012 due to the relative economics of gas compared to coal and continuing excess capacity on the system.

Table 1A – Historical average Load factors[14]

	1996	2001	2006	2011
Average CCGT load factor (%)	71	67	55	48

1.9. There is currently over 14 GW of gas plant with consent in England and Wales,[15] and an additional 1 GW in Scotland.[16] In addition to the above, there are 2 plants awaiting consent

[11] www.carringtonpower.co.uk/news/10/
[12] 'Load factors' are understood here to mean actual generation compared with the maximum that could have been generated, expressed as a percentage.
[13] Major Power Producers
[14] DUKES 2012, Table 5.10
[15] This excludes ESB's Carrington plant, for which an investment decision has recently been reached.
[16] This includes 0.4 GW of Open Cycle Gas Turbine and 0.9 MW of CCGT to be later converted to coal-fired IGCC with CCS.

under s36 of the Electricity Act, totalling just over 2 GW. Since 2011, applications for consent for nationally significant infrastructure projects have been made under the Planning Act 2008, with recommendations now being made by the Planning Inspectorate and decisions taken by the relevant Secretary of State.[17] To date, no applications have been made for new gas-fired power stations under the Planning Act, although there are a number of pre-applications underway, totalling over 6 GW.[18] In Scotland, Scottish Ministers have devolved powers relating to consents of electricity generation and transmission infrastructures under s36 and s37 of the Electricity Act 1989. The Scottish National Planning framework[19] identifies a range of generation and energy infrastructure projects in Scotland deemed to be National Developments in Scotland.

1.10. Despite the considerable amount of capacity consented, there is some uncertainty on whether and when this will be built. Other than ESB's recent announcement regarding its new plant to be built at Carrington, we are not aware of final investment decisions being made on the other consented plants.

1.11. The amount of electricity produced from gas generation has been notably lower in 2012 than in previous years. In the second quarter, for example, gas generation was at its lowest levels for at least 14 years at 25.2 TWh. Between January and July, gas accounted for around 28% of generation, while coal accounted for around 39%. These lower levels of generation are predominately due to higher gas prices, which, coupled with low carbon prices, make coal generation more economic.[20]

Natural Gas CHP

1.12. The most energy-efficient way of using gas is to convert it into power and heat simultaneously. This delivers primary energy savings by reducing energy rejected as waste heat relative to separate power and heat generation. There is a cost in terms of a loss in electrical conversion efficiency, but this is more than made up for in terms of the take-off of useable heat. Combined Heat & Power (CHP) only works, however, where there is a local use for the heat. The Government therefore has a CHP Quality Assurance scheme to ensure that only schemes that deliver genuine energy—hence carbon—savings are eligible for support.

1.13. Where dependable heat loads exist, gas CHP can deliver primary energy savings of up to 30% relative to separate generation of heat and power. Gas CHP plants can also contribute to peaking capacity, either by operating only at peak times, or, if they are flexibly configured, by switching from CHP to power-only operation to meet demand. In 2011, gas CHP accounted for 4.6 GW of capacity and provided 20.6 TWh of electricity generation in addition to 33.3 TWh of heat. This represented 5.2% of UK generating capacity, 5.6% of all electrical energy generated and 14% of electrical energy from gas generation. CHP capacity in the UK covers a wide range of plant sizes, from a few kW to 1.3 GW electrical

[17] Previous to the Localism Act 2011, decisions were taken by the Infrastructure Planning Commission.
[18] Excluding plant proposed solely for industrial purposes.
[19] Long term spatial strategy for Scotland's development: http://www.scotland.gov.uk/Publications/2009/07/02105627/0
[20] Energy Trends – September 2012

plant. The majority of UK CHP capacity is in industrial sectors, supplying heat to meet the demand of various industrial processes.

Chapter 2 – Future Role of Gas Generation

Chapter Summary

- **Government expects that gas will continue to play a major role in our electricity mix over the coming decades, alongside low-carbon technologies as we decarbonise our electricity system. There are several scenarios that may ensue depending on a range of factors, such as fossil fuel prices, carbon prices, demand and the deployment rates and levels of low marginal cost, low-carbon generation.**

- **Including capacity commissioned this year (or expected to be commissioned shortly), we could see a need for investment in up to 26 GW of new gas capacity by 2030.**

- **Our analysis indicates that in the 2020s, some CCGTs (those with the highest efficiencies, i.e. those which are newest or the most recent to have undergone significant maintenance) could achieve load factors over 85%.**

- **By 2030, average load factors across the fleet are likely to be lower than they have been historically.**

- **Gas could play a more extensive role, with higher load factors, should the 4th Carbon Budget be revised upwards. Including capacity commissioned this year (or expected to be commissioned shortly), this could lead to a need for investment in up to 37 GW of new gas capacity by 2030.**

- **There will be an important role for gas in 2030 and beyond, with the ability for gas to provide significant amounts of low-carbon electricity with CCS.**

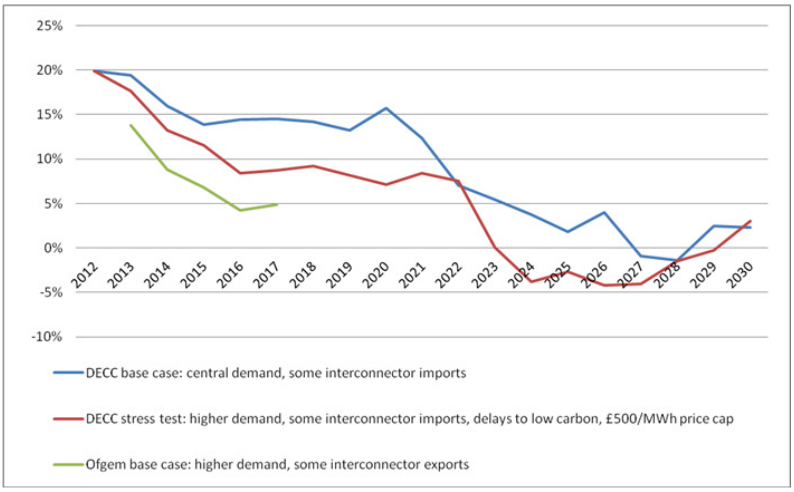
Introduction

2.1. The precise role for gas generation will depend on how the market develops over the coming years and the level and pace of development and deployment of other (particularly low-carbon) technologies, overall electricity demand and capacity retirements. It will, however, continue to play an integral role in the UK's electricity mix both in maintaining sufficient capacity margins and in balancing out increasing quantities of low-carbon generation, much of which is relatively inflexible or intermittent.

2.2. Up to 2030, we will need significant new investment in CCGTs as existing capacity reaches the end of its life, potentially up to 26 GW including capacity that has recently been commissioned or is expected to commission shortly.

Box 2A – Tightening Future Capacity Margins

Capacity margins are set to tighten over the coming years. The chart below illustrates differing DECC and Ofgem modelling on capacity margins.



Source: DECC, Ofgem

Coal closures are one of the major contributing factors to tightening capacity margins. Coal-fired generation currently represents around 28 GW, or over 30% of total capacity. Having opted out of the Large Combustion Plant Directive (LCPD), 8 GW will come offline by the end of 2015 (along with around 4 GW of oil). Beyond this, further closures are likely as environmental requirements tighten through the Industrial Emissions Directive (IED). There is, however, significant uncertainty over the timing of such retirements.

According to current timetables, around 4 GW of existing nuclear generation capacity will have closed by the end of 2020. However, the operating lives of nuclear power plants can be extended with the approval of the Office for Nuclear Regulation (ONR). The decision on whether to seek to extend is a commercial decision for the operators. Some lifetime extensions for nuclear power plants have been included as a modelling assumption in DECC analysis.

New gas plant will play an important role in helping to replace those plants that retire and, increasingly, in helping to balance the intermittency and inflexibility of other forms of generation coming online.

2.3. While our analysis indicates much of this capacity is needed in the 2020s, given the significant uncertainties, some of this investment may be needed this decade, particularly if more capacity retires than projected. For example, National Grid scenario data from the UK Future Energy Scenarios document suggests that some 9 GW of investment in new unabated gas-fired capacity[21] could be required by 2020.

2.4. Alongside this new capacity, the UK's existing gas capacity will also be of critical importance. With around 9 GW of efficient gas generation commissioned (or shortly due to be) since 2009, we benefit from a number of relatively new and efficient power stations that will continue to provide critical capacity and generation in the coming years.

Scenarios to 2030

2.5. Given the considerable uncertainty over how the electricity sector will develop to 2030, we have modelled this development using different sets of assumptions in order to simulate a number of different scenarios. This includes a scenario with a diversified electricity mix as well as scenarios in which one low-carbon generation technology is deployed more heavily than the others. However, under all scenarios we expect to see a continued need for new investment in gas plant to maintain adequate capacity margins, meet demand and provide supply side flexibility for an increasingly intermittent and inflexible generation mix.

2.6. The analysis presented is based on an agreed set of assumptions including technology costs and electricity demand at the time the analysis was undertaken, but with no affordability constraint. This set of assumptions is set out in the Analytical Annex. It has not been possible to reflect the very recent decision on the Levy Control Framework or the OBR growth figures published alongside the Autumn Statement.

Diversified Electricity Mix Scenario

2.7. This scenario represents a plausible outcome following Electricity Market Reform, characterised by a diversified supply mix and an assumption on carbon intensity of 100g CO2/kWh in 2030, which is an illustrative level of decarbonisation in the power sector, consistent with previously published EMR impact assessments. Contracts for Difference (CfDs) are used to achieve both, diversification and the emissions intensity level. Diversification reflects in part the objective of support for the development of a portfolio of low-carbon generation technologies in order to reduce the technology risks associated with the decarbonisation objective for the power sector.

Capacity

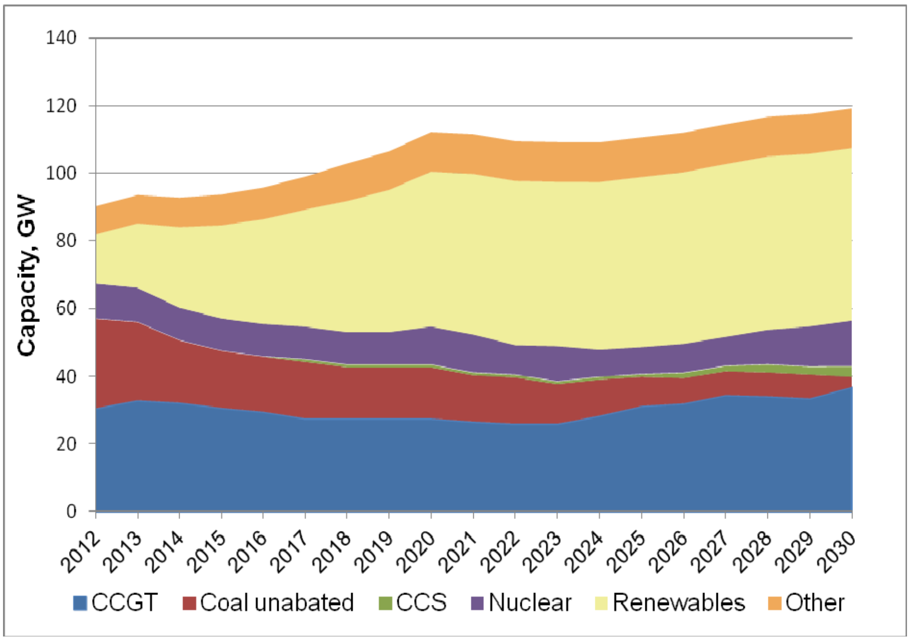
2.8. Under this scenario, 26 GW of new CCGT capacity is deployed by 2030, including the capacity that was commissioned this year and is expected to commission next year (over 3 GW in total[22]). This latest estimate is larger than the estimate of 10-20 GW from analysis

[21] This figure includes CHP plants.
[22] This does not include Carrington CCGT (880 MW), which ESB recently announced would be built and is scheduled to be commissioned by 2016.

carried out to support the Carbon Plan due to more CCGT retirements and higher demand projections towards 2030 in DECC's latest analysis, resulting from higher population projections and higher transport electricity demand.

2.9. Over the period 2012-2030, it is estimated that there will be around 21 GW of retirements, yet some of today's existing capacity is expected to still be operational in 2030. This results in an estimated total capacity of 37 GW of CCGTs in 2030, around a 5 GW increase compared to today's level.

Figure 2A: Estimated Total Capacity, 2012-2030



Source: DECC analysis 2012

Generation

2.10. Under this scenario, it is estimated that CCGTs generate 61 TWh of electricity in 2020; this rises to 105 TWh in 2025 as unabated coal-fired plants and biomass-conversion plants close and demand increases. In 2020, CCGTs are estimated to have an average load factor of 25%, rising to 38% by 2025.

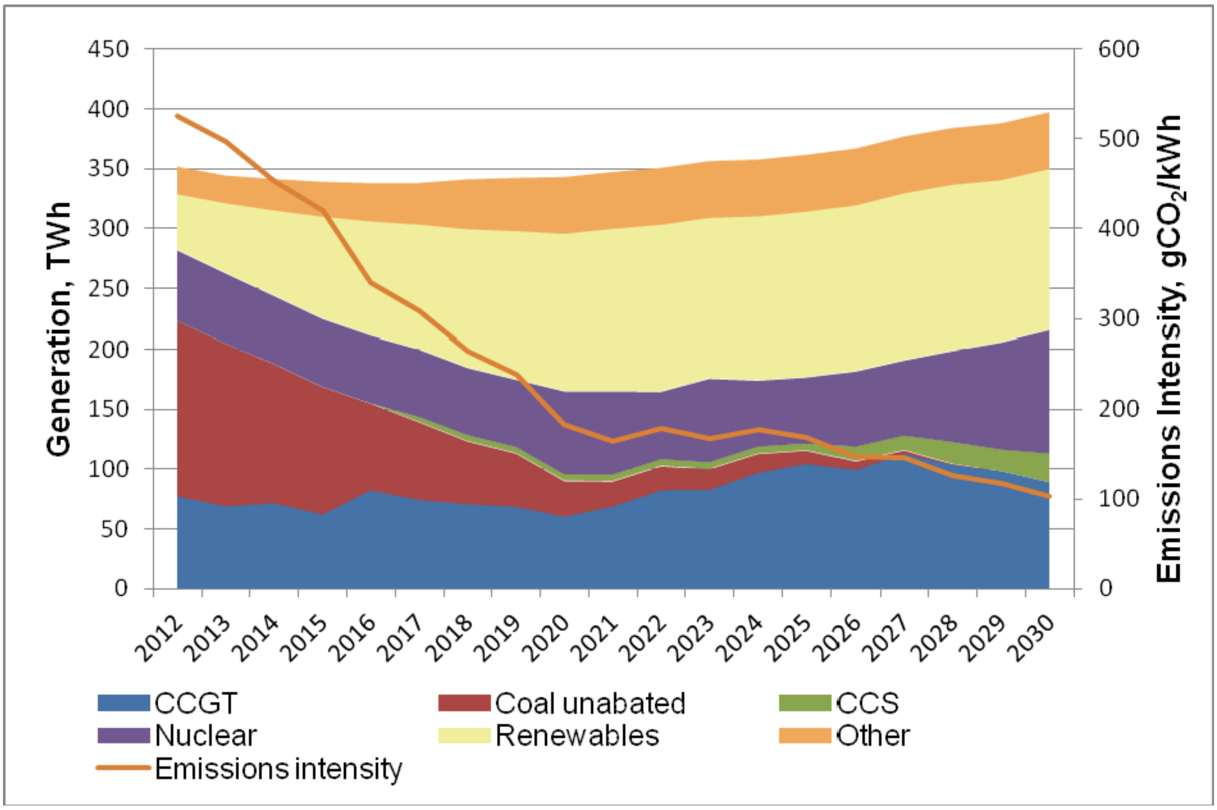
2.11. After this period, generation from nuclear and CCS is projected to increase and as these forms of generation are estimated to have lower marginal costs, they will dispatch before CCGTs.[23] In 2030, it is projected that CCGTs will supply 88 TWh of electricity, representing 22% of electricity generated in that year. This translates into an average load factor of 27% for the CCGT fleet.

2.12. The generation estimates discussed are averages for the CCGT fleet. Underlying these averages, individual CCGTs have load factors ranging from less than 10% to baseload

[23] In the case of CCS, the carbon price is projected to be at a level where the CCS operating costs are lower than the costs of paying for carbon on an unabated CCGT.

(85% or more) in the 2020s. Those CCGTs with the highest efficiencies, i.e. which are new or have just undergone significant maintenance, could achieve load factors over 85% in the early years of their operation. Older plants and those CCGTs with relatively lower efficiencies will run less but still perform a vital role and contribute to security of supply.

Figure 2B: Generation Mix, 2012-2030



Source: DECC Analysis, 2012

Alternative Scenarios

2.13. DECC's Carbon Plan,[24] published in 2011, set out a vision for the long-term transition to a low-carbon economy by 2050. Given the long time horizon, there are uncertainties over how that vision will be achieved. In order to capture this in the analysis, alongside considering outputs of a "core" run of the cost-optimising model, MARKAL,[25] Government developed three further "future" scenarios. These attempt to stress test the results of the core run by recognising that there will be changes that we cannot predict in the development, cost and public acceptability of different technologies in every sector of the economy.

2.14. In keeping with this approach of modelling different potential 'futures', GB electricity sector scenarios to 2030 were modelled in which one low-carbon generation technology is deployed more heavily than the others; namely, a higher renewables scenario, a higher CCS scenario and a higher nuclear scenario.

[24] Carbon Plan: http://www.decc.gov.uk/en/content/cms/tackling/carbon_plan/carbon_plan.aspx
[25] 'MARKAL' stands for MARKet ALlocation.

2.15. These scenarios represent a departure from the diversified mix scenario presented above, but still include many of the same assumptions such as modelling all EMR policies, fossil fuel prices, demand and the decarbonisation of the power sector to 100g/kWh by 2030. Gas-fired generation will have a significant role under all of these scenarios. Results from these scenarios are presented in Table 2A below.

Table 2A: Capacity and generation estimates under alternative scenarios in 2030 (with average emission intensity at 100g/kWh)[26]

	Gas	Nuclear	CCS	Renewables
Total Capacity, GW	Up to 41	Up to 19	Up to 13	Up to 72
Total Generation, TWh	Up to 90	Up to142	Up to 99	Up to 207

Source: DECC Analysis, 2012

Sensitivities

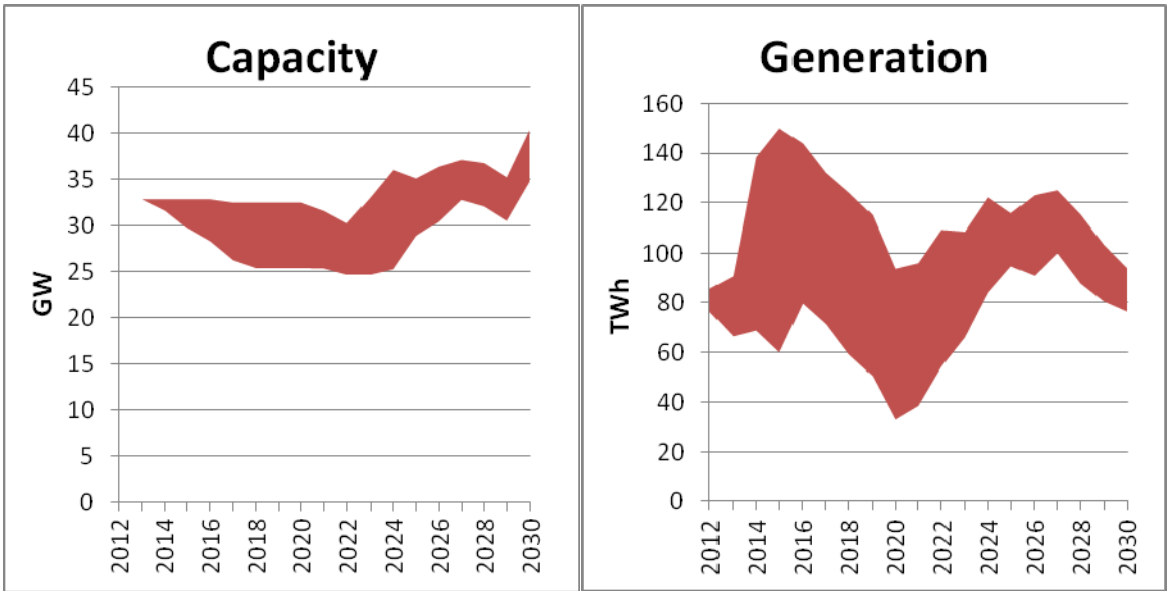
2.16. This section explores the effect of varying assumptions about demand and fossil fuel prices on the role of gas to 2030. These sensitivities have been applied to the diversified mix scenario and do not include the scenario analysis presented in the preceding Scenarios to 2030 section.

2.17. Figure 2C illustrates the range of capacity and generation estimates for CCGTs to 2030 if these assumptions are varied. Demand assumptions have been varied in line with the high and low demand estimates presented in DECC's Energy and Emissions projections,[27] while fossil fuel prices have been varied in accordance with DECC's fossil fuel price scenarios.[28]

2.18. Given the uncertainty over the future, these ranges do not cover all possible outcomes, but they do give an indication that CCGTs will have a significant role to play under a variety of demand and price scenarios.

[26] It will be up to the market to determine how much of each type of generation to bring forward.
[27] Energy and Emissions Projections: http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx
[28] *Ibid.*

Figure 2C: Range of capacity and generation estimates for CCGTs from sensitivities on demand and fuel prices (with average emission intensity at 100g/kWh in 2030)



Source: DECC Analysis, 2012

The impact of demand

2.19. As the charts above show, the uncertainty in generation is greater than that for capacity. This indicates that variations in demand may have a greater effect on load factors than build rates.

2.20. Higher demand requires high levels of generation to meet it, and vice versa. Our analysis indicates that some additional new build capacity is needed in the 2020s to meet a higher demand scenario, while the level of new build needed in a low-demand scenario is lower.

2.21. In 2030, generation from gas will be higher if demand is higher than assumed in the Diversified Mix scenario. Similarly, if demand is lower, all else being equal, generation from gas will be lower. This is true under all scenarios and sensitivities considered.

The impact of fossil fuel prices

2.22. A higher gas price is likely to result in a slightly reduced role for gas. Not only does a higher gas price lead to a higher wholesale price during this period, reducing demand for electricity, but a higher gas price also worsens the economics for gas-fired generation compared to coal. However, this second impact would lessen by 2030 as unabated coal generation diminishes by 2030.

2.23. With a lower gas price, there is likely to be a more significant role for gas. A lower gas price results in a lower wholesale electricity price, which in turn will increase demand for electricity, benefitting gas-fired generation. Also, the lower gas price improves the economics of gas-fired generation compared to coal, but again, as coal generation is likely to diminish by 2030, this second impact will lessen throughout the 2020s.

Power Sector Decarbonisation

2.24. The Government will take a power in the Energy Bill to set a decarbonisation range in secondary legislation. The power will provide for flexibility in the setting or reviewing of the range by consideration of wider economic factors. A decision to set the range for carbon emissions in 2030 will be taken when the Committee on Climate Change has provided advice on the 5th Carbon Budget and once the Government has set that budget.

2.25. The level of decarbonisation in the electricity sector assumed by 2030 impacts on the role of gas as it indicates the proportion of total generation that would be provided by fossil-fuel power plants. Due to the age of the existing coal-fired fleet and the impact of a rising carbon price, throughout the 2020s CCGTs provide an ever-increasing proportion of generation from fossil-fuel plants.

2.26. This Strategy considers three different decarbonisation trajectories to 2030 set out in Table 2B below. The main analysis reflects the central assumption used consistently in analysis of Electricity Market Reform by DECC, namely a trajectory to around 100g CO2/kWh grid emissions intensity in 2030. The second is a sensitivity analysis based on a trajectory to around 200g CO2/kWh in 2030, which is taken as a proxy for a scenario in which the 4th Carbon Budget is revised upwards following the 2014 review in line with a continuation of the EU ETS's current trajectory. The third is a sensitivity analysis based on a trajectory to around 50g CO2/kWh in 2030, reflecting the advice of the Committee on Climate Change on an appropriate level for 2030.

2.27. Under the Climate Change Act, emissions reductions by the UK's industrial and power sectors are determined by the UK's share of the EU Emissions Trading System (EU ETS) cap. This protects UK industrial and power sectors from exceeding EU requirements. However if the EU ETS cap is insufficiently ambitious, this could mean placing disproportionate strain on other sectors outside the EU ETS such as transport.

2.28. To overcome this and to provide clearer signals for businesses and investors, the Government will review progress towards the EU emissions goal in early 2014. If at that point our domestic commitments place us on a different emissions trajectory than the EU ETS trajectory agreed by the EU, we will, as appropriate and consistent with the legal requirements of the Climate Change Act, revise up our budget to align it with the actual EU trajectory.

Box 2B – Carbon Budgets

In order to drive progress and keep the UK on a pathway to achieve our 2050 target, the Climate Change Act introduced a system of Carbon Budgets, which provide legally-binding limits on the amount of emissions that may be produced in successive five year periods.

The 4th Carbon Budget, covering the period 2023-27, was set in law in June 2011 and required emissions to be reduced by 50% below 1990 levels. The level of the 4th Carbon Budget assumes a split between emissions that will fall in the traded sector and those that will fall in the non-traded sector.

In the traded sector, emissions are capped by the EU ETS. The current EU ETS cap is not sufficiently tight to deliver the necessary emissions reductions to meet the 4th Carbon Budget. The UK is pushing for the EU to show more ambition by moving to a tighter 2020 emissions target, which, in turn, will drive a more stringent EU ETS cap. We will review our progress in early 2014 and if, at that point, our domestic commitments place us on a different trajectory from the one agreed by our partners in the EU under the ETS, we will revise up our budget as appropriate to align it with the actual EU trajectory. Before seeking Parliamentary approval to amend the level of the 4th Carbon Budget, the Government will take into account the advice of the Committee on Climate Change, legal requirements in the Climate Change Act and any representations made by the Devolved Administrations.

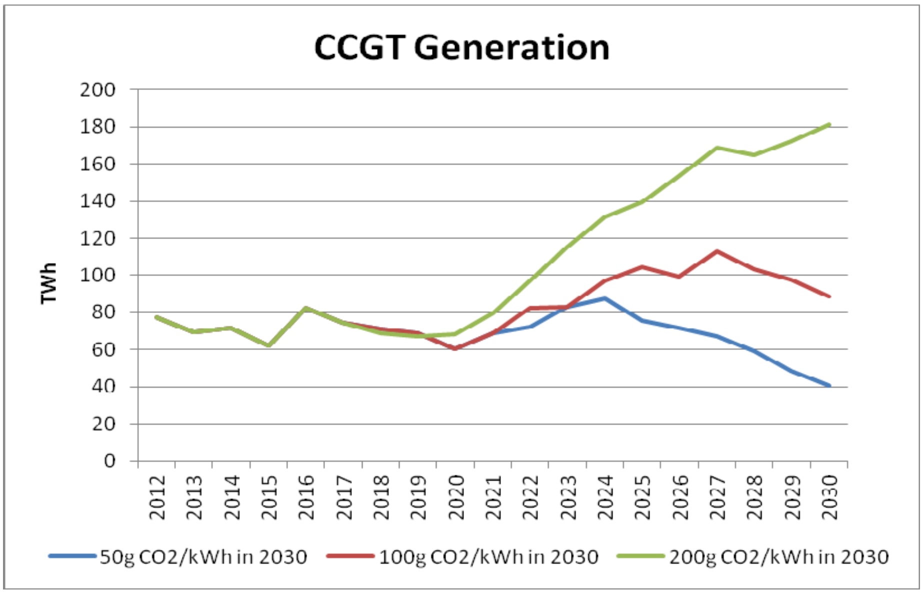
2.29. A lower level of decarbonisation, i.e. not reducing emissions by as much, will mean that CCGTs will generate more compared to a higher level of decarbonisation.

Table 2B: Capacity and generation estimates in 2030 under alternative decarbonisation trajectories

	100gCO_2/kWh	200gCO_2/kWh	50gCO_2/kWh
New CCGT Capacity, GW (2012-2030)	26	37	19
Total CCGT Capacity, GW (2030)	37	49	31
CCGT Generation, TWh (2030) ; % of total generation	89 22%	181 45%	41 10%
Average CCGT load factor (2030)	27%	43%	15%

Source: DECC Analysis, 2012

Figure 2D: Range of generation estimates for CCGTs in 2030 from different decarbonisation trajectories



2.30. These trajectories would be affected by demand and price sensitivities in a similar way as described above.

Longer term—Beyond 2030

2.31. Looking further into the future the picture is inevitably increasingly uncertain, as underlying technology, costs and demand assumptions, for example, are themselves very uncertain over four decades. The alternative scenarios described previously in this Chapter, namely, a higher renewables scenario, a higher CCS scenario and a higher nuclear scenario, can be used to create a range of estimates for total unabated CCGT capacity (i.e. not including CCS capacity[29]) in 2049. The estimates presented in Table 2C indicates that even by 2049, unabated gas could still have an important role to play in ensuring a secure and flexible, low-carbon system, albeit operating much less than it does today. However, given the level of uncertainty, the range of capacity below should be viewed as purely illustrative.

[29] CCS could form an increasingly large proportion of CCGT capacity. Estimates of CCGT capacity and generation in the main analysis to 2030 above similarly do not include CCGT with CCS.

Table 2C: Capacity estimates for unabated CCGTs by 2049 under alternative scenarios

	Diversified electricity mix scenario	Higher nuclear scenario	Higher CCS scenario	Higher renewables scenario
Capacity	47 GW	44 GW	33 GW	48 GW

Source: DECC analysis, 2012

CCS

2.32. DECC analysis suggests that, depending on the mix of generation that is built, CCS could contribute as much as 13 GW of capacity by 2030 and up to 40 GW by 2050. The CCS Association, the representative body for the CCS industry, have set out their ambition for 20-30 GW of CCS to be deployed by 2030.[30] The measures being taken by Government, as set out in the CCS Roadmap,[31] should enable CCS to be a significant part of the generation mix, subject to CCS demonstrating its effectiveness as a cost-competitive, low-carbon source of electricity generation in time to meet projected demand.

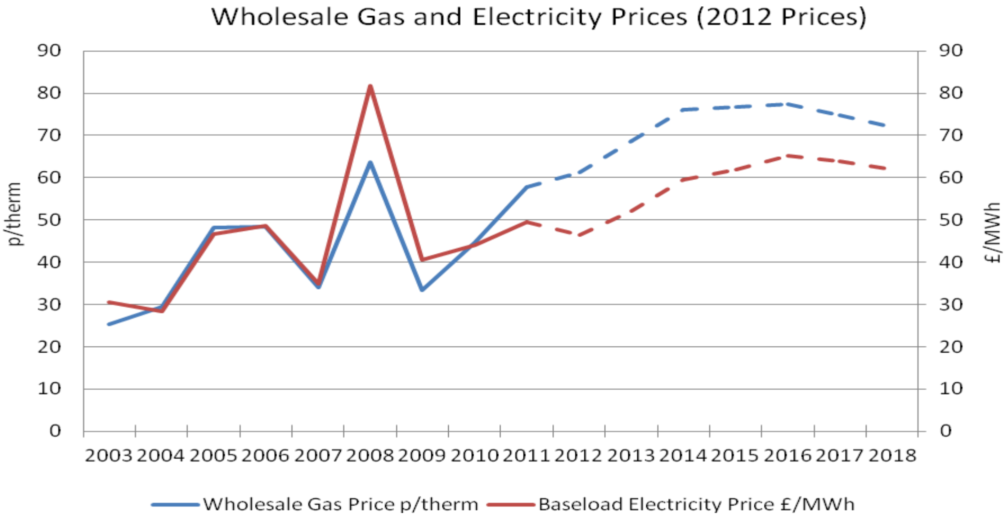
Gas-fired generation and retail electricity prices

2.33. Gas-fired plant sets the electricity wholesale price for much of the year, which means that the gas wholesale price is a key driver of the wholesale electricity price. The diagram below depicts the movements of historic and projected wholesale gas and wholesale electricity prices.

[30] CCSA, 2011. A Strategy for CCS in the UK and Beyond. www.ccsassociation.org/press-centre/reports-and-publications

[31] DECC, 2012. CCS Roadmap, Supporting deployment of Carbon Capture and Storage. www.decc.gov.uk/assets/decc/11/cutting-emissions/carbon-capture-storage/4899-the-ccs-roadmap.pdf

Figure 2F: Historic and projected wholesale electricity and gas prices (2012 prices)



Sources: UK gas price: historic data from ICIS Heren, projected data is DECC's 2012 central projection; GB electricity price: historic data from LEBA, projected data from DECC 2012 analysis; Historic prices adjusted to 2012 prices using GDP Deflator.

2.34. While gas-fired generation is expected to continue to influence significantly the wholesale electricity price in the future, it is expected to set the electricity wholesale price for less of the year than it has done in the past. Yet, as long as gas-fired generation continues to set the electricity price, a lower (or higher) gas price will lead to a lower (or higher) wholesale electricity price, which in turn will affect the retail electricity price that consumers face.

2.35. Wholesale electricity costs make up around half of the retail electricity price paid by households (more for business) and are currently the biggest drivers of movements in retail energy prices in the UK.

2.36. However, while a reduction in the wholesale electricity price may reduce retail electricity prices, retail electricity prices also reflect the costs of operating an energy supply business, the costs of transporting electricity through the grid, supplier margins and costs of energy and climate change obligations. There are also other factors that will affect retail prices that may not always move with wholesale costs, for example, the cost of the Feed-in Tariff with Contracts for Difference(CfDs). If the wholesale electricity price increases, the CfD element of the retail electricity price will decrease, and the opposite is also true.

2.37. As such, even if the wholesale price of electricity were to fall, increases in the other components of the retail price may mitigate some or all of the effect of this fall on retail electricity prices.

Changing Patterns of Supply and Demand

2.38. The evolving generation landscape will require changing patterns of generation from gas-fired plant.

2.39. Gas and coal currently provide flexibility in meeting the peaks and troughs of daily demand, which can vary as much as 20 GW.[32] With less unabated coal as we decarbonise, gas will provide an increasing proportion of this flexibility. With significant increases in relatively inflexible and intermittent capacity on the grid, there will be a greater need for flexible capacity to ensure supply can meet demand at all times, which will further add to the short-term variability of generation from gas (in turn leading to more short-term variability in demand for gas, discussed further in Chapter 4). Further, this could become more significant with daily peaks and troughs set to become more extreme as the level of electricity consumption increases with the expected electrification of heat and transport.

2.40. Increasingly, the role of flexible generation will sit alongside other technologies that can be used to help balance the supply and demand for electricity. In particular, demand side response (DSR), electricity storage and interconnection will be important alongside smarter networks, and all are likely to be required to help match the supply and demand of electricity efficiently and cost effectively. Further details on the Government approach to different balancing technologies can be found in the Government's "Electricity System: Assessment of Future Challenges" document.[33]

2.41. Continuous improvements in gas-fired generating technology will also be important, not least to ensure that gas plants can operate efficiently under changing conditions. The efficiency of gas plants has improved significantly since the first CCGTs were built. While there is a general consensus that further developments are likely to happen more slowly, it will be important that technological developments continue.

2.42. There have been a number of welcome developments by equipment suppliers in both improving the flexibility of plant and in maintaining high efficiencies under more flexible conditions. The continuation of these technological development trends will be of further benefit in enabling new CCGTs to operate more efficiently as a flexible source of generation, well-suited to complementing an increasingly intermittent and inflexible generating mix and in maintaining a cost-effective, efficient and low-emissions system.

[32] Based on Winter 2011/12 peak day of 8th February 2012
[33] Networks Strategy and Regulation: www.decc.gov.uk/en/content/cms/meeting_energy/network/strategy

Chapter 3 – Enabling Investment in Gas Generation

Chapter Summary

- **Current excess capacity is creating downward pressure on spark spreads.**
- **While these conditions are expected to improve, uncertainty on future load factors and revenues means investment decisions are more difficult.**
- **Therefore, we are taking actions to enable sufficient investment in gas generation infrastructure to take place, including:**
    - **taking powers in the Energy Bill to run a Capacity Market. The Government is minded, subject to need, to run the first auction in 2014, for delivery of capacity in the year beginning in the Winter of 2018/19;**
    - **proposing powers in the Energy Bill, which will enable Government to take action to improve wholesale electricity market liquidity if necessary; and,**
    - **bringing forward proposals to improve the planning regime in each part of Great Britain.**

Introduction

3.1. Chapter 1 highlighted that, historically, investment in gas-fired generation has proven to be attractive to developers, and Chapter 2 detailed the likely need for investment in new plants in the future. This Chapter outlines the current economics of gas generation, the barriers to investment in gas plant that have been identified by responses to our Call for Evidence, and the Government's approach to enabling sufficient investment in gas generation capacity to come forward.

3.2. The Call for Evidence highlighted a number of reasons why investment in gas plant is currently less attractive than it has been historically and why attracting investment in gas plant in the future may be more difficult unless the Government takes action to reduce market uncertainty.

The Case for Investment

3.3. As detailed in Chapter 1, in the mid-2000s the case for investment in CCGT was strong and capacity in the electricity market increased with new build plants coming on to the system. At the same time, the recession resulted in unexpectedly lower demand (both in absolute terms and relative to forecasts for 2012 demand made in 2008).

3.4. Further, a combination of high gas prices relative to coal prices and low carbon prices have increased the competitiveness of coal generation relative to gas generation, which has reduced the pricing power[34] of gas generators. Relative fuel prices have recently been more favourable to coal partly due to increases in gas prices as a result of increasing global demand in the wake of the Fukushima incident. At the same time, lower demand for coal has resulted in falling coal prices, particularly in the United States as a result of increased use of shale gas. Low carbon prices have further reduced the competitiveness of gas compared to coal.

3.5. In its winter consultation report for 2011/12, National Grid reported that the cost of gas-fired generation was higher than coal and consequently coal became a baseload fuel source with an increasing dominance as the winter progressed.

3.6. As a consequence, and given the overcapacity in the GB generation fleet, clean spark spreads[35] are low and, if they were to stay there, would be insufficient to drive investment.

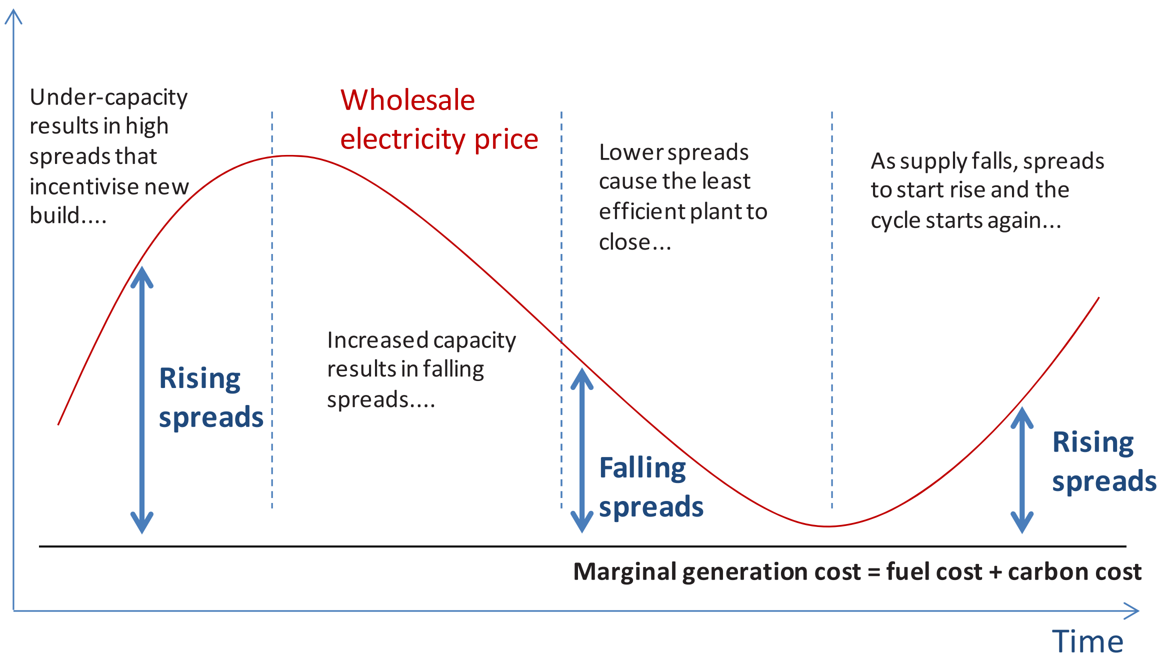
The case for future investments - outlook for clean spark spreads

3.7. A reduction in capacity or an increase in demand for electricity would reduce the generation oversupply that currently exists, which would in turn be expected to increase clean spark spreads and, ordinarily, the case for investment.

3.8. Historically, investment in gas plant in the GB power sector has typically followed the cyclical pattern illustrated below.

[34] Pricing power is an economic term that refers to the effect that a change in the price of a firm's product has on the quantity demanded of that product. The more pricing power a firm has, the lower the reduction in demand for the firm's product when it increases prices.
[35] Spark Spreads: the difference between the wholesale (electricity) price and the marginal cost of a reference gas plant, a measure frequently used to assess profitability.

Figure 3A: Cyclical pattern on investment in gas plant



3.9. There is evidence that the GB market may be close to the bottom of the cycle, with a number of recent decisions to mothball or close plant, and around 12 GW of capacity closing as a result of opting out of the Large Combustion Plant Directive (LCPD). Ordinarily, this reduction in capacity would be expected to improve the case for investment. For gas plant, this would be further improved through rising carbon prices (including from the Carbon Price Floor), which will make gas generation less expensive relative to coal and, therefore, more competitive. This is supported by the recently announced decision by ESB to take forward a new 880 MW plant at Carrington, which will provide valuable capacity as these plants close.

3.10. However, despite some investment taking place, responses from the Call for Evidence suggest that current market conditions and uncertainty about the longer-term outlook for gas plant could mean that we do not see enough investment come forward to maintain sufficient capacity margins.

3.11. In the short term, uncertainty about tightening margins and increasing clean spark spreads exists for a number of reasons. Plant owners may be keeping currently uneconomic CCGT open as an 'option' in the hope that market conditions improve (e.g. due to the closures of coal plants, or capacity payments). There is also uncertainty about the exact timing of the retirement of coal plants that have opted out of the LCPD. A further complication is the possibility that opted-out coal plants may convert to biomass and take the measures necessary to remain on the system.[36]

3.12. This lack of visibility on the timing and extent of any future market tightening and its consequent impact on spreads, reduces the likelihood of investment in gas generation assets in anticipation of an increase in spreads.

[36] To do this, they would need to, in effect, reopen as a 'new' plant and meet the environment standards prescribed for new plant under the Industrial Emissions Directive.

3.13. In the longer term, there is even greater uncertainty about the outlook for gas plant. In particular, as the amount of intermittent and inflexible low-carbon generation increases, gas plant load factors are likely to become increasingly uncertain, and there are concerns that returns and revenue certainty will be reduced. This is discussed further below.

Enabling Investment - Maintaining Security of Supply

3.14. There are significant security of supply challenges in the coming years as capacity margins tighten. Government is taking a number of steps to address these, including policies to reduce demand for electricity and increase the responsiveness of the demand side, working to ensure we have a diverse mix of electricity supplied from different sources, and supporting Ofgem's work to reform cash out.

3.15. Government is also continuing to support and influence the European Commission's work towards a better functioning and more integrated, single European electricity market. The single market should deliver lower costs for consumers (e.g. by facilitating trade between competing suppliers and generators), greater security of supply (by reducing the need for GB backup capacity), and lower carbon emissions by enabling more efficient use of renewables.

Box 3A—Cash Out

'Cash out' is the process used to settle differences between the financial contracts and the physical metered volumes of market participants. Cash out prices are intended to reflect the costs the System Operator incurs when balancing the system.

The Government welcomes Ofgem's decision on 28th March 2012 to conduct a Significant Code Review (SCR) on electricity cash out arrangements, which could provide better signals for investment and increase security of supply, in addition to providing a useful reference price for the penalty models that employ market-based penalties. We will continue to work closely with Ofgem to ensure consistency between the EMR policy proposals and the electricity cash out SCR, and will carefully consider the interactions between the EMR Capacity Market and any electricity cash out reforms.

Ofgem is currently in the initial consultation phase of the significant code review, and intends to publish a draft decision document in Spring 2013.

3.16. Even with these measures, investment in new gas plant will be critical in maintaining secure and affordable electricity. However, as outlined above, changes in the market create a particular challenge for gas investors, who will be increasingly reliant on high prices in short periods to recover their costs of investment. While, in theory, some investment should take place under these conditions, in practice prices in the electricity market may not provide the correct signals to ensure enough investment in flexible plant comes forward to maintain optimal security of supply.[37]

3.17. This market failure is commonly referred to as the problem of 'missing money'. There are at least two reasons for 'missing money':

- due to the current imbalance settlement pricing system (cash out), the scarcity price of electricity does not rise high enough to reflect costs of action taken to balance the system, or the true value of preventing power cuts to consumers; and,
- at times when the wholesale electricity market prices peak to high levels, investors fear that either the regulator or Government will act on a perceived abuse of market power, for example, through the introduction of a price cap.

3.18. Investors are therefore faced with uncertainty on load factors for their plant, uncertainty on when and how often it will run, and uncertainty on the prices that can be achieved when it does run.

3.19. Ofgem is considering reform of balancing arrangements to better reflect costs at times of scarcity (see Box 3A). Some of Ofgem's considerations may help address part of the 'missing money' problem in the electricity market by providing generators with greater opportunities to recover their fixed costs.

3.20. However, with the possibility of capacity margins tightening later this decade,[38] and the long-term nature of work to increase the responsiveness of the demand side, to develop the single market and to reform cash out, Government recognises the need for intervention as part of Electricity Market Reform.

3.21. That is why we are introducing legislation for a Capacity Market, in which generation and non-generation providers of capacity like demand side response (DSR) and storage will be paid for providing reliable capacity. In return, capacity providers will be obliged to deliver energy at times of system stress, and will be penalised if they fail to do so. In this way, a Capacity Market will directly tackle the 'missing money' in the electricity market by explicitly paying for resource adequacy and ensuring adequate investment to minimise the chances of blackouts.

The Capacity Market

3.22. More detail on the Capacity Market can be found in the EMR overview document, in particular in Annex C.[39] In summary, the Capacity Market, if initiated, will work as follows:

- a forecast of future peak demand will be made, four years ahead of the delivery year in which it is needed;

[37] For example, this could be due to increased risks to investments and increases in the cost of capital.
[38] Both DECC and Ofgem modelling projects falling capacity margins over the next decade. Ofgem's recent capacity assessment is available here:
http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Pages/index.aspx.
DECC has published a response to this report including comparison of the Ofgem and DECC projections.
[39] Electricity Market Reform: www.decc.gov.uk/en/content/cms/meeting_energy/markets/electricity/electricity.aspx

- the net amount of capacity needed to ensure security of supply (which is likely to be informed by an enduring reliability standard) will be contracted through a competitive annual central auction run by the System Operator;

- generation and non-generation approaches such as demand side response will be able to participate in the capacity auction. All generation plants, including existing plants, will be eligible to participate in this auction, with some exceptions (e.g. low-carbon plants receiving CfDs);

- providers of capacity successful in the auction will enter into capacity agreements, committing to provide electricity or reduce demand for electricity when needed in the delivery year/s (in return for steady capacity payments) or face financial penalties; and,

- the costs of the capacity payments will be shared between electricity suppliers in the delivery year.

3.23. Ofgem has recently completed an assessment of future electricity capacity in the GB market over the next four years, and DECC has also carried out further modelling on future capacity margins. DECC's analysis for the middle of the decade projects higher margins than Ofgem's modelling, with lower risks to security of supply, but all models predict a further tightening of capacity margins as we move towards the end of this decade and into the 2020s. See Chapter 2 for more details.

3.24. Given the likelihood of margins falling over the coming years, **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**. 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.

3.25. The Government believes this strikes the right balance between the need to provide industry certainty, the need for a Capacity Market to address security of supply concerns, and the need to ensure a competitive capacity auction by having long enough between the auction date and the delivery year to enable the participation of new market entrants.

3.26. The Government will provide further analysis on the evidence of need for a capacity auction, including in its first delivery plan. This will be published by the end of 2013 (subject to the Energy Bill receiving Royal Assent) and will be informed by evidence and analysis including Ofgem's statutory Electricity Capacity Assessments for 2012 and 2013 and analysis provided by National Grid as the delivery body for EMR.

3.27. The Government recognises the importance of clarity for investors on the forward process for the Capacity Market, and will aim to publish final detailed design proposals on the Capacity Market by May 2013, and alongside this, provide further details on the possible timing for a 2014 capacity auction.

3.28. It would be possible to run the first capacity auction in 2014 with the first delivery year in 2015/16, i.e. with a compressed lead time. However ,this option carries significant risk, in particular, the lack of time between the auction and delivery year would exclude new capacity as it would not be able to build in time to compete. This could lead to an uncompetitive auction. We would also have to run several auctions in the first auction process (for delivery in 2015/16, and potentially also 2016/17, 2017/18 and 2018/19) if we wanted to give the maximum possible lead times for bringing on any required new capacity before delivery was required. This would significantly increase the importance of the first auction process and there would therefore be increased risks. As such, the Government is minded to run the first auction in 2014 for delivery in the year beginning in the Winter of 2018/19.

3.29. If implementing the Capacity Market, we intend to run pilot DSR and storage capacity auctions for delivery in the years before capacity from the primary auction is in place; namely 2015/16, 2016/17 and 2017/18. This will help to stimulate the market for these approaches (as has been seen overseas) and provide additional capacity during this period, which will help minimise security of supply risks. DECC will also continue to monitor the security of supply outlook and will respond to an earlier problem if necessary.

3.30. The Capacity Market will not apply in Northern Ireland, since Northern Ireland is part of a separate capacity mechanism covering Ireland and Northern Ireland. We will, however, continue to work with colleagues in Northern Ireland on relevant design issues.

3.31. The Capacity Market will extend to Scotland and Wales. We will continue to work with colleagues in the Scottish and Welsh Governments to ensure we develop the best possible design for the GB market as a whole.

3.32. We are considering how the Capacity Market interacts with State Aid rules, and will engage closely with the European Commission to ensure that the policy is consistent with those rules.

Figure 3B: Summary of Capacity Market Design Choices

Design area	Current position
Initiating the Capacity Market	• 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. 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. • 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.
Setting the volume of capacity to contract for	• The net amount of capacity needed to ensure security of supply (which is likely to be informed by an enduring reliability standard) will be decided by Ministers in advance of the auction.

Timing of auctions relative to delivery year	• Competitive central auctions for capacity will be held four years before the delivery year. Secondary auctions are likely to be useful to contract for additional capacity nearer to delivery if required.
Eligibility of capacity to participate	• Generation and non-generation approaches such as DSR will be able to participate in the capacity auction. • All generation plants, including existing plants, will be eligible to participate in this auction, with some exceptions (e.g. low-carbon plants receiving CfDs). • Transitional arrangements for DSR and storage will be developed to remove barriers to their participation. • All participants will be subject to pre-qualification checks.
Penalties for non-delivery	• Providers of capacity successful in the auction will enter into capacity agreements, committing to provide electricity or reduce demand for electricity when needed in the delivery year/s (in return for steady capacity payments) or face financial penalties.
Payment	• A settlement agency will coordinate payments for capacity between suppliers and capacity providers. The costs of the capacity payments will be shared between electricity suppliers in the delivery year.

Enabling Investment – Providing Policy and Regulatory Certainty

3.33. The Government recognises the importance of providing investors with certainty, particularly around Electricity Market Reform. Indeed, respondents to the Call for Evidence highlighted regulatory uncertainty as a key barrier to making investment decisions in new plant.

Certainty on Decarbonisation

3.34. The UK is legally bound and committed to reducing greenhouse gases by at least 80% by 2050 compared to 1990 levels. The Government is agreed on the need to encourage a least-cost approach to meeting this target and, as highlighted in the Government's Carbon Plan, deep cuts in power sector emissions are necessary during the 2020s to keep us on this approach.

3.35. As discussed in Chapter 2, the precise level of decarbonisation of the power sector will be a critical factor in determining, overall, how much electricity gas plant will be able to generate and the prices they achieve. The greater amounts of low-carbon capacity on the system, the less gas plants would be able to generate, acting more to provide flexible generation and help balance increasing amounts of relatively intermittent and inflexible low-carbon generation on the system.

3.36. The Government is seeking to provide certainty for investors in both low-carbon energy sources and gas. To this end, we are setting a sustainable and affordable cap on the Levy Control Framework out to 2020 and reiterating that our approach to decarbonisation will continue to stay in step with other EU countries throughout the 2020s.

Certainty on Electricity Market Reform and the future power market

3.37. Throughout the year we have taken a number of steps to improve regulatory certainty on EMR. For example, in March we announced our decision to remove regulatory uncertainty from the proposed Emissions Performance Standard by introducing the concept of "grandfathering". This maintains the emissions level that applies at the time a new plant receives planning consent until 2045 and gives investors certainty over the regulatory regime under which their assets will operate.

3.38. This approach removes a regulatory risk that may potentially deter investment in new gas or increase the costs of investments, while leaving other market–based mechanisms in EMR to drive increasing amounts of low carbon and, therefore, determine the level and future role of gas. As such, the approach is consistent with both maintaining security of supply and decarbonising our electricity supply.

3.39. We have also provided more details on the design of the Capacity Market. For example, we set out high-level designs in May this year as part of our Design and Implementation update.

3.40. We have now provided further details on the Capacity Market, as set out earlier in this Chapter, and have also published a number of documents that will give greater certainty on how the market will operate under Electricity Market Reform. These include:

- **the Annual Energy Statement**,[40] provided to Parliament to help set strategic energy policy and guide investment;
- **the updated Energy Bill**, which provides greater certainty on the legislative regime for EMR;
- **the EMR Policy Overview Document**,[41] which describes the importance of EMR and why it is needed, Government's objectives for EMR and our long-term vision for the electricity market, and details on what EMR is and how the key aspects of it will work. This includes:
    - CfD Operational Framework;
    - CfD Heads of Terms;

[40] Annual Energy Statement: http://www.decc.gov.uk/en/content/cms/meeting_energy/aes/aes.aspx
[41] Electricity Market Reform: http://www.decc.gov.uk/en/content/cms/meeting_energy/markets/electricity/electricity.aspx

- Capacity Market: design and implementation update;
- Institutional Framework: Delivering EMR;
- Institutional Framework: Delivery Plan; and,
- the EMR Implementation Roadmap.

3.41. We have also published a strategy on energy security, which assesses four characteristics of energy security: adequate capacity, diversity, reliability and demand side response for gas, electricity and oil. The Strategy describes Government's methodology for ensuring energy security and presents indicators for each of these.

3.42. Further, we have published an Energy Efficiency Strategy,[42] launched a consultation on Electricity Demand Reduction,[43] and have updated our Renewable Energy Roadmap.[44]

3.43. Combined, these documents provide significant amounts of detail on how the energy markets will evolve over the coming years, and provide greater clarity on the markets that gas generation assets will be operating in.

3.44. Given the long lifetimes of generation assets, we also recognise the importance of providing details of our long-term vision for EMR and the electricity market. Further details are provided as part of the EMR Policy Overview document.[45] In summary, our long-term vision includes a transition to a market where low-carbon technologies can compete fairly on price. The process for achieving our vision will involve a movement from administrative price setting for low-carbon technologies, through to technology specific auctions and then to competition between all forms of electricity generation. We envisage EMR will progress through four stages:

i. During Stage One, the Renewables Obligation will operate alongside the new CfDs until 2017. During this stage, and following consultation with the Devolved Administrations, CfD prices for renewables will be set administratively. Government is also minded to run the first Capacity Auction in 2014 if needed, for delivery of DSR and storage capacity from Winter 2015/16, and delivery of market wide capacity from Winter 2018/19.

ii. Stage Two, which will run from 2017-2020s, will involve prices increasingly being set by competitive technology-specific auctions. If the first auction is held in 2014, the Capacity Market will be fully operational and delivering capacity in this period.

iii. We believe that in Stage Three, which will likely begin during the 2020s, there will be a growing maturity of technologies and movement towards technology neutral auctions. Demand side response, additional storage and interconnection, and well-

[42] Energy Efficiency Strategy:
http://www.decc.gov.uk/en/content/cms/meeting_energy/renewable_ener/re_roadmap/re_roadmap.aspx
[43] Electricity Demand Reduction: Consultation
http://www.decc.gov.uk/en/content/cms/consultations/edr_cons/edr_cons.aspx
[44] Renewable Energy Roadmap:
http://www.decc.gov.uk/en/content/cms/meeting_energy/renewable_ener/re_roadmap/re_roadmap.aspx
[45] Electricity Market Reform:
http://www.decc.gov.uk/en/content/cms/meeting_energy/markets/electricity/electricity.aspx

functioning energy markets across the EU, will play an increasingly large role in managing supply and demand.

iv. Stage Four will run from the late 2020s and beyond, when technologies should be mature enough, and the carbon price sufficiently high, to allow all generators to compete without intervention. By this stage, Government's role in the electricity market will largely be restricted to the setting of high level objectives for diversity and security of supply.

Enabling Investment – Addressing Barriers

Planning

3.45. Some developers identified the current planning and consent regime as a potential barrier to investment. They argue that applications under the Planning Act[46] regime in England and Wales require more 'front loading' than under the previous Electricity Act, and that this adds cost to development. This is compounded by a concern that the new system is less flexible than the previous one, making it harder to make changes to an application after submission (even when those changes would not have any additional impacts and, for example, would increase the efficiency or flexibility of the plant).

3.46. Further, it is currently difficult to vary the terms of consent for those projects permitted under s36 of the Electricity Act, making it harder to develop those projects[47] in line with latest technologies and market developments. If a developer finds it cannot build a plant within the terms of its s36 consent, the only option at present is to apply for a new Development Consent Order for the revised scheme, which severely delays construction, and, given the associated costs, could potentially deter development of these consented sites.

3.47. It is likely that we will need to see both development of projects that are already consented, and proposals for, and development of, new projects. The market and planning frameworks, therefore, need to allow prospective projects to come forward within reasonable timescales and provide flexibility for those projects consented but not yet developed to accommodate technological changes.

3.48. While the major infrastructure planning regime is relatively new, and already has a number of existing flexibilities, for example in how consultation is undertaken, how development consent orders are drafted and through the use of the "Rochdale Envelope" approach,[48] the Government considers that there is more that can be achieved to improve the balance between consultation, scrutiny and delivery timescales. The Government is, therefore, proposing action to reduce front-loading requirements where they appear to be over prescriptive based on early experience of the new regime. In particular, we are consulting on proposals for expanding and improving the 'one stop shop' approach to non-planning

[46] Applicable in England and Wales; electricity consents are devolved to Scottish Ministers in Scotland
[47] Over 15 GW have been consented, but not yet constructed.
[48] See: http://infrastructure.independent.gov.uk/wp-content/uploads/2011/02/Advice-note-9.-Rochdale-envelope-web.pdf

consents for the nationally significant infrastructure regime and proposals for streamlining the list of prescribed consultees.[49]

3.49. We recognise, however, that there may be other actions that can be taken to further improve the nationally significant infrastructure regime. We would welcome further suggestions as part of this consultation, and will continue to work with stakeholders to identify and, where practical, implement actions to help reduce the time it takes to bring forward an application. For example, we are looking at these issues through our "Light Touch Review" of Planning Act guidance, on which we are giving priority to the pre-application guidance and associated development guidance.

3.50. We also recognise the concerns over the flexibility of the system for newly proposed projects. The Government will set up a working group aimed at providing more clarity on how planning frameworks allow gas plant developers a degree of flexibility in their applications and subsequent consents under the Planning Act (such as use of the 'Rochdale envelope'). Such flexibility may be needed, for example, to accommodate technology or environmental considerations. We will report on this work in Autumn next year.

3.51. We are also taking action to increase the flexibility of the planning system for existing consents. We are introducing changes as part of the Growth and Infrastructure Bill to allow greater flexibility for those proposals that have been granted consent under s36 of the Electricity Act, but are not yet built. This will allow them to develop their projects in a way that takes account of the latest design improvements, including advances in technology and improvements in environmental protection without having to re-start their application under the Planning Act.

3.52. The Government has also already announced a package of housing and planning reforms that will create the conditions that support local economic growth. Some of these proposals will deliver improvements for major energy infrastructure, including reforms to Special Parliamentary Procedure.

3.53. These measures and proposals under consideration will together provide for more timely and flexible planning processes commensurate with the need for, and scale of, gas-fired generation.

3.54. In Scotland, Scottish Ministers have devolved powers relating to consents of electricity generation and transmission infrastructures under s36 and s37 of the Electricity Act 1989. The Scottish National Planning framework[50] identifies a range of generation and energy infrastructure projects in Scotland deemed to be national priorities in Scotland.

Barriers facing independent generators

3.55. Historically, a significant amount of investment in gas generation plant has been undertaken by independent generators. A number of responses to the Call for Evidence have highlighted barriers to investment specific to that group.

[49] Consultation can be found at: https://www.gov.uk/government/consultations/nationally-significant-infrastructure-planning-expanding-and-improving-the-one-stop-shop-approach-for-consents

[50] Long term spatial strategy for Scotland's development: http://www.scotland.gov.uk/Publications/2009/07/02105627/0

3.56. Non-vertically integrated market participants need to be confident that they can manage key risks such as their route to market and imbalance.[51] They therefore need:

a. Sufficient liquidity in the forward, day-ahead and intra-day markets that ensures they have risk management and trading opportunities;

b. Power Purchase Agreements (PPA) that facilitate independent generators' access to market, with PPA discounts that reasonably reflect the cost of managing their imbalance; and,

c. Reliable forward wholesale prices that reflect supply and demand fundamentals in order to provide investment and operational signals.

Box 3B – Liquidity

Liquidity can be defined as the ability to buy or sell quickly a desired commodity or financial instrument without causing a significant change in its price and without incurring significant transaction costs. A key feature of a liquid market is that it has a large number of buyers and sellers willing to transact at all times.

Liquid wholesale energy markets are important for, amongst other factors, providing a mechanism for selling electricity, managing risks more effectively and at lower cost, and providing robust price signals.

Liquidity

3.57. A number of respondents to the Call for Evidence have highlighted lack of liquidity in wholesale power markets as an issue facing independent generators. In particular, a number of respondents stated that they considered forward markets to be illiquid beyond one to two years out, and possibly even less. As a result, these forward markets are not providing robust and reliable price signals to drive investment, and make it more difficult to manage risks.

3.58. The absence of reliable future price signals makes it more difficult for independent developers to forecast the returns they might earn on a new gas plant and, therefore, increases the level of risk associated with the investment, adds cost and reduces the likelihood of it proceeding.

3.59. Lack of liquidity may be acting as a barrier to investment in other, additional ways. Independent generators require a route to market for their power and need to be able to sell their power ahead of delivery to hedge their price risk. A lack of liquidity makes it more difficult to find a buyer at a price reflective of supply and demand fundamentals, and thus increases uncertainty and risk for independent generators. Ofgem identified liquidity as a significant barrier to entry in their 2008 Energy Supply Probe and have undertaken a number of market assessments and consulted on a range of proposals since then.

[51] Imbalance Settlement or 'cash out' is the process used to settle differences between the financial contracts and the physical metered volumes of market participants. Imbalance risk is the risk of being out of balance and facing 'cash out' prices as a consequence. A liquid market allows participants to better manage this risk.

3.60. Market participants have taken some steps to improve liquidity. In January 2010, a new exchange platform was launched and in the past 12 months, we have seen significant increases in the volume of power traded on the platform's day-ahead auction. In September 2012, 45% of GB power traded through the auction.[52] This is positive for transparency; however, forward market liquidity still remains low. Ofgem's latest assessment shows a further, albeit slight, deterioration from a low starting point.[53] This suggests that in the absence of adequate industry led progress, regulatory intervention may be justified. Ofgem remains the primary vehicle for delivering any regulatory intervention and they are now consulting on proposals to 'Secure and Promote' recent industry led improvements in liquidity and push for further improvements where necessary including possible fair and reasonable trading requirements.[54]

3.61. However, given the long-standing nature of this issue and its importance to the delivery of Government objectives, including EMR, it is important to be confident that the necessary improvements will be made. We are, therefore, including in the Energy Bill powers that will enable the Government to act in order to improve wholesale electricity market liquidity if necessary.

Access to finance for independent generators

3.62. Some independent generators may require a level of project finance to fund their investments. Providers of project finance to gas generation assets typically require a long-term toll[55] or Power Purchase Agreement (PPA) from credit-worthy counterparties to be in place because they are reluctant to take exposure to market risk, either for the price of gas needed to fuel the plant or the price of electricity sold by the plant. Historically, a long-term toll/PPA may have been obtained from one of two sources; a vertically integrated utility that required the power for its supply arm; the other through a financial intermediary.

3.63. However, responses to the Call for Evidence suggested that a major barrier currently faced by independent generators is a lack of appetite for such tolls or PPAs from credit-worthy counterparties.

3.64. Independent renewable developers have raised similar concerns about difficulties they currently face in securing bankable PPAs. In response to these concerns, the Government published a call for evidence on the 5th July on barriers to securing long-term contracts for independent renewable generation investment, seeking to build the evidence base for policy development in this area. The call for evidence closed on 16th August. The evidence that we received broadly supports the views of the independent generators that the market has shifted in recent years and that generators are finding it harder to secure PPAs on terms that are as beneficial as they used to be. A summary of the responses to this call for evidence, along with the Government's response, can be found in the technical annexes that accompanied the Energy Bill.[56]

---

[52] N2EX/Nord Pool Spot, APX Power UK Auction, Elexon
[53] Ofgem's Retail Market Review letter to stakeholders: http://www.ofgem.gov.uk/Markets/RetMkts/rmr/Documents1/July%202012%20liquidity%20open%20letter.pdf
[54] http://www.ofgem.gov.uk/MARKETS/RETMKTS/RMR/Pages/rmr.aspx
[55] Under a natural gas tolling arrangement, the toller supply the raw fuel to the power station and purchases the electricity generated at a pre-established tolling charge.
[56] Energy Bill: http://www.decc.gov.uk/en/content/cms/legislation/energybill2012/energybill2012.aspx

3.65. To ensure that the Government can act in a timely way, should it be necessary, the Energy Bill includes powers that would enable the Government to make modifications to electricity supply licences for the purpose of reducing barriers to entry associated with the PPA market. Such powers may be used in relation to gas generation development if that is necessary and appropriate.

3.66. A number of respondents to the Call for Evidence on gas generation suggested, however, that finance could be available to generators in the absence of a PPA if the generator were to obtain some other form of long-term revenue certainty or greater levels of liquidity in the forward markets (see above). For example, it has been suggested that the Capacity Market could provide sufficient revenue certainty, although for this to happen the term of the capacity contract may have to be of a sufficient duration to be financeable. Our current thinking is that new plant could choose a capacity agreement length of between one to around ten years. We intend to make final proposals alongside other aspects of auction design by May 2013, and would further welcome views on whether this would support independent investment as part of our ongoing engagement on the design of the Capacity Market.

Barriers facing Combined Heat and Power development

3.67. Although CHP delivers primary energy savings relative to separate generation of heat and power in gas boilers and power-only CCGT, it is required to deliver higher investment return rates than CCGT in order to secure financing. This is believed to be due to the perceived risk of loss of heat loads and to the difference in expectations of rates of return between utilities – which typically build power-only gas plants – and industrial businesses, which need the heat for their core business and are effectively diversifying into electricity generation as a sideline. Utilities typically accept lower rates of return over longer time scales, because power generation is their core business. This makes development of CHP capacity in the industrial sector more challenging than development of power-only CCGT. However, the Government believes it is worth encouraging such investment, as it introduces new players and new money into gas generation as well as delivering carbon savings as compared with power-only CCGT plants.

3.68. Providers of finance for CHP projects also consider the long-term security of the project's heat customer, requiring the generator to secure not only long-term Power Purchase Agreements (PPAs), but also long-term heat supply contracts with credit-worthy customers. Where CHP development is funded by industry from their own capital (to meet their own heat loads), availability of PPAs for the sale of surplus electrical output remains important, in addition to which these projects will be competing with other business development opportunities for limited funding. These factors combine to make the outlook for CHP more challenging than power-only CCGT despite its energy and carbon saving potential.

3.69. The Government already has a range of measures to support gas CHP including Enhanced Capital Allowances, preferential Business Rates and exemption from the Climate Change Levy (CCL).[57] In addition, CHP below 2 MW capacity is exempt from Carbon Price Support costs. Nevertheless development of additional gas CHP capacity faces high investment hurdle rates. The Government believes there is a case for

[57] From 1st April 2013 electricity exported from CHP to the grid will become subject to Climate Change Levy although heat from CHP and electricity consumed on-site will remain exempt.

encouraging investment in such capacity in view of the additional carbon and other benefits it delivers relative to power-only plants and, as such, CHP projects will be eligible for consideration for funding via the Green Investment Bank.

3.70. We are also investigating the role of gas CHP and its interaction with other measures in the development of policy on decarbonising heat. In particular, this includes investigating the synergies between CHP and heat networks, exploring the scope for network development to reduce risk in heat markets and for gas CHP to support the economic case for heat network development.

Chapter 4 – Ensuring Secure and Affordable Gas Supply

Chapter Summary

- **The strong role for gas generation in the UK has been supported by a secure supply of fuel, which is not only important for generation, but also a critical component of the heat market.**
- **The global outlook for gas supply is good, and has been enhanced by developments in unconventional gas extraction. However, global demand is expected to rise too, and we should be cautious when predicting significant changes to global gas prices.**
- **The UK has a resilient and liquid gas market compared to our European competitors, and spare import capacity. However, our domestic production rates are declining, and an increased reliance on global markets brings new risks for us to manage.**

Introduction

4.1. The UK has a resilient, liquid and well-supplied gas market that has been critical in allowing gas-fired generation to provide us with secure and affordable electricity.

4.2. Gas also plays a critical role in the UK's energy mix beyond power generation. In 2011, it was the most significant fuel overall, accounting for 37% of our primary energy use, with the majority[58] used for heat in the domestic, commercial and industrial sectors.[59] Gas will still play a leading role in supplying cost-effective heating in 2030. In the future, it is expected that the proportion of heat provided directly by natural gas will fall as the use of low-carbon technologies increases, but this is expected to be a gradual process, taking many decades to complete.

4.3. This chapter sets out how the UK intends to maintain secure and diverse sources of gas supply for both power stations and heat customers, including developing the UK as a "hub" for gas supply to and from continental Europe. The Government's view of the UK's energy security across different primary fuel types and electricity can be found in the recently published Energy Security Strategy.[60] Energy security is also a priority for Governments

[58] 57%
[59] Currently gas accounts for around 70% of energy consumption for heating. Gas is also used as a feedstock in some industries, however this is less than 1% of total demand.
[60] Energy Security Strategy: www.decc.gov.uk/en/content/cms/meeting_energy/en_security/en_security.aspx

across the UK, and the UK Government therefore works closely with Devolved Administrations on this subject.

Conventional UK Gas Production

4.4. Production of gas in the UK continues to serve a substantial proportion of domestic demand, and UK policies, including licensing, have ensured that exploitation of the UK's Continental Shelf has been a major success. By the end of 2011, cumulative net gas production amounted to 2,380 billion cubic metres (bcm[61]). However, UK gas production peaked in 2000 and since then has been steadily declining despite measures introduced to sustain activity. By 2011, net UK gas production had fallen by 60% to 43 bcm from the peak of 108 bcm in 2000. DECC's latest (March 2012) central projection is for production to fall by a further 25% to 32 bcm by 2020, and by a further 40% to 19 bcm by 2030, although there is still substantial uncertainty surrounding these projections.

4.5. Despite the decline, the North Sea still attracts global investment and maximising economic recovery of our hydrocarbon resources has significant benefits from both an energy security and an economic perspective. For example, the extraction industry supports around 350,000 direct and indirect jobs, in addition to another 100,000 in export of goods and services.

4.6. Future UK gas production is expected to come increasingly from High Pressure/High Temperature fields in the central North Sea and from fields to the west of Shetland through the approval of the large Cygnus Field in August 2012, assisted by the introduction of a field allowance for large shallow-water gas fields. The approval of the slightly smaller Breagh Field in July 2011, which has resulted in a northern extension of the Southern Gas Basin, shows there is still potential in the southern North Sea.

[61] 1 bcm is 11 TWh

Box 4A – Maximising Conventional Resources & Tax Incentives

Government is determined to ensure that the UK maximises its indigenous oil and gas resources. We are working on a number of fronts to incentivise further investment. We continue to licence new acreage for exploration and have very strong interest from industry with our latest, 27th, licensing round receiving the largest number of applications (224) since offshore licensing began in 1964.

We have also been engaging constructively with companies on tax issues that could promote confidence and facilitate further investment. In the 2012 Budget, the Chancellor announced the introduction of a package of oil and gas measures to secure billions of pounds of additional investment. This included a contractual approach to offer long-term certainty on decommissioning relief and a set of changes to the field allowance regime to encourage investment in commercially marginal fields.

More specifically, to incentivise tapping of remaining gas reserves, this July the Chancellor announced a new field allowance for large shallow-water gas fields.

In particular, this will help ensure that the Cygnus undeveloped gas discovery, which was discovered in 1988 but has lain dormant due to marginal economics, will now be able to be taken forward to development and production.

Also on taxation, this September Government announced that it would introduce a new Brown Field Allowance which will shield up to £250m of income in qualifying brown (older) field projects, or £500m for projects in fields paying Petroleum Revenue Tax, from the 32% Supplementary Charge rate. This is something which the industry has welcomed.

Global Gas Supply

4.7. The decline in UK gas production has increased the importance of imported gas for UK supply, and our integration with European and global markets. This increasing integration can bring greater resilience through a greater diversity of gas supply sources. However, it can also bring new risks associated with the influence of geopolitical events, different gas prices by regional market and trade disputes.

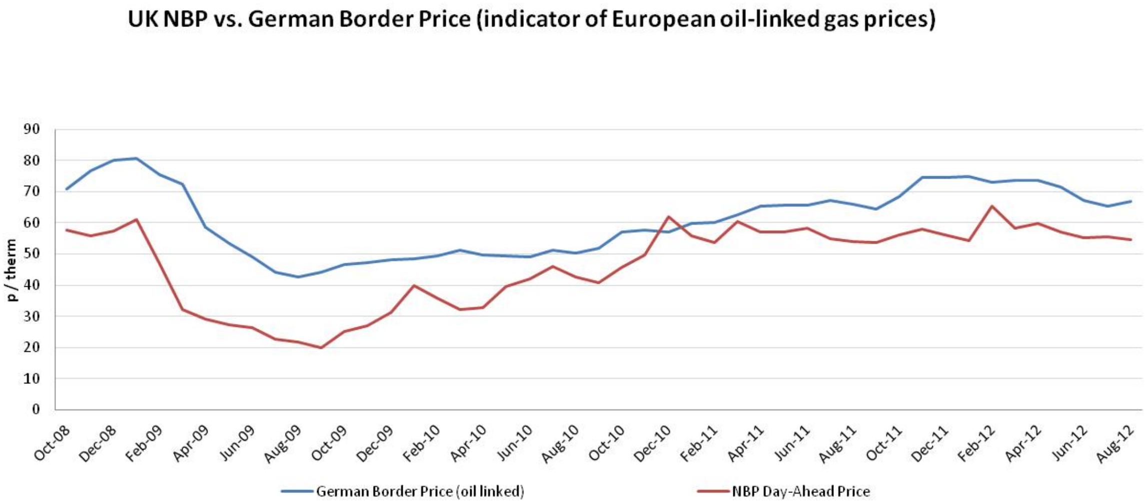
4.8. While global gas demand is set to rise rapidly, the global outlook for gas supply is good. The International Energy Agency (IEA) has described the global gas resource base as “vast and widely dispersed geographically”, and has estimated remaining recoverable reserves of conventional gas as equivalent to 130 years of current consumption. Large-scale global development of shale gas would improve this global gas supply picture, increasing estimated total recoverable resources to a level that could sustain today’s production for over 250 years. The expansion in unconventional gas production in North America in recent years has already helped the United States move from being a net importer to virtual self-sufficiency in gas.

4.9. However, the outlook for global gas supply and demand is highly uncertain. Global gas demand is forecast to rise dramatically, by 55% by 2035 according to IEA, driven especially by demand growth in Asian economies. A global move away from nuclear power following Fukushima could add to this rising demand. As such, even if gas supply increases we may not see prices going down; this is reflected in central DECC gas price assumptions. This rising demand could lead to a tightening of global Liquefied Natural Gas (LNG) markets in the middle years of this decade prior to the completion of significant new LNG export infrastructure projects such as those in Australia.

Outlook for UK gas prices

4.10. The UK has the most liberal gas market in Europe, making us an attractive destination for overseas gas producers, and encouraging competition between gas suppliers. This has, in turn, encouraged diversity of supply and undermined the influence of high-priced, oil-linked contracts in the UK. Reforms to EU gas markets are seeking to emulate the UK's approach, which would put further pressure on the oil link in Europe. The UK currently has low wholesale gas prices compared to other European markets.

Figure 4A: UK NBP and Oil Linked Gas Prices, Q3 2008—Q2 2012



4.11. The combination of shale gas production and a lack of export infrastructure has pushed US wholesale gas prices to less than half those in the UK. If proposed US export facilities develop, this will put downward pressure on UK and global gas prices and improve the economics of further shale gas production in the United States. However, liquefaction plants are expensive and transport and liquefaction costs need to be added when comparing potential US gas export prices to the buying price in markets such as the UK. This contributes to uncertainty around the timing, and scale, of US exports.

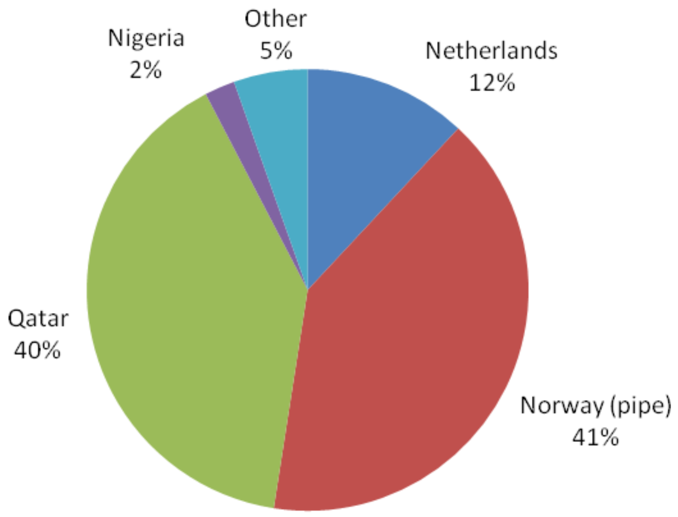
4.12. The uncertainty around future unconventional gas production, and levels of global gas demand makes predicting possible effects on global, EU or UK gas prices and markets difficult. Forecasters generally expect prices will rise over the coming decades,[62] but increases in unconventional gas production make it likely that this growth will be more moderate than in the absence of unconventional sources. Ultimately, there is significant uncertainty about future gas prices, so we need to be prepared for both low and high future gas price scenarios.

UK gas supply and outlook

4.13. An important component of the Government's energy security policy is to ensure that the UK is not over-dependent on any individual fuel source, either in our overall energy mix or for power generation. Over-reliance on gas, or any energy source, could put us at risk of more severe impacts from any disruption to supply. Such risks are likely to become greater for gas as we become more reliant on imports while our domestic production declines. Diversity of primary energy fuels, energy supply sources and supply routes is therefore key given the uncertainty around future energy and gas market developments.

4.14. After being a net gas exporter from 1997 to 2003, the UK became a net gas importer in 2004. UK gas demand is met by a diverse range of sources: from domestic production (which currently meets around half of annual demand) and imports. In 2011, our largest international gas suppliers were Norway, Qatar, and the Netherlands.

Figure 4B: UK Gas Imports by Origin, 2011



Source: DUKES 2012

[62] For example under the IEA New Policies scenario the price of European imports of gas increases from \$11/mmbtu in 2010 to \$14.4/mmbtu in 2035.

The UK as a gas hub

4.15. The UK is well placed to act as a hub for European gas trade, with high levels of gas trading capacity via pipeline interconnectors with the Netherlands and Belgium, import pipelines from Norway, LNG import capacity, which acts as a link between European and global markets, and a liquid wholesale gas trading market within the UK. GB annual gas import capacity is now 156 bcm per annum, with the majority of this infrastructure having been built in the last ten years. This investment has given us enough import capacity to meet 188% of GB 2011 domestic gas demand with total gas deliverability into the gas network (including UK production and storage) being higher still.

4.16. Britain also has the most liberalised gas market in Europe with the easiest trading conditions due to a high level of market liquidity.[63] Together with our spare import capacity, this makes the UK an attractive market for gas importers to land gas for European markets. In 2011, 16 bcm of gas was exported to the Continent and Ireland. As European gas markets liberalise and become more integrated, the opportunities for landing gas in the UK and trading onwards to Europe will increase.

4.17. The Third Package of EU legislation on the internal electricity and gas market will increase competition and transparency across the EU, encourage trading, increase market liquidity and maximise the efficient use of existing pipeline capacity. Ongoing work at European level includes the development of EU-wide network codes for gas trade across borders and the Commission's new legislative proposals on infrastructure, which aim to help deliver investment in energy supply infrastructure, on which the Government is actively working with the Commission, regulators and industry. The end result should be increased competition, greater energy resilience and downward pressure on gas prices, as these prices will better reflect market fundamentals rather than being fixed to the price of oil. However, these changes, and associated impacts on prices, are likely to happen over the longer term.

4.18. The Government is committed to capitalising on the UK's strength as a gas trading hub, and developing our role as a transit route for gas from global markets to enter North West Europe. To promote gas supply into the global market and to ensure the UK has access to a range of supply sources we are working internationally by:

- supporting environmentally sound exploitation of conventional and unconventional gas sources through working with other countries to support emerging standards of global best practice, and supporting UK firms seeking to invest;
- increasing reliability of gas supply through supporting strengthened infrastructure and bilateral trading links, including long-term contracts;
- promoting diverse and efficient gas markets; for instance, by facilitating the commercial development of new gas supply routes such as the Southern Corridor;

[63] It was estimated that in 2010 gas traded on the UK's National Balancing Point (NBP) had a churn ratio of 15 while the churn ratio in the gas hubs of Continental Europe did not rise significantly above 4. The churn ratio is a measure of how liquid a market is and is a comparison of volumes of gas traded to volumes consumed. Figures from Reference - p15 of Rogers and Stern *The Transition to Hub-Based Gas Pricing in Continental Europe* Copyright © 2011 Oxford Institute for Energy Studies (ISBN 978-1-907555-22-0)

- working to enhance gas price stability through international work to increase transparency of gas price formation (Joint Organisations Data Initiative); and,

- pressing for restrained global gas demand (via energy efficiency, low-carbon alternatives and phasing out fossil fuel subsidies).

4.19. On 1st October, Ofgem launched a study into the efficiency of flows across our gas interconnectors in collaboration with the Belgian and Dutch regulators. This will be useful in identifying any necessary steps to facilitate efficient trade between the UK and continental Europe, with mutual security of supply benefits. We are also announcing that we intend to remove the need for onshore gas producers to hold a gas transporter licence, reducing regulatory burdens on producers who can diversify our gas supply.

Maintaining Security of Gas Supply

4.20. As well as ensuring the physical supply of gas through domestic production and imports, there are a number of other measures that support the UK's secure electricity supply, for example, gas storage, demand side response and measures to incentivise market participants to match supply and demand.

Gas Storage

4.21. At present, there are 9 commercial gas storage facilities in Great Britain, with a total capacity of 4.4 bcm. The UK's largest gas storage facility, Rough, is capable of delivering over 10% of typical UK winter daily demand and could do so continuously for about eleven weeks if it started from full. Other facilities have less total capacity than Rough, but can deliver greater volumes of gas into the grid over a shorter timescale.

4.22. Three new storage facilities[64] are currently under construction, and one existing facility is being expanded, adding around 0.9 bcm of capacity, and almost doubling UK storage deliverability. All of these are "fast-cycle" storage facilities that have high injection and withdrawal rates relative to their overall size. There are another 16 proposed storage facilities, 9 of which have the necessary planning consent.[65] However, there is uncertainty on when these will move forward.

Demand side response

4.23. Demand side response is an important tool to balance gas demand and supply at short notice. Most demand side flexibility is provided by the power generation sector, primarily through switching between gas and coal or oil-fired generation. As gas market tightness

[64] The three gas storage facilities currently under construction are: Holford in Cheshire, due to be commissioned 2011/12; Hilltop Farm in Cheshire, due to be commissioned 2011/12 and Stublach in Cheshire, due to be commissioned 2013/14. The Aldbrough facility in Yorkshire began commercial operations in 2009/10 and is currently undergoing expansion.
[65] National Grid, "Gas Transportation Ten Year Statement 2010" (Dec. 2010)

pushes gas prices higher, gas-fired power stations become relatively less economic to run than coal because their fuel input costs become relatively higher. However, the actual level of demand side response from gas-to-coal switching depends primarily on the amount of gas used in power stations, and the capacity of any spare coal generation at any given time.

4.24. By the end of 2015, the scope for such switching will reduce as 8 GW of coal-fired power generation capacity closes due to the Large Combustion Plant Directive. Some plants may close earlier if allowed hours are used up, for example, operators have already announced that 5 GW will close by the 31st March 2013. In the longer term, further coal plants will close as a result of increasing carbon prices and requirements under the Industrial Emissions Directive.

Further measures to enhance security of supply

4.25. The Government took steps through the Energy Act 2011 to give 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 could help underpin commercial demand for the range of supply infrastructure we are likely to need in the future, including gas storage.

4.26. In parallel, Ofgem launched a review of the arrangements underpinning gas-deficit emergencies through the Gas Security of Supply Significant Code Review (Gas SCR).[66] Ofgem announced their provisional final decision on 31st July that they would be reforming the emergency cash out arrangements, to reflect the value that customers place on uninterrupted gas supply.

4.27. Ofgem consider reforming cash out will reduce the likelihood of a gas supply emergency occurring and reduce the duration or severity of such an emergency should one occur. Allowing the cash out price to rise will increase the ability of the GB market to attract additional gas supply, and will provide a strong incentive to shippers, who are better placed than consumers to manage security of supply risks, to undertake actions that reduce the risk of a gas supply problem.

4.28. In November 2011, DECC asked Ofgem to produce a report on the risks to gas security and assess the case for further market interventions. This report was published alongside the Energy Security Strategy.[67]

4.29. We are encouraged by the analysis in this report showing robustness of the UK gas market, and potentially helpful developments of EU and global gas markets. We support Ofgem's intention, in the light of this report, to consult on further light-touch interventions to enhance energy security, via increased transparency and standard contract terms, and to launch an investigation into the price responsiveness of interconnector flows, since this has a significant bearing on energy security.

[66] All documents relating to the Gas SCR are available at:
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Pages/GasSCR.aspx
[67] Electricity Market Reform:
http://www.decc.gov.uk/en/content/cms/meeting_energy/markets/electricity/electricity.aspx

4.30. Given the importance of gas to our energy mix, we need to ensure our gas security of supply arrangements are adequate. We will therefore give consideration as to whether there is a case for further measures to encourage gas storage, and will publish our findings in Spring 2013.

4.31. Energy security will also be helped if gas generation and supply infrastructure is planned and designed to be resilient to future climate change risks (e.g. increased flooding).[68]

Managing Intermittency

4.32. While National Grid Gas (NGG) forecast declining annual and (to a lesser extent) peak gas demand, they expect volatility of gas use to increase in coming years, particularly volatility of demand from the power sector driven by increased intermittency, as CCGTs will have an increase balancing role.

4.33. The UK's gas supply arrangements and infrastructure will need to be flexible in the way they respond to this changing demand pattern. Gas storage and upgraded network infrastructure and rules will both have a key part to play in mitigating that risk.

4.34. The gas market already has a number of tools to deal with this need for greater flexibility. Volumes can be flexed from import pipelines, or from increased linepack (more gas in the pipes held through pipeline extensions and/or the use of higher pressure). The impacts of intermittency will happen gradually, and industry is able to amend its own business rules to address this. In addition, Ofgem has wide powers to amend licence conditions.

4.35. Network reinforcement may be required to allow those facilities to ramp-up injection and withdrawal rates sufficiently quickly to respond to sudden drops in wind output.

4.36. Flexible gas supply infrastructure, including gas storage and volumes held at LNG regasification terminals, will become increasingly important as volatility increases. Pöyry's 2010 analysis[69] found that despite the changes in swing required to manage flexibility, the gas market was broadly able to deliver in a more intermittent world. The amount of flexible gas storage, expressed crucially in terms of the withdrawal (and injection) rate, will be key in helping to meet short-term demand fluctuations. Pöyry's study showed a potential need for more fast-storage facilities by the end of the decade. We will take this into account as part of our consideration on whether there is a case for further measures to encourage gas storage.

[68] Further information can be found in National Policy Statements for Energy Infrastructure, available at http://www.decc.gov.uk/en/content/cms/meeting_energy/consents_planning/nps_en_infra/nps_en_infra.aspx
[69] Pöyry (2010) How Wind Generation could transform gas markets in Great Britain and Ireland. Available at: http://www.poyry.co.uk/sites/www.poyry.co.uk/files/264_gasintermittency_publicsummary_v1_0_0.pdf

Chapter 5 – Developing Shale Gas Resources

Chapter Summary

- **There are very large quantities of gas in the shales beneath the UK, but not enough is known to estimate what fraction of this could be produced.**
- **If economic and safe, shale gas could, however, offer new economic opportunities for the UK. DECC will set up an Office for Unconventional Gas and Oil, which, working with Defra and other Government Departments, will join up responsibilities across Government, provide a single point of contact for investors and ensure a simplified and streamlined regulatory process.**
- **HM Treasury has opened discussions with industry on the appropriate structure of a fair tax regime for future shale gas production, and DECC will consult on how its licensing regime could be modified to support the particular characteristics of shale gas developments. DECC will also consult on an updated Strategic Environmental Assessment with a view to further onshore oil and gas licensing.**
- **If testing proves positive, shale gas production might commence in the second part of this decade, but production is likely to grow more slowly than has been seen in the United States.**

Introduction

5.1. Shale gas is, like gas, produced from the offshore fields in the southern North Sea, predominantly composed of methane. However, it is produced from very fine-grained sediments called shales. These are the source rocks in which organic matter was deposited. Through the application of heat and pressure over geological time, hydrocarbons (gas and oil) are produced. However, shales are much less permeable to gas than the kinds of rocks from which most oil and gas is produced today. This means that the gas can flow out of the shale and into a well only at very low rates. It has not been economically worthwhile to produce gas from shales until relatively recently, when two existing technologies—horizontal drilling and hydraulic fracturing (fracking)—were more intensively employed in the United States.

5.2. Horizontal drilling is a technique by which the well trajectory is turned horizontally, sometimes running for thousands of feet along a layer of rock. A single horizontal well can access a much larger volume than a vertical well, reducing the number of wells that need to be drilled, and thereby the overall cost of production.

5.3. Once a well is drilled, fractures (cracks) are created in the shale by injecting high pressure water into carefully selected sections of the well (fracking). A granular material, usually sand, is then injected into the fractures to stop them from closing. The fractures then form a permanent pathway for the gas to flow more easily into the well, in much the same way as tributaries drain the large catchment area of a river.

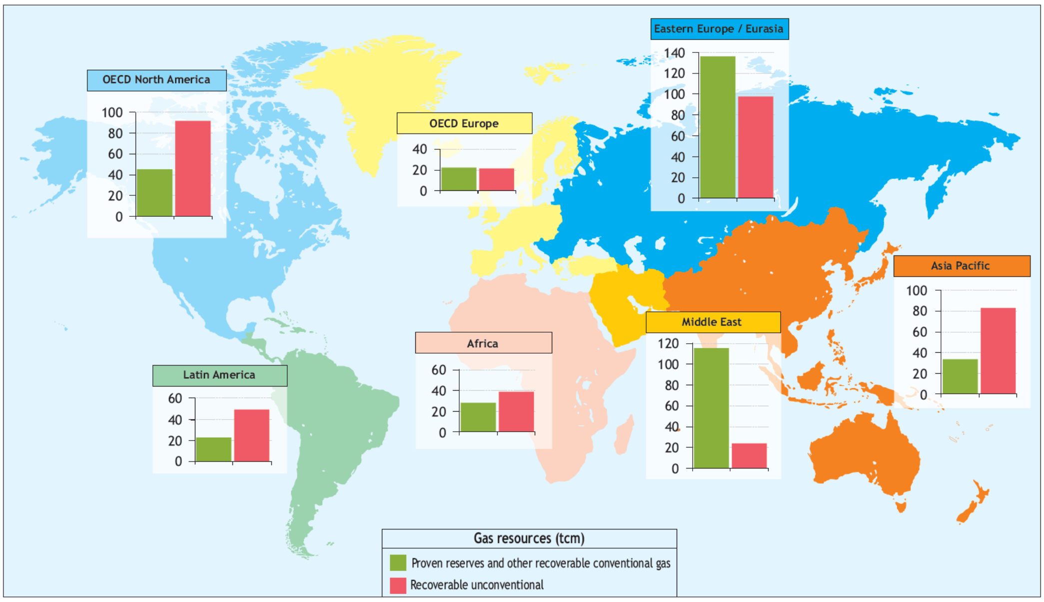
5.4. Not all shales are capable of producing gas. Some did not contain enough organic material when first buried, some have not been sufficiently buried and heated, some hold gas but cannot sustain sufficiently high rates to be commercial.

Shale gas worldwide

5.5. Based on data from several sources, the IEA estimate that the remaining recoverable resources of shale gas worldwide amount to 208 trillion cubic metres (tcm), and they comment that the extent to which countries exploit their unconventional resources will be a key determinant of future global gas supplies.

5.6. The recent boom in shale production in the United States was supported by favourable geology, low population density, a competitive supply industry that 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. Various analysts estimate serious exploitation in the EU to be a decade away.

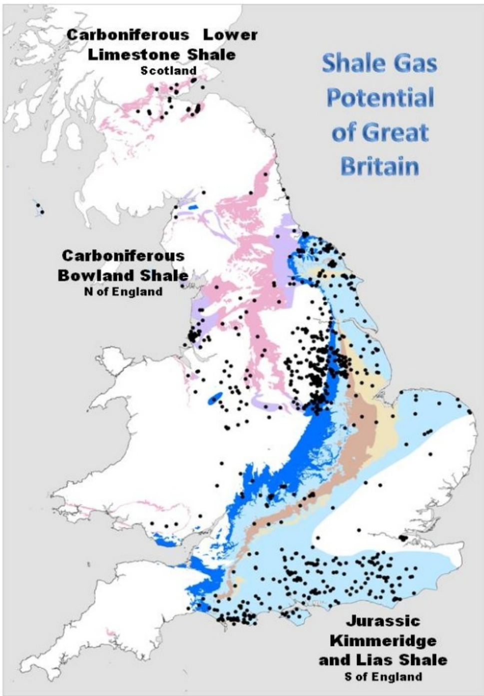
Figure 5A: Map of World Gas Resources (tcm)



Source: IEA

5.7. The European Commission has undertaken to assess Europe's potential for sustainable extraction and use of conventional and unconventional fossil fuel resources in order to further enhance Europe's security of supply. In line with this work, a number of studies on shale gas have recently been released. They are aimed at informing ongoing work to examine the need for a risk management framework in Europe and (if needed) the form it might take.

Figure 5B: Shale Gas Potential of Great Britain



UK Shale Gas Potential

5.8. As set out in Chapter 4, the UK has derived huge benefit from its offshore natural gas resources. By comparison, the UK's onshore gas production contributes less than 1% to our gas supply, despite the long history of onshore exploration. (Figure 5B shows the number of wells, represented by the black dots, which have been drilled onshore to date).

5.9. However, Figure 5B also shows that large areas of the UK are underlain by shale rocks, some of which are likely to contain substantial quantities of shale gas. The horizontal drilling and fracturing developments described above raise the prospect that commercially viable production could also be achieved in the UK.

5.10. Current work commissioned from the British Geological Survey on the most promising of these shales (the Bowland shale in Lancashire) suggest that a very substantial quantity of gas is present. This is consistent with individual company estimates, for example, Cuadrilla's estimate that some 6 tcm of gas lies beneath their licence in Lancashire. These are very large quantities of gas, but the proportion that can be economically produced is not yet known.

5.11. Experience shows that an estimate of the amount of recoverable gas can only be made once several wells have been drilled and their production characteristics tested over a significant period of time. As production properties vary by location and within a single rock formation, resource estimates (including for producing US shale gas), have been subject to frequent and dramatic changes.[70]

5.12. Some features of the geology are positive, such as the lateral continuity. However, other characteristics such as the organic content are much less well defined at this stage. And to date, only one well in the UK has been partially fractured and tested. So while it may be the case that shale gas could form a part, and perhaps a significant part, of the UK's gas supply in the longer term, considerably more exploration and testing is needed to establish a meaningful reserve estimate.

Factors Contributing to Successful Shale Gas Production

5.13. In addition to the favourable geological and engineering factors outlined above, successful shale gas development requires that production costs are sufficiently below the price at which the gas can be sold to make the development commercially viable. The current costs of drilling and fracturing in Europe are relatively high in comparison to those in North America, where a long history of onshore oil and gas activity, and very substantial economies of scale, have driven costs down substantially. By its nature, shale gas production requires a more sustained level of drilling to maintain production. After fracturing, individual well production falls fairly rapidly, requiring new wells to be drilled into fresh areas of the shale (or re-fracturing of older wells). In addition to securing the consent of individual landowners, securing community support and planning permission for whatever pattern of development is proposed will be crucial to sustaining shale gas activity and production. The areas of the United States in which shale gas development has grown most rapidly have much lower population densities than the UK.

5.14. Overall, it is likely that the pace of development of shale gas in the UK will be slower than has been seen in the United States. If exploration is successful, early production is likely to be seen in the second half of this decade, but any substantial contribution to the UK's gas supply is unlikely until further into the 2020s.

Extracting Shale Gas Safely and Without Damage to the Environment

5.15. The rapid development of shale gas in the United States has been accompanied by increasing debate over its environmental impact. Particular concern focuses on fracking, with claims that it has resulted in water and air pollution. Many of the incidents reported,

[70] For example, recent experience in Poland, which is slightly ahead of the UK in terms of resource assessment, has seen an EIA estimate in 2011 of technically recoverable resources at 5295 bcm significantly revised downwards in 2012 following work by the Polish Geological Institute, with a "most probable" range of 345-750 bcm.

when investigated by the relevant authorities, have been found to be unrelated to shale gas or fracking. However, there have been instances of methane in water due to unsatisfactory construction of the wells (inadequate cementing), and of chemical contamination of water by leaks and spills from surface facilities. (There is no confirmed instance to date of subsurface contamination attributable to fracking).

5.16. Other concerns generated by the early exploration activities in Lancashire include traffic levels, noise and impacts on general amenity. The first shale gas fracking operations also triggered two small earthquakes, which were wholly unexpected and heightened concerns over shale gas exploration and production in the UK. At present, further fracking operations are suspended pending consideration of the scope for mitigating these risks.

5.17. As with any industrial activity, shale gas exploration and development could give rise to unacceptable safety and environmental impacts. To extract shale gas safely in the UK and without damage to the environment, it is critical that competent companies follow best practice and work under a robust planning and regulatory regime.

5.18. All shale gas activities require planning permission, which is a matter for the minerals planning authority (for Lancashire, the County Council). For the operational phase, the Environment Agency, the Health and Safety Executive and the corresponding bodies in Scotland and Northern Ireland are the primary regulating authorities in the UK. DECC issues licences, considers the geotechnical aspects, and issues drilling consents and field development consents.

5.19. For the current exploration phase, these bodies already have the powers and resources to ensure that shale gas companies conduct their activities, including fracking, safely and without damage to the environment. Should shale gas progress to a production phase, additional regulatory resources may be required in response to the increased scale of activity.

5.20. There have also been concerns about the carbon footprint of shale gas use. CO_2 emissions from combustion of shale gas contribute to climate change in exactly the same way as from combustion of conventional gas, but methane emissions from the production process, if not properly controlled, can result in significant additions to greenhouse gas emissions.

5.21. The variety of circumstances of recovery, processing and use, and the difficulty of measuring indirect emissions accurately have resulted in a wide range of estimates of the carbon intensity of shale gas, and conflicting conclusions on its relative carbon footprint as compared to coal. A recent study undertaken by consultants for the European Commission, however, supports the view that life-cycle carbon emissions, even on a worst case scenario, are significantly lower than coal.

5.22. So far as the UK is concerned, emissions are already subject to control, and emissions from current exploration activities will in any case be too small to add materially to the UK's greenhouse gas inventory.

5.23. The *Golden Rules for a Golden Age of Gas* report, published by the US Energy Information Administration (EIA) in May 2012, looks in depth at prospects for global unconventional gas resources, and reviews the environmental and social risks associated with their extraction. It recommends a set of 'golden rules' to allow their development in a way that minimises environmental impact. The full report can be downloaded at:

www.worldenergyoutlook.org/goldenrules/. They estimate that these measures would add only around 7% to project costs for a shale-gas well.

Development of UK Shale Gas

5.24. If it can be shown to be economic and safe, domestic shale gas production could offer a significant economic opportunity for the UK, with the prospect of new sources of indigenous supply, new industrial activity and skilled jobs.

5.25. To help the industry pursue these opportunities, DECC will set up an Office for Unconventional Gas and Oil, which, working with Defra and other Government departments, will join up responsibilities across Government, provide a single point of contact for investors, and ensure a simplified and streamlined regulatory process.

5.26. DECC will also consider its development policy and guidance to ensure that it is appropriate for shale gas production. The areas already covered by onshore licences currently overlie many prospective shale gas deposits. The terms and durations of current licenses have provided the right framework for the early exploration activities for shale gas, but may need further development to match the needs of a production phase.

5.27. Shale gas development is likely to differ from conventional oil and gas in an extended pattern of capital investment and an extended pattern of drilling. These differences will create a demand for more contiguous licensed acreage, held for longer periods of time. DECC will therefore open a dialogue with interested licence holders to establish whether a different approach is required to meet the characteristics of future shale gas developments. It is expected that this dialogue will reach conclusions by mid 2013.

5.28. The Chancellor of the Exchequer announced in October that the Government will develop a targeted tax regime for the shale gas industry. HM Treasury is currently engaging with companies to ensure that the final structure of the regime is appropriately targeted while maintaining a fair return for the Exchequer. This work will report at Budget 2013. DECC and HM Treasury will ensure that the work on the development of the licensing regime is compatible with the emerging fiscal regime.

5.29. Existing onshore licenses already overlie a good portion of the potential shale gas formations shown in Figure 5B. DECC had already commenced a Strategic Environmental Assessment (SEA) in 2010, with a view to further onshore licensing, and conducted a public consultation in the latter part of that year. Work on the SEA has however been in abeyance following the seismic tremors in 2011.

5.30. DECC will now commission further work on the environmental implications of further licensing, taking account of all new knowledge arising since the earlier assessment was compiled, and will conduct a full public consultation on the extended assessment. The results of this consultation will be fully considered before any decisions are taken on new licensing.

Chapter 6 – Carbon Capture and Storage

Chapter Summary

- **While unabated gas will remain important, in the longer term CCS will be essential if fossil fuels are to provide significant amounts of generation as part of a low-carbon energy mix.**
- **The Government is committed to CCS and has one of the best offers in the world to bring forward this technology, including a £1bn commercialisation competition, £125m for research and development and ongoing support through electricity market reforms.**
- **The CCS Cost Reduction Task Force believes UK CCS has clear potential to be cost competitive with other forms of low-carbon generation, delivering electricity at a levelised cost approaching £100/MWh by the early 2020s.**
- **Four projects have been shortlisted in the Government's £1bn competition. Decisions on which projects to take further will be taken in the new year.**

Introduction

6.1. This Strategy sets out the Government's view that unabated gas generation will remain an important part of our generation mix even as more low-carbon generation comes on the system in the 2020s.

6.2. However, while using gas for generation emits less carbon dioxide (CO_2) than other forms of fossil fuels such as unabated coal and oil, to achieve our carbon targets most of the pathways in the Carbon Plan suggest that a significant proportion of the generation mix will need to be equipped with Carbon Capture and Storage technology (CCS).

6.3. CCS is a technology that can remove CO_2 emissions created by the combustion of fossil fuels, both coal and gas, in power stations as well as in a variety of industrial processes and transport it for safe storage underground, for example, deep under the North and Irish Seas, where some of the best CCS storage sites in Europe are found. It has the potential to be one of the most cost-effective technologies for the decarbonisation of the UK's power and industrial sectors, as well as those of economies worldwide.

6.4. CCS can play a significant role in achieving decarbonisation of the UK economy at least cost. DECC analysis suggests that, depending on the mix of generation that is built, it could contribute as much as 13 GW of capacity by 2030 and up to 40 GW by 2050.

6.5. Outside the UK, CCS has an even greater role to play. Many of the world's major economies such as the United States, India and China are heavily dependent on fossil fuels. The IEA estimate that without CCS the delivery cost of meeting a 50% global emissions reduction target by 2050 will be 70% higher.

6.6. Currently, however, the costs of CCS are high in comparison to other low-carbon technologies partly because it has only been deployed at commercial scale in a limited number of cases worldwide, and not yet in the UK. The Government is therefore committed to helping make CCS a viable option for reducing emissions in the UK and in doing so to accelerate the potential for CCS to be deployed in other countries.

6.7. To drive forward the development of CCS in the UK the Government is assisting industry to reduce the costs and risks associated with the technology so that it can be deployed cost-competitively in the 2020s alongside other low-carbon technologies and approaches.

CCS Roadmap

6.8. To enable the widespread commercial deployment of CCS in the UK, the Government set out in the CCS Roadmap,[71] published in April 2012, a programme of interventions that is one of the most comprehensive offered by any country in the world. The programme of interventions includes:

- The CCS Commercialisation Programme, which includes £1 billion in capital funding;
- A £125m, 4 year, co-ordinated R&D and innovation programme covering fundamental research and understanding;
- The stimulation of additional and large-scale investment in all forms of low-carbon electricity generation (including CCS-equipped generation plant) through the incentives created under Electricity Market Reform (EMR), including Contracts for Difference (CfDs); and,
- International engagement focussed on sharing the knowledge we have generated through our programme and learning from other projects around the world to help accelerate cost reduction.

Research and Development

6.9. The UK is a world leader in CCS research. In recognition of its crucial role in the roll-out of commercial scale CCS in the 2020s, the Government is providing £125m for a CCS research, innovation and development programme. The programme – which includes funding from DECC, the Technology Strategy Board, Energy Technologies Institute and Research Councils – covers:

[71] CCS Roadmap: Supporting deployment of Carbon Capture and Storage in the UK: http://www.decc.gov.uk/assets/decc/11/cutting-emissions/carbon-capture-storage/4899-the-ccs-roadmap.pdf

- support for fundamental research at our Universities and research organisations including launching a £13m UK CCS Research Centre[72] in April 2012;

- support for development and demonstration of CCS components and CCS related technology; and,

- pilot scale projects to bridge the gap between research and commercial scale deployment, for example launching the 5 MW post combustion carbon capture pilot at Ferrybridge power station.[73]

6.10. On 21st November, DECC announced a further set of projects funded under the Programme following the £20M CCS innovation competition launched in March 2012. £18.3m has been awarded to 13 projects[74] involving a range of UK universities and world leading energy and technology companies. At the same time the UK CCS Research Centre announced a further £1.8m Government funding for another 13 projects to fund research needs set out in the DECC CCS Roadmap.

Commercialisation Programme

6.11. On 3rd April 2012, the Government launched the CCS Commercialisation Programme and associated competition. This programme represents one of the best offers in the world, with £1 billion in direct capital grant funding available to support the design and construction of CCS projects. Projects will be able to earn revenue from the sale of clean electricity in the reformed electricity market and able to benefit from the increased price certainty provided by a CfD.

6.12. The CCS Competition aims to support practical experience in the design, construction and operation of commercial scale carbon capture and storage. Through the construction and extended operation of commercial scale CCS plant, this programme will:

- generate learning that will help to drive down the costs of CCS,

- significantly reduce the remaining technology risks,

- test and build familiarity with the CCS specific regulatory framework,

- encourage industry to develop suitable CCS business models, and,

- contribute to the development of early infrastructure for carbon dioxide transport and storage.

---

[72] UK Carbon Capture and Storage Research Centre: http://www.ukccsrc.ac.uk/
[73] SSE's Ferrybridge CCS Project: http://www.sse.com/Ferrybridge/TheCCSProject
[74] DECC Press Notice: *Innovation to Drive Cuts in Carbon Capture and Storage Costs* : http://www.decc.gov.uk/en/content/cms/news/pn12_143/pn12_143.aspx

6.13. The competition closed on 3rd July 2012, having received eight bids. Following a detailed analysis, four bids, all full chain capture, transport and storage projects, are now being taken forward in a short intensive phase of negotiations.[75]

6.14. Decisions on which projects to support further will be taken in the new year. This is likely to include some further design and engineering work before entering into full project contracts. Final investment decisions will be taken by the end of 2014.

6.15. The regime created under EMR will incentivise further investment (additional to that supported under the CCS Commercialisation Programme competition) in CCS-equipped generation plant, alongside other forms of low-carbon generation such as renewables and nuclear.

6.16. As detailed in Chapter 3, our long-term vision for EMR includes a transition to a market where low-carbon technologies can compete fairly on price. This competition between technologies will drive down costs and allow us to meet our objectives for the electricity system in the most cost-effective way. EMR provides the tools for transition to get to this vision, and will provide the necessary support to low-carbon technologies, including CCS, that could enable them to get to a level of maturity where they are able to compete fairly on price in the longer term.

6.17. The revenue support available under the CfD is a key element of this. It will provide increased price certainty to low-carbon generators, including CCS. As set out in EMR documents published alongside the Energy Bill, working with the Devolved Administrations, we are continuing to develop options for the CfD allocation and price-setting processes that will apply to CCS and nuclear projects and will provide further detail on these processes in July 2013.

Cost Reduction Task Force

6.18. Partnership between industry and the Government is essential if we are to bring forward the deployment of CCS. The Government therefore asked the Carbon Capture and Storage Association to establish a Cost Reduction Task Force to advise Government and industry on reducing the unit cost of CCS, so that it can compete with other low-carbon technologies in the electricity market by the early 2020s.

6.19. The Task Force comprises 30 members from the engineering, hydrocarbon, finance, project developer and academic sectors, representing a broad spectrum of UK and international organisation with expertise in all aspects of CCS. The group is chaired by the Chief Executive of the Carbon Capture and Storage Association (CCSA).

6.20. The objective of the Task Force is to publish a report to advise Government and industry on reducing the cost of CCS so that projects are financeable and competitive with other low-carbon technologies in the early 2020s. The Task Force published their interim report[76] on 21st November 2012 setting out the opportunity for cost reduction and the planned

[75] The four projects, in alphabetical order, are: Captain Clean Energy Project; Peterhead' Teesside Low Carbon Project; White Rose Project. Further information can be found at: www.decc.gov.uk/en/content/cms/news/pn12_136/pn12_136.aspx

[76] UK CCS Cost Reduction Task Force: Interim Report: www.decc.gov.uk/assets/decc/11/cutting-emissions/carbon-capture-storage/6987-the-potential-for-reducing-the-costs-of-cc-in-the-.pdf

programme of work (see Box 6A). This will be followed by a final report in Spring 2013, setting out recommendations for action by Government and Industry to realise these savings.

6.21. The Government welcomes the work undertaken and the interim findings of the Task Force. It notes the clear view of the group that CCS can be cost competitive with other forms of low-carbon generation, potentially as soon as the early 2020s. The Task Force has suggested some broad candidate actions to bring about these savings, and the Government looks forward to these being developed into practical, achievable actions in the final report next year.

Box 6A – CCS Cost Reduction Task Force: Interim Findings

The key conclusion of the CCS Cost Reduction Task Force's interim report is that: UK gas and coal power stations equipped with carbon capture, transport and storage have clear potential to be cost competitive with other forms of low-carbon power generation, delivering electricity at a levelised cost approaching £100/MWh by the early 2020s, and at a cost significantly below £100/MWh soon thereafter.

The Task Force found these cost reductions could be achieved through:

1. investment in large CO_2 storage clusters, supplying multiple CO_2 sites;
2. investment in large, shared pipelines, with high utilisation;
3. investment in large power stations with progressive improvements in CO_2 capture capability which should be available in the early 2020s;
4. exploiting potential synergies with CO_2-based EOR in some Central North Sea oil fields; and,
5. a reduction in the cost of project capital through a set of measures to reduce risk and improve investor confidence in UK CCS Projects.

The Task Force believe the cost reductions can only be achieved under a favourable 'CCS Landscape' in the UK, including long-term UK Government policy commitment to CCS, successful deployment of the projects coming out of the commercialisation programme and continued engagement with the financial sector.

CCS Infrastructure

6.22. In most circumstances in the UK, the most significant opportunity for cost saving is provided by reducing the overhead cost of CCS infrastructure. The work of Mott Macdonald for DECC[77] and by the CCS Cost Reduction Task Force suggests that significant reductions in the cost of CCS can be achieved by carbon capture projects sharing the transport infrastructure connecting to the CO_2 storage sites. In part that is because incremental increases in the size of one pipeline are likely to be more cost effective than installing new pipelines.

[77] See DECC Discussion Paper: *Potential cost reductions in CCS in the power sector*: http://www.decc.gov.uk/assets/decc/11/ccs/5237-potential-cost-reductions-in-ccs-in-the-power-sect.pdf

6.23. Spreading these costs over multiple projects will reduce the cost of CCS provided the infrastructure is used as expected. Such cost savings might be achieved if CCS projects developed in “clusters” to maximise the amount of CO_2 that can be transported through shared infrastructure. This could mean that new CCGT plants fitted with carbon capture choose to site themselves close to other high-carbon emitting sources.

6.24. However, constructing larger and more extensive infrastructure increases capital requirements. Uncertainty about the level and timing of demand for carbon dioxide infrastructure is the main obstacle to this investment coming forward.

6.25. The Government is considering the case for supporting investment in additional CCS infrastructure for early stage projects that are part of the CCS commercialisation programme where such investment represents value for money and where there is strong evidence of realisable demand.

6.26. Beyond these early stage projects, the Government expects that investment will emerge in time in line with demand. However, the Government is concerned that these investments are made in an efficient and timely way and that duplication is avoided where it is feasible to do so. For this reason we have taken powers to assist third party investment and access to CCS infrastructure where it is practical and cost effective.[78]

6.27. The CCS Cost Reduction Task Force also highlighted storage and transport as two key areas where cost reductions could be achieved, through more efficient use of capital assets. We are working closely with the Task Force to develop actions for their final report that will help put these recommendations into practice and stimulate the investment needed to ensure these savings can be realised. We are also considering what steps Government might take in order to overcome barriers to this investment as part of a Storage strategy.

Carbon Capture Readiness

6.28. The CCS Directive,[79] and now the Industrial Emissions Directive,[80] require developers to assess whether it will be technically and economically feasible to retrofit carbon capture to their proposed plant, whether transport facilities are technically and economically feasible, and whether suitable storage sites exist for captured carbon emissions. Where these conditions are met, suitable space must be put aside on the site for carbon capture equipment.

6.29. Recognising the significant role that CCS could play in the UK’s energy future, the Government has built on this requirement.

6.30. In England and Wales, to receive development consent there is a requirement for any new thermal power stations,[81] including gas, at or over 300 MWe to have demonstrated that it will be technically and economically feasible to retrofit CCS to that power station in the future, and in Scotland, the Scottish Government has specified that new build thermal

[78] The Storage of Carbon Dioxide (Access to Infrastructure) Regulations 2011
[79] Article 33 of Directive 2009/31/EC on the geological storage of carbon dioxide
[80] Article 36 of Directive 2010/75/EU on industrial emissions (integrated pollution prevention and control)
[81] Of a type covered by the Large Combustion Plant Directive

power stations should be able to deliver suitable CO_2 abatement.[82] These requirements are known as Carbon Capture Readiness (CCR) requirements.

6.31. The responses to the Call for Evidence were mixed in relation to the CCR requirement with some stakeholders calling for the requirements to be relaxed, while others called for them to be strengthened with a particular focus on location of developments.

6.32. We have introduced this requirement so that fossil-fuel power stations cannot be constructed unless they are technically capable of being retrofitted with CCS. Many of the gas power stations consented and built from now on could still be operating into the 2030s and beyond.

6.33. Given the opportunities that CCS could present for these stations, enabling them to provide significant quantities of low-carbon generation and, therefore, operate at higher load factors, it is important that we do not “lock out” the possibility of them retrofitting CCS at some point should it prove an attractive option, either through carbon pricing or through incentives from Electricity Market Reform.

6.34. Otherwise some of these plants will start to see declining load factors as more low-carbon plants come online. Whether stations actually chose to fit CCS in the future will be an economic decision for power station operators, balancing the location of the plant and the capital outlay required against the cost of emissions and the impact of reforms to the electricity market on their competitiveness in a future electricity market that will favour the production of low-carbon electricity.

6.35. The Government, therefore, does not believe it prudent at this stage to change the CCR requirements and feels that it is best left to the market, prompted through signals such as transmission charging or the location of renewable energy resources, to determine the best location for capacity. Equally, we do not believe the requirements should be relaxed, as this could reduce the feasibility of retrofit to those plants where it would prove advantageous.

The Future for Gas Generation with CCS

6.36. In the long term, the development of cost-competitive CCS should ensure gas (and coal) can continue to play a full role in a decarbonised electricity sector. Gas with CCS offers the benefits of flexible fossil fuel generation, but without the damaging carbon emissions. It could be particularly valuable in balancing intermittent and inflexible low-carbon energy sources such as wind or nuclear. CCS will allow us to use existing fossil fuel supply more cleanly, tackling climate change and keeping us on track to meet our legally-binding carbon targets.

6.37. The Government is committed to supporting the development of cost-competitive CCS in the UK, and wants to see a thriving industry with deployment at scale in the 2020s. We have implemented the initiatives in this Chapter to facilitate this, but the private sector has the key role in building on this commitment. Our Commercialisation Programme has four

[82] National Policy Statements for Energy Infrastructure: www.decc.gov.uk/en/content/cms/meeting_energy/consents_planning/nps_en_infra/nps_en_infra.aspx, and Carbon Capture Readiness (CCR): A guidance note for Section 36 Electricity Act 1989 consent applications – available at www.decc.gov.uk/en/content/cms/meeting_energy/consents_planning/electricity/electricity.aspx

promising short-listed projects vying for the £1bn capital fund. The programme was designed to attract projects that will demonstrate the technologies at scale, helping improve confidence, reduce risk and bring costs down. Our intention is to select the projects to be supported early in 2013 and for those to start to become operational from 2016.

6.38. Delivery of this programme will kick start the first wave of CCS projects in the UK and the work of the Cost Reduction Task Force can help guide it towards cost-competitive deployment at scale in the 2020s. We are committed to working with industry to address other important areas including developing the CCS supply chain, storage and assisting the development of CCS infrastructure on a timescale consistent with the development of CCS as a viable carbon abatement technology. We will work positively with the Cost Reduction Task Force to turn its recommendations into firm proposals for action that industry can take forward with our support. In consultation with the Devolved Administrations, we will also develop the design of the CfD likely to be necessary to stimulate further investment in CCS projects beyond those that are part of the CCS Programme.

Chapter 7 – Next Steps

7.1. This strategy sets out the important role that gas generation will play in any future generation mix, supporting a reliable, secure, low-carbon and affordable electricity system. The policies set out in this strategy aim to deliver an adequate level of overall generation capacity, which includes a significant role for gas (including with CCS), to ensure security of supply and an affordable energy mix as we move in to a low-carbon economy.

7.2. The policies and actions aimed at delivering the outcomes summarised below. The aim of delivering security of supply at an affordable cost to consumers is shared by Governments in each part of the UK. For example, in Scotland the draft Electricity Generating Policy Statement[83] clearly sets out the ongoing role of baseload generation, including gas. We are therefore working – and will continue to work – closely with the Devolved Administration to these ends.

Enabling Investment in Gas Generation

- The Government recognises that support for other forms of generation could undermine certainty for gas investors. We are therefore seeking to provide certainty for investors in both low-carbon energy sources and gas. To this end, we are setting a sustainable and affordable cap on the Levy Control Framework out to 2020. We are also reiterating that our approach to decarbonisation trajectories will continue to stay in step with other EU countries throughout the 2020s and consistent with a least-cost approach to our legally-binding 2050 decarbonisation objective and the 4th Carbon Budget.

- We have included provisions for a Capacity Market in the Energy Bill, and 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. 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. If initiating the Capacity Market, the Government also intends to run pilot auctions for delivery of demand side response (DSR) and storage from 2015 – 18, to provide additional capacity during this period.

- We have set out further Capacity Market design proposals to provide investors with certainty. These include details on the penalty regime, the payment model and rules on the eligibility of different types of capacity in the Capacity Market.

- Ofgem is currently in the initial consultation phase of a Significant Code Review (SCR) of cash out. Ofgem has identified a number of aspects of the arrangements that may be dampening or distorting incentives and is considering reform of the balancing arrangements to better reflect costs at times of scarcity. Some of the considerations may help address part of the missing money problem in the

[83] The Scottish Government: Electricity Generation Policy Statement: http://scotland.gov.uk/Topics/Business-Industry/Energy/EGPS2012

electricity market by providing generators with greater opportunities to recover their fixed costs. It intends to publish a draft decision document in Spring 2013.

- We have introduced powers in the Energy Bill that will enable Government to act in order to improve wholesale electricity market liquidity if necessary.

- We have brought forward proposals to improve the planning regime in each part of Great Britain by introducing greater flexibility for existing consents, and have committed to consider improvements to front-loading requirements and provide more clarity on flexibility available for new applications under the Planning Act.

Carbon Capture and Storage

- We have developed a world leading support package for CCS including capital funding, operational support through CfDs, £125m for research and development, and a well-developed regulatory environment.

- We have short-listed four projects to bring forward into a period of intense negotiations in our £1bn Commercialisation Competition.

- We have set up a CCS Cost Reduction Task Force to advise Government and Industry how best to ensure CCS can be cost-competitive with other low-carbon technologies.

Ensuring secure gas supply

- We support Ofgem's intention to consult on some light touch further interventions to enhance energy security, via increased transparency and standard contract terms and their investigation into the price responsiveness of interconnector flows.

- We will consider whether there is a case for further measures to encourage gas storage, and will publish our findings in Spring 2013.

- We will continue to work internationally to enhance the UK's gas security of supply through promoting (i) increased use of gas trading through supporting the development of a more integrated and liquid gas market in Europe, and (ii) sustainable production through working with gas producers bilaterally and through multilateral organisations.

Development of gas resources

- We have announced that DECC will establish an Office for Unconventional Gas and Oil, that, working with Defra and other Government departments, will join up responsibilities across Government, provide a single point of contact for investors and ensure a simplified and streamlined regulatory process.

- We have announced our plans to consult on an appropriate fiscal regime for shale exploration, on an appropriate pattern of licensing, and on an updated Strategic Environmental Assessment for further onshore licensing.

7.3. The delivery of these policies will be monitored through a number of existing routes. Investment, and prospects of investment (including planning), in gas generation will be monitored by DECC, Ofgem and National Grid as now, and reporting will form part of the annual Security of Supply reports and, in the case of the Ofgem report, Government's response. The Government aims to publish final detailed design proposals on the Capacity Market by May 2013, and alongside this, provide further details on the possible timing for a 2014 capacity auction.

7.4. Progress on CCS and policy responses to this will be undertaken as part of the updates to the CCS Roadmap. The CCS Cost Reduction Task Force has released an interim report with a full report early next year. We will provide a formal response to this.

7.5. We will report on policies to ensure secure gas supply, and progress on development of gas resources (both North Sea and unconventional) as part of the Annual Energy Statements.

7.6. Future Annual Energy Statements will also provide an overview on gas generation more generally, and we will report on overall progress on our strategy for gas generation as part of this.

Department of Energy & Climate Change

Published by TSO (The Stationery Office) and available from:

Online
www.tsoshop.co.uk

Mail, telephone, fax and email
TSO
PO Box 29, Norwich NR3 1GN
Telephone orders/general enquiries: 0870 600 5522
Order through the Parliamentary Hotline Lo-Call 0845 7 023474
Fax orders: 0870 600 5533
Email: customer.services@tso.co.uk
Textphone: 0870 240 3701

The Houses of Parliament Shop
12 Bridge Street, Parliament
Square, London SW1A 2JX
Telephone orders/general enquiries: 020 7219 3890
Fax orders: 020 7219 3866
Email: shop@parliament.uk
Internet: http://www.shop.parliament.uk

TSO@Blackwell and other accredited agents

ISBN 978-0-10-184072-9

Department of Energy and Climate Change
3 Whitehall Place, London, SW1A 2AW
www.decc.gov.uk