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Project Discovery
Energy Market Scenarios

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Overview:

In early 2009 Ofgem launched Project Discovery with the objective of examining the prospects for secure and sustainable energy supplies over the next 10-15 years. This investigation is wide ranging and uses scenario analysis to put the debate regarding UK energy in the wider global and environmental context. The purpose of this document is to consult across all stakeholders on these scenarios.

Ofgem has drawn up four scenarios for the next decade and beyond. Each scenario shows that energy supplies can be maintained, but the analysis exposes real risks to supplies, potential price rises and varying carbon impacts.

Retirements of older nuclear plant and closures of coal and oil plant by the end of 2015 under European environmental legislation could pose a threat to security of supply. Increasing gas import dependency could be exacerbated by growth in gas-fired power generation. Significant changes in the way in which we generate and consume power may be needed to manage the variability associated with increasing reliance on wind power.

High levels of investment are likely to be needed to secure energy supplies and meet carbon targets – up to £200 billion may be required over the next 10-15 years. This would more than double the recent rate of investment.

Consumer bills rise in all scenarios due to the levels of new investment required and increasing costs of carbon, and especially so if oil and gas spot prices spike sharply or continue their underlying rise since 2003.

Existing regulatory and market arrangements may well be seriously tested. We are currently conducting an assessment of these arrangements given the challenges that we have identified, and are considering what policy responses may be required.

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1. Introduction and Summary

Background

1.1. Since privatisation of the GB gas and electricity sectors in the late 1980s and early 1990s, energy policy has been based on the view that competition between companies to generate and supply energy would deliver the best outcome for consumers. To that end, Ofgem's focus in protecting consumers has been to promote effective competition in the supply of gas and electricity[1]. We have now entered a period where energy markets are being tested and challenged. As a result, existing market and regulatory arrangements need to be re-examined to see if they are still appropriate. Amongst the most significant challenges are the following:

- Since 1998 the global energy market background has been driven by rising oil, gas and coal prices. Oil prices between 1998-2009 increased four-fold, while GB gas and coal prices have more than doubled on average during that period;
- The important requirement to address climate change and other environmental concerns is now embedded in EU and UK legislation. Reflecting this, Government intervention in energy markets has become broader, including significant subsidies for renewable generation. The trend towards a more proactive role for Government in determining specific forms of investment means it is necessary to examine what role the market will play in delivering future investment;
- EU environmental legislation, specifically the Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED)[2] will place restrictions on the operation of coal and older gas plant and will lead to major plant closures during the next decade, which is likely to coincide with closures of some nuclear plant. This capacity will need to be replaced;
- Recent events such as the Russia-Ukraine gas crisis have raised concerns about the security and price of gas supplies at a time when many European countries, including GB, are becoming increasingly dependent on imports;
- The scale of investment required to deliver security of supply and meet our environmental objectives is very large. However, the recent financial crisis, and resulting difficulties in arranging finance for certain types of projects, highlights the potential challenges that may lie ahead and the risk of delays in investment;

[1] Where this is not possible Ofgem regulates the natural monopoly businesses such as transmission and distribution using effective price regulation.
[2] The European Council reached a political agreement on the IED in June 2009. It is still awaiting its first reading in the European Parliament, and hence is yet to pass into law.

- The recession that has resulted from the financial crisis has led some larger players to make strategic decisions to postpone investments (taking pressure off stretched balance sheets in some cases). With ongoing uncertainty regarding the speed and pace of economic recovery, there is a risk that new investment will lag the bounce back in energy demand when it comes; and

- Finally, lessons from the financial crisis mean that it is prudent to examine whether we can rely on the risk management actions of individual market participants to deliver wider objectives on security of energy supply.

1.2. Against this backdrop, Ofgem's statutory duties were extended in the 2008 Energy Act[3] to put more emphasis on the achievement of sustainable development and to consider the interests of future as well as current customers. The Government's Low Carbon Transition Plan, published in July of this year also emphasised that Ofgem's duties to protect current and future customers include tackling climate change and ensuring security of supply, by competition or otherwise[4].

Project Discovery and its context

1.3. Ofgem's Project Discovery began in early 2009 and explores whether current market arrangements are capable of delivering secure and sustainable energy supplies, and what the costs to customers will be.

1.4. As the independent regulator, our work draws on a depth of knowledge and confidential information made available to us, as well as wide ranging experience of assessing and understanding gas and electricity markets.

1.5. Project Discovery comprises three stages:

- First, identifying the scale of the challenge and risks facing the GB and wider European and global energy markets over the next two decades through scenario and stress test analysis. This consultation document seeks views on the results of that analysis;

- Second, reviewing the current market arrangements to see if they are appropriate for this challenge; and,

- Third, if there are areas that need changing, identifying policy responses and testing these against our scenarios and stress tests.

[3] http://www.opsi.gov.uk/acts/acts2008/pdf/ukpga_20080032_en.pdf
[4] These clarifications are expected to form part of the Government's Fifth Session Energy Bill.

1.6. It is only appropriate to make policy recommendations on the basis of sound analysis and evidence. Hence, it is important to subject the Discovery scenario work to wider scrutiny, and we welcome feedback on our assumptions, methodology and the outcomes of our modelling as set out in this document. Ofgem intends to draw on this analysis in our ongoing work on secure and sustainable energy supplies and consultation questions are included at the beginning of each chapter.

1.7. Work on the second and third stages of the project is ongoing. In light of the risks and challenges identified in this document and responses to this consultation, we will set out our assessment of how current market arrangements could be improved, and in particular whether they enable appropriate response on both the demand and supply side. We will also set out our views as to whether any further policy responses are required to deliver secure and sustainable energy supplies. In making these recommendations we will need to consider what level of security of supply is acceptable to current and future customers in terms of balancing risks against costs, and how the policy responses are likely to affect this trade-off.

1.8. The interest in the ability of energy markets to deliver secure and affordable energy and at the same time meet environmental objectives is intense. This summer the Government's Low Carbon Transition Plan[5] and the Renewable Energy Strategy[6] set out how the Government expects the supply of energy from renewables and other low carbon sources to expand over the next decade. The Prime Minister's special representative on international energy, Malcolm Wicks, also produced his report on International Energy Security in August[7] and the CBI published its report on energy security this summer[8]. Later this month, the Committee on Climate Change will publish its first statutory progress report assessing the progress made in reducing emissions against carbon budgets. Project Discovery is also taking place in the context of significant developments in European policy, notably implementation of the Third Package, the establishment of the Agency for the Cooperation of Energy Regulators (ACER) and the proposed Regulation for security of gas supply.

Scenario analysis - our approach to risk and uncertainty

1.9. Risk and uncertainty are at the heart of any study of security of supply. Project Discovery addresses this challenge through building a framework against which risks can be assessed and the benefits of policy responses can be evaluated. In order to understand the range of possible outcomes and in particular the risks to security of supply, meeting our environmental objectives and costs to consumers, we have adopted the widely used approach of scenario analysis (as in our previous work on future of energy networks, LENS[9]). The Discovery scenarios represent a series of

[5] http://www.decc.gov.uk/en/content/cms/publications/lc_trans_plan/lc_trans_plan.aspx
[6] http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/res/res.aspx
[7] http://www.decc.gov.uk/en/content/cms/news/pn090/pn090.aspx
[8] http://climatechange.cbi.org.uk/latest_news/00281/
[9] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/lens/Pages/lens.aspx

diverse, but plausible and internally consistent, futures that will allow us to test current arrangements and possible future policy responses. The scenarios are not meant to represent forecasts and many other possible outcomes can be envisaged.

1.10. In developing our scenarios we have considered a wide range of uncertainties. From these, we selected the two key global drivers which we believe will most likely shape different outcomes for the GB energy markets over the next decade or so. They are first the speed of global economic recovery, and second the extent of globally co-ordinated environmental action. These global drivers will affect the supply and demand for energy, and influence policy decisions, at the EU and national levels. The combination of the two drivers yields four scenarios as set out in Table 1.1 below.

Table 1.1: Global drivers and scenarios

		Economic recovery	
		Rapid	**Slow**
Environmental action	**Rapid**	Green Transition	Green Stimulus
	Slow	Dash for Energy	Slow Growth

1.11. We are able to relate many other scenario assumptions to these two scenario drivers. For example, rapid economic growth is associated with high demand, high levels of investment and high commodity prices; the speed of environmental action drives our assumptions on energy efficiency, renewables deployment and carbon prices. Not all scenario assumptions can be related back to the two scenario drivers, for example the impact of geopolitics on the oil price, or the speed of technological development. For these variables we have made assumptions that support the emerging picture from each scenario.

1.12. In all our scenarios we assume market participants respond adequately to market signals. Within our model this means that we assume new investment takes place where companies could earn a reasonable return on their investment under each scenario's assumptions, taking into account the risks they face. It also means that assets are retired when they are no longer profitable. The assumption of how market participants respond (particularly in the face of policy uncertainty and intervention) is one we will be examining carefully when assessing whether current arrangements remain adequate and exploring potential future policy responses.

1.13. To capture those risks that could be best described as shocks, such as major infrastructure failures, and which could occur in any scenario in any year, we have designed a number of stress tests. The stress tests are used to demonstrate how the resilience of the market may evolve over time, and differ between scenarios.

Key messages

1.14. Our scenarios show that gas and electricity supplies can be maintained to customers provided the market participants respond adequately to market signals - but each scenario comes with real risks, potential price rises and varying carbon impacts. Britain's ability to meet its demand for gas and electricity is therefore poised to be tested over the next decade or so. Growing exposure to a volatile global gas market and ageing power plant nearing the end of its life, along with the need to tackle climate change, are the central challenges the country faces.

1.15. High levels of investment are likely to be needed – up to £200 billion may be required by 2020[10]. This would imply more than doubling the recent rate of investment.

1.16. Consumer bills rise in all scenarios due to the levels of new investment required and increasing costs of carbon, and especially so if oil and gas spot prices spike sharply or continue their underlying rise since 2003.

1.17. In addition, the key risks emerging in our scenarios over the next decade are as follows:

- Under some scenarios, the current environmental targets - including the EU renewables target and Government carbon budgets - are not met or are at risk of not being met;
- Gas import dependency will increase dramatically, especially where environmental measures only achieve partial success, exposing the country to a greater range of potential supply shocks;
- The greatest risk to security of supply appears to be maintaining gas supplies through a severe winter;
- Uncertainty relating to the impact of environmental policy makes forecasting future gas demand much more challenging for potential investors than might have been the case historically. This may delay investment in gas infrastructure that might be required should environment measures not fully deliver;
- Planned closures of ageing nuclear plant and the removal, by the end of 2015, of a significant amount of coal and oil-fired power stations under European environmental legislation is likely to lead to a large fall in the electricity capacity margin;

[10] Excluding investment in UK Continental Shelf gas production

- Gas import dependency could be exacerbated by growth in gas-fired power generation to replace lost nuclear and coal-fired capacity in some scenarios;

- A rapid expansion of renewables would lessen the risk of gas import dependency, but would require thermal plant to operate more flexibly to manage variability in wind output, which may require further investment; and,

- A more flexible demand side may be required in the future to better manage any shocks in gas or electricity supplies.

1.18. While the outlook in the very near term is more comfortable - National Grid's Winter Outlook Report notes we enter the 2009/10 winter with a very high capacity margin (by historical standards) and a sound gas infrastructure - the scenario and stress test analysis presented in this report suggests that existing regulatory and market arrangements may well be tested severely over the next two decades. This is why Ofgem is carrying out this review now. In particular, we need to consider whether early action would avoid more expensive action being required in the future.

1.19. When considering how best to meet these challenges Ofgem will be open minded and will explore a full range of policy responses. At the same time we must recognise that a perception of increased regulatory risk can itself be detrimental to security of supply, and this must also be considered carefully in developing future policy responses.

1.20. The next chapter of this consultation document sets out our approach to the scenario and stress test analysis. Chapter 3 then develops and explains each of our four scenarios and Chapter 4 presents the results of our stress test analysis. Below we have provided a short summary of the scenarios and stress tests set out in these chapters.

Scenario overview

Green Transition

In this scenario….

- There is a rapid economic recovery and significant new investment globally
- A global agreement on tackling climate change is reached
- Energy efficiency measures are effective
- New nuclear and CCS demonstration projects come on-line before 2020
- Gas prices are moderate, carbon prices are high, and coal prices are relatively low as demand is suppressed by the high carbon prices
- GB gas demand falls but electricity demand grows on the back of wider deployment of heat pumps and electric vehicles

Key features

- Gas imports increase until 2016 and then stabilise
- Diverse generation mix
- Risk from generation intermittency towards the end of the period due to high levels of wind generation
- 2020 renewables targets met: 30% electricity, 12% heat
- Carbon dioxide emissions from the electricity and gas sectors: down 33% from 2005 levels
- Domestic consumer bills: increase by 23% by 2020
- Total investment costs 2009-2020: £200bn

Green Stimulus

In this scenario….

- There is a slow recovery from recession and restricted availability of finance
- A global agreement on tackling climate change is reached and governments implement 'green stimulus' measures
- Energy demand falls globally in the near term
- Fuel prices are relatively low
- The combination of relatively high carbon prices and direct government support to nuclear, CCS and large scale renewables promote rapid decarbonisation of the generation sector

Key features

- Gas imports increase until 2012 and then stabilise
- Lower gas prices favour gas-fired generation over coal
- Risk from generation intermittency towards the end of the period due to high levels of wind
- 2020 renewables targets met: 30% electricity, 12% heat
- Carbon dioxide emissions from the electricity and gas sectors: down 43% from 2005 levels
- Domestic consumer bills: increase by 14% by 2020
- Total investment costs 2009-2020: £190bn

Dash for Energy

In this scenario….

- Global economies bounce back strongly
- Security of supply concerns prevail over environmental concerns: there is no global agreement on tackling climate change
- Gas supply is tight and fuel prices are high
- Investment is forthcoming but not always timely
- Significant expansion of CCGT generation capacity
- Planning and supply chain constraints prevent new nuclear plant becoming operational before 2020
- Planning delays push back storage investment

Key features

- Sharp increase in gas import dependence
- Gas increases its share of the generation mix
- Shortage of gas storage coincides with peak energy prices in 2015
- 2020 renewables targets are not met: 15% electricity, 4% heat
- Carbon dioxide emissions from the electricity and gas sector: down 12% from 2005 levels – insufficient to meet carbon budgets
- Domestic consumer bills: rise with high and volatile commodity prices, increasing over 60% by 2016 before falling back
- Total investment costs between 2009-2020: £110bn

Slow Growth

In this scenario….

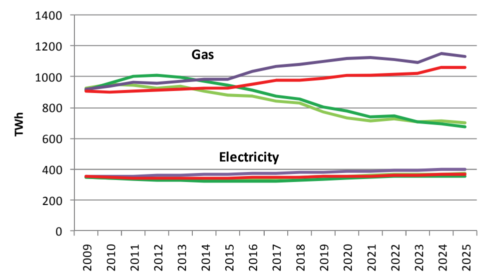
- Impact of recession and credit crisis continues
- Low levels of investment
- Low commodity and carbon prices, reducing incentives for renewables, nuclear and CCS
- Generation build is dominated by CCGTs
- Energy efficiency measures have limited impact but demand is low initially due to slow economic growth

Key features

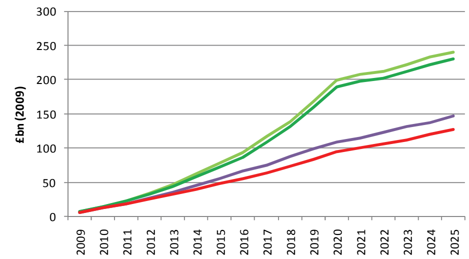
- Increasing dependence on gas imports and gas-fired electricity generation
- Tight supply margins due to lack of investment when economic growth returns
- 2020 renewables targets are not met: 15% electricity, 4% heat
- Carbon dioxide emissions from the electricity and gas sector: down 18% from 2005 levels – insufficient to meet carbon budgets
- Domestic consumer bills: relatively low in early years but increase by 22% by 2020 as market tightens
- Total investment costs between 2009-2020: £95bn.

Scenario analysis – Key results

Annual demand

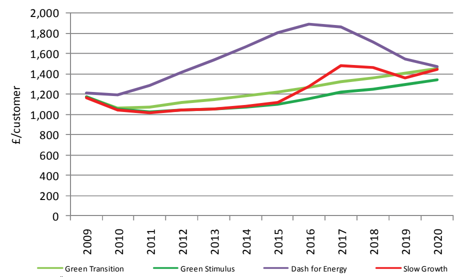


Cumulative investment required[i]



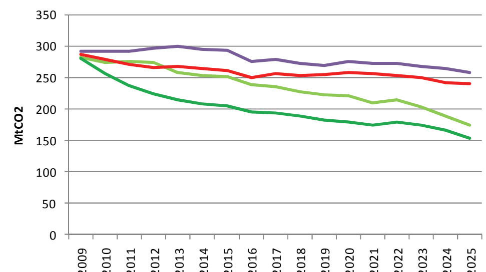
[i] Cumulative investment in electricity and gas infrastructure from 2009 (excluding upstream UKCS)

Average domestic consumer bill[ii]

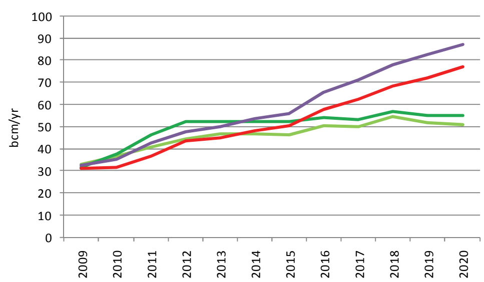


[ii] Based on 3300 kWh electricity and 700 th gas, reducing with energy efficiency measures

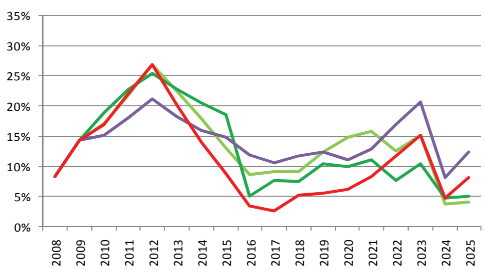
CO_2 emissions from electricity and gas sectors



Annual gas imports



Electricity de-rated capacity margins[iii]



[iii] Excess of 'de-rated' capacity to meet peak demand expressed as a percentage of peak demand.

Green Transition | Green Stimulus | Dash for Energy | Slow Growth

Stress tests

Stress test	Period	Today	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
Re-direction of LNG supplies	1-in-20 severe winter	Low impact	Moderate impact	Moderate impact	High impact	High impact
Russia-Ukraine dispute	1-in-20 severe winter	Moderate impact	Moderate impact	Moderate impact	High impact	High impact
Bacton outage	1-in-20 peak day	Moderate impact	Moderate impact	Moderate impact	Moderate impact	Moderate impact
No wind output	1-in-20 peak day	Low impact	Moderate impact	High impact	Low impact	Low impact
Electricity interconnectors fully exporting	1-in-20 peak day	Low impact	High impact	High impact	Moderate impact	Moderate impact

Low impact ● Moderate impact ● High impact ●

2. Approach and assumptions

Chapter Summary

In this chapter, we discuss what we mean by secure and sustainable energy supplies and explain how we measure this within Project Discovery. We outline our methodology for exploring uncertainty using scenarios and stress tests, and introduce our four scenarios. We describe the key input assumptions for each scenario, and provide an overview of the analytical tools that we use to model the scenarios and stress tests.

Question box

Question 1: Please provide comments on our approach of using scenarios and stress tests to explore future uncertainty, and as a basis for evaluating policy responses.

Question 2: Are there other techniques for analysing uncertainty that we should consider?

Question 3: Do you agree with how we measure the impacts of our scenarios and stress tests?

Question 4: Do you agree with our key scenario drivers and choice of scenarios?

Question 5: Do you believe our scenarios sufficiently cover the range of uncertainty facing the market, and hence cover the areas where future policy responses may be required?

Question 6: Do you have any specific comments on scenario assumptions, and their internal consistency?

Question 7: Do you agree with our methodology for modelling gas and electricity supply/demand balances?

Question 8: Do you agree that LNG is the likely medium-long term source of "swing gas" for the European market?

Secure and sustainable energy supplies

2.1. Although Project Discovery approaches the functioning of energy markets primarily from the perspective of security of supply, a sustainable outcome also requires consideration of both the environmental impact and the costs to consumers. In line with our statutory duties, we need to consider, in the interests of current and future consumers, all three aspects in our analysis and decision making.

2.2. We use the term 'secure and sustainable' energy supplies to describe this balance between security of supply, environment and costs to consumers. Delivering secure and sustainable energy supplies means in broad terms that:

- No customer loses supply of gas or electricity if they would have been willing to pay more for a more reliable supply (or is adequately compensated if they do lose supply);
- Environmental targets to tackle climate change and air pollution are achieved; and,
- Consumers pay no more than they need to, in order to achieve these objectives, whilst at the same time prices are sufficient for investors to make adequate returns.

2.3. We recognise that there are important issues surrounding affordability, since in all our scenarios there is an increase in consumer bills to a greater or lesser extent. When assessing policy options in the next stage of Project Discovery we will need to consider the impacts on vulnerable customers carefully.

Exploring uncertainty through scenarios and stress tests

2.4. Energy markets are inherently uncertain. At both a global and regional level, there are a profusion of interacting factors affecting wholesale and retail energy markets that are constantly in flux. We do not believe it is possible to predict with any certainty the likely future development of the market particularly over the longer term. Nevertheless, it is important to understand the range of possible outcomes and in particular the risks to secure and sustainable energy supplies.

2.5. In order to explore this uncertainty, we have used the widely recognised approach of scenario analysis, which is in turn supplemented by stress testing. Scenarios are used to illustrate alternative, yet plausible and internally consistent, views of the future; stress tests are used to demonstrate how the resilience of the market may evolve and differ between scenarios.

2.6. In developing our four distinct scenarios we have taken into consideration work done by other bodies in this area including the Department of Energy and Climate Change and National Grid[11], referred to a number of published sources, and have engaged with external parties and advisors.

[11] http://www.nationalgrid.com/NR/rdonlyres/32879A26-D6F2-4D82-9441-40FB2B0E2E0C/35116/Operatingin2020Consulation.pdf

Measuring impacts

2.7. We assess the impacts of our scenarios and stress tests on secure and sustainable energy supplies using the range of measures described below.

Measures of security of supply

2.8. There are different ways in which security of supply can be measured. The primary measure of security of supply is the extent to which available sources of gas and electricity are able to meet peak demand:

- Electricity: the extent to which electricity generation capacity is sufficient to meet demand requirements and cover plant outages; and
- Gas: the extent to which there is sufficient gas available to the GB market to meet demand (including from the generation sector). We are also interested in the trends in utilisation of gas infrastructure to understand how resilient the system is to shocks.

2.9. Further details of how these measures are defined are provided in Box 1 below.

Box 1: Measures of security of supply

Electricity

The adequacy of generation capacity is measured using the de-rated peak capacity margin - the excess of 'de-rated' capacity to meet the peak in demand (highest demand during an average cold spell) expressed as a percentage of peak demand. The de-rated capacity is the expected availability of plant during the peak taking into account the risk of unforced outages and variability of renewables generation output.

Gas

We measure the adequacy of gas supplies to meet the demand on the coldest day in a twenty year period (the 1-in-20 peak day) and also to last through a period of sixty days of exceptionally high gas demand statistically occurring every twenty years (the 1-in-20 severe winter). We are also interested in trends in utilisation (i.e. as an indicator of the amount of spare capacity) in key gas infrastructure, namely interconnectors, LNG regasification terminals and storage. Security of supply concerns may be more acute where high utilisation of the gas infrastructure is required to meet demand (particularly imports through interconnectors, the flows through which are dependent on Continental markets), since the system is less resilient to shocks.

2.10. We have not, in this paper, sought to define an adequate level of security of supply. Indeed security of supply is not absolute and a shortage of supply is likely to result in a demand response in order of least cost - for example, with voluntary reductions in industrial demand occurring ahead of involuntary disconnections.

Measuring the impact on price

2.11. To measure the impact on prices we project the total investment required under each scenario, and estimate the impact of our scenarios on wholesale electricity prices, consumer bills, subsidies (energy efficiency, renewables, and CCS), and transmission and distribution charges.

2.12. We convert these costs into the typical domestic consumer bills for electricity and gas, taking into account expected reductions in consumption over time through energy efficiency measures.

Measures of environmental impact

2.13. Our different scenarios result in different levels of renewables deployment and carbon emissions from the electricity and gas sectors. We compare these to the 2020 renewables targets[12] and the carbon budgets[13] respectively.

2.14. In the traded sector (electricity generation and energy intensive industry) the level of physical domestic emissions does not affect whether carbon budgets will be achieved. This is because power generators are covered by the EU Emissions Trading System (EU ETS), and the level of carbon savings are determined by the number of allowances the UK receives (the sum of the UK's auctioning rights plus any free allowances given to UK industry, described by the Government as the UK's 'De Facto Cap') in the EU ETS and not by the level of physical emissions. However, the level of physical emissions affects the number of allowances that UK firms have to buy or sell, and therefore, they affect the cost of achieving carbon budgets in the traded sector. In the non-traded sectors (residential, commercial, smaller scale industry, transport) failure to meet the carbon budgets may also mean that the country would be in breach of its EU commitments (the UK's non traded sector target from 2013—2020) and liable to penalties from the European Commission.

[12] Under the EU Renewables Directive, the UK is committed to meeting 15% of its energy needs from renewable sources by 2020.
[13] With the introduction of the Climate Change Act, the UK is committed to legally binding carbon reductions consistent with the EU framework. These 'carbon budgets' are between an interim target (a 21% reduction by 2020 from 2005 levels) which would apply in the absence of a global agreement on emissions reductions, and an intended target (a 31% reduction by 2020 from 2005 levels) would apply if a global agreement on emissions is reached.

Constructing the scenarios

2.15. In developing our scenarios we have considered a wide range of uncertainties. From these, we selected the two key uncertainties which we believed will most likely shape different future outcomes for the GB energy markets. These are, first the speed of global economic recovery, and, second the extent of globally co-ordinated environmental action. The combination of these drivers yields four scenarios as set out in Table 2.1 below.

Table 2.1: Global drivers and scenarios

		Economic recovery	
		Rapid	**Slow**
Environmental action	**Rapid**	Green Transition	Green Stimulus
	Slow	Dash for Energy	Slow Growth

2.16. We are able to relate many other scenario assumptions to these two scenario drivers. For example, rapid economic growth is associated with high demand, high levels of investment and commodity prices. The speed of environmental action drives our assumptions on energy efficiency, renewables deployment and carbon prices. Not all scenario assumptions can be related back to the two scenario drivers, for example the impact of geopolitics on the oil price, or the speed of technological development. For these variables we have made assumptions that support the emerging picture from each scenario. For uncertainties that we deemed not to be material, we have made the same assumption for each scenario.

2.17. When constructing our scenarios we have not attempted to construct a central case or best estimate of the shape of the future energy market because the future is inherently more uncertain than such an approach would imply. We have tried to reflect what we view as reasonable outcomes subject to given global conditions. We could have gone further in developing the range of scenarios, for example, our Dash for Energy scenario is not the most extreme example we could envisage should global energy demand surge. Similarly, our 'Green scenarios' do not assume the highest possible level of environmental action. For this reason we welcome views on whether the range of scenarios we have developed is appropriate for assessing current market arrangements and any alternative policy responses.

2.18. To capture those risks that could be best described as shocks, such as major infrastructure failures, and which could occur in any scenario, we have designed a number of stress tests. The stress tests are used to demonstrate how the resilience of the market may evolve over time and differ between scenarios.

2.19. In all of our scenarios we assume market participants respond adequately to market signals. In other words the market arrangements and structure within GB remains largely the same. We have not made any explicit assumptions regarding the pace of liberalisation in Continental European markets, but through our stress tests explore the ongoing risks that gas and electricity may not be freely traded over interconnectors in response to price signals due to differences in market arrangements.

2.20. We should note that our model assumes a purely economic response within the market. Where energy supply is scarce and a response on the demand-side is required, the model allocates energy to customers that most value it, and in the form (i.e. electricity or gas) they most value. However, imperfections in the market rules, combined with technical difficulties in isolating individual customer segments, may prevent this. The ultimate purpose of Project Discovery is to examine whether the current GB arrangements need to be improved to promote the delivery of secure and sustainable energy supplies.

2.21. Our analysis demonstrates the scale of response required to meet demand, including the levels of investment to deliver the envisaged scenario outcomes. However, it is not possible to conclude from the analysis in this first stage of the project what level of secure and sustainable energy supplies the current market arrangements would deliver.

The four scenarios

2.22. This section briefly describes the scenarios, and the remainder of this chapter then sets out in more detail the key assumptions and modelling approach. The scenarios are described more fully in Chapter 3 and the stress tests in Chapter 4. Further details on the assumptions underpinning each scenario and stress test are provided in Appendix 2.

Green Transition

2.23. This scenario is characterised by rapid economic recovery and a significant expansion in investment in green measures. A global agreement on tackling climate change is reached leading to the EU implementing a target of a 30% reduction in carbon dioxide emissions from 1990 levels by 2020.

2.24. The EU 2020 renewables target is met and deployment reaches 30% and 12% in the electricity and heat sectors respectively. Energy efficiency measures are also effective, and carbon dioxide emissions reduce rapidly.

2.25. New nuclear and CCS demonstration projects are operational by 2020, supported by high carbon prices and/or additional subsidy.

2.26. Total energy demand is lower towards the end of the next decade. Gas demand falls but electricity demand increases on the back of increasing electrification of the heat[14] and transport[15] sectors. Against the backdrop of economic recovery, investment in gas and electricity infrastructure worldwide is significantly higher than current levels. There is some rebound in the supply of pipeline gas from outside the EU and of indigenous gas production from recession levels, but not as rapidly as the Dash for Energy scenario (below). As a result, the LNG market is tight into the medium term, but demand later falls back as renewables investment comes through.

2.27. This is a world of high gas and carbon prices but relatively low coal prices due to the shift to cleaner forms of thermal (i.e. gas and coal) production.

Green Stimulus

2.28. In this scenario recovery from the recession is slow and there is a higher cost and restricted availability of credit. A global agreement on climate change is reached, and governments across the world implement 'green stimulus' packages in order to achieve environmental goals and support economic recovery. In addition to the existing customer funded support mechanisms in place (such as the Renewables Obligation) there would be direct government investment in large generation projects and the infrastructure projects required to decarbonise the energy sector. These may include smart grids, bio-methane networks, electric vehicle charging infrastructure and carbon dioxide transportation/storage infrastructure. Additional subsidy may also be provided to new nuclear projects.

2.29. Energy demand would be low due to the weak economy. In addition, there would also be significant effort in improving energy efficiency through incentives coupled with generous grants. The fall in electricity demand would be offset to a degree through the greater electrification of the heat and transport sectors, but the drop in gas demand by 2020 would be significant.

2.30. As a consequence of this and financing constraints, investment in international gas and electricity infrastructure would reduce considerably from pre-recession levels. Against this backdrop, future pipeline gas supplies to the EU and indigenous gas production are relatively low. The LNG market remains consistently well supplied.

2.31. This is a world of relatively low commodity prices but high carbon prices because energy demand is low but governments pursue strict environmental policies.

2.32. Renewables targets would be met (aided by the falling demand) and carbon dioxide emissions would fall significantly.

[14] Through the deployment of heat pumps in response to the Renewables Heat Incentive. Since heat pumps have efficiencies of over 100% the increase in the electricity demand from their deployment is less than the gas demand they displace.
[15] Through the deployment of electric vehicles.

Dash for Energy

2.33. Under this scenario, the recession proves short-lived. Demand bounces back strongly and then increases over time, although investment levels take some time to become re-established following the hiatus caused by the credit crisis.

2.34. Security of supply concerns prevail over environmental concerns in Europe, and negotiations on tackling climate achieve limited success. In GB, the proportion of energy delivered through renewables is less than half of the 15% target albeit against a high demand backdrop. Progress on CCS is slow and there are delays in commissioning new nuclear plant. Reductions in domestic carbon dioxide emissions are insufficient to meet the Government's 2018-2022 interim carbon budget, requiring large quantities of allowances to be brought in to cover shortfalls in the traded sector, and resulting in potential financial penalties for failure to meet the non-traded sector targets.

2.35. High gas demand results from strong growth in the global economy and there is significant expansion of gas-fired generation in GB and across Europe. International gas and electricity infrastructure investment is restored to pre-credit crunch levels.

2.36. Against this backdrop, EU indigenous gas production levels are relatively high. There are high levels of gas production outside the EU, but future pipeline gas supplies do not fully reflect this due to international competition for these resources. For similar reasons, the LNG market is tight. Furthermore, there are barriers to new storage development (for example, caused by planning hold-ups) and there is increasing reliance on LNG imports to provide seasonal gas.

2.37. This is a world of high commodity prices. We assume new nuclear plant do not become operational before 2020 due to planning and supply chain constraints.

Slow Growth

2.38. Under this scenario, the recession and the ensuing effects of the credit crisis continue to drag on for a long time. Global and GB demand remain depressed, and as a consequence of this and financing constraints, international gas and electricity infrastructure investment reduce considerably from pre-credit crunch levels.

2.39. Against this backdrop, future pipeline gas supplies to the EU and indigenous gas production are relatively low. Initially, the LNG market is over-supplied, before tightening due to lack of investment.

2.40. This is a world of relatively low commodity and carbon prices, reflecting low energy demand and the lack of a global agreement on climate change. UK renewables targets are not met, largely in response to reduced economic incentives caused by lower prices.

2.41. There is limited investment in new nuclear with the focus shifting to obtaining life extensions for existing nuclear assets.

Key assumptions

Summary

2.42. The assumptions for the two scenario drivers (highlighted in orange) and scenario variables are summarised in Table 2.2 below. We provide further details of our commodity price, GDP and demand assumptions in this section. Further details of our input assumptions can be found in Appendix 2.

Table 2.2: Assumptions used for the scenario drivers and scenario variables

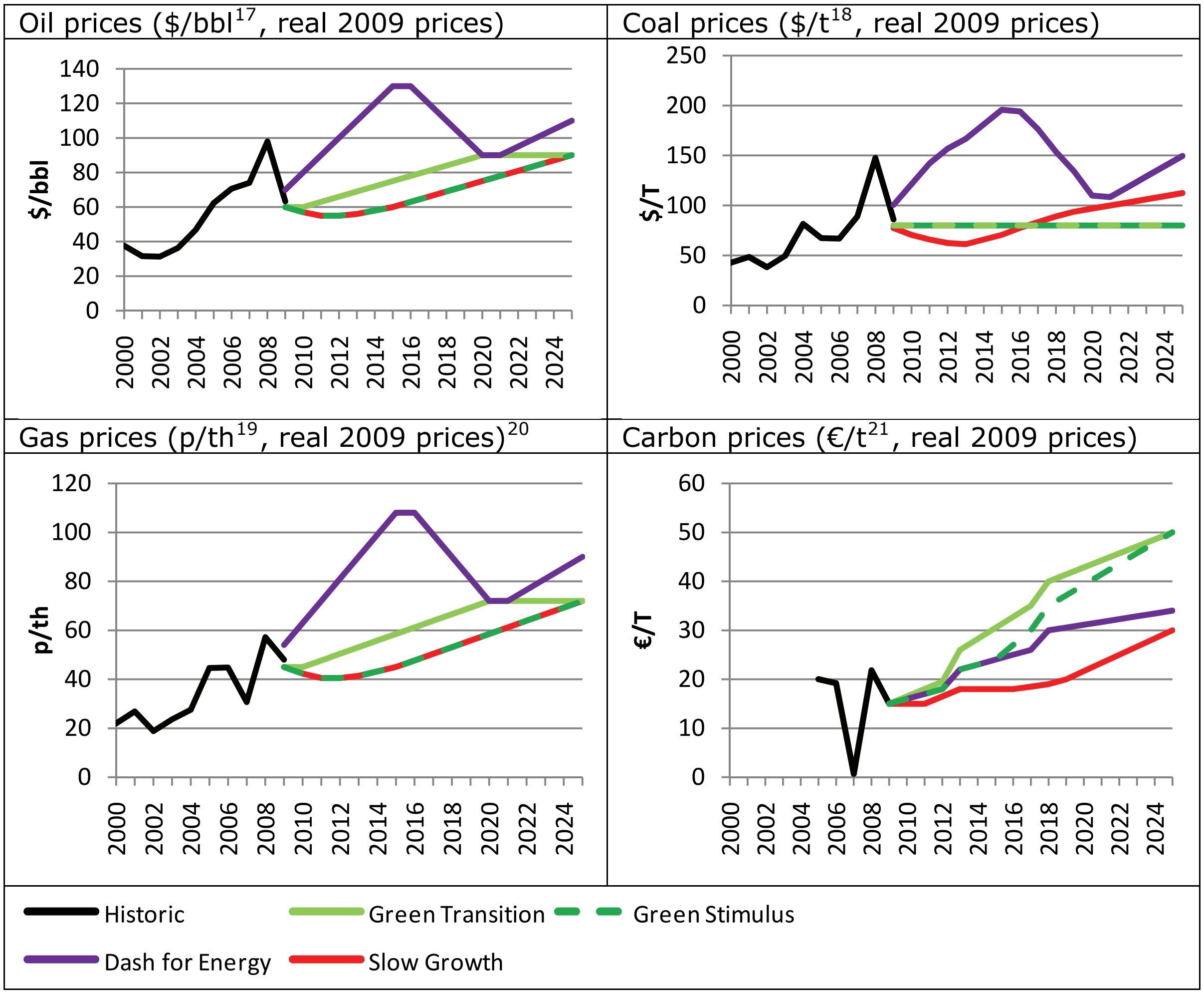
	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
Economic recovery	Rapid	Slow	Rapid	Slow
Environmental actions	Rapid - Renewables targets met, investment in CCS	Rapid - Renewables targets met, investment in CCS	Slow - Renewables targets not met, limited CCS	Slow - Renewables targets not met, no CCS
Gas demand	Falls: energy efficiency, renewables heat	Falls: recession, energy efficiency, renewables heat	Increases	Falls until 2012 - recession, then increases
Electricity demand	Falls until 2015: energy efficiency Increases longer term: electrification of heat, transport	Falls until 2015: energy efficiency Increases longer term: electrification of heat, transport	Increases	Falls until 2012 - recession, then increases
Supply of pipeline gas to EU	Medium	Low	Medium (high production, but diverted to East)	Low
Global LNG market	Tight in the medium term, before falling back	Over-supplied	Tight	Over-supplied initially, becoming tighter
Commodity prices	Medium gas, high carbon, low coal	Low fuel prices, high carbon	High fuel prices, moderate carbon prices	Low fuel and carbon prices
Nuclear	Further extensions, strong new nuclear	Further extensions, strong new nuclear	No further extensions, new nuclear delayed	No further extensions, no new nuclear

Commodity prices

2.43. We have developed four commodity price outcomes which reflect the differing levels of demand and investment under the four global scenarios. There is a huge range of uncertainty surrounding commodity price projections and our selection of four particular price tracks may not capture fully the extent and volatility year on year of any future price moves. Rather, they are intended as a starting point from which to understand the implications of a plausible range of commodity price outcomes which are broadly consistent with the main global scenario drivers of economic growth and environmental action.

2.44. Figure 2.1 shows the assumptions we have made for commodity price paths under the four scenarios.

Figure 2.1: Commodity price path assumptions under the four scenarios (2000 - 2025)[16]



2.45. In the Dash for Energy scenario, we assume oil prices peak at around $130/bbl and thereafter fall back briefly as incremental upstream investments come through

[16] Our oil and gas prices in all four scenarios tend to converge around 2020 - which appears to imply they are reverting to a long term mean, however, the trends are different in each scenario and if extrapolated further would tend to diverge again post 2025.
[17] Oil prices are expressed as US dollars per barrel of Brent crude.
[18] Coal prices are ARA expressed as US dollars per metric tonne of coal excluding land transportation costs.
[19] Gas prices are expressed as pence Sterling per therm at the UK National Balancing Point.
[20] For comparison, as of October 2009, the gas forward curve shows prices of 41.3p/therm for 2010 and 52.9p/therm for 2011.
[21] Carbon prices are for EUAs expressed as Euro per metric tonne of carbon dioxide emitted.

before trending back up towards $110/bbl longer term. Although our peak price of $130/bbl is less than peak oil prices during 2008 of $147/bbl, our assumption remains higher than the average month-ahead oil forward price during 2008 of around $100/bbl. In the longer term beyond the model horizon, our oil price trend is broadly consistent with the 2030 $120/bbl (2007 real prices) reference benchmark of the International Energy Agency (IEA)22 and the $130/bbl (2007 real prices) reference benchmark of the Energy Information Administration (EIA)23.

2.46. In our Green Transition scenario, we explore a world of lower and less volatile oil prices which are dampened in the longer term by a global shift towards alternative energy sources.

2.47. In our Green Stimulus and Slow Growth scenarios, due to lower global economic growth and hence lower energy demand, our oil price curve tracks below the current market forward curve in the medium term rising towards $90/bbl in the long term. By comparison, the EIA low scenario is $50/bbl in 2030 (2007 prices).

2.48. In all scenarios, gas prices rise broadly in line with oil due to the contractual linkage of gas prices in Europe. In our Dash for Energy scenario, the gas price peak of >100p/therm is significantly higher than previous annual price peaks, because we are taking full account of the lag effect due to the sustained period of high oil prices assumed.

2.49. Carbon prices are assumed to rise to €50/t by 2025 under the Green Transition and Green Stimulus scenarios as a result of tightening of the EU-ETS and achieving a global agreement on climate change at Copenhagen. Higher carbon prices could be envisaged in these scenarios, although the level of additional financial support for renewables and CCS will promote significant low carbon investment thus reducing demand for carbon allowances and limiting future price increases. In the Dash for Energy scenario, we assume a more moderate out-turn price of €34/t by 2025 due to the lower pressure under this scenario for environmental action. This is also the case under the Slow Growth scenario, but due to lower emissions the carbon price only reaches €30/t by 2025.

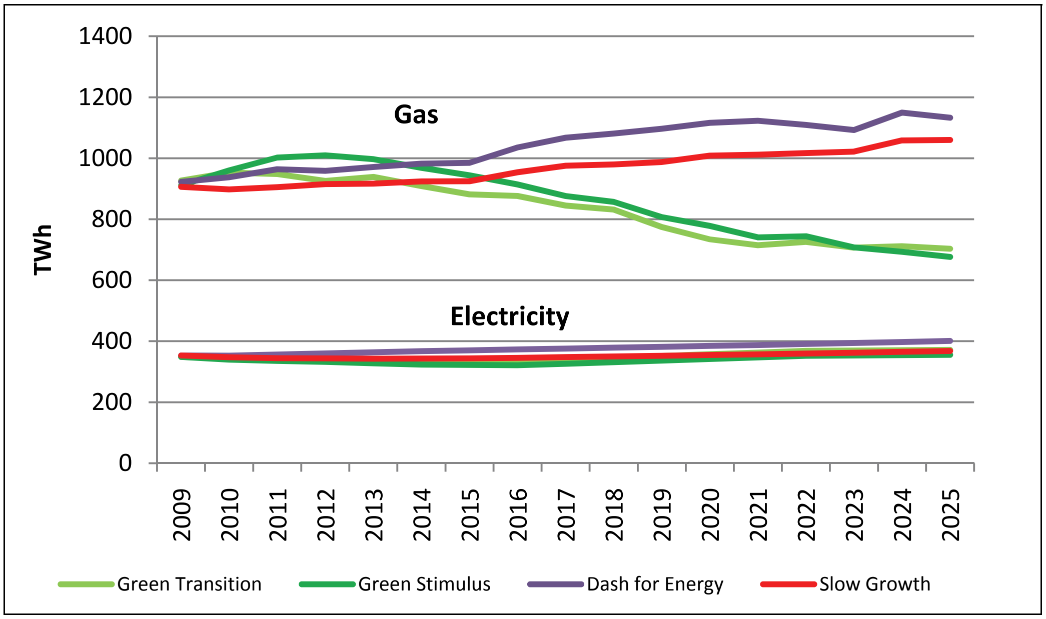
2.50. In three of the four scenarios, we have priced coal to make it broadly competitive with gas on a short-run basis in the generation sector, taking into account the cost of carbon. In the Green Stimulus scenario, we assume a world of low energy prices but with a commitment to high carbon prices which creates a scenario under which coal will become relatively less competitive with gas for generation.

[22] As published in the IEA document "World Energy Outlook", 2008
[23] As published in the EIA document "International Energy Outlook", 2009

Demand

2.51. Figure 2.2 shows the demand for electricity and natural gas in GB expressed in TWh. Our end user demand assumptions are a function of GDP growth and progress of energy efficiency measures. Total gas demand is also affected by demand in the generation sector (which is itself a function of the competitiveness of gas in the generation market relative to other fuels) and the deployment of renewables heat technologies that will reduce demand for natural gas.

Figure 2.2: GB energy demand (2009 - 2025)



Investment behaviour

2.52. In order to construct our scenarios we have needed to project investment in new power stations, storage facilities, LNG terminals and interconnectors. At this stage, we have not attempted to simulate investor decisions dynamically. Instead we have made assumptions on new build that are consistent with companies earning a return on their investments. Hence, in scenarios with lower prices there is less investment than in scenarios with higher prices.

2.53. The amount of renewables build in electricity is a scenario assumption. In our Green scenarios we assume that 30% of electricity is generated from renewables sources by 2020. We make assumptions on the Renewables Obligation banding, and level of Feed-in Tariffs for sub-5 MW plant, to ensure that investors would earn a reasonable return, and implicitly assume that planning, connection access and supply chain issues are not a barrier to achieving this target. In the Slow Growth and Dash for Energy scenarios we assume that only 15% of electricity is generated from renewables sources by 2020, and that barriers remain to achieving a higher level of deployment.

2.54. Likewise for renewable heat, we assume that barriers to deployment are addressed, and that the level of Renewable Heat Incentive is sufficient to deliver 12% renewables heat by 2020 in our Green scenarios. In the other two scenarios, we assume that only 4% penetration is achieved, with the Government prepared only to implement lower subsidies in worlds where there is less global commitment to tackling climate change.

2.55. We have reflected the uncertainties facing investors in their required rates of return, but assume that they have reasonable visibility on which scenario they are in i.e. consistent with the prevailing prices and demand in each scenario. If companies invest on the expectation of one set of outcomes, and then the world turns out very differently this could lead to under-investment or over-investment. The scenarios do not illustrate this risk, but this raises an important issue that warrants further consideration.

Modelling approach

Overview

2.56. We have developed a detailed model which enables us to investigate potential outcomes for secure and sustainable energy supplies from our global scenarios and stress tests. Our model allows us to examine the impact of global and European gas markets on the GB outlook. We also capture the interaction between the gas and electricity markets. Throughout we have sought to ensure our gas and electricity scenarios are internally consistent in terms of assumed price levels and the level of investment.

Gas market

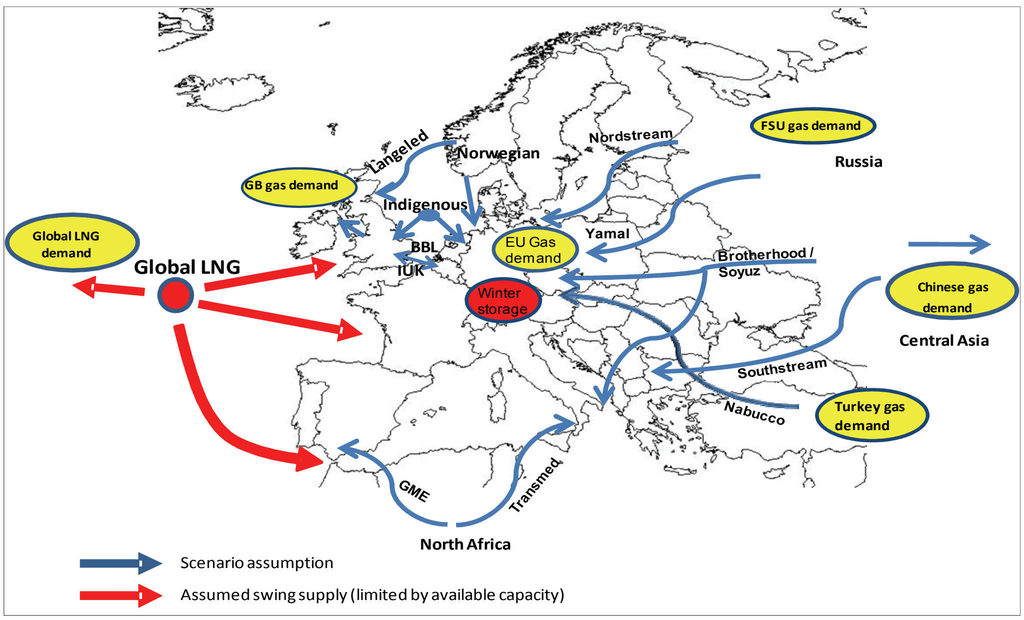
2.57. Gas prices (annual average) are input into the model as a scenario assumption. We apply some seasonal shape to these prices based on historic relationships between summer and winter prices. The gas price can spike within the model when demand is interrupted as explained further in Appendix 2.

2.58. We have made a number of assumptions on the investment in new interconnectors, LNG terminals and storage capacity reflecting the expected returns for these investments and availability and cost of finance in each scenario.

2.59. Our assumptions on the volumes of gas that will flow to GB via Liquefied Natural Gas (LNG)[24] and interconnectors are also critical to the analysis, since having the import capacity available does not guarantee sufficient gas will be delivered to meet GB demand.

2.60. We have necessarily adopted a simplified model for how gas will flow into Europe and the GB market. This is illustrated schematically in Figure 2.3 below.

Figure 2.3: Potential gas flows in GB and Europe under the scenario assumptions



2.61. For Europe, we have made fixed assumptions for each scenario regarding annual demand, indigenous production, and flows of pipeline gas from Russia, Central Asia and North Africa. We then assume "swing supply", i.e. gas required to meet the balance of demand, is provided by LNG. We recognise that this is a simplified assumption since existing LNG supplies are typically contracted and not subject to year-on-year swing. However, over the longer term we believe that it reasonable to assume that LNG will be the most significant swing source of supply into the European markets.

[24] Liquefied Natural Gas (LNG) is used for transporting gas to global markets by sea transport. Gas is first cooled and hence liquefied in a process referred to as liquefaction. On reaching its destination, the LNG is subject to re-gasification rendering it suitable for transport in conventional pipelines.

2.62. For GB, we have created annual interconnector flow assumptions based upon the 2008 National Grid Ten Year Statement, and, as for the EU as a whole, assume that swing supply is provided by LNG on an annual basis. The logic is illustrated schematically in the diagram above.

2.63. For winter and peak gas supplies into GB, we assume that LNG terminals will be operating at close to maximum capacity (taking into account a de-rating factor to reflect the risk of outage), and that net flows over interconnectors are at their annual average. We then assume swing supply is provided by storage facilities[25]. These assumptions are tested as part of our stress tests, as described in Chapter 4.

Electricity market

2.64. Electricity prices are calculated within the model using a simple merit order stack according to the scenario fuel and carbon prices. The stacks are broken down by season, and there is a separate stack for the peak day. This produces a price based on the short run cost of the marginal plant in each demand block. An uplift component designed to reflect scarcity is added to this price to calculate the electricity prices in each period. The uplift function has been calibrated by analysing the historic relationship between spot prices, the short run cost of the assumed marginal plant and the system margin.

2.65. Any spikes in gas prices are reflected in the electricity price through the short run marginal cost component of the price. This enables us to understand how the demand side might respond across the gas and electricity sectors during periods when energy supplies are constrained. This is further explained in Appendix 2.

2.66. The model includes all generating units within the GB market (including those under construction) with capacity added and retired according to the scenario. The amount of renewables and plant fitted with carbon capture and storage (CCS) depends on the extent of environmental action in the scenario, with sufficient subsidies provided via the Renewables Obligation Mechanism, or Feed-In Tariffs for sub 5MW plant, to provide adequate returns to support each level of investment[26]. Likewise, the speed of new nuclear deployment is a function of the scenario. Thermal capacity, typically CCGT, is built where prices are sufficient to earn a return on investment. In the Green scenarios, little additional investment is required beyond renewables, CCS and nuclear.

[25] Gas storage is used to meet seasonal variations in demand. Gas is injected into storage facilities when demand and prices for gas are low. It is then withdrawn when demand and prices for gas are high. The gas is typically stored in some form of underground reservoir, such as a salt cavern or depleted gas field.
[26] For simplicity we have used a 10% cost of capital (post tax nominal) throughout. In the scenarios with slower economic growth we have assumed that capital is harder to come by but not more expensive.

2.67. Plant are dispatched based on their position within the merit order stacks, taking into account annual availabilities. Output constraints imposed by the LCPD and IED are captured within the model. This allows us to calculate the gross margins for different plant on the system. Where these gross margins are insufficient to cover the annual fixed operating costs of the plant, we assume that it is retired. The act of retiring plant reduces the de-rated capacity margin which feeds back into higher prices.

Modelling supply shortfalls

2.68. The model will adjust to a loss of supply or capacity by increasing supply from other sources: in the case of gas, from LNG or from storage in the winter; in the case of electricity, by dispatching spare generating capacity.

2.69. Where our scenarios show that there is still insufficient supply or capacity to meet demand, normally as a result of applying a stress test, we assess the resulting 'gap' in terms of different possible responses to balance the system. This will include curtailment of demand (voluntary and involuntary) and, in the case of gas, substitution by other fuels, to the extent that these are available. Further details of how we model the demand side impact are included in Appendix 2.

3. Scenario analysis

Chapter Summary

In this chapter, we present the key results from our scenario analysis, comparing outcomes between scenarios in the context of security of supply, environmental outcomes and the impact on prices and investment costs. At the end of the chapter we summarise the key messages from the scenario analysis.

Question box

Question 1: Do you have any observations or comments on the scenario results?

Question 2: Do you agree with our assessment of what the key messages of the scenario analysis are?

Question 3: Are there other issues relating to secure and sustainable energy supplies that our scenarios are not showing?

Question 4: To what extent do you believe that innovations on the demand side could increase the scope for voluntary demand side response in the future?

Introduction

3.1. Below we present the key results from our scenario analysis, looking first at security of supply for gas and electricity, and then covering environmental outcomes and the impact on prices and investment costs. We draw key messages from the scenario analysis at the end of the chapter.

Security of supply - gas

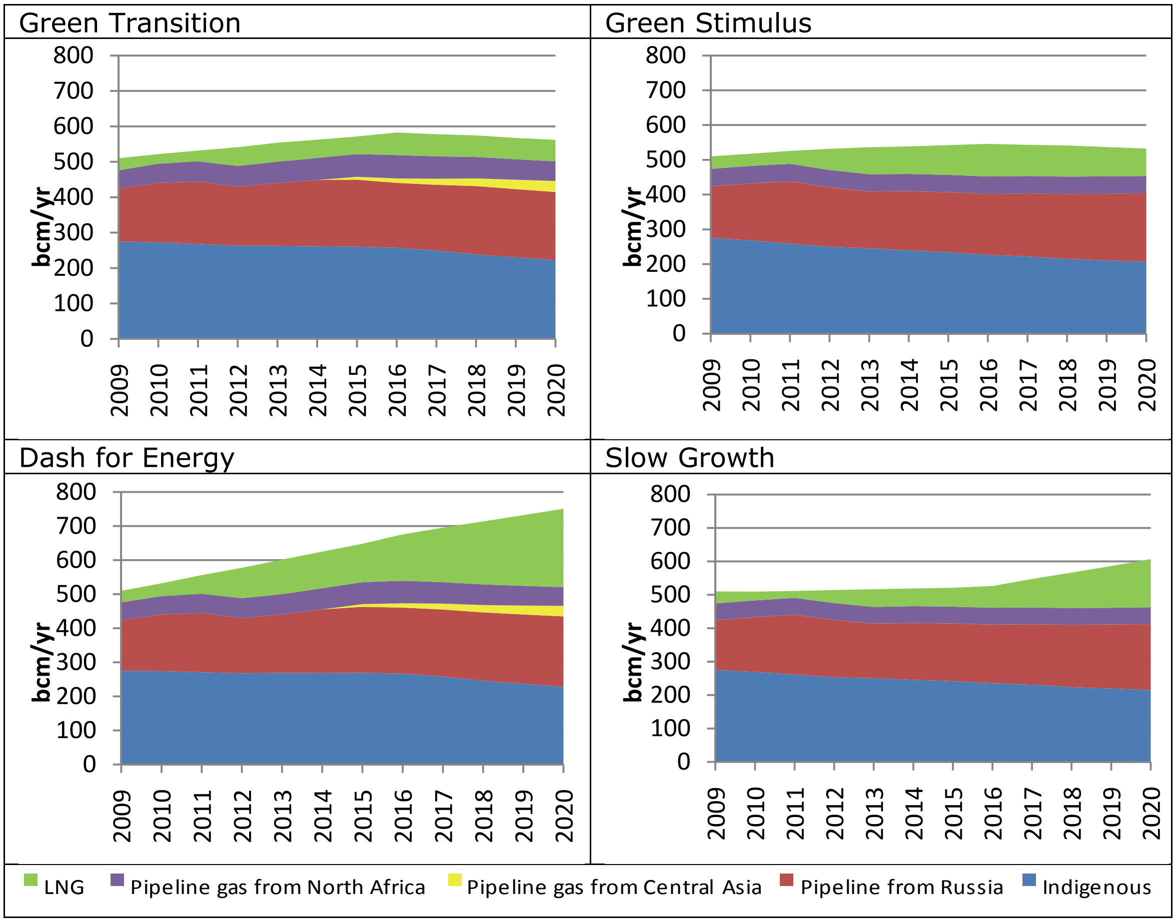
3.2. Given the increasing dependence on imports from Europe and the global LNG market, we start by presenting the demand and supply balance for these markets, before setting out the results for the GB market.

Annual EU gas supplies

3.3. GB security of gas supply is directly impacted by the supply and demand balance of gas in the EU. A shortage of gas and hence high prices in the EU could result in diversion of supplies away from the GB market e.g. LNG, Norwegian gas and potentially even gas held in GB storage through the interconnectors (as occurred during last winter's Russia-Ukraine gas dispute).

3.4. Figure 3.1 shows for each of our four scenarios how EU gas demand would be met from different different sources, including indigenous gas, pipeline supplies and LNG.

Figure 3.1: Sources of gas supply to EU



3.5. In arriving at our underlying trend for Russian pipeline gas supplies, we have assumed significant investment in existing fields and Yamal[27]. In the Dash for Energy case we have also assumed Shtokman[28] goes ahead (by 2017) and that Russian domestic gas subsidies remain in place, supporting high levels of domestic demand. Under the Dash for Energy and Green Transition scenarios (i.e. those assuming rapid

[27] The Yamal-Europe pipeline connects natural gas fields in West Siberia and in the future, the Yamal Pensinsula, with Germany. Yamal comes on in 2013 in our Green Transition and Dash for Energy scenarios, and in 2014 in our Green Stimulus and Slow Growth Scenarios.
[28] Shtokman is one of the world's largest gas fields, lying in the centre part of the Russian sector of the Barents Sea.

economic recovery), we assume Nabucco[29] is built and brings Central Asian gas to the EU. In the other two scenarios, we assume Central Asian gas flows into Russia.

3.6. There is a significant divergence between the scenarios in terms of overall demand for gas in the long term. Under Dash for Energy, we see EU gas demand rising to over 700bcm/yr from the current level of about 500bcm/yr. Under the Green Transition scenario, gas demand peaks to nearly 600bcm/yr in the medium term but then falls back as a result of environmental actions. The Green Stimulus scenario results in the least demand for EU gas, with demand not rising significantly above current levels.

3.7. Through all our scenarios we make the simplifying assumption that LNG provides 'swing supply' to Europe. Both the Slow Growth and Dash for Energy scenarios place increasing reliance on LNG to meet demand in the longer term. In the Dash for Energy case, the EU market becomes very reliant on LNG imports which account for around 32% of gas demand by 2020, notwithstanding increases in Russian pipeline gas and indigenous production levels. Under the Green Transition scenario, LNG supply does not grow significantly from current levels.

3.8. It is clear that under all scenarios there is a need for both Russian gas imports to increase and, under some scenarios, a significant increase in LNG imports in order to meet EU demand. In all our scenarios the market is operating with significant uncertainty about the level of Russian gas. Higher levels of Russian gas imports would reduce the LNG requirement that we have assumed, and vice versa.

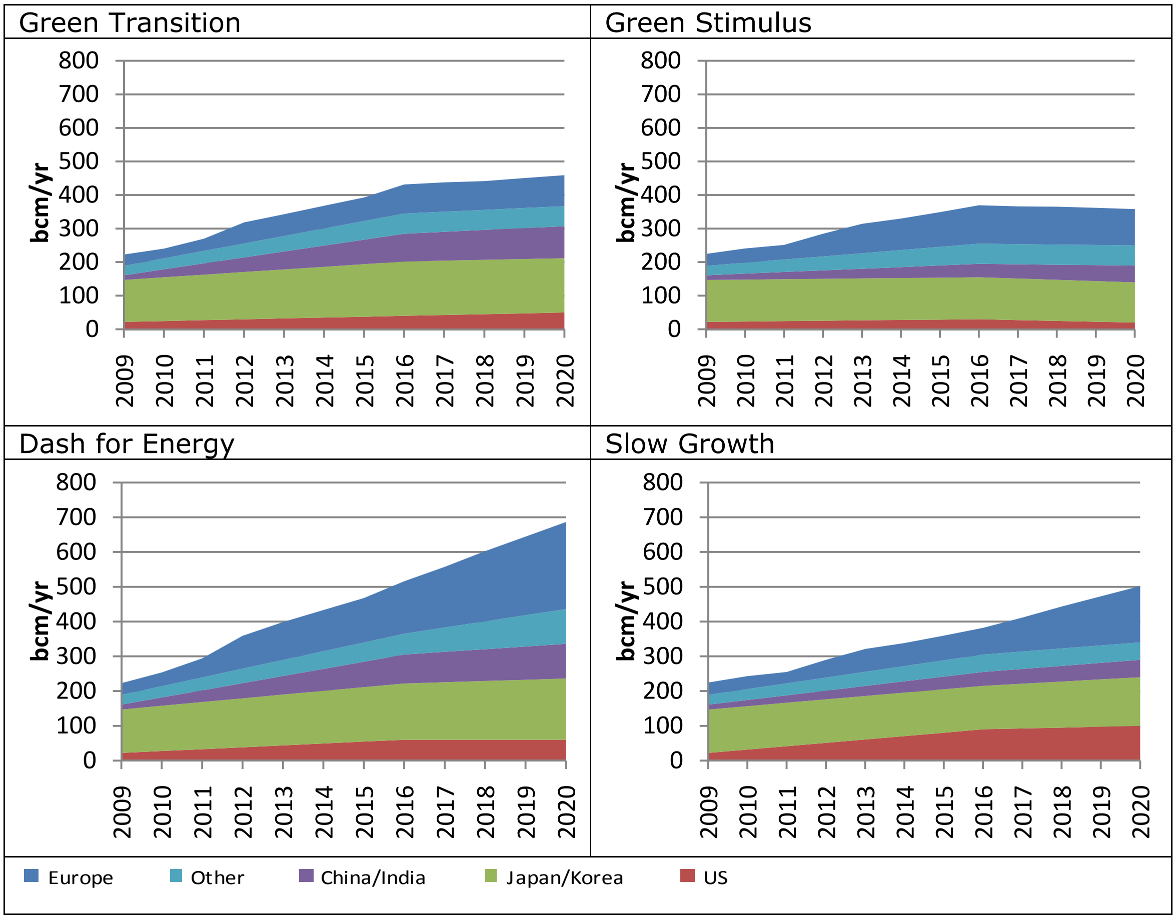
Global LNG demand and liquefaction capacity

3.9. As is apparent from the above analysis of EU gas supply, LNG plays an important role in meeting demand, particularly in the Dash for Energy scenario. Figure 3.2 shows the impact of EU LNG annual demand on global demand in our scenarios (using assumptions on demand from the rest of the world).

3.10. Our scenarios suggest global demand for LNG could double or even treble by 2020. Crucially, there is a very wide divergence of potential outcomes due to the different results in the different scenarios with global LNG demand ranging between 350bcm/yr and 700bcm/yr by 2020 depending on the scenario.

[29] The Nabucco project is a planned natural gas pipeline to run between Turkey and Austria, diversifying the current gas supply routes into Europe and giving additional access to Asian gas supplies.

Figure 3.2: Global LNG demand



3.11. We have assumed that there is an expansion of unconventional gas in the US in response to higher gas prices under all scenarios except Slow Growth. The reduced demand for LNG in the US may release incremental LNG supply to other markets. The availability of domestic gas sources means that the US does not present a significant demand centre for LNG going forward under three of our four scenarios.

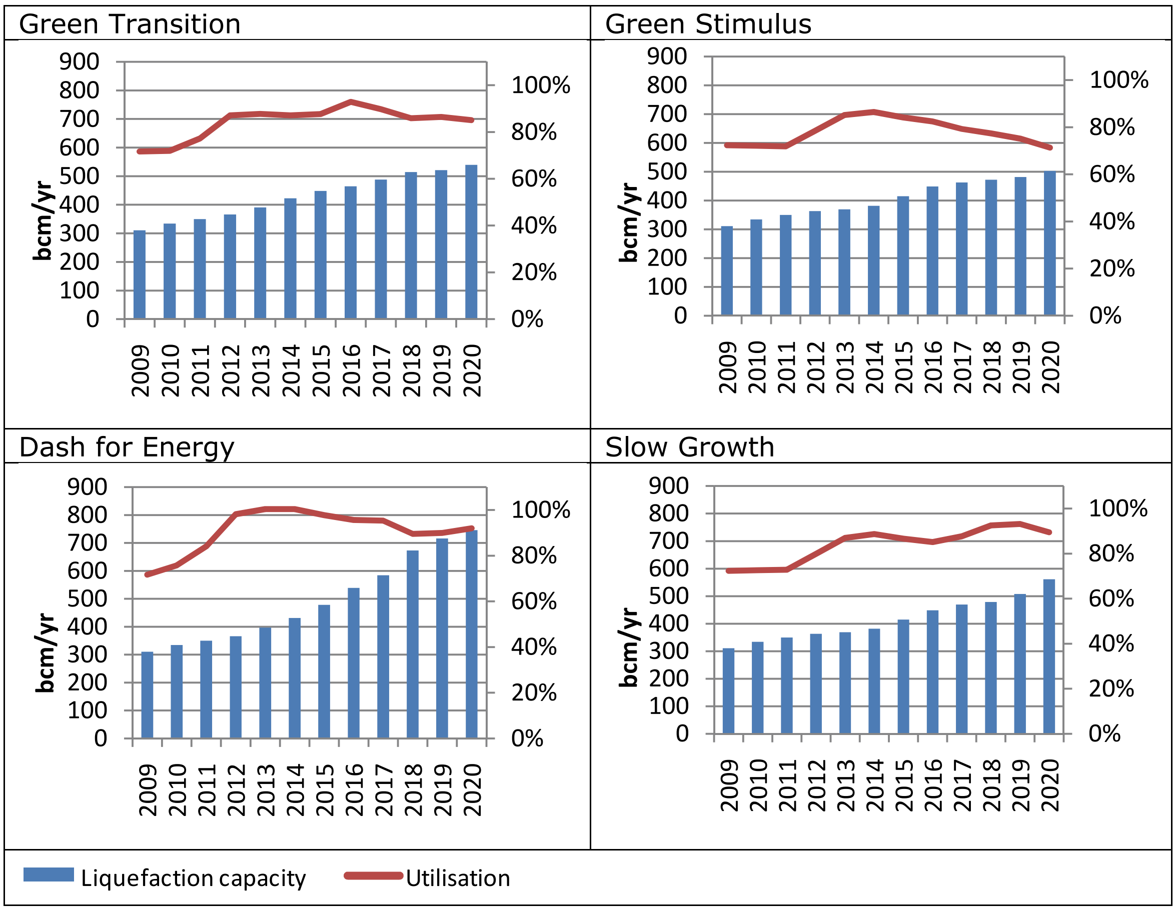
3.12. Our assumption is that the major LNG dependent importers (Japan/Korea) continue to consume with only modest growth from current levels. We assume most growth in non-European global LNG demand is driven by the emerging economies such as China and India.

3.13. Figure 3.3 shows the annual volumes of global LNG liquefaction capacity we assume are available under the four scenarios. We also plot the utilisation factor of the assumed capacity, assuming throughput volumes consistent with the global LNG demand identified above.

3.14. In order to deliver the substantial increases in global LNG supply projected in the previous section, significant new investment in liquefaction capacity is required.

3.15. We see LNG supply becoming tight by the middle of the next decade in all of our scenarios, with slightly less pressure in the case of Green Stimulus. Under the Dash for Energy scenario, we see a doubling of liquefaction capacity being required by 2020. Utilisation factors may exceed 100% of existing nameplate capacity which is technically possible in some cases but leaves the global LNG market at a higher risk of 'shocks' from failure of capacity.

Figure 3.3: Global LNG liquefaction capacity and terminal utilisation



3.16. This analysis considers LNG supply and demand in terms of the global balance. However we recognise that the market is regional. There may be constraints in shipping which mean that some LNG supply sources (e.g. Asia, Australia) may not always be available to meet EU demand.

Annual GB gas supplies

3.17. Having considered what the scenarios look like with respect to the European demand and supply market and the global LNG market, we now turn to the GB market. We start by considering GB gas demand on an annual basis before examining the demand supply balance during a cold (1-in-20) winter and on a peak winter day (1-in-20 cold day).

3.18. Figure 3.4 shows the sources of supply meeting annual GB gas demand[30] until 2020 in the four scenarios, including indigenous gas and imports (through the interconnectors and LNG), measured in bcm/yr. We also show the extent of LNG regasification terminal utilisation based on imported LNG volume throughput and projected capacity.

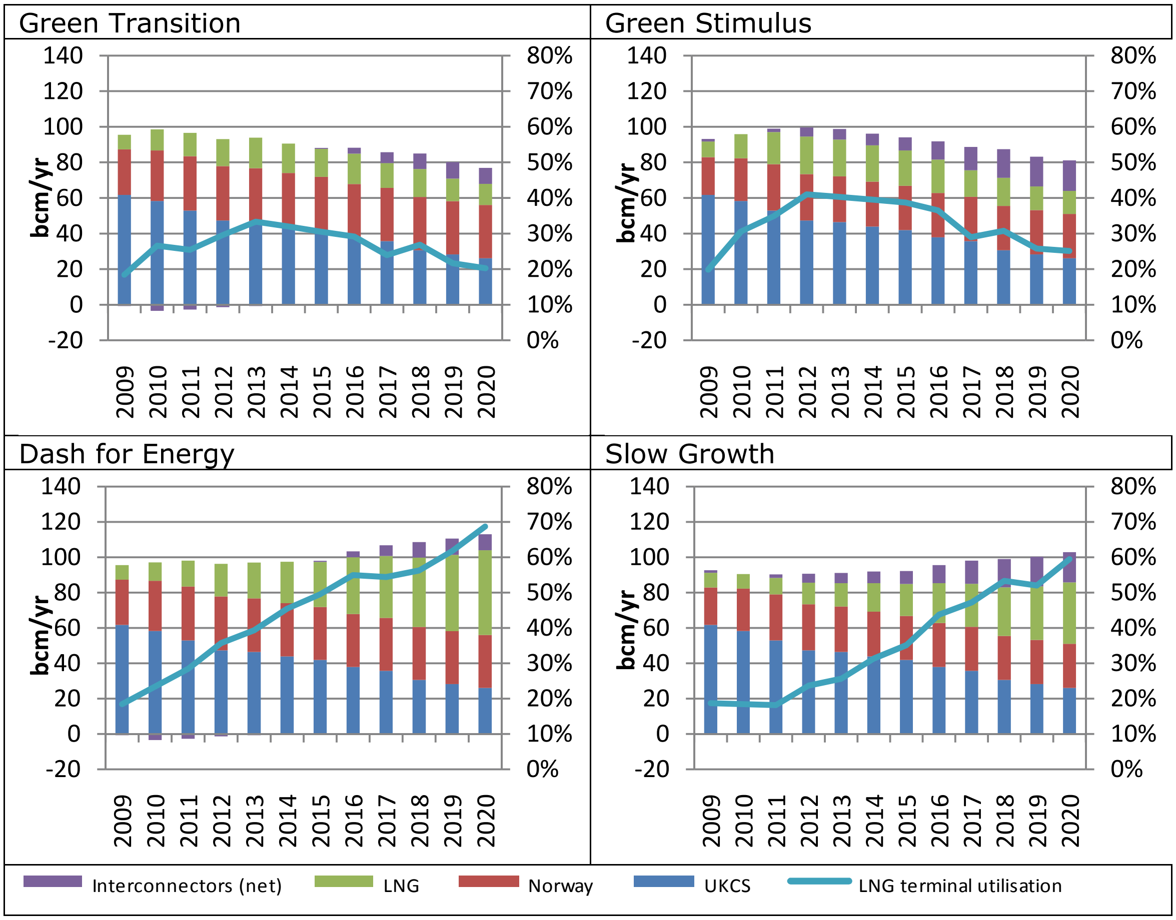
3.19. In the Green scenarios there is a significant drop in gas demand by 2020 through the combination of energy efficiency measures, reduced demand from the power sector due to expansion of renewables, and the displacement of gas used for heating by renewable heat sources[31].

3.20. To simplify our analysis, we have assumed interconnector flows based on cases in National Grid's Ten Year Statement. UK Continental Shelf indigenous gas resources are assumed to deplete from around 60bcm/yr in 2009 to around 26bcm/yr by 2020 under all scenarios. We assume LNG acts as the source of 'swing gas' to meet GB demand, subject to fulfilling minimum contractual arrangements.

3.21. Norwegian gas imports increase to around 30bcm/yr by 2011 in the Green Transition and Dash for Energy scenarios and to around 25bcm/yr in the other scenarios where we have assumed lower Norwegian production.

[30] By gas demand we are referring to natural gas. We assume biogas/biomethane will displace some demand for natural gas over time particularly in our Green scenarios.
[31] This includes a reduction in demand for piped gas resulting from greater penetration of solar thermal, biomass combined heat and power (CHP), biomass boilers and heat pumps and through the displacement of some natural gas by biomethane injected directly into the grid.

Figure 3.4: Annual GB gas supplies and LNG regasification terminal utilisation



3.22. Under all scenarios, the GB market is well supplied (as a result of falling demand) in the early years and hence there is relatively low LNG terminal utilisation. In the medium to longer term, the GB market is increasingly reliant on imports to meet demand.

3.23. There are clearly two very different futures for LNG terminal usage. Under the Slow Growth and Dash for Energy scenarios, there is increased reliance on LNG imports in the longer term, with regasification terminal utilisation factors rising to 60-70% from current levels of around 20%. Under the Green Stimulus and Green Transition scenarios LNG usage falls, and in the latter case capacity becomes significantly underutilised over time, in line with falling gas demand due to expansion of renewables and energy efficiency.

3.24. The range of uncertainty facing the market is huge: expectations of declining LNG utilisation may deter further LNG investment and yet significant new capacity may be required in the Dash for Energy scenario[32].

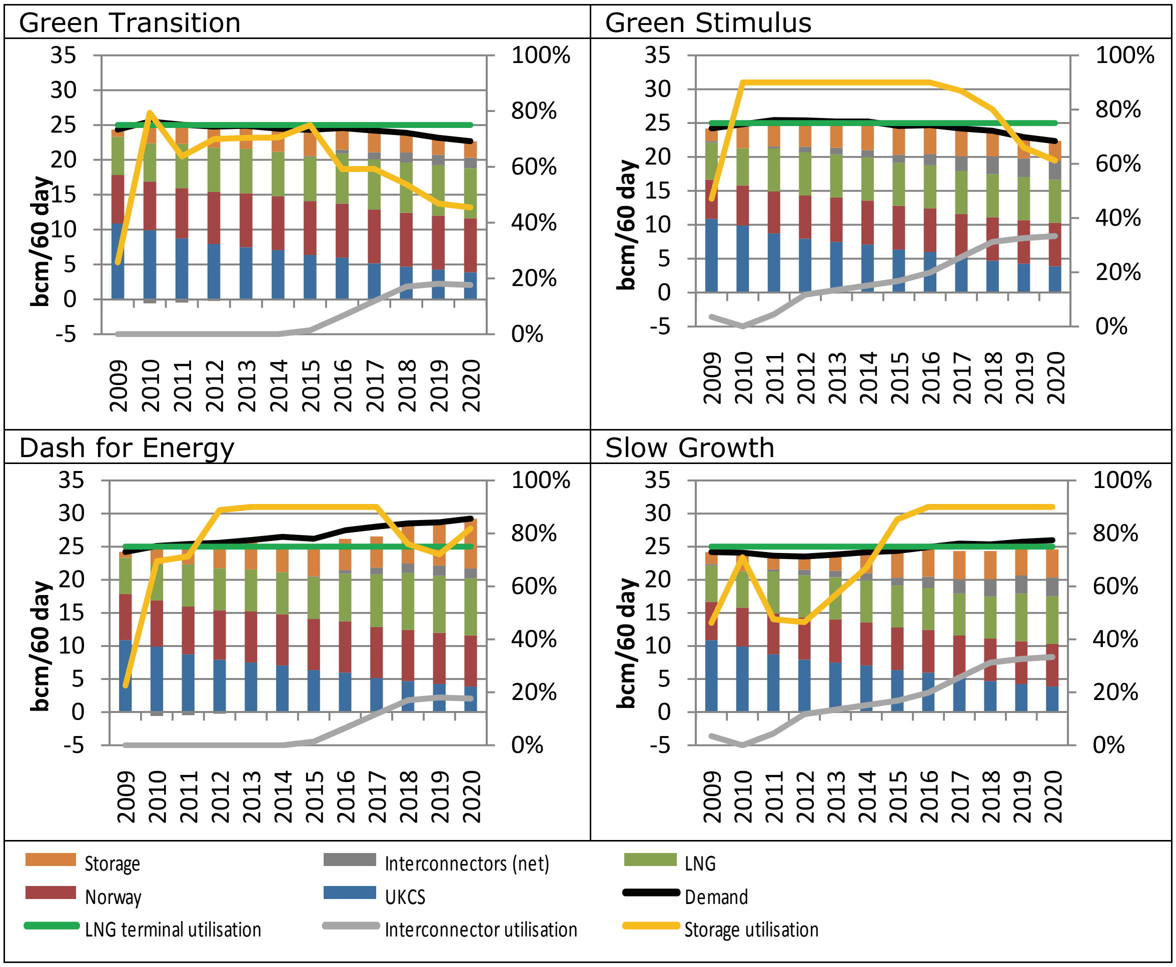
GB severe winter gas supplies

3.25. The above section looked at the outlook for annual demand and supply. In this section we consider how demand can be met during a severe winter. Figure 3.5 sets out the picture for GB gas supplies during a severe (1 in 20) winter measured over the coldest 60 day period (as previously defined in Box 1 in chapter 2). We show the level of GB demand (solid black lines on the graphs below) and the sources of supply available to the GB gas market in the short term, shown in the vertical stack bars in the graphs - including storage, interconnectors, LNG, UK Continental Shelf (UKCS) and Norwegian gas.

3.26. For these illustrations, we have assumed LNG terminals are utilised at 75% of total capacity during the winter (represented by the green lines) and interconnector flows are at the annual average rate (represented by the grey lines). Subject to there being sufficient stored gas available, withdrawals from storage provide the swing gas to meet demand during the winter. Storage is assumed to be full at the start of the winter, but we assume no further injections occur in the 60 day period (storage utilisation is represented by the yellow lines).

[32] Under the Dash for Energy scenario we assume that a further 25 bcm/yr of regasification capacity is constructed by 2020 in addition to the existing South Hook, Dragon, Isle of Grain and Excelerate terminals.

Figure 3.5: GB winter gas supplies during a 1-in-20winter



3.27. Two of our four scenarios would either require the interconnectors to operate at a higher level than the annual average[33] and/or balancing by way of demand reduction.

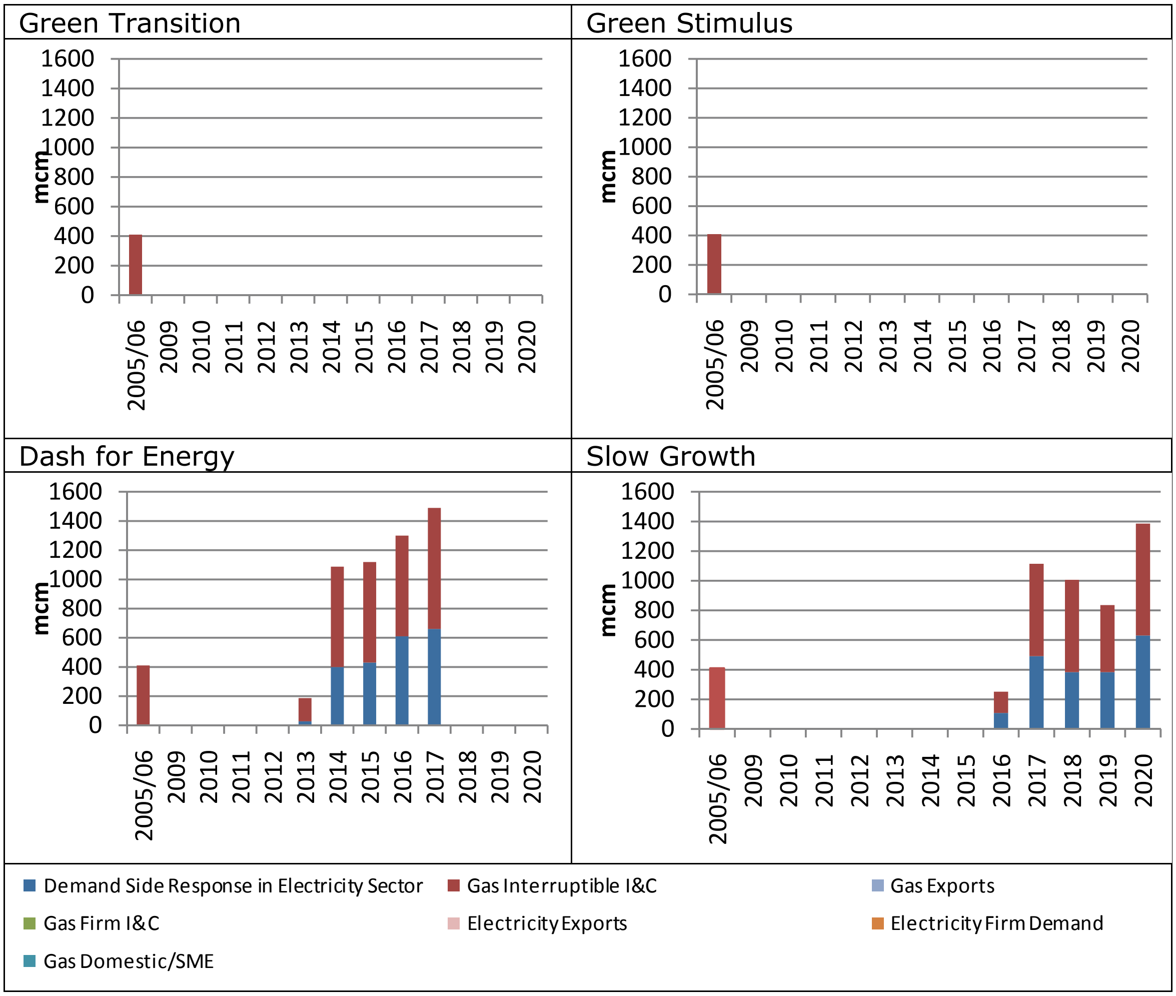
3.28. Under the Slow Growth scenario, lack of investment results in long term supply failing to meet modest demand growth. In Dash for Energy, there is insufficient near term investment to meet demand in the medium term, however in the longer term investment comes through in response to price spikes and supply catches up with demand.

[33] Lower levels of imports or indeed exporting through interconnectors would exacerbate any shortfall. This possibility is explored in our stress test analysis.

3.29. In the Dash for Energy and Slow Growth scenarios, assuming interconnectors only flow at the annual average rate through the severe winter, voluntary demand reduction occurs (in response to high prevailing prices or through the terms of interruptible contracts), but there is no firm load shedding (i.e. involuntary curtailment). This is illustrated in Figure 3.6. For reference, the figure also shows the estimated level and composition of demand curtailment which took place in the winter of 2005/06[34]. In that period, there were at least 400mcm of interruptions, over the 60 highest demand days due to cold weather in GB as well as the Continent, and to the Rough storage facility being unavailable at the end of the winter. The figure shows the levels of curtailment would potentially be considerably higher than those experienced in 2005/6.

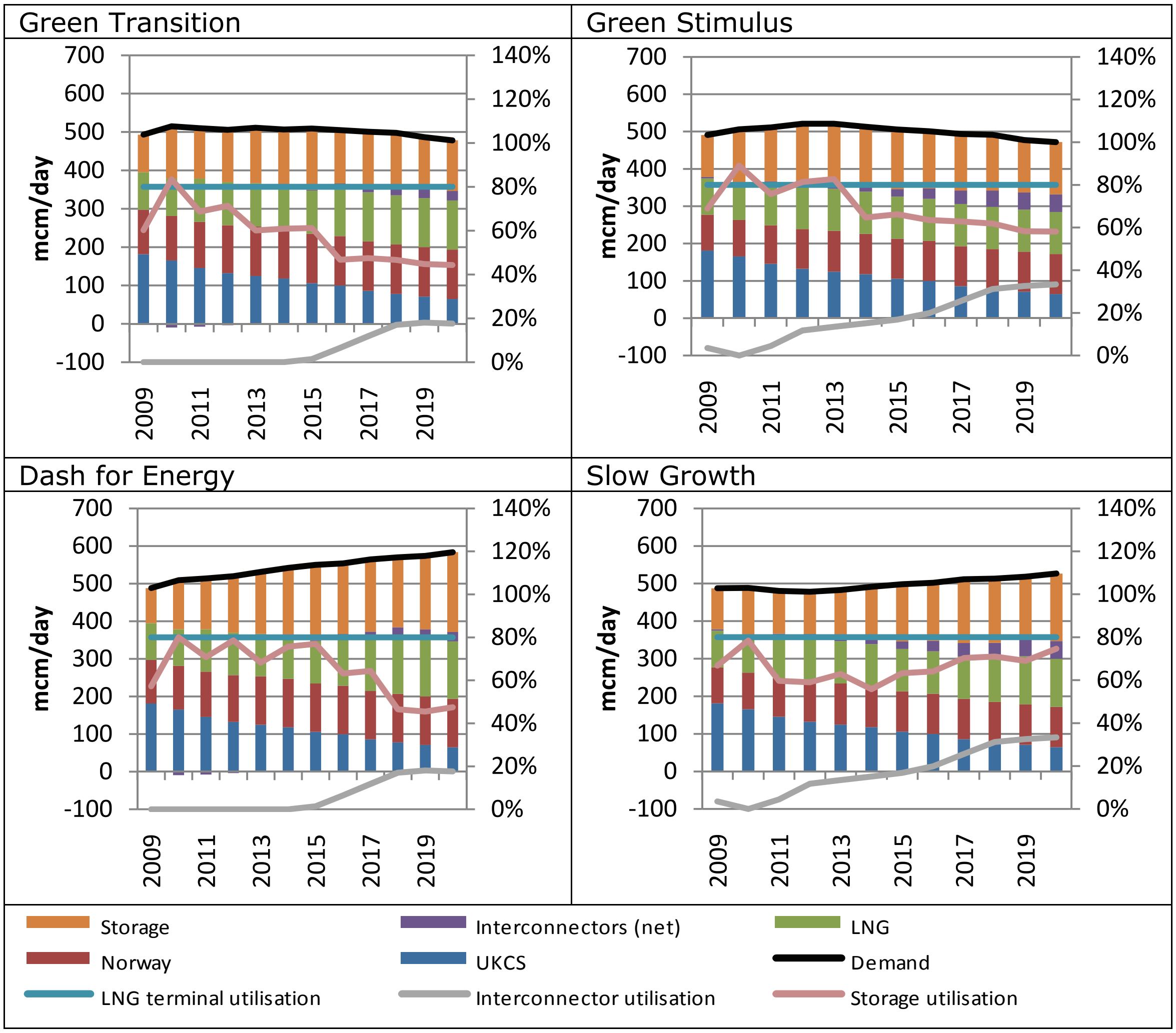
[34] The 2005/06 demand curtailment shown on Figure 3.6 and in later chapters refers to Interruptible Local Distribution Zone (LDZ) daily-metered demand response.

Figure 3.6: Demand curtailment in a 1-in-20winter under the Green Transition and Green stimulus scenarios (2009 - 2020)



3.30. In addition to considering how supply and demand may balance over a cold winter, we have also examined the demand and supply balance for a peak day (1-in-20 winter day), measured in mcm/day. Figure 3.7 shows that there is sufficient gas daily deliverability capacity to meet peak demand (in the absence of shocks) in all four scenarios.

Figure 3.7: GB gas supply and demand on a 1-in-20 peak winter day



3.31. Above, we have presented the scenario results with respect to meeting gas demand on an annual basis, over a cold (1-in-20) winter and on a peak winter's day (1-in-20). Our scenarios show that the greater risk is of having an insufficient supply of gas to last through a severe winter, rather than meeting demand on a peak day.

Security of supply - electricity

GB generation capacity

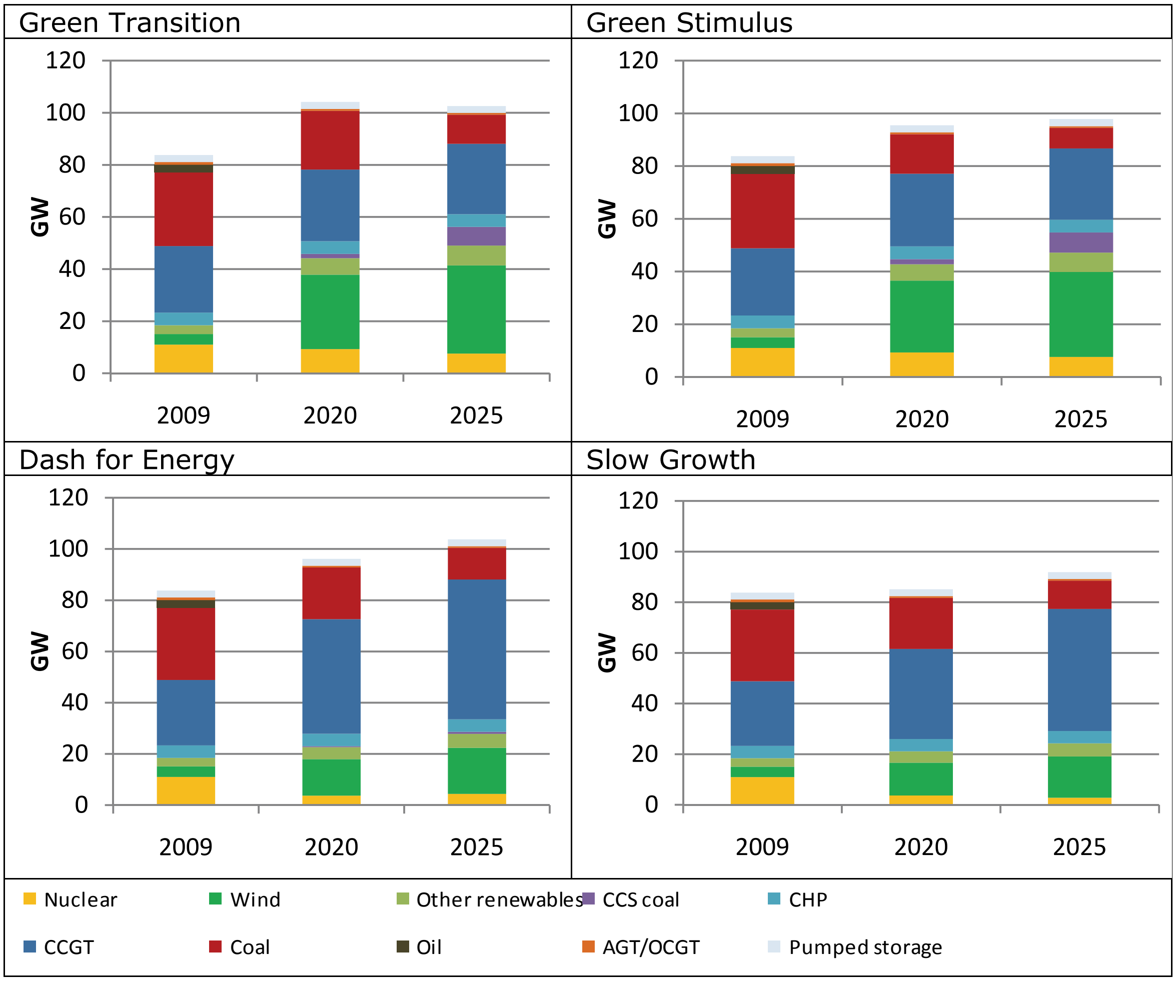
3.32. We now consider security of supply in the electricity sector under our four scenarios.

3.33. Figure 3.8 shows the projected GB generation capacity picture derived from our analysis under the four scenarios. GB capacity is currently dominated by flexible coal and combined cycle gas turbine (CCGT) capacity. We have assumed an appropriate mix of future capacity ensuring future plant remains profitable under the commodity price assumptions we adopt in each scenario. We have extended the electricity graphs to 2025 (as opposed to 2020 used in the gas graphs) because nuclear new build/CCS will only start to impact materially after 2020 but are likely to affect investment decisions before 2020.

3.34. In a world of low environmental action, where the penetration of renewables is modest, there remains a marked difference in levels of investment and capacity build out between the Slow Growth and Dash for Energy scenarios. In both these scenarios, the capacity shortfall caused by nuclear, coal and oil closures between 2012-16 leads to a significant build out of CCGT capacity, which increases the GB's gas import dependence.

3.35. In a world of significant environmental action, the penetration of renewable and nuclear due to subsidy and/or high carbon prices results in a lower growth in CCGT and a decreased reliance on gas. More coal and oil is retired in these scenarios. Coal plant fitted with CCS also plays a role. There is a higher level of intermittent generation on the system in the long term, implying that remaining thermal assets will need to be flexible to manage the variability on the system.

Figure 3.8: GB generation capacity

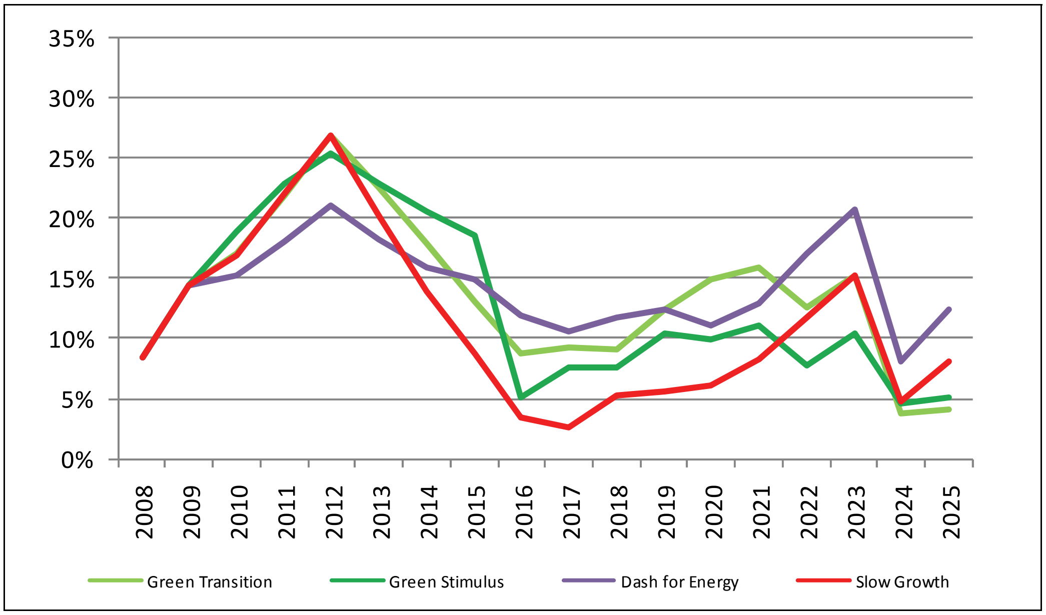


GB electricity de-rated capacity margins

3.36. Figure 3.9 shows the electricity de-rated capacity margin in each of the four scenarios. For this illustration of electricity security of supply we adjust the nameplate capacity of different generation types to reflect better the probable contribution it is likely to make to meeting peak demand. Therefore, wind assets will have a significant de-rating to reflect the lower average availability and risks of correlated periods of low output. Conversely, CCGTs which tend to be reliable, would have a relatively low de-rating factor.

3.37. The overall de-rated capacity margin is defined as the excess of 'de-rated' capacity to meet peak demand expressed as a percentage of peak demand. We de-rate wind to 15% of its nameplate capacity in our analysis[35].

Figure 3.9: GB electricity de-rated capacity margins



3.38. Figure 3.9 shows that under all scenarios there is an expectation that the de-rated capacity margin will rise in the near term through a combination of lower demand and commissioning of new CCGTs and renewables. The strong bounce back in demand under the Dash for Energy scenario means that the de-rated capacity margin does not rise to the same extent as in the other scenarios. Under the Green Transition scenario there is also strong demand growth, but the greater investment in renewables leads to higher de-rated capacity margins than under the Dash for Energy scenario.

[35] The annual availability, or capacity factor, of wind plant typically varies between 28% and 38%. On average, it might be expected that the contribution of any individual wind plant to security of supply might be equivalent to its capacity factor. However, statistical analysis demonstrates that the expected contribution that wind plant make to security of supply (the capacity credit) diminishes the more wind there is on the system due to the correlated nature of its output. This is because there is a far greater risk of no output from a fleet of wind plant than a fleet of thermal plant. Some studies suggest the capacity credit could fall as low as 10% for high levels of wind penetration. Whilst we recognise that the capacity credit is a function of wind penetration, for simplicity we use a flat 15% de-rating factor for wind throughout. Of course, during the period of peak demand the availability of wind plant could be higher or lower than this value. We have included a period of no wind coinciding with the peak demand day as one of our stress tests, in recognition of this risk.

3.39. After 2012, there is a significant impact from the Large Combustion Plant Directive (LCPD) on all scenarios, as oil and some coal plant that have opted-out are forced to close.

3.40. Under the Slow Growth and Dash for Energy scenarios, the Wylfa Magnox nuclear plant closes in 2012 and the Hunterston and Hinckley Point AGR nuclear plant close in 2016. Under Green Transition and Green Stimulus, there are extensions of two years on Wylfa and five years on Hunterston and Hinckley Point[36].

3.41. Under Slow Growth, where investment in new generation is low, this results in very low de-rated capacity margins in 2016 and 2017. De-rated capacity margins are also low during this period under Green Stimulus since although there is greater renewables build, there are further closures of coal and gas plant that are no longer economic under the Industrial Emissions Directive (IED) which succeeds the LCPD in 2016.

3.42. Under the IED, plant that do not meet the tighter NOx emissions limits, and have not invested in the necessary NOx reduction equipment, have the choice of operating under the Transitional National Plan (TNP) or the Limited Lifetime Opt-out (LLO). Under the TNP, plant must meet a progressively tightening annual limit on NOx and SOx emissions until 2020, and thereafter have their operation limited to 1500 hours per year. Under the LLO, plant can operate for up to 20,000 hours between the beginning of 2016 and 2023 but then must close.

3.43. The individual decisions of plant to invest in NOx-reduction equipment or to opt into the TNP or LLO depend on the economics of each scenario. The effect of closures of plant operating under the LLO on the de-rated capacity margin can be seen in 2023 in all scenarios. If a greater proportion of plants opt into the LLO rather than the TNP, this could have implications for security of supply as more plant would close over a short space of time. The increase in de-rated capacity margins prior to 2023, reflects market expectations of the forthcoming closures and, to an extent, mirrors the pre-LCPD spike in de-rated capacity margins that we anticipate in the near term.

3.44. A key message of the analysis presented above is that under our scenarios electricity capacity margins are uncertain and likely to vary considerably due to a complex array of different factors, including environmental policy.

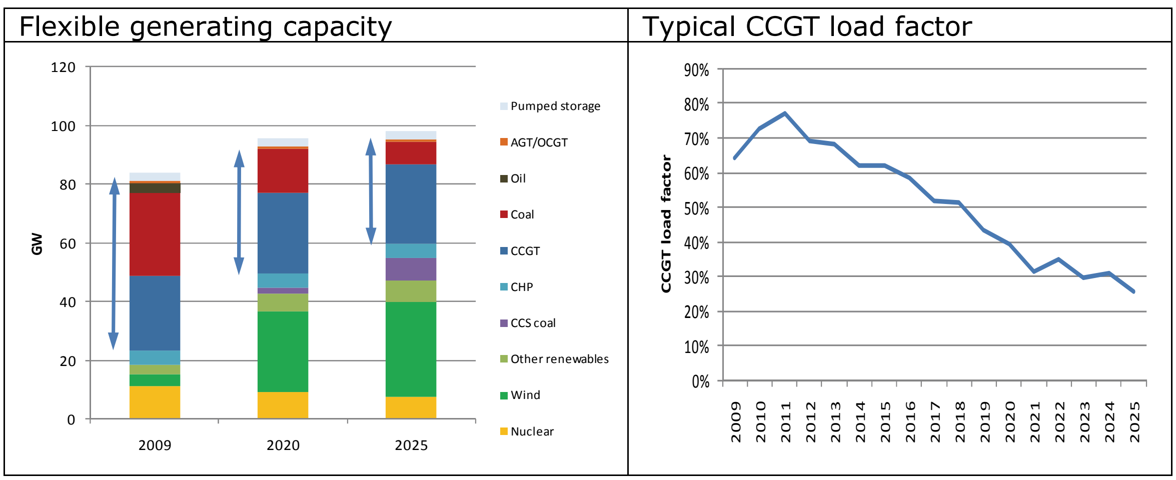
[36] In all scenarios we assume that the lifetimes of Heysham and Hartlepool are extended to 2019.

Managing intermittency

3.45. Under the Slow Growth and Dash for Energy scenarios, there is a growing dependence on gas-fired capacity. Under both Green scenarios, there is a high proportion of intermittent generation by 2020 where environmental policies have been successful. Under these scenarios gas dependence in the generation sector does not increase. All scenarios imply a diminishing role for coal fired capacity (until CCS is feasible).

3.46. Under the Green scenarios, the amount of flexible thermal capacity (i.e. coal and gas, indicated by arrows in the graph on the left in Figure 3.10 below) declines over time. CCGTs make up an increasing proportion of what remains. CCGT load factors in our model decline as renewables, CCS and nuclear are commissioned. As a result, the GB system will increasingly rely on CCGTs to operate flexibly in the future. The graph on the right of Figure 3.10 illustrates the declining load factor of a typical CCGT plant from our model under the Green Stimulus scenario.

Figure 3.10: Flexible generating capacity and typical CCGT load factors under the Green Stimulus scenario



3.47. In order for CCGTs running at low load factor to remain profitable, prices would need to be allowed to peak to high levels during periods of low wind output. As part of Project Discovery we are considering whether current market arrangements are adequate to provide the necessary price signals to ensure sufficient peak thermal capacity remains on the system, and/or that increased investment in demand side response occurs.

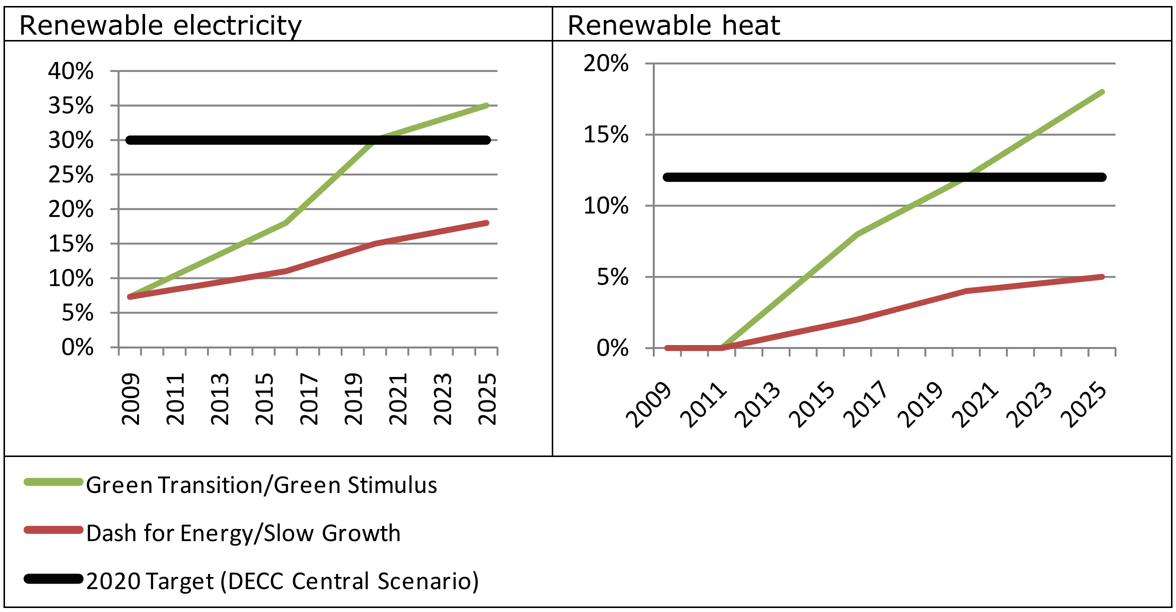
3.48. We present a stress test in Chapter 4 of this report where we show what would happen if a period of no wind output coincided with a peak demand day.

Environmental impact

Progress towards UK renewables target

3.49. Figure 3.11 shows our assumptions on renewable electricity and heat penetration across the scenarios. We also show the 2020 target which for the UK as a whole is for 15% of energy provision to be from renewables by 2020, broken down according to DECC's central scenario published with the Renewable Energy Strategy published in July 2009 i.e. 30% for renewables electricity and 12% for renewables heat. Under the Green scenarios these targets are met, but under the Dash for Energy and Slow Growth scenarios investment falls short. In these scenarios, renewables only make up 15% and 4% of the electricity and heat sectors respectively by 2020.

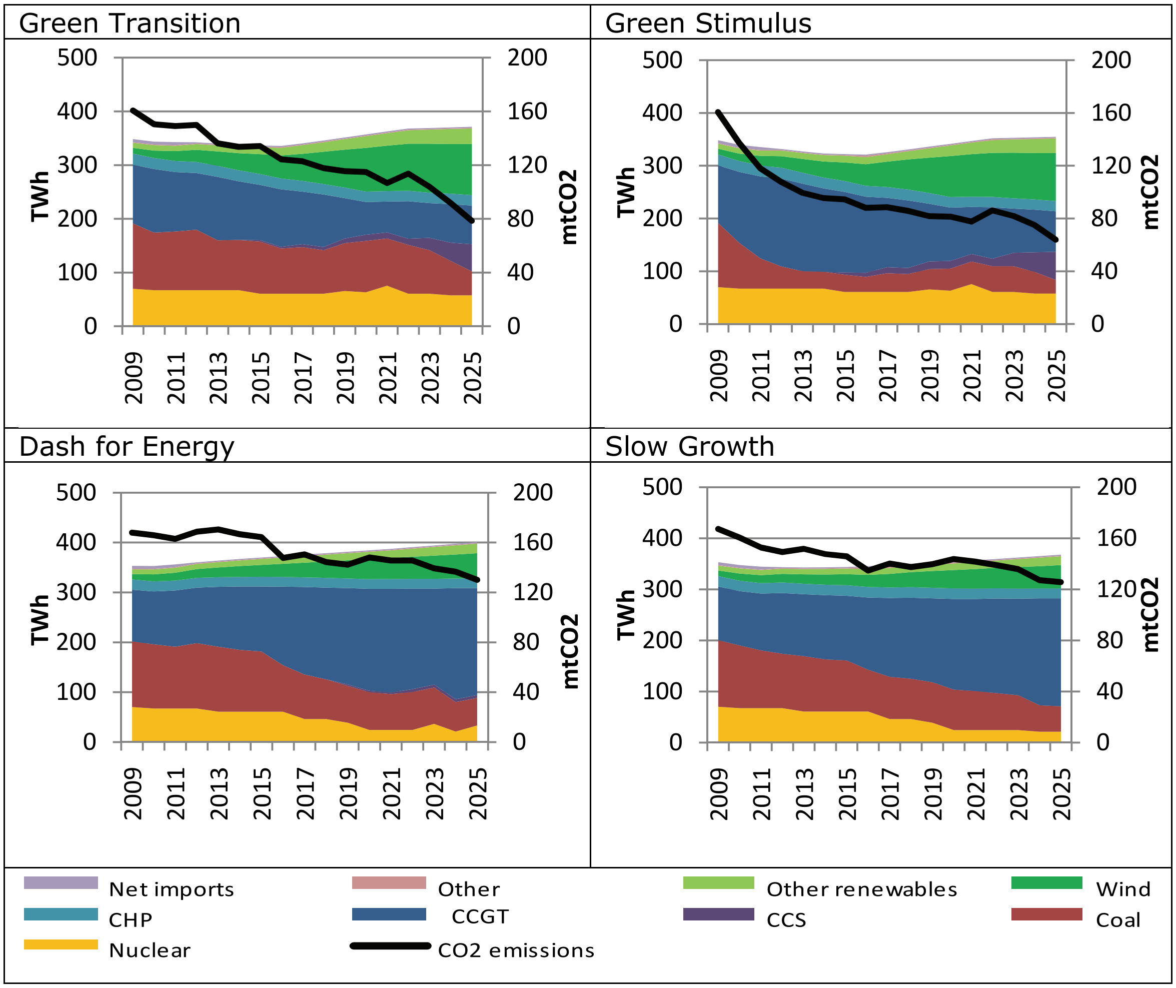
Figure 3.11: Renewable heat and electricity penetration assumptions



Emissions from GB generation sector

3.50. Figure 3.12 shows the model's outputs for GB annual generation output under the four scenarios in TWh by generation type, and the carbon dioxide emissions from the sector.

Figure 3.12: GB generation output and carbon dioxide emissions from the generation sector



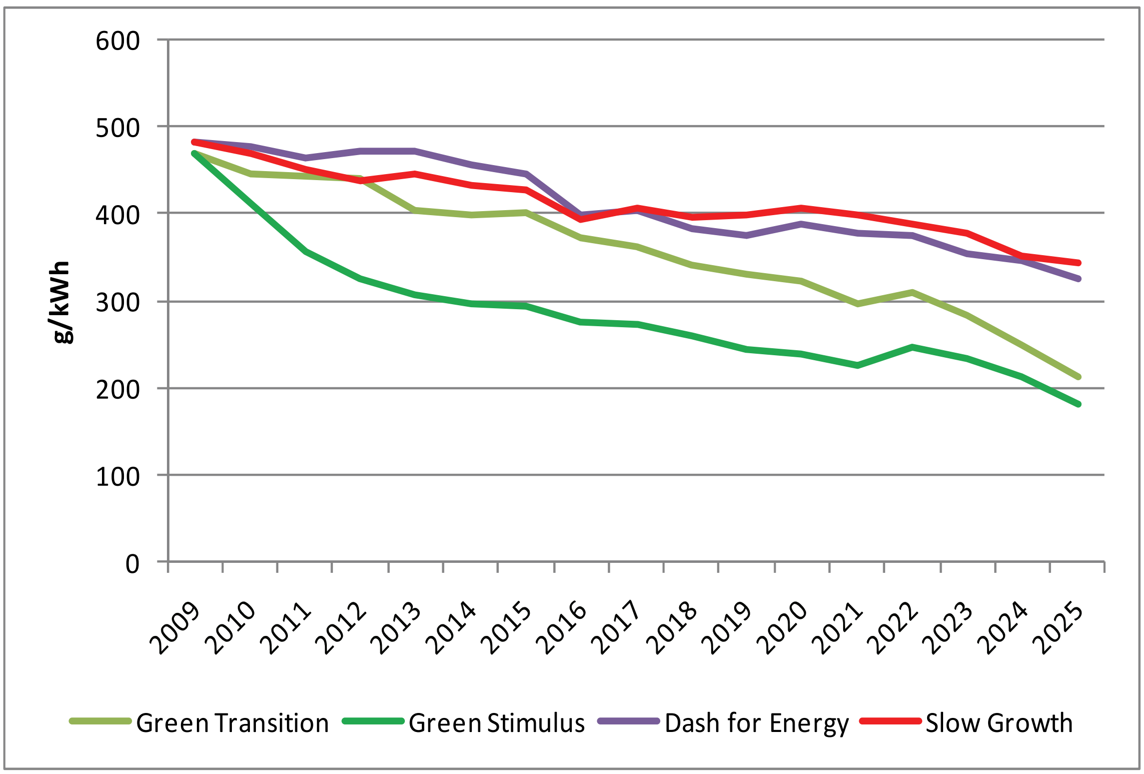
3.51. In the near term, the scenarios differ with respect to the proportion of gas and coal fired generation output, reflecting the relative cost of fuels we have assumed. We should note that demand reductions in the near term are most significant in the Green Stimulus scenario because we assume a higher impact from energy efficiency measures which combine with the impact of lower economic activity.

3.52. In the longer term, there is a significant increase in gas-fired generation output in the Slow Growth and Dash for Energy scenarios as a result of new CCGTs replacing retiring coal and nuclear capacity. There is also an increase in renewable generation. In the Green scenarios, there is rapid expansion of renewables together with new investment in nuclear and CCS plant. As a result, gas-fired generation declines.

3.53. Carbon dioxide emissions vary significantly between the scenarios. As expected, the Green scenarios have a much greater reduction in overall CO2 emissions by 2025. The reason for the slight increase in CO_2 emissions under these scenarios around 2020 is that the proposed CCS demonstration plants will be only required to fit CCS technology to part of their plant in the first instance and hence there is temporarily an increase in unabated coal on the system. Once CCS is technically and economically proven (which we assume to be the case) the remaining units on the plant must be retrofitted and hence carbon dioxide emissions subsequently fall.

3.54. Carbon intensity in 2020 varies from 408 g/kWh under the Dash for Energy scenario to 240 g/kWh under the Green Stimulus scenario. As a reference the Committee on Climate Change[37] indicates that assuming a goal to decarbonise the electricity sector by 2050 (as part of an overall 80% reduction from 1990 levels), the carbon intensity of the generation sector should be in the region of 300 g/kWh by 2020, and 75 g/kWh by 2030. Figure 3.13 below shows how the carbon intensity evolves through time under each of our four scenarios.

Figure 3.13: Carbon intensity in the GB generation sector

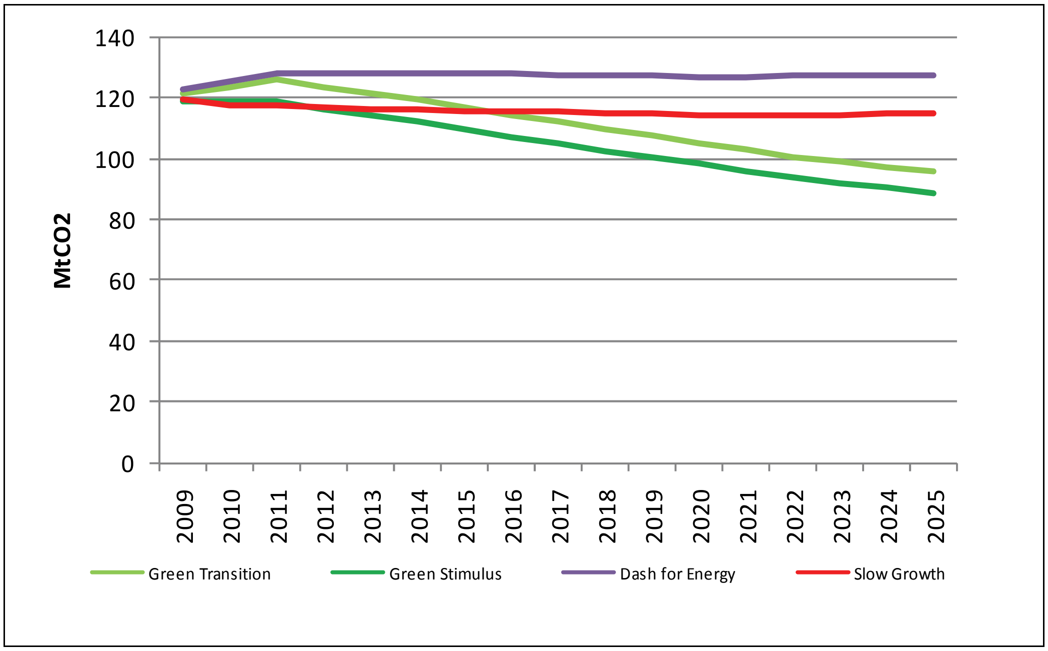


[37] http://www.theccc.org.uk/reports/building-a-low-carbon-economy

Emissions from GB gas sector

3.55. Figure 3.14 shows our estimates of carbon dioxide emissions from the gas sector (non-generation) under the four scenarios. Emissions fall rapidly in the Green scenarios through the combination of effective energy efficiency measures and the rapid deployment of renewable heat technologies.

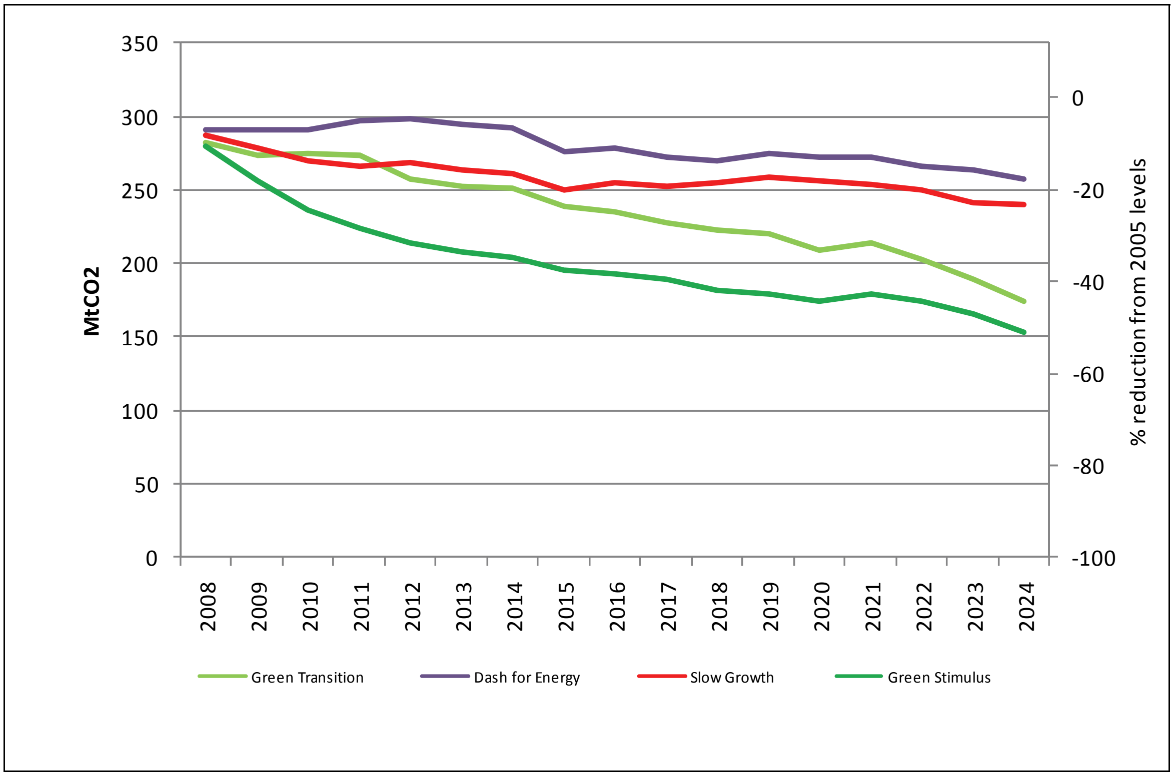
Figure 3.14: Carbon dioxide emissions from the GB gas sector



Combined emissions across the electricity and gas sectors

3.56. Figure 3.15 combines the carbon dioxide emissions from the electricity and gas sectors. We show the total emissions in MtCO2 and the percentage reductions from 2005. By 2020, reductions range from 43% in the Green Stimulus scenario to only 12% in the Dash for Energy scenario. By comparison the Government's carbon budgets require reductions of between 21% under the interim target and 31% under the intended target across the economy as a whole.

Figure 3.15: Combined carbon dioxide emissions from the GB generation and gas sectors



Investment, prices and consumer costs

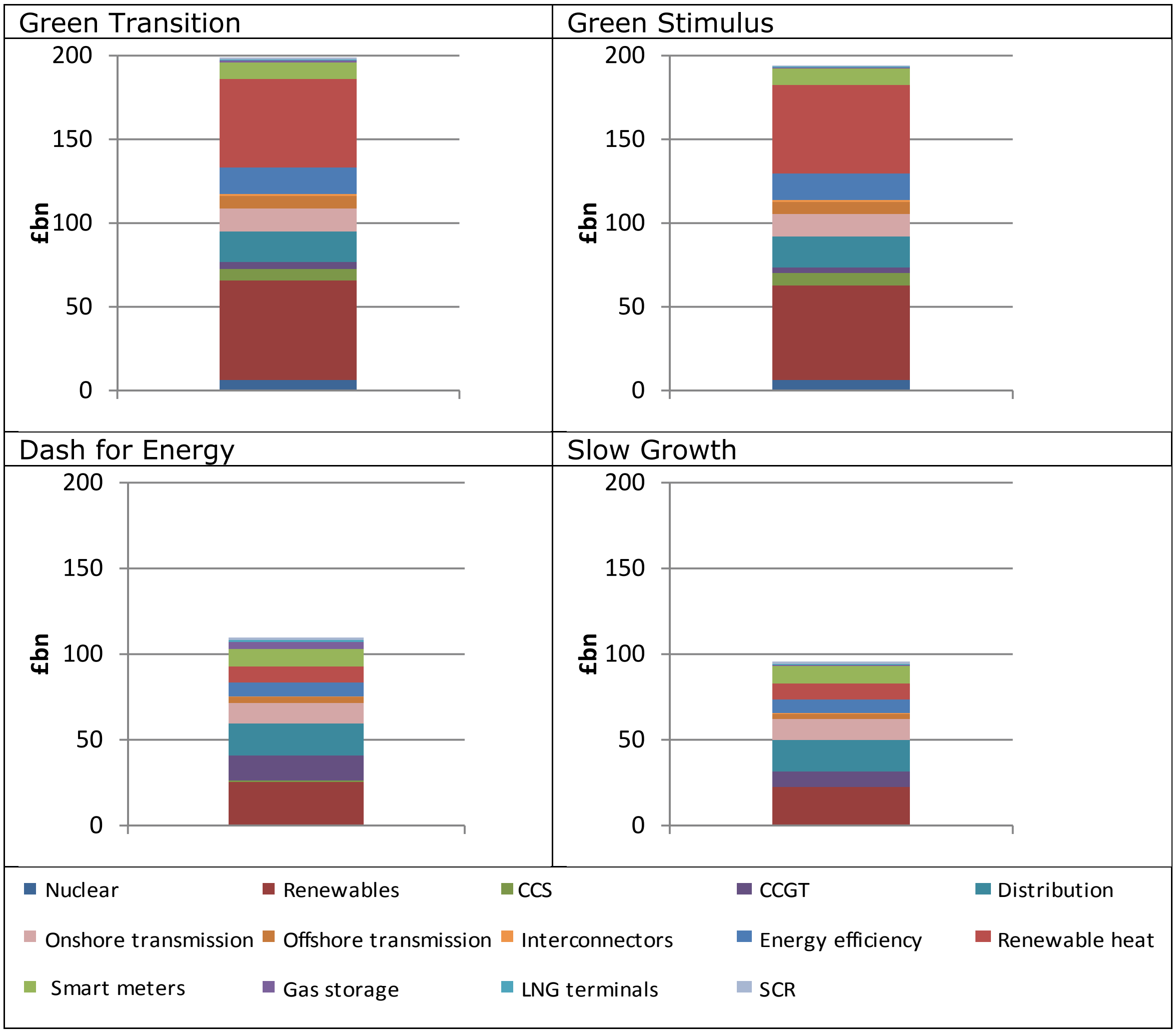
Investment costs

3.57. Figure 3.16 shows the assumptions we have made on future investment in the four scenarios from 2009-2020 inclusive[38]. The extent of capital required varies significantly for the different cases, with the Green scenarios requiring higher initial investment. It should be noted however, that the graphs only include capital expenditure and do not reflect the different marginal costs associated with each approach. Nor do the graphs reflect the different present values of energy associated with the varying capacity mixes which arise under each scenario.

[38] The figures include investment required in generation, renewables, LNG, transmission and distribution (both replacement and expansion), storage, interconnectors and energy efficiency. They exclude investment in upstream UKCS production.

3.58. The numbers shown below include capital already committed in 2009 and the projected costs of plant expected to be commissioned by 2020. However, the numbers exclude investment in new nuclear and CCS commissioning after 2020.

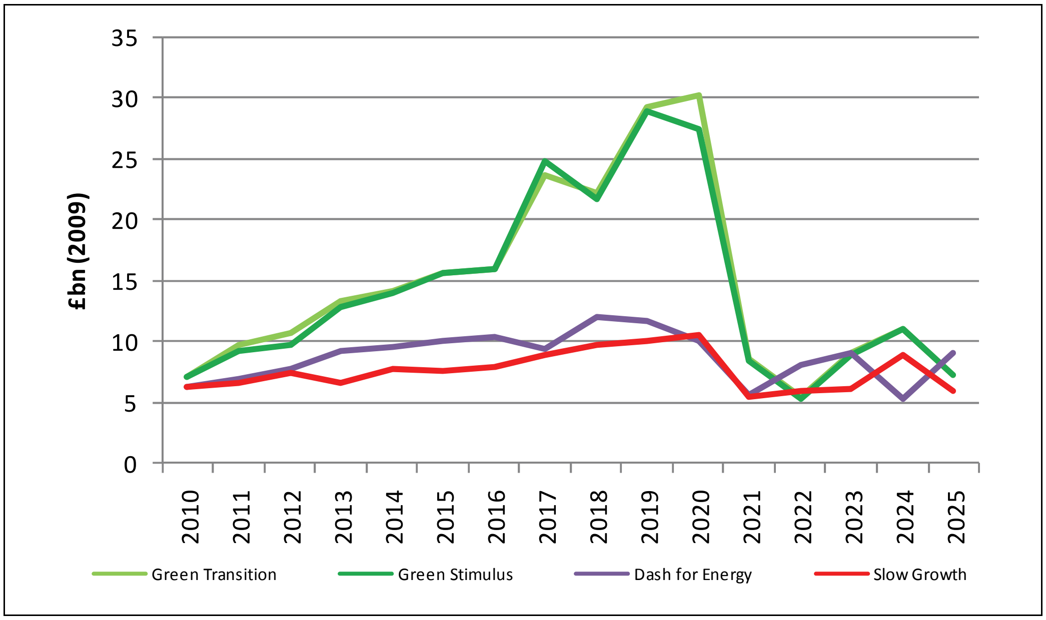
Figure 3.16: Required investment between 2009 and 2020



3.59. Figure 3.17 below shows the investment on an annual basis for each scenario. The investment is shown in the year that the assets are commissioned. There is a peak in investment in the run up to 2020 in our green scenarios driven by renewable in order to meet the 2020 targets.

3.60. To put these numbers in context, GB energy utility capital expenditure in 2008 was estimated at approximately £8bn (up about 40% on 2007 levels).

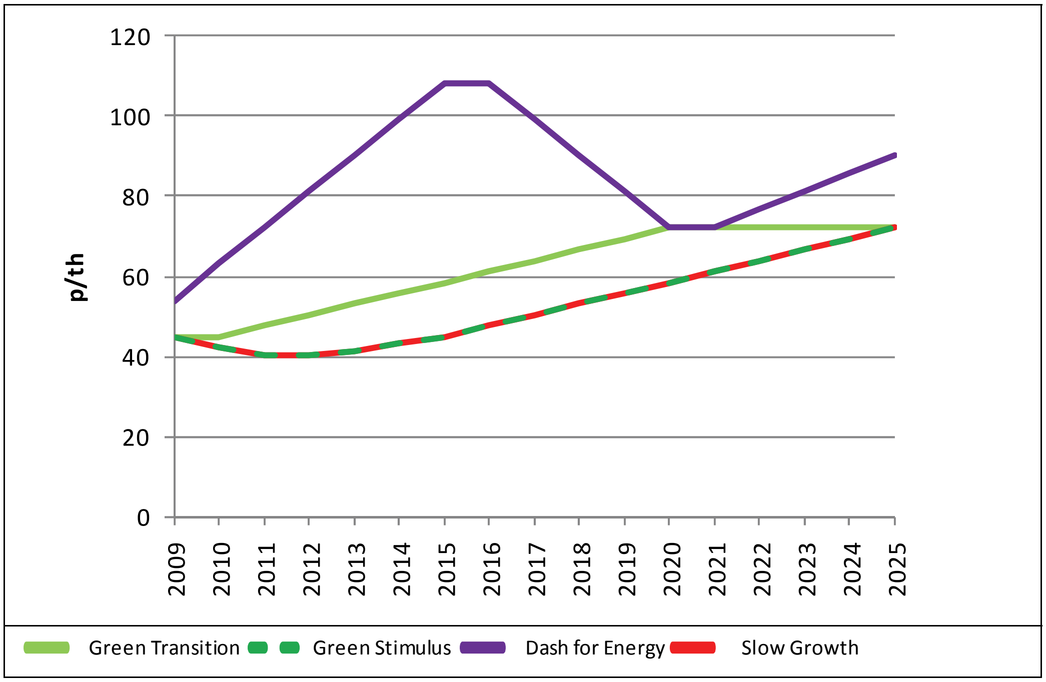
Figure 3.17: Annual investment required



Wholesale energy costs

3.61. In general our scenarios show increasing gas prices reflecting tightening supply as EU indigenous production declines, as shown in Figure 3.18. The exception is in the near term under Slow Growth and Green Stimulus where falling demand leads to lower prices over the next few years.

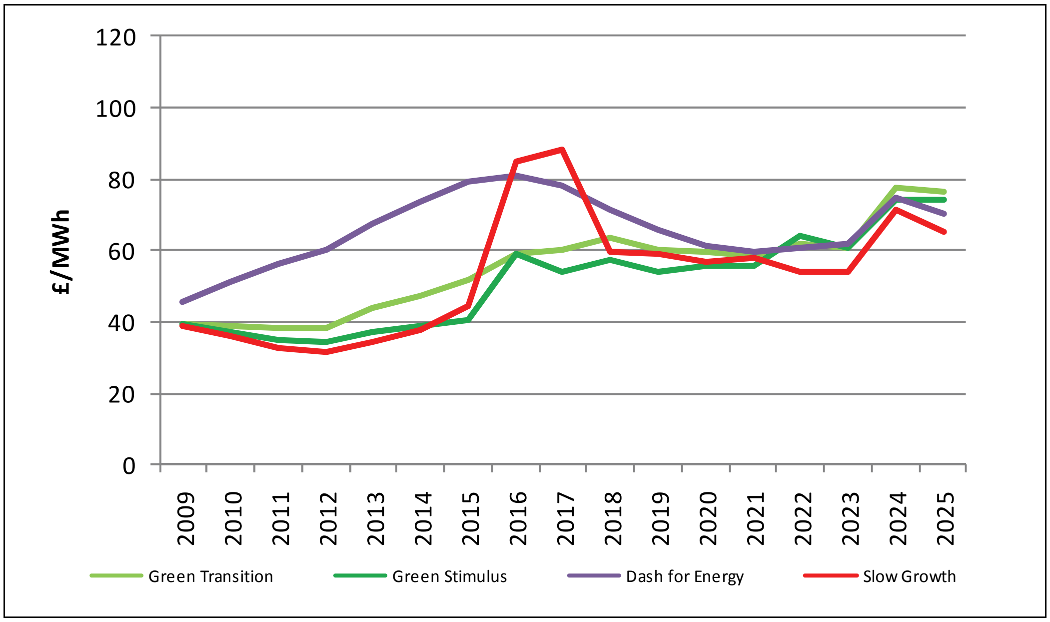
Figure 3.18: Gas prices



3.62. The combination of increasing gas and carbon prices[39] pushes up electricity prices in our scenarios. Electricity prices are also a function of the de-rated capacity margin. A spike in electricity prices can clearly be seen in Figure 3.19 below under Slow Growth in 2016 and 2017 when the de-rated capacity margin becomes particularly tight.

[39] Consumers will be exposed to the increasing cost of carbon which will be reflected in the electricity prices. However, the auctioning of carbon allowances will generate revenues for Treasury which may benefit consumers in other ways.

Figure 3.19: Wholesale electricity prices



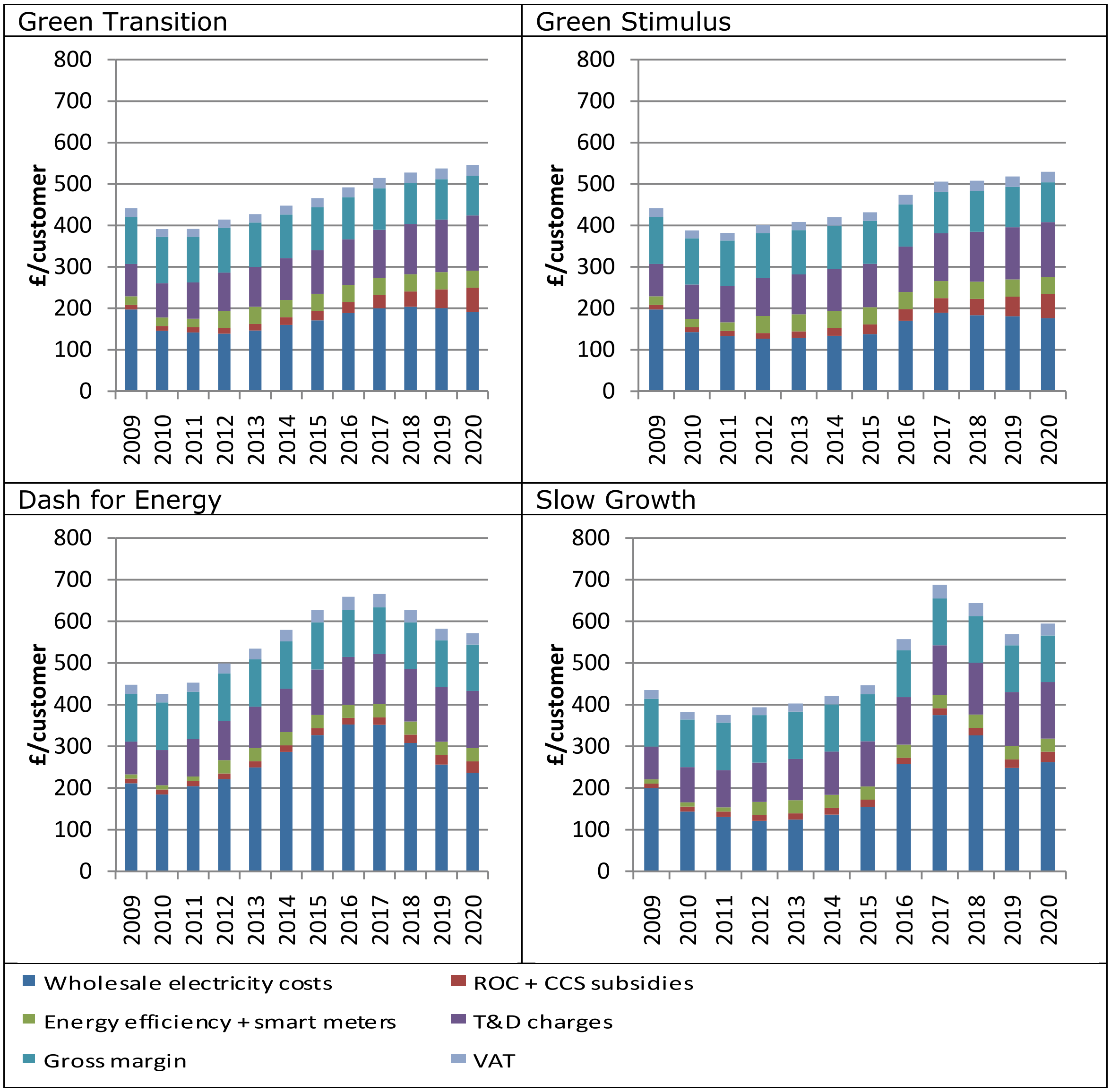
Impact on consumer bills

3.63. In Figures 3.20 and 3.21, we show the estimated impact on domestic consumer bills of the different scenarios. The impact includes the effects of wholesale energy costs, environmental costs (ROCs and CCS subsidies, energy efficiency measures and smart meters) as well as network costs, margins and VAT. Similar trends occur in electricity and gas costs to industrial and commercial (I&C) consumers. In all scenarios, we assume the consumer bears a significant portion of the cost of all investment in renewables and energy efficiency measures.

3.64. Some care should be taken when interpreting these graphs. They reflect the annual costs, but do not reflect the potential future benefits of a particular scenario. For example, significant upfront investment in renewables today might lead to cheaper energy bills later, since customers will to some extent avoid paying for (potentially increasingly expensive) fossil fuels.

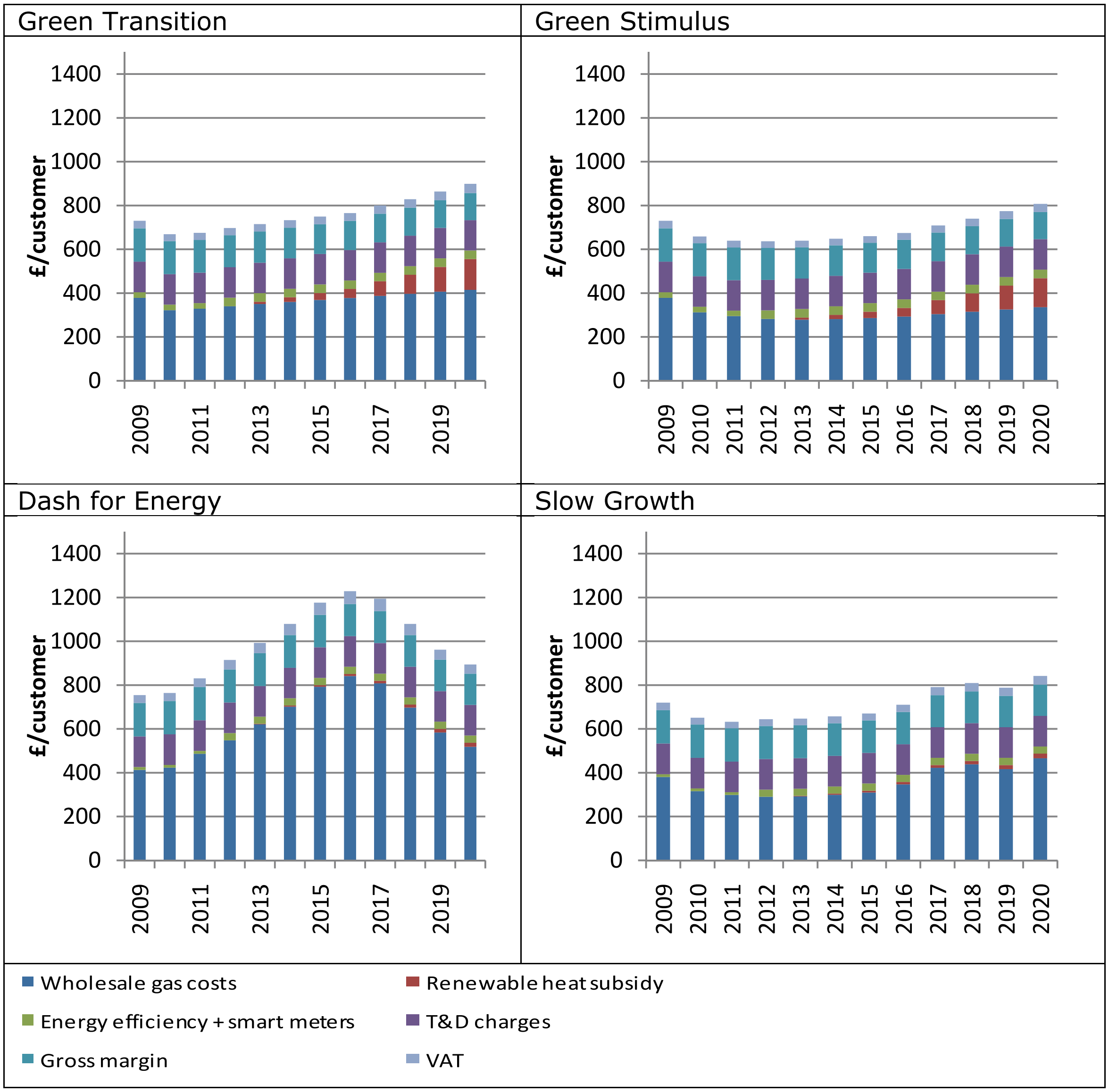
3.65. For these illustrations, we assume average annual domestic user consumption of 3300kWh in electricity and 700th in gas. We assume average consumption reduces over time in line with energy efficiency measures[40].

Figure 3.20: Average domestic consumer electricity bill



[40] Note these illustrations do not take into account how the consumption pattern of a domestic user might change through greater deployment of heat pumps and electric vehicles in the future.

Figure 3.21: Average domestic consumer gas bill



Key messages from the scenario analysis

3.66. Table 3.1 below summarises some of the key conclusions for each scenario.

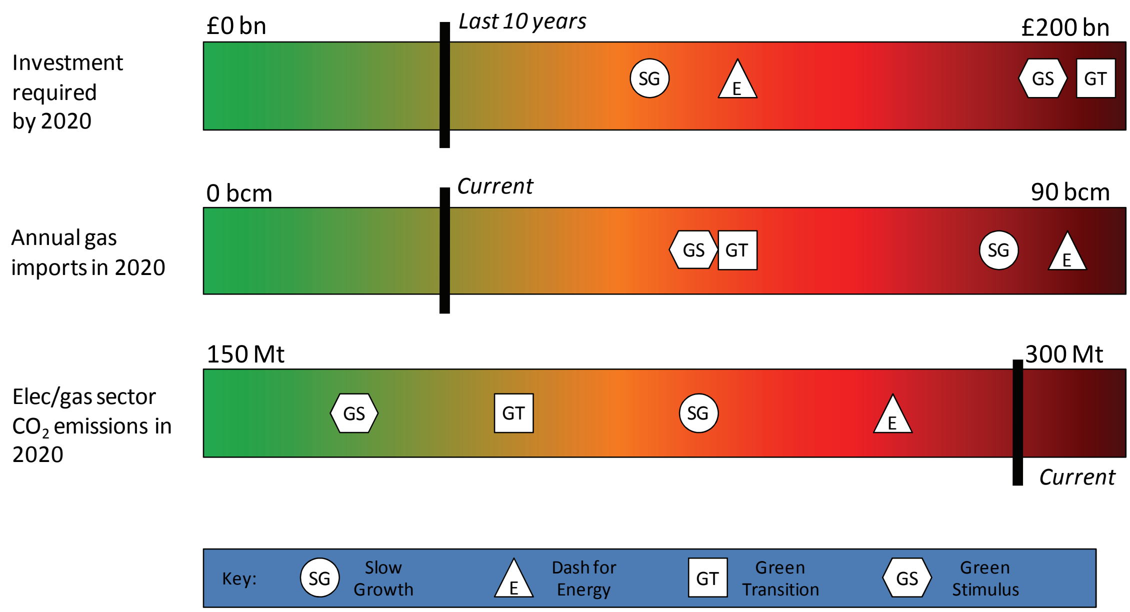
Table 3.1: Key messages from the scenarios

Green Transition	Green Stimulus
Under the Green Transition scenario, the EU renewables target and the Government's carbon budgets are met, but at a cost to consumers in the near term who would be required to fund the investment. This scenario is generally favourable to security of supply due to a combination of falling demand through energy efficiency measures and the stimulated investment in new renewables and CCS capacity. With new nuclear as well, the generation mix is well diversified in this scenario relative to the Slow Growth and Dash for Energy scenarios. The greatest risk to security of supply would be from intermittency of renewables generation, although with a more responsive demand side enabled by new technologies such as smart meters, the market's ability to manage potential shortfalls should be enhanced.	The Green Stimulus scenario experiences similar levels of investment in low carbon generation as the Green Transition, and with lower demand could represent a more benign outcome for security of supply. However, low electricity prices may lead to closures of plant that might otherwise have provided back-up, and the market may be less able to deal with renewables intermittency as a result. The Green Stimulus scenario would lead to significant reductions in carbon dioxide emissions. With low fuel prices, the additional costs of the low carbon technologies would be very significant in this scenario. Furthermore, customers (and Government) may be less able to afford these costs than they would under Green Transition with its stronger economy.
Dash for Energy	**Slow Growth**
The Dash for Energy scenario is characterised by the very tight global energy supply/demand balance in the middle of the next decade, with resulting high energy costs. Investment would be forthcoming which could improve diversity of supplies in the longer term, relative to the Slow Growth scenario, but would not necessarily always be timely. For example, there is a shortage of storage which coincides with the peak in world energy prices in the middle of the next decade. There would be heavy reliance on imported gas, which due to the high prices would be very costly to consumers and the economy as a whole. De-carbonisation objectives would not be met.	The Slow Growth scenario may be good for security of supply in the near term but the general lack of investment may result in tight supply margins and price spikes once economic growth returns in the middle of the next decade. Lack of investment in nuclear and CCS, together with relatively low renewables penetration results in a generation sector dominated by gas. Lack of investment in storage would mean increasing reliance on high levels of LNG imports and flows through interconnectors to meet demand through a severe winter, and some interruption of firm customers (even in the absence of shocks) is possible. In terms of costs to consumers, there would be low energy costs, interspersed with periods of higher prices where margins became tight. Renewables targets and carbon budgets would not be met.

3.67. Our scenarios show that gas and electricity supplies can be maintained to customers provided the market participants respond adequately to market signals - but each scenario comes with real risks, potential price rises and varying carbon impacts. Britain’s ability to meet its demand for gas and electricity is therefore poised to be tested over the next decade or so. Growing exposure to a volatile global gas market and ageing power plant nearing the end of its life along with the need to tackle climate change are the central challenges the country faces.

3.68. Figure 3.22 highlights the risks under the different scenarios in terms of the level of investment required, gas import dependency and carbon dioxide emissions. Red implies higher risk and green lower risk to achieving secure and sustainable energy supplies.

Figure 3.22: Risk profiles of achieving secure and sustainable energy supplies under the four different scenarios



3.69. The figure shows investment needs to rise substantially in all scenarios relative to the baseline of the previous 10 years, particularly in the Green scenarios. For example, in the Green Transition scenario we assume that £200bn[41] of investment could be funded and achieved before 2020 including significant progress on efficiency and renewable heat. This would imply more than double the rate of investment spending compared to the last 10 years. The duration of the current global financial crisis raises questions over the financing of that investment.

3.70. Costs to consumers are likely to rise substantially in order to fund the new investment required, and particularly where oil and gas prices continue their underlying rise since 2003 and where prices spike.

3.71. Reliance on imported gas increases under all scenarios, and in particular in Dash for Energy and Slow Growth. This could expose the economy to greater energy price volatility, giving greater importance to long term energy contracting by suppliers and consumers to mitigate these risks. It also highlights the increasing importance of strong short term price signals to attract LNG and gas flows through the interconnectors to meet peak and winter demand which can no longer be met from indigenous swing gas production and storage.

[41] Excluding investment in UK Continental Shelf gas production.

3.72. Figure 3.22 shows that only in the Green Transition and Green Stimulus scenarios would the UK's physical emissions be close to those suggested by the Government's carbon budgets. It is not possible to say whether carbon budgets will be missed, because of the complexities of carbon accounting and the need to examine all the flexibilities involved. However, the chart suggests that in the other two scenarios, and particularly in Dash for Energy, it would be very challenging to meet carbon budgets and that the UK could be at risk of missing its non-traded EU targets through purely domestic action.

3.73. Figure 3.22 highlights that there are security of supply risks within each scenario, but as important is to consider the implications for security of supply resulting from the huge range of uncertainty that the scenarios cover. For example, by 2020 gas demand could be as low as 77 bcm/yr or as high as 113 bcm/yr depending on the scenario, low carbon generation could make up anywhere between 21% and 52% of the mix, the levels of investment required in the GB energy market (excluding upstream investment) could range between £96bn and £200bn depending on the extent of environmental actions. Together with more traditional risk factors such as commodity prices and project risks, this means that investors face difficult decisions before committing large sums of capital to new projects.

3.74. In conclusion, Ofgem's scenarios highlight a number of risks:

- Under some scenarios, the current environmental targets - including the EU renewables target and Government carbon budgets - are not met or are at risk of not being met;
- Gas import dependency will increase dramatically, especially where environmental measures only achieve partial success, exposing the country to a greater range of potential supply shocks;
- The greatest risk to security of supply appears to be maintaining gas supplies through a severe winter;
- Uncertainty relating to the impact of environmental policy makes forecasting future gas demand much more challenging for potential investors than might have been the case historically. This may delay investment in gas infrastructure that might be required should environment measures not fully deliver;
- Planned closures of ageing nuclear plant and the removal, by the end of 2015, of coal- and oil-fired power stations under European environmental legislation is likely to lead to a large fall in the electricity capacity margin;
- Gas import dependency could be exacerbated by growth in gas-fired power generation to replace lost nuclear and coal-fired capacity in some scenarios; and,
- A rapid expansion of renewables would lessen the risk of gas import dependency, but would require thermal plant to operate more flexibly to manage variability in wind output, which may require further investment.

4. Stress tests

Chapter Summary

This chapter sets out the results from our five stress tests. We illustrate the impact of each stress test against the scenario where its impact is most material. Finally, we summarise the key messages from the stress test analysis.

Question box

Question 1: Do you agree that our stress tests are representative of the types of risks facing the GB energy sector over the next decade?

Question 2: Are there further stress tests that you think should be considered?

Question 3: Do you agree with the assumptions behind our stress tests?

Question 4: Do you have any views on the probabilities of these stress tests occurring?

Question 5: Do you agree with how we have modelled demand curtailment in response to constrained supply?

Question 6: Do you have any other comments on our stress tests?

Overview

4.1. By applying stress tests to the scenarios, we can demonstrate the magnitude of the impact and risk arising from selected extreme events and test how the ability of the market to deal with such shocks may differ between scenarios and may change over time.

4.2. We have identified a number of potential stress tests as part of Project Discovery, with varying degrees of materiality and probability of occurring. Table 4.1 below outlines the stress tests that we have included within this consultation document. These have been chosen since they cover a wide range of potential material risks to the GB market. At the same time these stress tests are not so extreme as to be 'uninsurable'.

4.3. We have not at this stage attempted to estimate the probability of each of these stress tests occurring, but this will be an important consideration when developing any future policy responses.

Table 4.1: Summary of stress tests

Title	Description	Period over which issue persists
Re-direction of LNG supplies	Re-direction of LNG supplies away from GB market due to higher prices in other global markets	1-in-20 severe winter
Russia-Ukraine dispute	Reverse gas interconnector flows resulting from a Russia-Ukraine gas dispute	1-in-20 severe winter
Bacton outage	Outage at GB gas import facility (Bacton)	1-in-20 peak demand day
No wind output	No output from GB wind generation fleet	1-in-20 peak demand day
Electricity interconnectors fully exporting	Reverse electricity interconnector flows due to sharper price signals in European countries	1-in-20 peak demand day

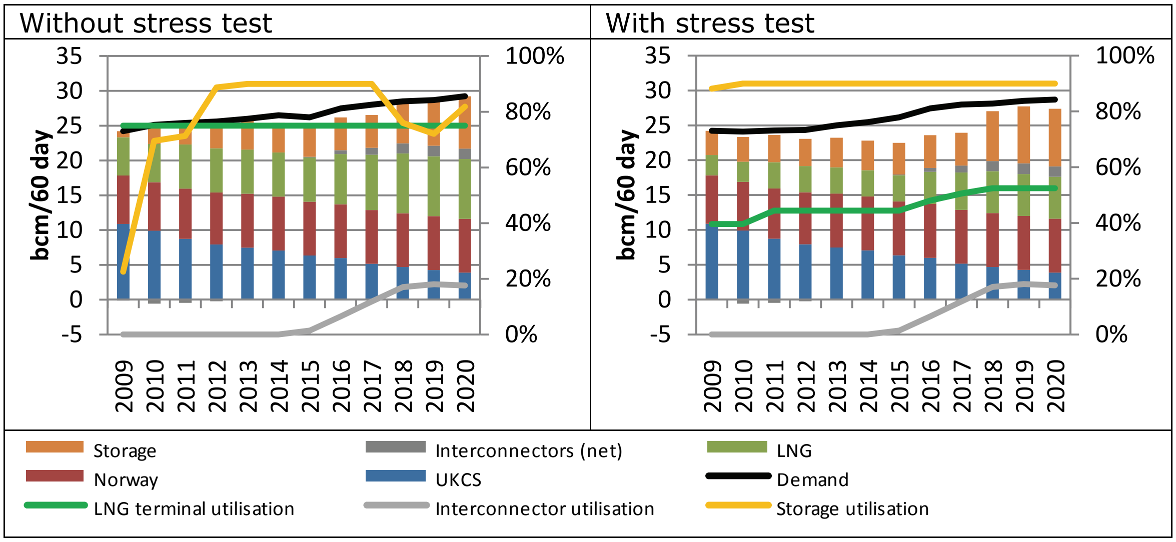
4.4. Other risks that we are using stress tests to explore, but are not included in this document, include the risk of delays in commissioning new capacity and infrastructure, lower than anticipating availability from the current nuclear fleet, and the impact of variations in gas quality on the maximum potential flows through interconnectors.

Re-direction of LNG supplies

4.5. For this stress test, we assume that there is a major reduction (40%) of LNG supplies to the GB market during a 1-in-20 winter period. This could be due to a prolonged demand/price spike in alternative global markets resulting in cargoes being redirected to markets with higher prices.

4.6. The scenario most affected by the stress test is Dash for Energy, where gas resources are scarce due to high levels of global demand. There is a significant shortfall under this scenario if it occurred in any year between 2013 and 2018, as shown in Figure 4.1. We assume that the GB market cannot rely on interconnector imports to resolve this since EU markets would be suffering from similar difficulties in obtaining scarce gas, and prices on the Continent may be equal or greater than the GB price. We assume interconnector utilisation is at the annual average and that storage provides the 'swing' supply to attempt to meet winter demand.

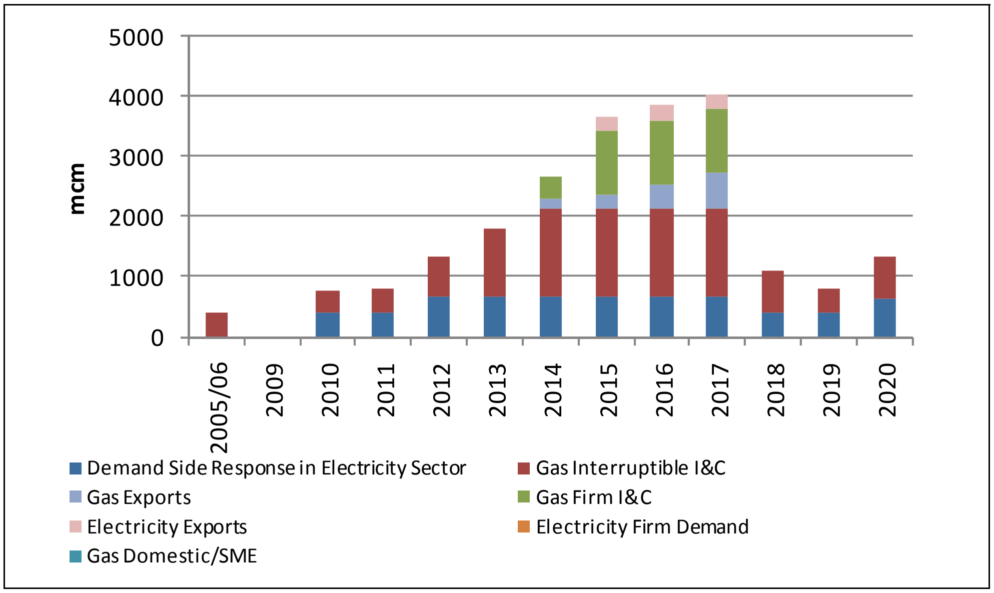
Figure 4.1: Stress testing the impact of a reduction in LNG supplies during a a 1-in-20 winter, Dash for Energy scenario



4.7. We show the impact of our stress tests in each year to illustrate how the risks change over time. It is, of course, unlikely that the same shock would occur in consecutive years.

4.8. Figure 4.2 shows the potential reduction in demand required if this stress test were to occur. Initially, only customers who are on interruptible contracts, or those who choose to self-interrupt, are affected, but in any year between 2014 and 2017 non-firm exports to Ireland and some firm industrial and commercial (I&C) customers would also be affected. The situation is notably worse than the historic curtailments required over the winter 2005/6 (see Box 2) when gas supply to GB was constrained.

Figure 4.2 - Demand curtailment required under the re-direction of LNG supplies stress test, Dash for Energy scenario



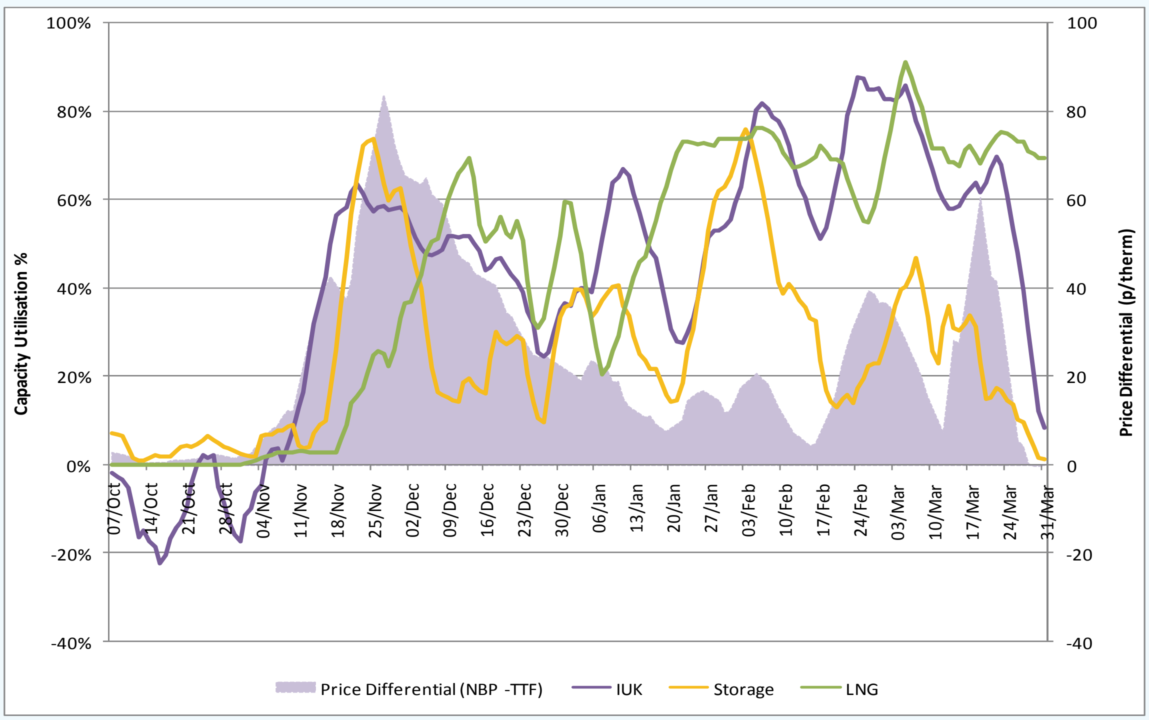
4.9. Clearly, any shortfall would also impact significantly on prices. This could have a knock-on impact on consumer bills to the extent that suppliers pass on these price increases. Larger industrial consumers may be directly exposed to any spikes in wholesale prices.

Box 2: Interconnector flows in winter 2005/06

One key argument against there being a physical shortfall in practice is that prices will simply adjust in order to encourage gas back to the GB market. However, flows do not necessarily follow price as Figure 4.4 shows. In the winter of 2005/6, the IUK often operated below maximum import capacity despite high price differentials, particularly in November. Later in the winter, the interconnector was more responsive to smaller price differentials.

Furthermore, during a severe winter prices could be higher in Continental markets than in the GB and hence it cannot be assumed that interconnectors will import at maximum capacity during peak demand in GB.

Winter 2005/6 interconnector utilisation rates



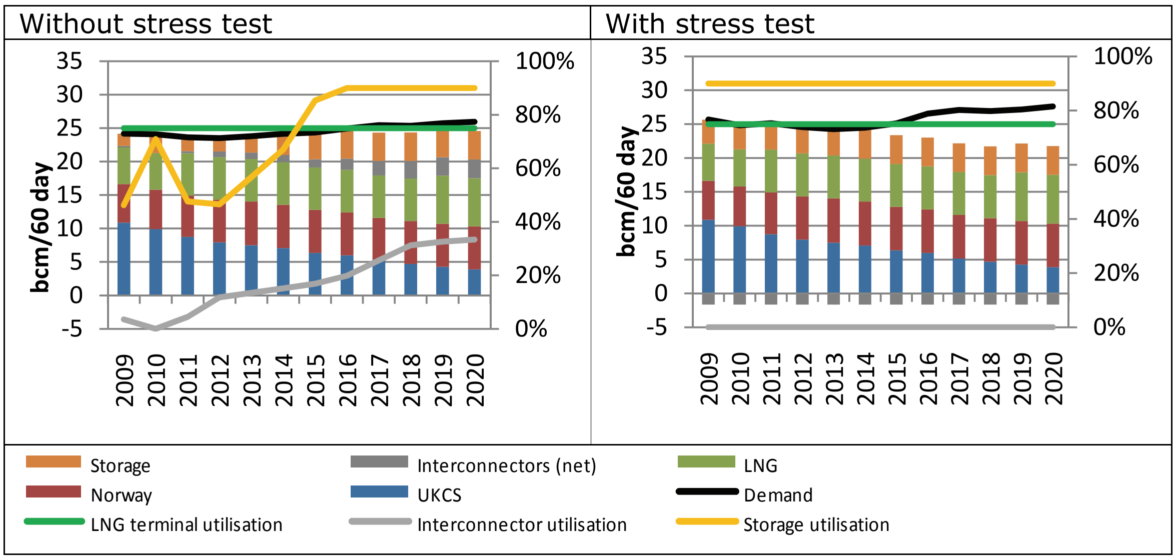
Russian-Ukraine dispute

4.10. For this stress test, we assume that the interconnectors are net exporting to the Continent (BBL at zero, IUK at 50% export) over the winter months, as was witnessed for a period during the last Russia-Ukraine crisis in January 2009. This caused GB storage to become depleted, falling rapidly compared to a typical winter, although this did occur towards the end of the 2008/9 winter period.

4.11. The scenario most affected by the stress test is Slow Growth, since it is under this scenario which the GB market would be most reliant on interconnector imports and where the least storage is built due to low demand and levels of investment.

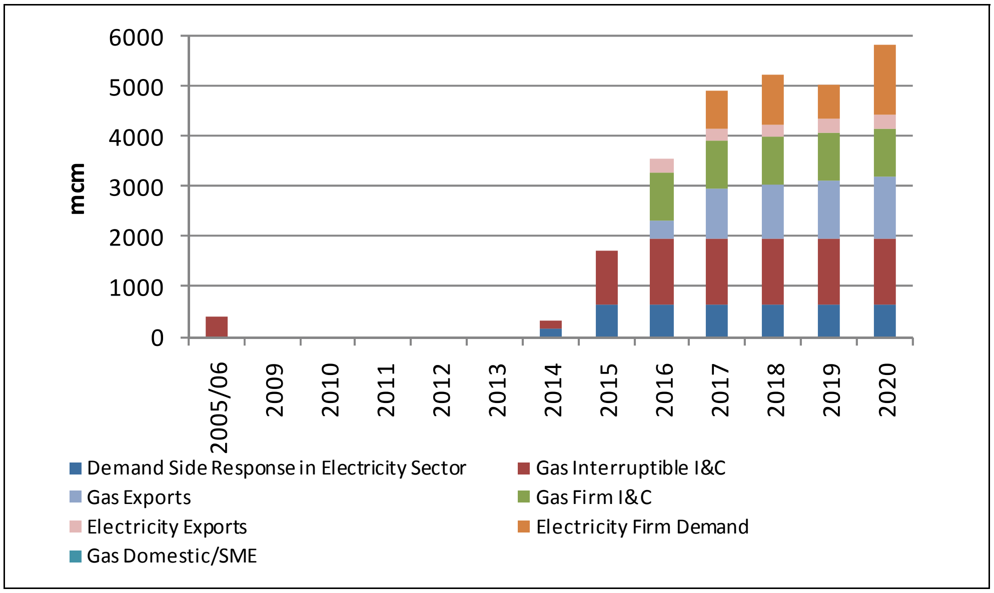
Under this scenario, the stress test highlights that there is an increasing risk over time of large shortfalls if gas flows out of GB during a severe winter, as can be seen in Figure 4.3.

Figure 4.3: Stress testing the impact of a Russia/Ukraine style dispute during a 1-in-20 winter, Slow Growth scenario



4.12. Figure 4.4 shows the demand reduction required in the Slow Growth scenario to cope with the supply-demand gap opened up by exporting GB gas in a severe winter. This includes non-firm exports to Ireland, and interruptible and firm gas and electricity I&C customers being affected, and reduced consumption from CCGTs requiring some demand reduction in the electricity sector.

Figure 4.4: Potential demand curtailment in response to exporting GB winter gas under the Slow Growth scenario (2005/6 - 2020)



Bacton outage

4.13. For this stress test, we have assumed that the entire Bacton[42] import facility suffers an outage on a 1-in-20 peak demand day[43], preventing beaching of all related flows from the UKCS and interconnectors. This stress test examines the peak daily gas flows into GB, measured in mcm/day, rather than supplies through a severe winter.

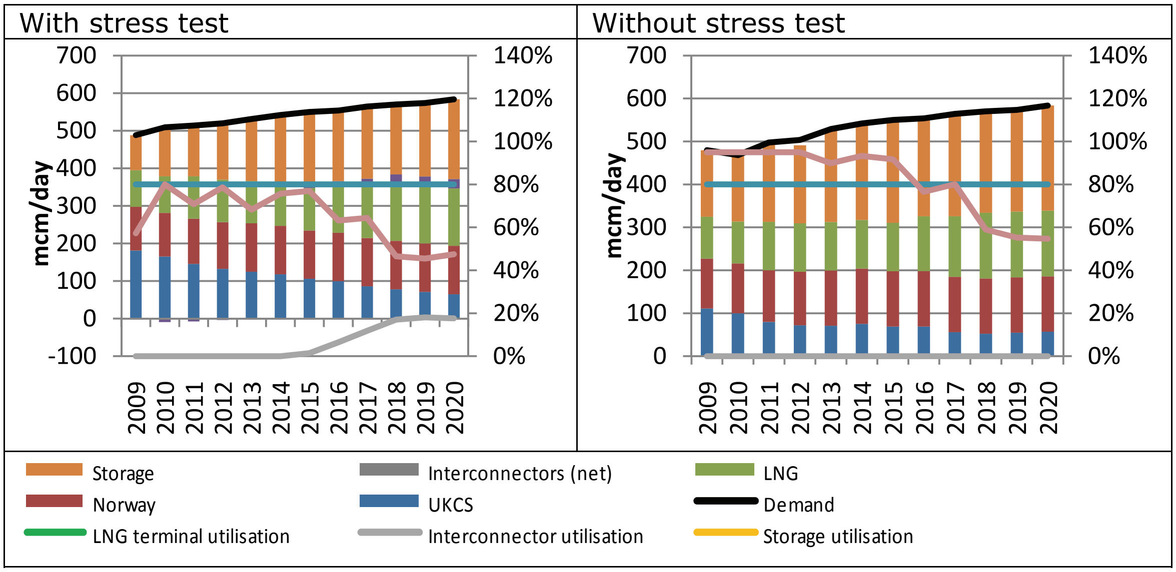
4.14. Figure 4.5 illustrates the impact of this stress test on the Dash for Energy scenario. It suggests that given high levels of LNG delivery (with re-gasification terminals operating at 80% capacity) and increased storage withdrawing up to close to maximum capacity, peak demand could just be met in most years under this stress test. The exceptions would be 2011 and 2012 where some voluntary demand curtailment would be required. If the outage were to last for longer than one day security of supply could be jeopardised due to exhaustion of storage or difficulty in maintaining high deliverability rates from LNG.

4.15. Under the other three scenarios peak demand could be met under this stress test. However, a more prolonged outage would likely require curtailment of interruptible I&C demand.

[42] The Bacton gas import facility consists of five separate sub-terminals, which receive gas from different fields as well as the BBL and IUK interconnectors. To maximise the impact of this stress test, we have assumed that supplies are lost to all of these sub-terminals, although in practice this would be unlikely to occur.

[43] Note that the impact of this stress test diminishes over time since the volumes of gas flowing through Bacton are likely to diminish as fields in the southern North Sea decline.

Figure 4.5: Stress testing the impact of an outage at Bacton on a 1-in-20 peak day, Dash for Energy scenario

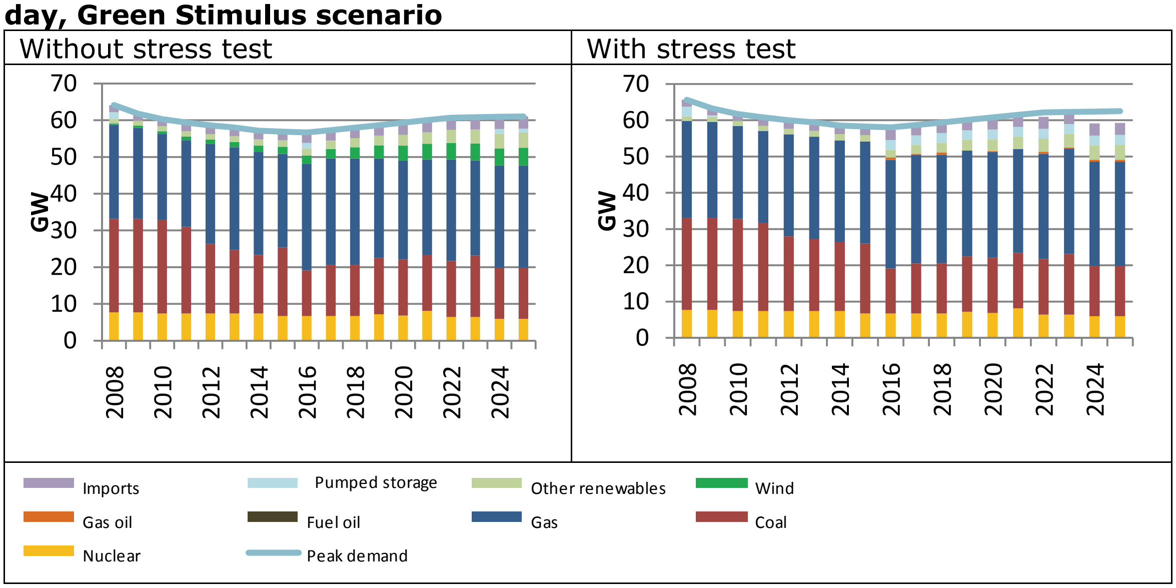


Low availability of wind capacity

4.16. For this stress test, we assume that there is no wind blowing across the whole of GB during the period of peak demand on a 1-in-20 winter day, compared to our baseline assumption of 15% output. Based on our understanding of published analysis in the area we believe that the probability of this event occurring is low, but we are interested in consultees' views on this.

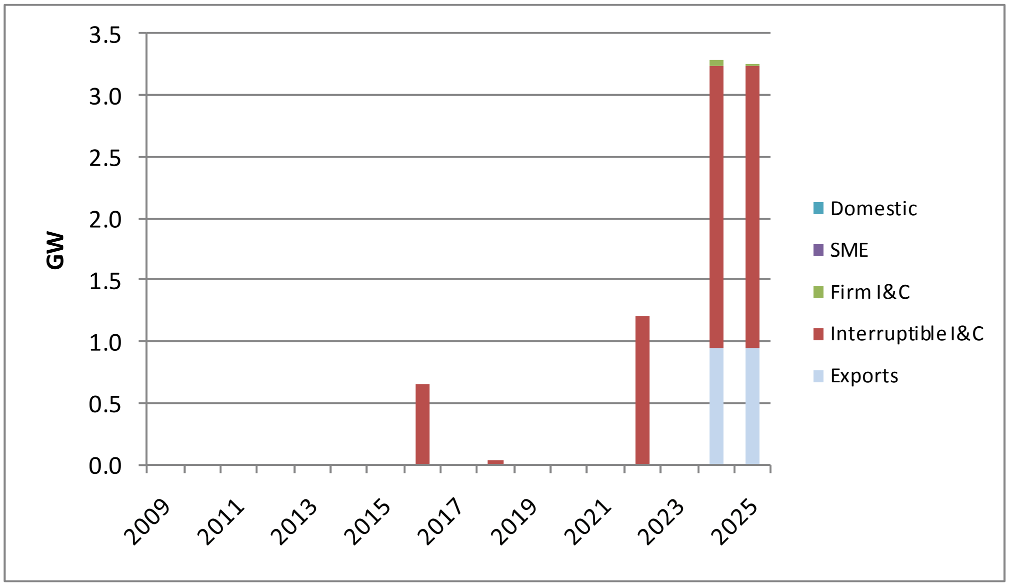
4.17. The scenario most affected by the stress test is Green Stimulus, where along with Green Transition we have greatest future dependency on wind generation. The stress test reveals that under such a scenario, the greatest risk of shortfall occurs in the period 2024-2025 following the closure of plant operating under a Limited Lifetime Opt-out under the IED. This is shown in Figure 4.6 below.

Figure 4.6: Stress testing the impact of no wind output on a 1-in-20 peak day, Green Stimulus scenario



4.18. The risk is illustrated more clearly in the demand curtailment graph in Figure 4.7. The shortfall after 2023 would, in addition, affect exports on the Irish interconnectors and there would be some firm load curtailment of I&C customers. However, it should be noted that by this time there may be greater voluntary demand side response on the system enabled by smart grid and smart meter technology.

Figure 4.7: Potential demand curtailment as a result no wind output during the peak period on a 1-in-20 winter day, Green Stimulus scenario

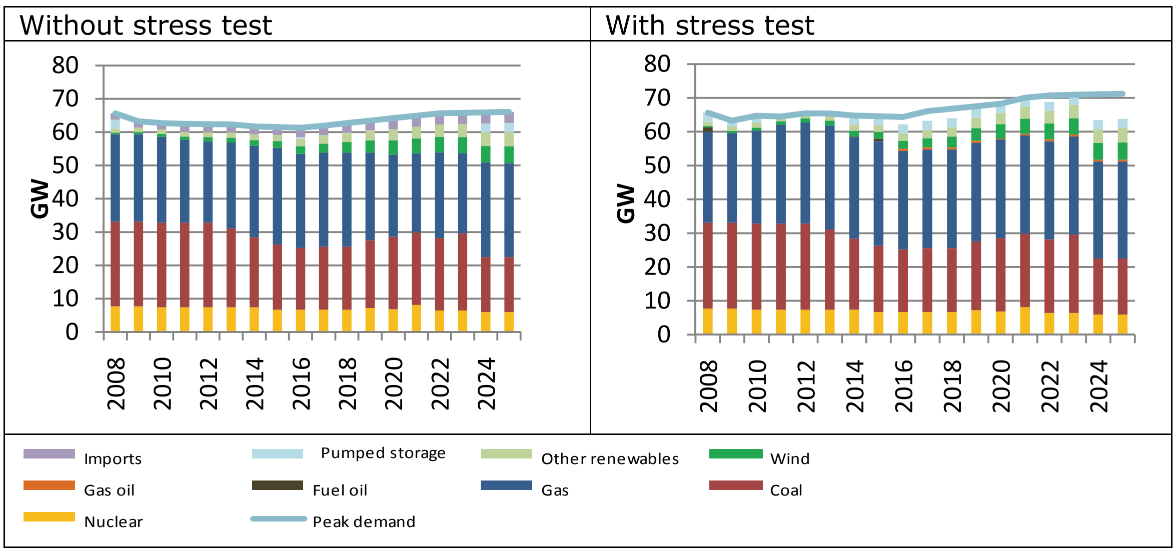


Electricity interconnectors fully exporting

4.19. For this stress test, we assume that the GB power interconnectors are exporting at maximum during the peak period on a 1-in-20 winter day in response to higher Continental prices. This may be because the Continental market has a greater need for power than in GB or the price signals are sharper in those markets.

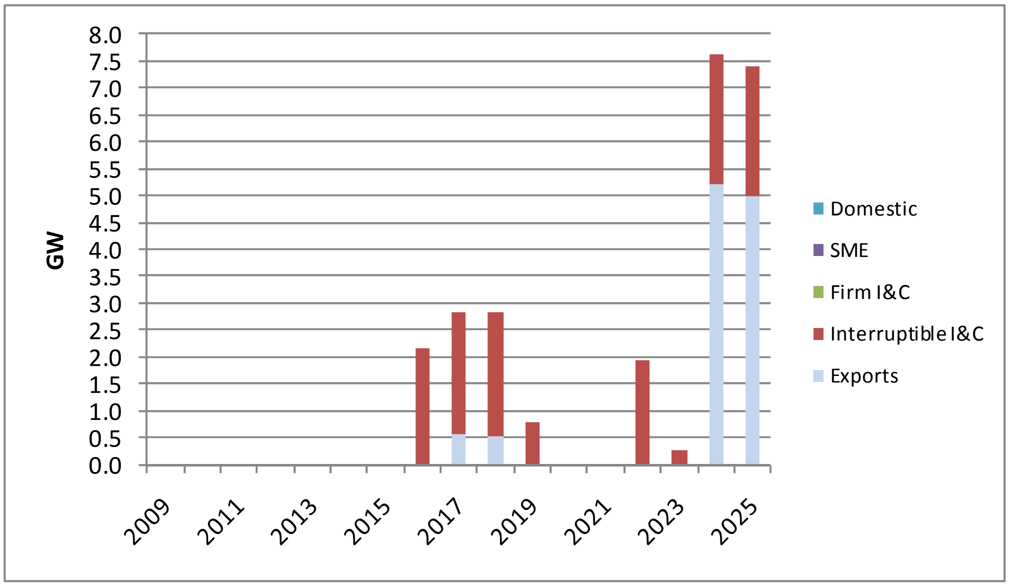
4.20. The scenario most affected is Green Transition, where there is already a heavy reliance on wind generation. The risk is exacerbated by a new 1 GW interconnector between GB and the Continent commissioned in 2016 in this scenario. The analysis in Figure 4.8 shows that there would be insufficient supply in this scenario to meet demand between 2016 and 2019, with further risks of shortfalls after 2022.

Figure 4.8: Stress testing the impact of interconnectors fully exporting during the peak period on a 1-in-20 winter day, Green Transition scenario



4.21. Figure 4.9 illustrates the demand reduction that would be required as a result. Most could come from voluntary interruption of I&C customers, but some reduction of exports on the Irish interconnectors would also be needed. As with the previous stress test it should be noted that other forms of demand side response may become available over time.

Figure 4.9: Potential load curtailment in response to electricity interconnectors exporting at maximum during the peak period on a 1-in-20 winter day, Green Transition scenario



Key messages from the stress test analysis

4.22. Dash for Energy and Slow Growth present the greatest risk from gas shocks due to the higher levels of gas import dependence in those scenarios. There is some risk of involuntary interruption. Demand response levels would need to be considerably higher than those experienced in winter 2005/6 when GB gas supply was temporarily constrained.

4.23. In the Dash for Energy scenario, the biggest risk appears to be in the middle of next decade when gas supply is tightest, before new investment in storage progressively improves the position.

4.24. In the Slow Growth case, lack of investment generally makes the problem of a potential gap between gas supply and demand progressively worse towards the end of the next decade.

4.25. The Green scenarios are less susceptible to gas shocks generally due to lower levels of gas demand under these scenarios. However, the Green scenarios suffer from greater renewables intermittency. Greater interconnection with Continental markets in these scenarios could mitigate the risks, although they may introduce new risks if electricity flows out of GB in response to higher prices in Continental markets. This latter risk looks manageable with I&C voluntary interruption plus curtailments of exports. However, security of supply could be jeopardised in the Green scenarios if periods of no wind or high electricity exports during cold winter weather coincided with gas supply shocks.

5. Next steps

5.1. Ofgem's Project Discovery began in early 2009 and explores whether current market arrangements are capable of delivering secure and sustainable energy supplies. As the independent regulator, our work draws on a depth of knowledge and confidential information made available to us, as well as wide ranging experience of assessing and understanding gas and electricity markets.

5.2. Each of our scenarios show that gas and electricity supplies can be maintained to customers provided the market participants respond broadly as they have in the past - but each scenario comes with real risks, potential price rises and varying carbon impacts. Britain's ability to meet its demand for gas and electricity is therefore poised to be tested over the next decade or so. Growing exposure to a volatile global gas market and ageing power plant nearing the end of its life along with the need to tackle climate change are the central challenges the country faces.

5.3. Our stress test analysis suggests that the market will be more vulnerable to shocks in the future, which may require greater response from the demand side in order to balance the gas and electricity systems.

5.4. We invite comments on the analysis outlined in this document, and in particular responses to the questions that we pose at the beginning of each chapter. We seek responses by 20th November 2009.

5.5. Work on the project is ongoing. In light of the risks and challenges identified in this document and responses to this consultation, we will set out our assessment of how current market arrangements could be improved, and in particular whether they enable appropriate response on both the demand and supply side. We will also set out our views as to whether any further policy responses are required. In making these recommendations we will need to consider what level of security of supply is acceptable to customers and broader society in terms of risks versus costs, and how the policy responses are likely to affect this.

5.6. If we identify, based on the results of our revised analysis and ongoing work, areas where the current market arrangements could be improved or alternative policy responses may be required, we will consult on these in a further paper to be published early next year.

Appendices

Index

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 20 November 2009 and should be sent to: project.discovery@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Next steps: Having considered the responses to this consultation, Ofgem intends to publish a document in early 2010 assessing how the current market arrangements could be improved upon and whether any further policy responses will be required. Any questions on this document should, in the first instance, be directed to:

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CHAPTER: One

There are no specific questions in this chapter

CHAPTER: T**wo**

Question 1: Please provide comments on our approach of using scenarios and stress tests to explore future uncertainty, and as a basis for evaluating policy alternatives.

Question 2: Are there other techniques for analysing uncertainty that we should consider?

Question 3: Do you agree with how we measure the impacts of our scenarios and stress tests?

Question 4: Do you agree with our key scenario drivers and choice of scenarios?

Question 5: Do you believe our scenarios sufficiently cover the range of uncertainty facing the market, and hence cover the areas where future policy responses may be required?

Question 6: Do you have any specific comments on scenario assumptions, and their internal consistency?

Question 7: Do you agree with our methodology for modelling gas and electricity supply/demand balances?

Question 8: Do you agree that LNG is the likely medium-long term source of "swing gas" for the European market

CHAPTER: Three

Question 1: Do you have any observations or comments on the scenario results?

Question 2: Do you agree with our assessment of what the key messages of the scenario analysis are?

Question 3: Are there other issues relating to secure and sustainable energy supplies that our scenarios are not showing?

Question 4: To what extent do you believe that innovations on the demand side could increase the scope for voluntary demand side response in the future?

CHAPTER: Four

Question 1: Do you agree that our stress tests are representative of the types of risks facing the GB energy sector over the next decade?

Question 2: Are there further stress tests that you think should be considered?

Question 3: Do you agree with the assumptions behind our stress tests?

Question 4: Do you have any views on the probabilities of these stress tests occurring?

Question 5: Do you agree with how we have modelled demand curtailment in response to constrained supply?

Question 6: Do you have any other comments on our stress tests?

CHAPTER: Five

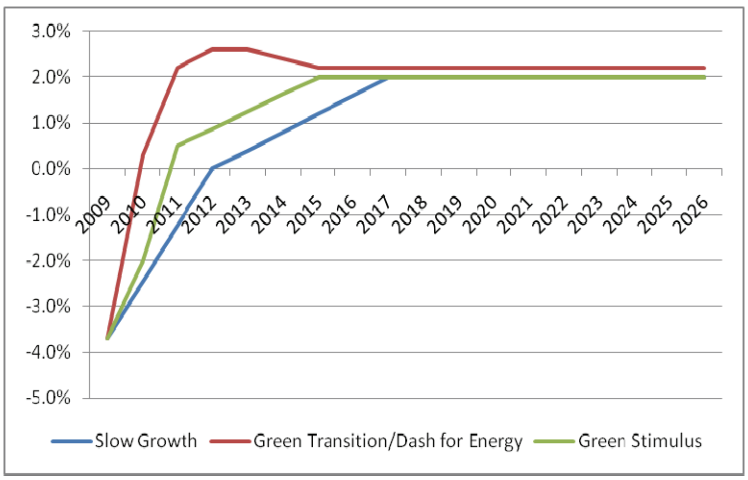
There are no specific questions in this chapter.

Appendix 2 – Summary of Key Model Assumptions

Common Assumptions

- All monetary terms are in 2009 money

GDP Growth Rate



Commodity Prices

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
$/bbl	Oil			
2010	60	57	80	57
2015	75	60	130	60
2020	90	75	90	75
2025	90	90	110	90
$/t	Coal			
2010	80	80	121	70
2015	80	80	196	71
2020	80	80	110	97
2025	80	80	149	112
p/th	Gas			
2010	45	42	63	42
2015	59	45	108	45
2020	72	59	72	59
2025	72	72	90	72
€/t	Carbon			
2010	17	16	16	15
2015	31	24	24	18
2020	43	39	31	22
2025	50	50	34	30

Exchange Rates

	All Scenarios, All years
$/£	1.50
€/£	1.20

Gas Assumptions - Inputs

Annual EU Gas Supplies

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
bcm	Annual EU Demand			
2010	524	517	537	513
2015	592	550	673	525
2020	593	553	780	616
bcm	Indigenous production			
2010	273	260	277	261
2015	260	224	279	232
2020	223	198	237	207
bcm	Pipeline Supplies - Russia			
2010	168	164	166	164
2015	189	173	194	173
2020	192	197	207	197
2010-2020	Shtokman starts production in 2017 in Dash for Energy. Not developed by 2020 in all other scenarios. Yamal starts production in 2013 in Green Transition and Dash for Energy and 2014 in Green Stimulus and Slow Growth.			
	Pipeline Supplies - Central Asia			
2010-2020	Nabucco comes on in 2015 in Dash for Energy and Green Transition. Capacity increases from 8bcm to 31bcm in 2020. Nabucco not built in Green Stimulus and Slow Growth scenarios			
bcm	Pipeline Supplies - North Africa[44]			
2010-2020	In Green Transition and Dash for Energy, gas flows from North Africa increase from 54bcm in 2010 to 66bcm in 2016, before decreasing back to 55bcm by 2020. In Green Stimulus and Slow Growth flows are 50bcm across the forecast period.			
bcm	LNG Supplies			
2010	29	43	39	37
2015	71	104	128	71
2020	92	108	250	162

[44] Including pipeline supplies from Algeria and Libya

For a graphical illustration of the annual EU supply-demand balance across the different scenarios, please see Figure 3.1 in the main document.

Global LNG Demand, Liquefaction Capacity and Utilisation Rate

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
bcm	Global LNG Demand			
2010	241	241	253	243
2015	393	349	468	359
2020	459	358	686	502
bcm	Global Liquefaction Capacity			
2010	334	334	334	334
2015	449	415	478	415
2020	540	502	746	561
%	Liquefaction Utilisation Rate			
2010	72	72	76	73
2015	88	84	98	87
2020	85	71	92	89

For a graphical illustration of the global LNG demand and liquefaction capacity across the different scenarios, please see Figures 3.2 and 3.3 in the main document.

GB Regasification Capacity and Utilisation Rates

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
bcm	GB LNG Regasification Capacity			
2010	44.5	44.5	44.5	44.5
2015	51.5	51.5	51.5	51.5
2020	58.4	51.5	69.8	58.4
%	GB Regasification Utilisation Rate			
2010	27	31	23	18
2015	31	39	50	35
2020	20	25	69	59

Gas De-rating Factors

	Peak	Winter
%	All Scenarios	
UK Continental Shelf	100	100
Norway	100	100
LNG	80	75
Storage	95	80
Interconnectors	80	50

Gas Energy Efficiency Assumptions

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
2010-2020	0.75% reduction in demand per year		0.25% reduction in demand per year	

Annual GB Gas Demand

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
bcm	Demand			
2010	95.1	95.8	93.7	89.9
2015	88.2	94.0	97.9	92.2
2020	76.9	81.1	113	102.9

Annual GB Gas Supply

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
bcm	Interconnectors			
2010	-3.4	-0.1	-3.4	-0.1
2015	0.6	7.3	0.6	7.3
2020	9.1	17.1	9.1	17.1
bcm	LNG			
2010	11.8	13.6	10.4	8.2
2015	15.7	19.9	25.5	18.1
2020	11.8	12.9	47.9	34.7
bcm	Norway			
2010	28.4	24.0	28.4	24.0
2015	30	24.9	30	24.9
2020	30	24.9	30	24.9
bcm	UK Continental Shelf			
2010-2020	In all scenarios we assume that UKCS production declines from 58.3bcm in 2010 to 26.1bcm in 2020			

For a graphical illustration of the annual GB demand and supply across the different scenarios, please see Figure 3.4 in the main document.

GB Severe Winter Gas Demand

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
bcm	Demand			
2010	24.9	25.3	24.5	24.1
2015	24.3	25.3	26.9	24.4
2020	22.7	22.4	29.2	26.5

GB Severe Winter Gas Supply

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
bcm	Interconnectors			
2010	-0.6	0	-0.6	0
2015	0.1	1.2	0.1	1.2
2020	1.5	2.8	1.5	2.8
bcm	LNG			
2010	5.5	5.5	5.5	5.5
2015	6.3	6.3	6.3	6.3
2020	7.2	6.3	8.6	7.2
bcm	Norway			
2010	7.0	5.9	7.0	5.9
2015	7.7	6.4	7.7	6.4
2020	7.7	6.4	7.7	6.4
bcm	UK Continental Shelf			
2010	In all scenarios we assume that UKCS winter production declines from 9.9bcm in 2010 to 3.9bcm in 2020			
bcm	Storage Capacity			
2010	3.1	3.6	2.7	2.8
2015	3.8	4.2	4.5	4.0
2020	2.4	2.9	7.5	4.2
%	Storage Utilisation			
2010	79	90	70	71
2015	75	90	90	85
2020	45	61	82	90

For a graphical illustration of GB severe winter demand and supply across the different scenarios, please see Figure 3.5 in the main document.

GB Peak Day Gas Demand

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
mcm	Demand			
2010	505.5	505.6	499.9	488.3
2015	508.9	505.4	550.0	498.3
2020	478.4	471.7	583.7	526.7

GB Peak Day Gas Supply

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
mcm	Interconnectors			
2010	-9.4	-0.2	-9.4	-0.2
2015	1.6	20.0	1.6	20.0
2020	24.8	47.0	24.8	47.0
mcm	LNG			
2010	97.5	97.5	97.5	97.5
2015	112.9	112.9	112.9	112.9
2020	128.0	112.9	153.0	128.0
mcm	Norway			
2010	116.0	97.8	116.0	97.8
2015	128.8	107.1	128.8	107.1
2020	128.8	107.1	128.8	107.1
mcm	UK Continental Shelf			
2010-2020	In all scenarios we assume that UKCS peak production declines from 165.3mcm in 2010 to 64.7mcm in 2020			
mcm	Storage Deliverability			
2010	136.1	145.1	130.4	127.9
2015	159.7	159.5	200.8	152.5
2020	132.0	140.0	212.4	179.9
%	Storage Utilisation			
2010	83	89	80	78
2015	61	66	77	63
2020	44	58	48	75

For a graphical illustration of GB peak demand and supply across the different scenarios, please see Figure 3.7 in the main document.

Gas Assumptions - Outputs

Gas Consumer bills

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
£/ customer	Wholesale gas costs			
2010	322	313	423	315
2015	369	286	792	310
2020	415	336	518	466
£/ customer	Renewable heat incentive			
2010	0	0	0	0
2015	32	29	8	8
2020	140	132	19	21
£/ customer	Energy efficiency and smart meters			
2010	25	25	13	13
2015	39	39	33	33
2020	39	39	33	33
£/ customer	T&D charges			
2010-2020	£140/customer in all years in all scenarios			
£/customer	Gross margins			
2010	151	151	152	152
2015	136	136	148	148
2020	124	124	143	143
£/ customer	VAT			
2010	32	31	36	31
2015	35	31	56	32
2020	42	37	42	40
£/ customer	TOTAL			
2010	670	660	764	651
2015	751	661	1177	671
2020	900	808	895	843

- Wholesale costs based on two year hedging strategy
- Consumer bills are based on a consumption level of 20,500KWh
- Assume reduced consumption in the years beyond 2009 due to energy efficiency measures, and the deployment of renewable heat technologies reducing the average domestic consumption
- Network charges and gross margin figures derived from Ofgem Quarterly Report Analysis (August 2009)
- VAT assumed as 5% of retail bill
- Bills presented as an average across payment types

Annual Gas Sector Emissions

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
mt	CO_2			
2010	124	119	125	118
2015	117	110	128	116
2020	105	98	127	114
2025	96	89	128	115

Electricity Assumptions - Inputs

Generation capacity

MW	Green Transition			
	2010	2015	2020	2025
CCGT	26787	29023	27533	27028
Oil	2964	1594	0	0
CHP	4851	4851	4851	4851
Coal	28255	21770	24170	18367
Nuclear	10550	9570	9300	7590
Wind	5208	13408	28564	33836
Other renewables	3487	4333	6337	7604
Pumped storage	2690	2690	2690	2690
Interconnectors	2000	2500	3500	3500
MW	Green Stimulus			
	2010	2015	2020	2025
CCGT	26787	29403	27533	27028
Oil	2964	460	0	0
CHP	4851	4851	4851	4851
Coal	28255	22170	16992	15450
Nuclear	10550	9570	9300	7590
Wind	5208	12783	27230	32227
Other renewables	3487	4276	6184	7382
Pumped storage	2690	2690	2690	2690
Interconnectors	2000	2500	3500	3500

MW	Dash for Energy			
	2010	2015	2020	2025
CCGT	26787	38832	44733	54628
Oil	2964	1594	0	0
CHP	4851	4851	4851	4851
Coal	28255	21370	20570	13167
Nuclear	10550	9570	3690	4390
Wind	5208	8735	14223	18000
Other renewables	3487	3907	4685	5415
Pumped storage	2690	2690	2690	2690
Interconnectors	2000	2500	2500	2500
MW	Slow Growth			
	2010	2015	2020	2025
CCGT	26787	29023	35533	48228
Oil	2964	1594	0	0
CHP	4851	4851	4851	4851
Coal	28255	21370	20170	11167
Nuclear	10550	9570	3690	2790
Wind	5208	8011	12930	16329
Other renewables	3487	3842	4537	5184
Pumped storage	2690	2690	2690	2690
Interconnectors	2000	2500	2500	2500

Environmental Assumptions

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
%	Proportion Renewable Electricity			
2009	7		7	
2016	18		11	
2020	30		15	
2025	35		18	
%	Proportion Renewable Heat			
2009	0		0	
2016	8		2	
2020	12		4	
2025	18		5	

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
%	Proportion Renewable Electricity			
2009	7		7	
2016	18		11	
2020	30		15	
2025	35		18	
%	Proportion Renewable Heat			
2009	0		0	
2016	8		2	
2020	12		4	
2025	18		5	

CCS Plant

	CCS Plant			
	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
2009	None		None	
2009	400MW demo	3 x 400MW demos	None	
2020	2 x 400MW demos 2 x 1.6GW stations with 400MW fitted with CCS	3 x 400MW demos 2 x 1.6GW stations with 400MW fitted with CCS	400MW demo	None
2025	2 x 400MW demos 2 x 1.6GW fully retrofitted 2 x 1.6GW of new fully CCS plant	3 x 400MW demos 2 x 1.6GW fully retrofitted 2 x 1.6GW of new fully CCS plant	400MW demo 2 x 1.6GW stations with 400MW fitted with CCS	None
	New Nuclear			
2009	None		None	
2016	None		None	
2020	2 x 1600MW		None	
2025	4 x 1600MW		2 x 1600MW	1 x 1600MW

Assumed Nuclear Closure Dates

	Assumed Nuclear Closure Dates			
	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
DUNGENESS B1	2018		2018	2018
DUNGENESS B2	2018		2018	2018
HARTLEPOOL	2019		2014	2019
HEYSHAM 1	2019		2014	2019
HEYSHAM 2	2023		2023	2023
HINKLEY POINT	2021		2016	2016
OLDBURY	2009		2009	2009
SIZEWELL B	2035		2035	2035
WYLFA	2014		2012	2012
HUNTERSTON	2021		2016	2016
TORNESS	2023		2023	2023

Demand

Demand is defined as that met by both transmission-connected and distribution-connected (embedded) generators in GB, at station gate, i.e. excluding station own use but including losses on transmission and distribution networks.

Peak demand

MW	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
2010	61,231	60,272	62,209	61,286
2015	60,057	56,907	65,669	61,090
2020	62,682	59,338	68,192	62,967
2025	64,535	61,039	71,071	65,276

Annual demand

TWh	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
2010	344	340	353	348
2015	337	322	370	344
2020	357	342	385	355
2025	372	355	401	368

Increase in Demand Due to Heat Pumps and Electric Vehicles

TWh	Green Transition and Green Stimulus	Dash for Energy and Slow Growth
2010	0.0	Assumed no increase for these scenarios.
2015	2.2	
2020	35.5	
2025	61.6	

Electricity Efficiency Assumptions

	Green Transition and Green Stimulus	Dash for Energy and Slow Growth
2010-2020	1.5% reduction in demand per year	0.3% reduction in demand per year

IED Assumptions

Green Transition/Dash for Energy/Slow Growth		
No. of plant	Coal	Gas
TNP	4	6
Fit SCR	19	4
LLO	20	3
Close	0	9
Green Stimulus		
The Green Stimulus scenario assumes plants make different decisions under the IED as the commodity and carbon prices in this scenario are less favourable to coal.		
No. of plant	Coal	Gas
TNP	8	7
Fit SCR	6	4
LLO	12	4
Close	17	7

Capital Costs (All Scenarios)

Plant type	Cost (£/kW)
CCGT	600
Clean Coal (ASC + CCS)	2,200
Nuclear (new)	2,000
Onshore wind	1,200
Offshore wind	2,800
Biomass regular	2,500
Biomass energy crop	2,500
Biomass CHP	3,000
Wave	4,000
Tidal Stream	4,000
Tidal Range	3,800
Biowaste	3,600
Biogas	6,600
OCGT	350
All capital costs as assumed constant in real terms.	

De-rating factors for existing plant

All Scenarios	De-rating factors for existing plant (%)	Annual Availability (%)
Pumped storage	100	15
Interconnectors	95	0
CCGT	90	Range from 17 to 81
OCGT	90	91
Coal	90	Range from 17 to 81
Oil	90	Range 28.5 to 32.6
CHP	90	Range 60 to 81
Nuclear	70	Range from 70 to 80
Hydro	40	35
Wind	15	Range 28 to 38
The annual availability of some existing plant, particularly gas and coal, depends on what decisions individual plants make with regards to the IED and LCPD directives. We have assumed different decisions for different plant of the same type. A range is an indication of the extent these assumptions vary.		

De-rating factors for new plant

	De-rating factors for new renewable plant (%)	Annual Availability
Biomass regular, Biomass energy crop, Biomass CHP	90	80
Biowaste, Biogas, Other renewable	40	40
Tidal stream	35	35
Wave	30	30
Onshore wind	15	28
Offshore wind	15	38
Tidal range	15	20
	De-rating factors for new plant (%)	
Coal (CCS demo, CCS active, CCS ready), New CCGT	90	83
New nuclear	80	87

Electricity Assumptions - Outputs

Wholesale electricity prices (time-weighted)

£/MWh	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
2010	38.9	37.1	51.1	35.9
2015	51.5	40.6	79.5	44.5
2020	59.4	55.9	61.3	56.6
2025	76.6	74.0	70.4	65.1

Generation Output

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
TWh	Nuclear			
2010	67.3	67.3	67.3	67.3
2015	60.9	60.9	60.9	60.9
2020	63.5	63.5	24.4	24.4
2025	57.8	57.8	33.4	21.3
TWh	CCGT			
2010	118.0	134.4	105.7	106.1
2015	102.7	152.6	130.3	126.6
2020	60.8	101.3	204.3	177.6
2025	71.9	76.8	214.4	211.2
TWh	Coal			
2010	107.5	86.8	128.8	123.0
2015	97.0	32.9	120.8	99.9
2020	95.6	41.9	75.7	79.3
2025	44.5	26.1	55.0	49.9
TWh	CCS			
2010	0.0	0.0	0.0	0.0
2015	2.9	4.3	0.0	0.0
2020	11.5	14.3	2.9	0.0
2025	50.7	53.4	5.8	0.0
TWh	Net imports			
2010	5.5	5.5	5.5	5.5
2015	2.0	2.0	2.0	2.0
2020	2.0	2.0	2.0	2.0
2025	2.0	2.0	2.0	2.0
TWh	CHP			
2010	20.6	20.6	20.4	20.6
2015	20.3	20.6	19.5	20.6
2020	19.4	19.9	19.6	20.5
2025	19.4	19.2	19.5	19.5
TWh	Wind			
2010	13.9	13.9	13.9	13.9
2015	37.0	35.2	23.8	21.8
2020	81.5	77.7	40.0	36.3
2025	95.5	90.9	50.4	45.6
TWh	Other renewables			
2010	10.0	10.0	10.0	10.0
2015	12.8	12.6	11.7	11.0
2020	21.8	20.1	14.5	12.9
2025	28.7	27.6	19.3	17.2
TWh	Other			
2010	1.2	1.1	1.2	1.2
2015	1.1	1.1	1.1	1.2
2020	1.1	1.2	1.2	1.9

2025	1.2	1.3	1.1	1.1
TWh	Total Generation Output			
2010	344	340	353	348
2015	337	322	370	344
2020	357	342	385	355
2025	372	355	401	368

Power Sector Emissions

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
mt	CO_2			
2010	150.4	137.4	165.8	160.5
2015	134.3	94.5	164.3	145.9
2020	114.9	81.4	148.1	143.7
2025	78.5	63.9	130.0	125.7

Electricity Consumer Bills

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
£/Customer	Wholesale electricity costs			
2010	146	138	184	143
2015	171	141	327	155
2020	191	179	236	262
£/Customer	ROC + CCS subsidies			
2010	12	12	12	12
2015	23	24	17	17
2020	58	58	27	25
£/Customer	Energy Efficiency + smart meters			
2010	21	21	10	10
2015	41	41	32	32
2020	41	41	32	32
£/Customer	T&D Charges			
2010	83	83	84	84
2015	105	105	109	109
2020	133	132	137	136
£/Customer	BSUOS			
2010	6	6	6	6
2015	5	5	6	6
2020	5	5	6	6
£/Customer	Gross Margin			
2010	112	65	114	114
2015	103	60	113	113
2020	96	56	112	112
£/Customer	VAT			
2010	19	16	21	19
2015	22	19	30	22
2020	26	24	27	29
£/Customer	TOTAL			
2010	404	346	437	394
2015	475	400	640	460
2020	550	495	577	602

- Wholesale costs based on two year hedging strategy
- Consumer bills are based on a consumption level of 3,300KWh, and assume reduced consumption in the years beyond 2009 due to energy efficiency measures
- Network charges and gross margin figures derived from Ofgem Quarterly Report Analysis (August 2009)
- Environmental costs are from Ofgem August 2009 Household Energy Bills Explained factsheet
- VAT assumed as 5% of retail bill
- Bills presented as an average across payment types
- Analysis excludes economy 7 customers

Cumulative investment costs

	Green Transition	Green Stimulus	Dash for Energy	Slow Growth
£bn	Nuclear			
2010	Assumed no investment costs for all scenarios			
2015	Assumed no investment costs for all scenarios			
2020	6.4	6.4	0	0
2025	12.8	12.8	6.4	3.2
£bn	Renewables			
2010	4.2	4.2	4.2	4.2
2015	21.8	20.4	11.8	10.2
2020	59.5	56.3	25.5	22.5
2025	71.3	67.6	34.2	30.3
£bn	CCS			
2010	Assumed no investment costs for all scenarios			
2015	0.9	1.8	0.0	0.0
2020	6.6	7.5	0.9	0.0
2025	15.8	16.7	3.3	0.0
£bn	CCGT			
2010	1.4	1.4	1.4	1.4
2015	4.4	4.4	9.9	4.4
2020	4.4	4.4	14.7	9.2
2025	4.4	4.4	20.9	17.1
£bn	Transmission & Distribution			
2010	5.9	5.9	5.7	5.7
2015	21.1	21.0	19.3	19.1
2020	39.5	39.0	33.9	33.5
2025	53.4	53.0	47.4	47.0
£bn	Interconnectors			
2010	0.0	0.0	0.0	0.0
2015	0.4	0.4	0.4	0.4
2020	1.0	1.0	0.5	0.5
2025	1.0	1.0	0.5	0.5
£bn	Energy Efficiency			
2010	2.7	2.7	1.3	1.3
2015	9.3	9.3	4.7	4.7
2020	16.0	16.0	8.0	8.0
2025	16.0	16.0	8.0	8.0
£bn	Renewable Heat			
2010	0.0	0.0	0.0	0.0
2015	13.0	13.0	3.2	3.2
2020	52.8	52.8	9.5	9.5
2025	52.8	52.8	9.5	9.5
£bn	LNG Terminals			
2010	0.0	0.0	0.0	0.0
2015	0.4	0.4	0.4	0.4

2020	0.7	0.4	1.3	0.7
2025	0.7	0.4	1.3	0.7
£bn	Gas Storage			
2010	0.0	0.0	0.0	0.0
2015	0.9	0.6	0.9	0.6
2020	1.0	0.6	4.2	0.6
2025	1.0	0.6	4.2	0.6
£bn	SCR			
2010	0.0	0.0	0.0	0.0
2015	1.2	0.6	1.2	1.2
2020	1.2	0.6	1.2	1.2
2025	1.2	0.6	1.2	1.2
£bn	Smart Meters			
2010-2025	In all scenarios, we assume that investment increases from 0 at present to £10bn by 2020.			
£bn	Total			
2010	14.1	14.1	12.6	12.6
2015	77.7	76.2	56.1	48.6
2020	199.0	195.0	109.6	95.6
2025	240.4	235.8	146.8	127.9

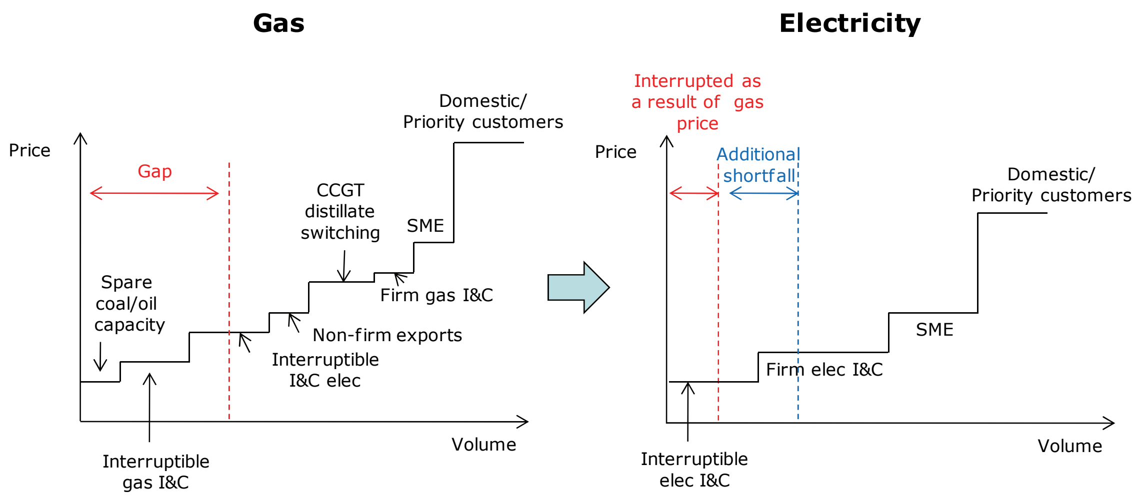
Modelling supply shortfalls

1.1. This section outlines our approach to modelling supply shortfalls.

1.2. The model will adjust to a loss of supply or capacity by increasing supply from other sources: in the case of gas from LNG or from storage in the winter; in the case of electricity, by dispatching spare generating capacity.

1.3. Where our scenarios show that there is still insufficient supply or capacity to meet demand, normally as a result of applying a stress test, we assess the resulting 'gap' in terms of different possible responses to balance the system. This will include curtailment of demand (voluntary and involuntary), and in the case of gas, substitution by other fuels, to the extent that these are available. We have constructed short-term curves for both peak day and severe winters showing the volume impact (and consequential price impact) of different types of interruption or substitution ranked in economic order for both electricity and gas. Our peak day curves are illustrated schematically as follows:

Figure A1: Demand Curtailment (Voluntary & Involuntary) in the GB Electricity and Gas Sectors



1.4. For gas, there are five options to reduce demand:

- Releasing gas volumes utilised by the power sector through switching to other forms of generation (coal, oil), to the extent spare capacity is available, or via gas-fired generators switching to e.g. distillate firing;
- Voluntary interruption (including self-interruption) of large industrial and commercial gas customers;
- Curtailment of non-firm exports to Ireland
- Releasing gas volumes from gas-fired power capacity through reductions in electricity demand by voluntary interruption of large industrial and commercial electricity customers; and
- Involuntary interruption of gas customers progressing from large industrial and commercial customers, through small and medium enterprise customers to domestic customers.

1.5. For electricity, the picture is simpler as demand is solely driven by the consumption patterns of electricity end-users.

1.6. In our illustrated example, the gas gap is addressed by displacing some gas-fired generation with coal and oil capacity, interruption of all interruptible gas I&C customers, and by reduction in electricity demand through interruption of some electricity I&C customers. In turn, this interruption of electricity I&C customers is shown on the corresponding electricity curve on the right (in red).

1.7. In the illustrated case, we have assumed that these gas shortfalls are further compounded by a shortfall in generating capacity. This additional gap in electricity requires interruption of the remaining interruptible and some firm electricity I&C customers.

1.8. We have chosen the illustrated example above as it shows the flexibility of our model to deal with the appropriate market response to a simultaneous gas and electricity shortfall. The approach assumes that where supply is constrained, energy will reach those customers who value it most highly[45], and in the form that it is most valued, i.e. gas or electricity.

Gas Demand Curtailment Assumptions

The table below shows our assumptions for the value of lost load for different customer types and their percentage of peak demand.

Type of Customer	% of Peak demand	Price (p/therm)
Large Interruptible I&C	0.74	125
Other Interruptible I&C 1	2.45	150
Other Interruptible I&C 2	3.68	300
Large firm I&C	2.4	750
Irish Exports - non-firm	-	500
Irish Exports - firm	-	2500
Other firm I&C	2.45	2000
Priority Customers	0.02	2800
NDM	88.21	6000

- Percentage of peak demand based on data from the DTI's October 2006 consultation on "The Effectiveness of Current Gas Security of Supply Arrangements"[46], adjusted to exclude demand for power generation.
- Value of lost load estimates based on Ofgem calculations

[45] We also need to recognise the impact on affordability of energy for customers, which is part of the Project Discovery scope.
[46] Link: http://www.berr.gov.uk/files/file34563.pdf

Electricity Demand Curtailment Assumptions

The table below shows our assumptions for the value of lost load for different electricity customer types and their percentage of peak demand.

Type of Customer	% of Peak demand	Price (£/MWh)
Interruptible I&C	2.30	100
Interruptible I&C	1.50	200
Export curtailment		1000
Firm I&C	16	4000
SME	30	25000
Domestic	50	5000

- Percentage of peak demand estimates are based on Ofgem calculations.
- Value of lost load estimates are based on a report by Global Insight 'Estimation of Industrial Buyers' Potential Demand Response to Short Periods of High Gas and Electricity prices', May 2005 as well as Ofgem calculations.

Stress Tests

Bacton outage

- Bacton import facility suffers an outage on day of peak demand; and
- This prevents beaching of all related flows from the UKCS and interconnectors.

Loss of Atlantic LNG Supplies

- Major loss of Atlantic LNG supplies during a severe winter period, reducing supplies to the GB market by about 40%;
- Interconnector imports do not increase to resolve the shortfall as EU markets are suffering from the same difficulty obtaining gas; and
- Storage provides the swing capacity.

Russia-Ukraine dispute

- Interconnectors are exporting to the Continent (BBL at zero, IUK at 50% export) during a severe winter.

Low availability of wind capacity

- No wind blows across the whole of GB on the peak demand day; and
- Wind peak de-rating factor is assumed to fall from 15% to 0%.

Electricity interconnectors fully exporting

- GB power interconnectors are exporting at maximum in response to Continental price signals (i.e. Interconnexion France Angleterre and Britned).

Appendix 3 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[47]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[48].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of existing and future consumers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[49];
- The need to contribute to the achievement of sustainable development; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[50]

[47] entitled "Gas Supply" and "Electricity Supply" respectively.
[48] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[49] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[50] The Authority may have regard to other descriptions of consumers.

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- Promote efficiency and economy on the part of those licensed[51] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[52] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[51] or persons authorised by exemptions to carry on any activity.
[52] Council Regulation (EC) 1/2003

Appendix 4 - Glossary

B

Bacton

One of the largest gas terminal complexes in GB, where gas lands onshore from the Southern North Sea, the Shearwater Elgin Area Line (SEAL), and the BBL and IUK interconnectors.

BBL

Balgzand Bacton Line: A pipeline through which gas is imported to the GB market from the Netherlands.

bcm

Billion cubic metre (of gas)

C

Capacity margin

The difference between installed generation capacity and average cold spell peak demand (normally expressed as a percentage of average cold spell peak demand).

CCGT

Combined Cycle Gas Turbine: A type of generation plant where the waste heat from gas generation is used to make steam to generate additional electricity, thereby increasing its efficiency. Most new gas power plants in Europe are of this type.

CCS

Carbon capture and storage: A means of reducing carbon emissions by capturing carbon dioxide from power plants, and storing it away from the atmosphere in a deep geological formation.

CHP

Combined Heat and Power: A technology where electricity is generated at or near the place where it is used, with the heat produced being used for space heating, water heating or industrial steam loads. This potentially leads to much higher efficiency than conventional generation.

D

DECC

Department of Energy and Climate Change.

De-rated capacity margin

A capacity margin which has been calculated by applying de-rating factors to plant or infrastructure capacities to reflect the risk of forced outages and the expected availability of intermittent renewables.

E

EU ETS

European Union Emission Trading Scheme: The EU-wide greenhouse gas emissions trading scheme, under which governments must set emission limits for all large emitters of carbon dioxide in their country.

F

Feed-in Tariff

An incentive structure to encourage the adoption of renewable energy through government legislation, where electricity suppliers are obligated to buy renewable electricity at above market rates set by the government.

Flexible plant

A flexible power generation plant is one which is able to alter its level of output easily in response to changes in market conditions.

G

GW

Gigawatt: a unit of energy equivalent to one billion watts.

I

I&C

Industrial and Commercial (customers)

IED

Industrial Emissions Directive: A proposed EU Directive on industrial emissions which will replace the LCPD and lead to higher constraints on power station emissions from 2016.

IUK

The Interconnector (UK) gas pipeline which runs between Bacton in GB and Zeebrugge in Belgium. The pipeline is able to transport gas in either direction.

L

LCPD

Large Combustion Plant Directive. This is a European Union Directive which aims to reduce emissions from large combustion plant. GB power plants must either comply with the LCPD through installing emission abatement equipment or 'opt-out' of the directive. An existing plant that chooses to 'opt-out' is restricted in its operation and must close by the end of 2015.

LNG

Liquefied Natural Gas: Used for transporting gas to global markets by sea transport. Gas is first cooled and hence liquefied in a process referred to as liquefaction. On reaching its destination, the LNG is subject to re-gasification making it suitable for transport in conventional pipelines.

Low Carbon Transition Plan

The UK Low Carbon Transition Plan was published by DECC in July 2009 and sets out how the UK will meet the target of a 34 percent cut in emissions on 1990 levels by 2020.

M

Marginal cost

The cost of producing an additional unit of output.

mcm

Million cubic metres (of gas).

Merit Order

The relative efficiency of plant on the system

N

Nabucco

The Nabucco project is a planned natural gas pipeline to run between Turkey and Austria, diversifying the current gas supply routes into Europe and giving additional access to Asian gas supplies.

Nameplate capacity

The maximum electrical output from a power plant.

NOx

Nitrogen oxides emitted through the burning of fossil fuels.

O

OGCT

Open Cycle Gas Turbine: A less efficient type of gas generation plant where the waste heat from generation is not used to generate additional electricity.

P

Peak Day

The highest demand day in a year.

Pumped Storage

Pumped storage is a type of hydroelectric power generation where energy is stored in the form of water pumped from a lower elevation to a higher elevation. During periods of high electrical demand, the stored water is released through turbines.

R

Renewables Obligation (RO)

The government's main support programme for renewable energy generation, under which electricity suppliers must source a proportion of their supply from renewable generation.

RES

Renewable Energy Strategy. This was published by DECC in 2009 and sets out how the target of ensuring 15% of our energy comes from renewables by 2020 will be met.

ROCs

Renewable Obligation Certificates: Certificates received by eligible renewable generators for each MWh of electricity generated. These can be sold to suppliers in order to fulfil their obligations under the RO.

Rough

GB's largest gas storage facility.

S

Severe Winter

The coldest 60 day period during the coldest winter in 20 years.

Shtokman

One of the world's largest gas fields, situated in the centre part of the Russian sector of the Barents Sea.

Smart Grids

A smart grid allows system and distribution network operators to balance supply and demand on their networks using new technology.

Smart Meters

A smart meter is an advanced meter which identifies consumption in more detail than a conventional meter and communicates that information back to the supplier for monitoring and billing purposes.

SME

Small and medium enterprise

Swing Supply

The supply that is required to meet the balance of demand

T

TWh

Terawatt hour: unit for measuring energy equivalent to 1,000,000,000 kilowatt hours.

U

Unconventional gas

Gas obtained from unconventional reserves including tight sands gas, shale gas and methane hydrates.

UKCS

UK Continental Shelf: GB's indigenous oil and gas reserves.

Y

Yamal

The Yamal-Europe pipeline connects natural gas fields in West Siberia and in the future, the Yamal peninsular, with Germany.

Appendix 5 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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