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Gas Security of Supply Report - Risks and resilience appendix

Ofgem report to Government supplementary appendices

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In November 2011, the Secretary of State requested Ofgem assess the potential risk to medium and long term gas security of supply in Great Britain and appraise potential further measures in the gas market which could enhance security of supply. This report responds to that request by:

1. Assessing the scale and nature of the risks to security of supply given developments in the global gas market;

2. Assessing the level of risk that remains after Ofgem's proposed reform of emergency gas cash-out arrangements;

3. Considering the range of potential measures in the UK gas market to mitigate risks that remain; and

4. Assessing the relative merits of each of these interventions, including the risks of market distortion, unintended consequences and provides initial views on cost-benefit comparisons. It also provides initial thoughts on how these interventions might be designed and implemented.

This appendix accompanies the Gas Report and, in particular, provides additional information behind chapter 2 of that report.

Contents

1. Introduction

1.1. This appendix presents our detailed analysis on gas market developments at a national, European and global level, including developments in the Liquefied Natural Gas (LNG) market. It also includes a chapter discussing the key potential domestic and external shocks to the Great British (GB) gas markets and a chapter providing more detail on the two modelling exercises undertaken as part of this review. This appendix accompanies the Gas Report and, in particular, provides additional information behind chapter 2 of that report.

1.2. Our assessment of gas market risks and resilience has been informed by a wide range of sources: Ofgem commissioned Redpoint and MJM Energy to perform an extensive review of the most significant reports in the past five years on GB security of supply and future market developments. In addition, we carried out over twenty face-to-face interviews with key industry stakeholders, academics and market participants. We also held a well-attended industry event to discuss emerging findings.

1.3. This exercise identified the major drivers and uncertainties to future levels of supply and demand at the GB, European and global levels, including developments in the LNG market. It also identified key sources of potential shocks to GB gas security of supply. These are events that could have significant implications for GB gas supplies and that could arise with little or no notice. We discuss our findings on market developments and shocks to security of supply in the second section of this chapter.

1.4. We have drawn on this information to develop scenarios that describe different outcomes for future GB gas demand and supply. We have used these scenarios in our resilience analysis to investigate the level of defence GB import infrastructure and storage provides in the face of high demand and shocks to supply, which we present in the third subsection of this chapter. We start this chapter with a short discussion on the recent history of GB gas supplies.

1.5. At a high level, key drivers to gas demand at both the global and domestic level include the extent countries commit to a low carbon agenda, the pace of economic growth and the role gas plays in the energy mix.

1.6. On the supply side, the International Energy Agency (IEA) has highlighted the extent to which countries exploit their unconventional resources, such as shale gas and coal bed methane, will be a key determinate of future global gas supplies.

1.7. Trade in gas will also continue to expand both through pipelines and LNG. We discuss how LNG markets are forecast to develop and show that there are a number of reasons to believe this market may tighten towards the middle of the current decade.

2. GB gas market developments

2.1. In this chapter we present our analysis on GB gas market developments in the medium and long-term, together with a short explanation of the current structure of GB gas supplies.

GB demand outlook

2.2. There is significant uncertainty regarding future GB gas demand and supply. To reflect this in our analysis we have constructed two diverse scenarios for future GB gas market outcomes:

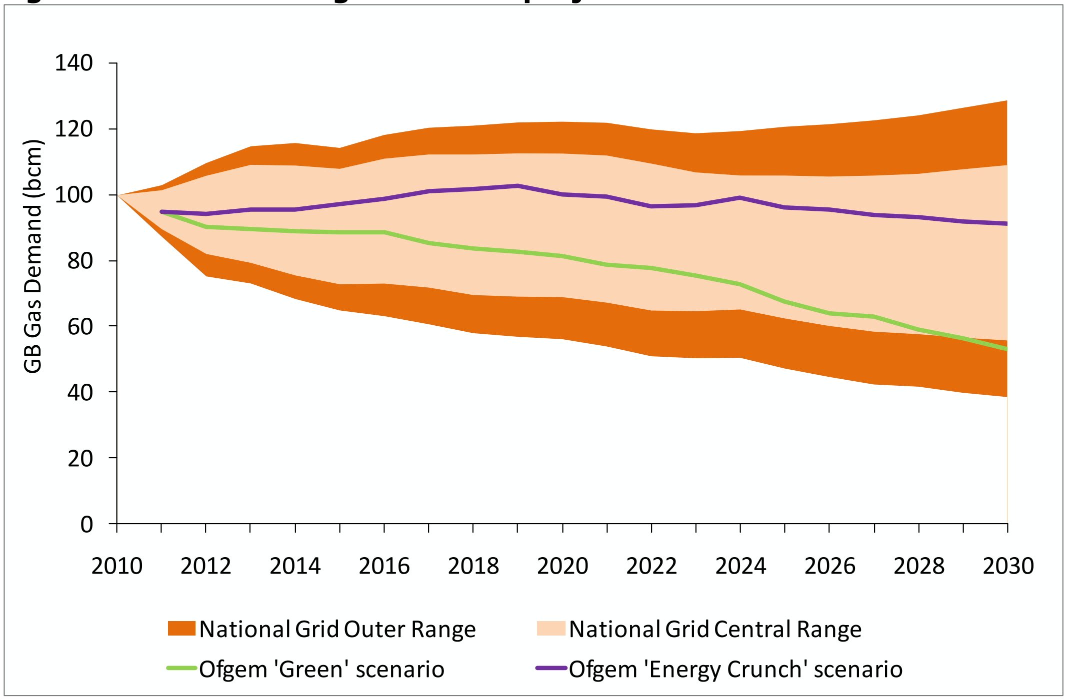
- **Green scenario:** This scenario is principally based on National Grid's Gone Green scenario, drawing on further assumptions from National Grid and the Department of Energy and Climate Change (DECC). It is assumed that a global agreement on emissions reduction is reached and the UK commits to Electricity Market Reform (EMR) and other environmental policies, meeting all low carbon targets as a result. This leads to a higher level of renewable and nuclear generation and lower levels of domestic gas demand, compared with today, as energy efficiency policies are introduced. Gas demand in this scenario therefore falls throughout the period to 2030.

- **Energy Crunch:** This scenario has been generated in house by Ofgem. It reflects a world where global environmental policies are scaled back and the ambition of the EMR and other GB environmental legislation is reduced. There is a reduced commitment to low carbon and renewable technologies and domestic energy efficiency policies. This leads to higher demand for gas from gas-fired generation and the domestic sector than in the Green scenario. Gas demand in this scenario therefore remains steady at current levels.

2.3. Figure 2.1 presents the paths of GB annual gas demand for the two scenarios described above. It shows the level of annual demand diverging in the two scenarios over the period. In the Green scenario, annual demand falls from around 90 billion cubic metres (bcm) today, to 53 bcm in 2030, while in the Energy Crunch scenario, demand remains roughly level throughout the period of the analysis. Figure 2.1 also presents National Grid's central and outer range[1]. This shows that the projected levels of gas demand, in both scenarios, stay within National Grid's central range throughout our outlook period, except in the last two years for the Green Scenario.

[1]National Grid's (NG) central and outer ranges illustrate the impact of different combinations of sensitivities more likely to occur together. For example, NG's high outer range would only be reached if all factors that drive up demand (such as the rate of economic growth or low gas prices) were all present and there were no factors acting to reduce demand. In practice the likelihood of these factors combining is low, so NG also calculate a narrower central range of more probable demand outcomes.

Figure 2.1: GB annual gas demand projections



Source: National Grid Ten Year Statement

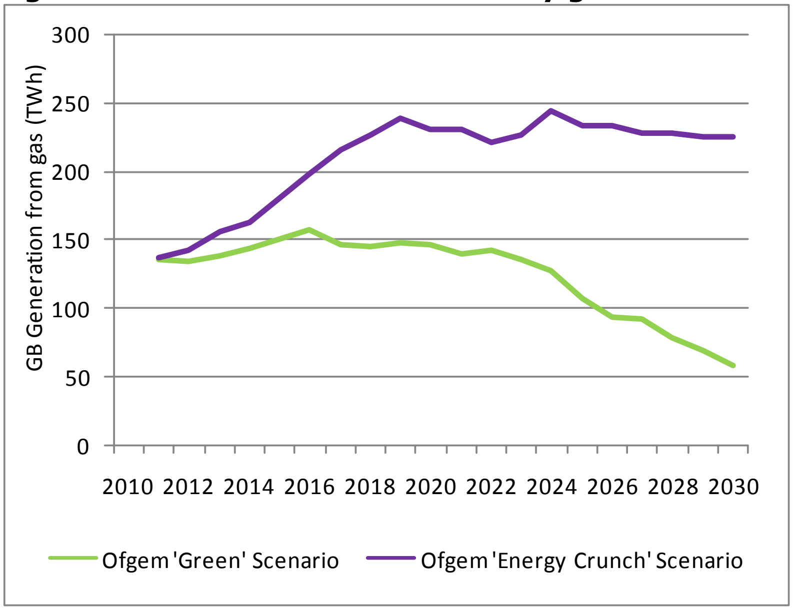
2.4. We discuss the different contributions in each of the scenarios from the main sectors of the economy in the subsections below.

Power generation demand

2.5. The primary difference between the two scenarios is largely due to different assumptions about the future role of gas in power generation. We highlight this difference in Figure 2.2, which forecasts the quantity of electricity generated by gas-fired plant over the outlook period in both our scenarios. For example, in the Energy Crunch scenario the quantity of electricity generated from gas-fired power stations rises steadily from levels of 147 TWh[2] today (equivalent to 40% of total electricity generated), to a peak in 2024[3], when the proportion of electricity generated by gas is above 60%. Following this peak it declines to around 55% in 2030. In the Green scenario electricity generated by gas rises to a peak in 2016 (around 43% of total generation). This then falls over the remainder of the outlook period reaching 16% in 2030.

[2] Digest of UK Energy Statistics (DUKES) - Energy Trends (ET 5.1): http://www.decc.gov.uk/media/viewfile.ashx?filepath=statistics/source/electricity/et5_1.xls&filetype=4&minwidth=true
[3] Taken from Ofgem internal analysis

Figure 2.2: Forecast for GB electricity generation from gas



Source: Ofgem Analysis

2.6. While the total level of gas demand from power falls in our Green scenario, it is likely that demand for gas from power will become more volatile over the forecast period as the role of gas-fired plant will increase in balancing the intermittent output of a growing quantity of installed renewable generation. Studies by National Grid and Pöyry provide some insight into this volatility by investigating the possible sizes of future within-day demand swing from gas-fired power generators. National Grid model the swing in gas demand in 2020/21 assuming 30 GW of installed wind moving from a load factor of 84% to 15% over a period of 15 hours. Under the assumption that the gap in generation output is filled by combined-cycle gas turbines (CCGTs), National Grid say this would result in an increase in gas demand equivalent to 90 mcm/day (around 30% of supply on a relatively high demand day) [4].

2.7. Pöyry carried out similar analysis looking further forward. Their 2010 analysis shows that the daily swing in power sector gas demand for the year 2029/30 (assuming around 40 GW of intermittent generation). These swings are of a similar magnitude to those noted by National Grid. For the GB market to successfully cope with such high demand volatility, both the flexibility of supplies and the effective operation of the national transmission system (NTS) will need to be sufficient in order to bring in and distribute the gas to the relevant loads. On the first point, Pöyry conclude in their 2010 analysis that despite the changes in swing required the gas market was able to deliver in an intermittent world with only relatively minor perturbations. However, their study did show a potential need for more fast-storage facilities by the end of the decade[5].

[4] National Grid (2011) Ten Year Statement.
[5] Pöyry (2010) Gas at the Centre for a Low Carbon Future, A review for Oil and Gas UK, September

2.8. On the second point, in its submission to the new transmission price control process (RIIO-T1), National Grid Gas (NGG) has asked Ofgem to clear some capital expenditure to address changing gas transmission network flow patterns required by its users. This includes expenditure to reverse flows to support diminishing UK Continental Shelf (UKCS) gas flows from St. Fergus; additional compression capacity in the South West; an unspecified quantity to deal with the dynamic nature of future flows (wind intermittency, central corridor congestion), and initial investments to fund projects to investigate future requirements.

2.9. At this stage, Ofgem believes only the funding for projects to enable reversal of flows towards Scotland to support peak demand and a contribution towards the future requirements projects are deemed appropriate. Instead, Ofgem has set out in its Initial Proposals, published 27 July[6], to have a mid-period re-opener to give NGG a chance to build a more detailed case for specific investments. In addition, Ofgem will develop an uncertainty mechanism to allow NGG scope to acquire additional funding during the price control if it becomes apparent that it is required.

Non-daily metered (NDM) demand

2.10. Economic growth and energy efficiency policies (alongside the electrification of heat) are the key drivers of falling levels of NDM demand in both of our scenarios. Energy efficiency savings are based on DECC's pathway 3 (or C)[7] in the Green scenario and pathway 2 (or B)[8] in the Energy Crunch scenario. Assumptions on the electrification of heat are taken from Redpoint's analysis of pathways 2 and 3 for Energy Crunch and Green, respectively.

2.11. NDM demand is currently around 44 bcm/a[9], (equivalent to 40% of total GB gas demand). In the Green scenario[10], domestic demand falls to around 40 bcm/a by 2019, (equivalent to 53% of total GB gas demand) and continues to fall in the long-term reaching 31 bcm/a by 2030, equivalent to 62% of total GB gas demand in that year. In the Energy Crunch scenario, the outlook for domestic demand is a steady decline over the period, falling to 37 bcm/a by 2030 (equivalent to 43%).

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[6] Available at following link. See chapter 7 (to p.125) for more detail: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIO%20T1%20NGGT%20and%20NGET%20Cost%20assessment%20and%20uncertainty.pdf

[7] Under this scenario, average room temperature decreases to 17°C. Over 18m homes increase their levels of insulation. The proportion of new domestic heating systems supplied using electricity is 30-60% by 2050. Energy demand for domestic lights and appliances decreases by 40% by 2050 and energy used for domestic cooking is entirely electric.

[8] Under this scenario, average room temperature increases to 18°C. Over 8m homes increase their levels of insulation. The proportion of new domestic heating systems using electricity rises to 20% by 2050. Energy demand for domestic lights and appliances is stable and energy used for domestic cooking is entirely electric.

[9] National Grid Ten Year Statement 2011- Appendix 2, Annual Gas Demand.

[10] Taken from Ofgem internal analysis, based on distribution network (DN) firm demand.

Industrial and commercial demand

2.12. Both our Green and Energy Crunch scenarios show industrial and commercial (I&C) gas demand declining slowly to 2030, with a greater rate of decline in the Green scenario. For changes to industrial energy efficiency, we have created a demand trajectory based on assumptions on economic growth and the DECC pathways[11] for energy efficiency, using pathway 3 (or C)[12] for the Green scenario 2 (or B)[13] and for the Energy Crunch scenario. With regards to the uncertainty surrounding economic growth, we assume growth is the same across the two scenarios.

Exports to Ireland

2.13. Our assumptions for exports to Ireland in the Green and Energy Crunch scenarios broadly follow the profile of GB demand. However, the effect of wind intermittency in Ireland is also expected to impact GB exports. Pöyry estimates that wind-induced variation in Irish gas demand may be as much as 15 mcm/day by 2030[14]. Since much of Irish gas demand is expected to be met by imports from GB, and Ireland has comparatively little gas storage at present, this could introduce further volatility to the GB system[15].

GB supply outlook

2.14. This section provides an overview of historical and possible future sources of supply to the GB gas market.

Structure and history of GB gas supply

2.15. As Figure 2.3 shows, over the past decade, the supply landscape in the UK has changed considerably. During the period 1997-2003 the UK was a net exporter of gas[16] following rapid expansion of North Sea production. However, in 2000

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[11] Definitions of the DECC pathways can be found on the control panel of the 2050 calculator, available online: http://www.decc.gov.uk/en/content/cms/tackling/2050/calculator_exc/calculator_exc.aspx

[12] Under this scenario, UK industrial output falls 30-40% by 2050, there is high electrification of energy intensive industries, space heating demand is stable, hot water demand increases by 25%, cooling demand is stable, the proportion of non-domestic heat supplied using electricity rises to between 30%-60% by 2050.

[13] Under this scenario, UK industrial output grows in line with current trends, some energy intensive processes are electrified, space heating demand increases by 30%, hot water demand by 50%, cooling demand by 60%, and the proportion of non-domestic heat supplied using electricity rises to 20% by 2050.

[14] Pöyry (2010) How Wind Generation could transform gas markets in Great Britain and Ireland. Available at:
http://www.poyry.co.uk/sites/www.poyry.co.uk/files/264_gasintermittency_publicsummary_v1_0_0.pdf

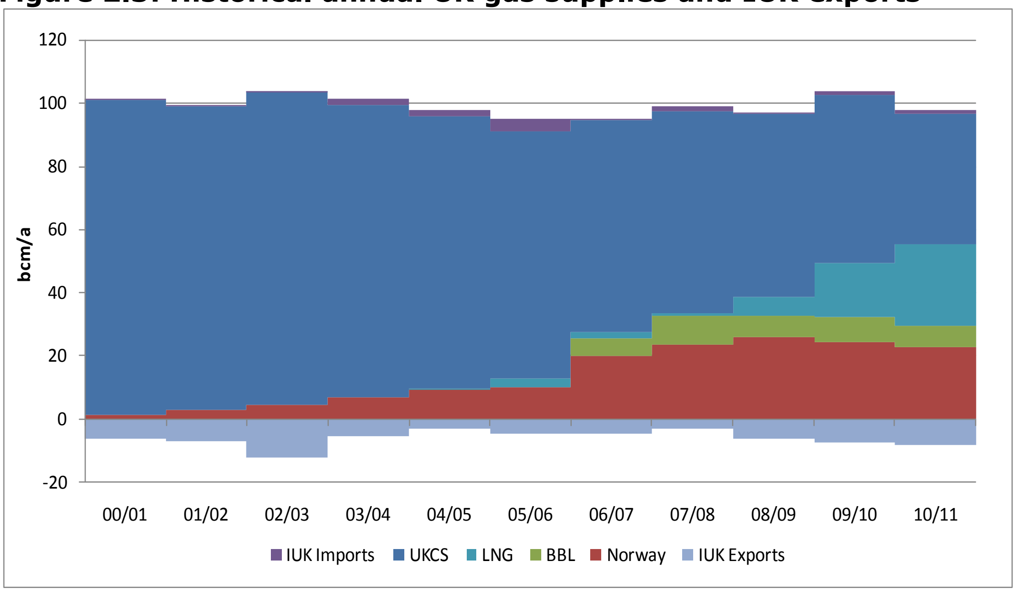
[15] For simplicity we have not assumed additional Irish volatility in our resilience analysis covered in Chapter 6 of this appendix.

[16] Before 1997 the Moffat interconnector (open in 1993) sent gas to Ireland, but GB still imported more gas from Norway, via St Fergus, than it exported until 1997.

supplies from UKCS peaked[17] and since 2004 the UK has been a net importer of gas[18].

2.16. The UK first imported natural gas in 1964, when it was delivered as Algerian LNG. Discovery of gas reserves in the North Sea in 1967 limited the quantity of LNG imported, although, deliveries still lasted until 1990. During the 1970s the UK also began to import gas from Norway via the Vesterled and TampenLink pipelines which link GB with Norwegian fields in the Northern Basin of the North Sea. From 2005, imports from Norway increased substantially when the Langeled pipeline became operational. The Langeled pipeline has an import capacity of 25.5 bcm/a, or roughly a quarter of annual GB demand.

Figure 2.3: Historical annual UK gas supplies and IUK exports



Source: National Grid Ten Year Statement 2011

2.17. In 1998 the bi-directional Interconnector (IUK) between Bacton in the UK and Zeebrugge in Belgium was commissioned. This created, for the first time, the possibility of exporting and importing gas from Continental Europe to GB. In 2005, the Balgzand-Bacton Line (BBL) interconnector was added connecting Bacton (UK) to Balgzand (Netherlands). Following a recent upgrade BBL now has a capacity of 19.5 bcm/a, with the option of virtual bi-directional trading with the continent[19]. IUK has also been significantly upgraded and now has a capacity of 20 bcm/a in Forward Flow (GB to Belgium) and 26.9 bcm/a in Reverse Flow (Belgium to GB)[20]. Therefore, combined, BBL and IUK could account for approximately 50% of GB annual gas demand and constitute 28% of GB's overall import capacity. This makes Bacton one of the most significant locations on the National Transmission System.

[17] DUKES, Table 4.2 Natural gas production and supply
[18] Ibid.
[19] National Grid (2011) Ten Year Statement.
[20] Ibid.

2.18. The UK also has four LNG import terminals: Grain LNG (commissioned 2005), Dragon LNG (2008), South Hook LNG (2008) and Teesside Gasport (2007)[21]. LNG made up 35% of the UK's imported gas in 2010, up from 25% in 2009[22]. While LNG plays a key role in supplying the UK with gas, there is considerable variability in day-to-day LNG flows. For example, the total LNG imports for 2010/11 were 18 bcm, while the highest daily flow of LNG to the UK was 85 mcm/d, equivalent to an annual flow rate of 31 bcm[23].

2.19. In 2011 the UK imported 25.4 bcm of LNG (around 30% of demand), over 85% of which came from Qatar[24]. While this is indeed a very high proportion, data from Wood Mackenzie, suggests that GB has long-term LNG contracts with at least five exporting countries. Although around two thirds of this is made up of gas imports from Qatar[25].

2.20. The importance of LNG to GB is made even clearer when looking specifically at high demand days. National Grid analysis has shown that on the highest winter demand days during 2011/12, LNG supplies make up the largest incremental source of supply after storage[26]. This shows that, at least during last winter, LNG was used by suppliers to a greater extent than pipeline imports to meet high demand days.

Gas supply to 2030

2.21. Figure 2.4 illustrates two annual gas supply scenarios for GB, based on Ofgem's analysis. There are strong similarities between flows from the UKCS, Norway and the Continent in both scenarios. The most significant difference is the extent to which LNG is utilised. For example, the Green scenario assumes only 4.4 mcm/day of additional LNG regasification capacity is built in 2018 over and above that already under construction, reaching 157 mcm/day[27] by 2020. On the other hand, the Ofgem Energy Crunch scenario assumes a much higher LNG import capacity build, with capacity growing to reach 208 mcm/day by 2020[28].

2.22. In addition to higher capacity levels the Energy Crunch scenario also assumes a higher level of LNG capacity utilisation. This reflects higher levels of GB demand in this scenario and an assumption that environmental policies in Europe are scaled back leading to higher European demand compared with the Green scenario and so less opportunity to import from the Continent.

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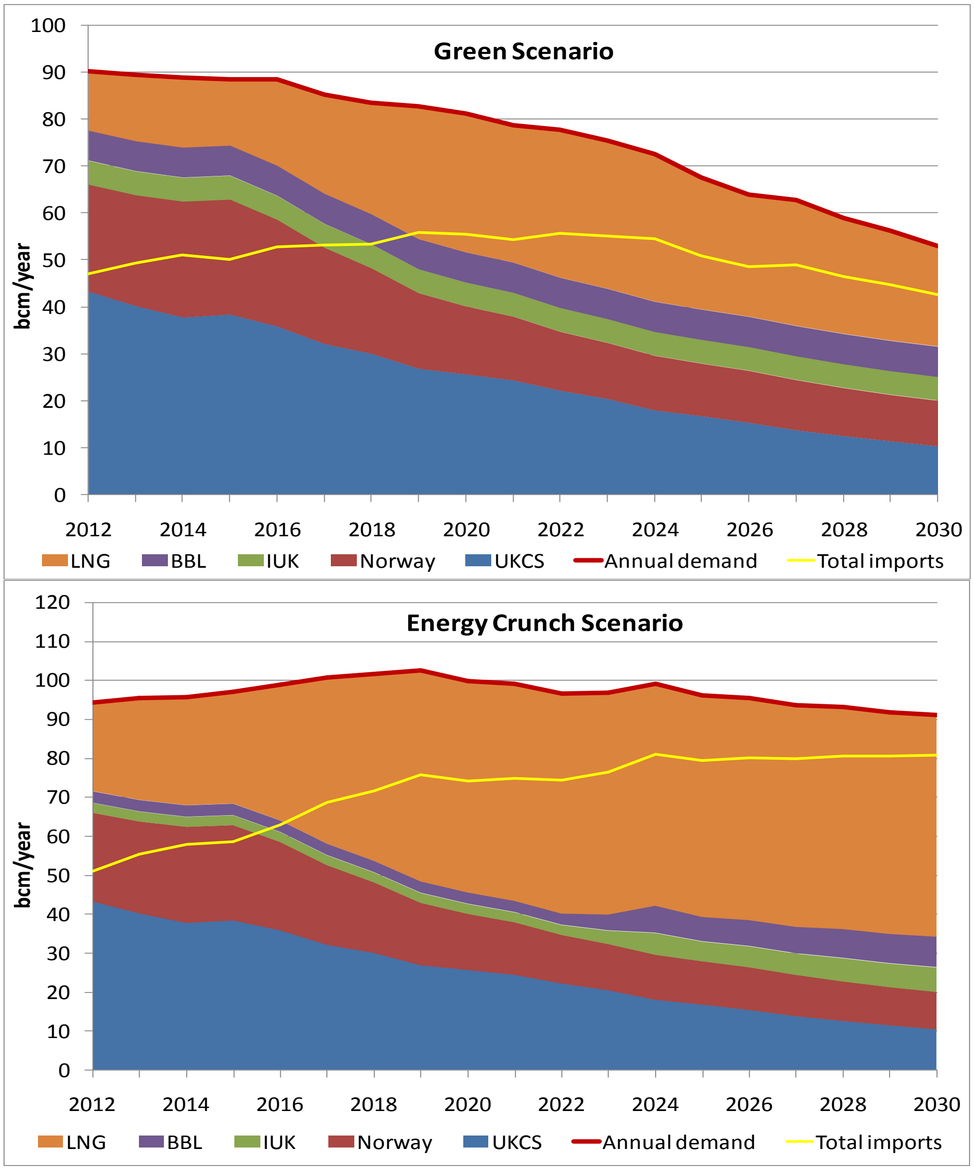
[21] The Teesside Gasport (also known as TeesPort) project is an onboard ship regasification facility.
[22] DUKES, Table 4.4 Natural gas production and supply
[23] National Grid (2011) Ten Year Statement.
[24] DUKES, DECC
[25] Source: DECC (2011) Statutory Security of Supply Report, Risk Assessment and Ofgem analysis.
[26] National Grid (2012) Winter Outlook Consultation Report.
[27] In our resilience analysis, we de-rate this figure to 150mcm/day at peak to reflect a range of possible constraints to the full deliverability rates of these terminals.
[28] In our resilience analysis, we de-rate this figure to 197mcm/day at peak.

2.23. Both scenarios show an increase in import dependency on gas. In the Green scenario import dependency reaches 80%, while in Energy Crunch it is even higher, reaching 89%.

Figure 2.4: GB Gas demand and sources for Green and Energy Crunch scenarios



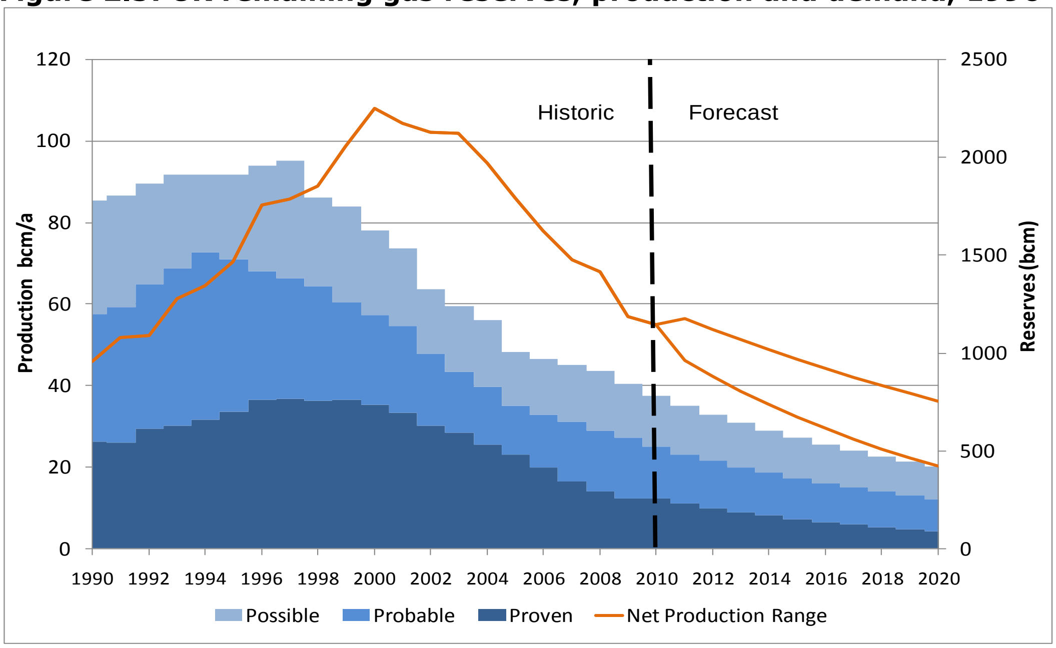
Source: Ofgem

2.24. In both scenarios, we show supplies from UKCS declining, based on the Slow Progression scenario in the 2011 Ten Year Statement. National Grid use a range for UKCS decline, as the orange lines show in Figure 2.5. This shows UKCS production to be between 20 and 40 bcm/a by 2020, with a central estimate of 26 bcm/a[29]. The

[29] National Grid data excludes non-NTS gas to power stations and direct exports

chart also presents the recent historic and forecast quantity of gas reserves in the North Sea. It shows that at the end of 2010 around 250 bcm of UKCS reserves were classed as 'proven'[30,31]. In 2010, 55 bcm of gas was produced from the UKCS, giving a reserves/production ratio of approximately 5 years[32]. However, falling yearly production levels will extend the duration that supplies will come from the UKCS well into the 2020s[33]. Also, new discoveries or transfer of reserves from more speculative reporting categories may also extend the lifespan. Further upside may also occur due to changes in technology that allow greater recovery rates, or positive changes in tax treatment.

Figure 2.5: UK remaining gas reserves, production and demand, 1990-2020



Source: National Grid, Ten Year Statement, p.25

2.25. While there is the possibility of new volumes of gas from unconventional reserves, in particular coal-bed methane, biogas and shale gas, National Grid's projections of UK remaining gas reserves exclude unconventional resources. However, a recent study for Ofgem by Pöyry suggested the contribution of shale gas to GB supplies is likely to be very modest by 2030[34].

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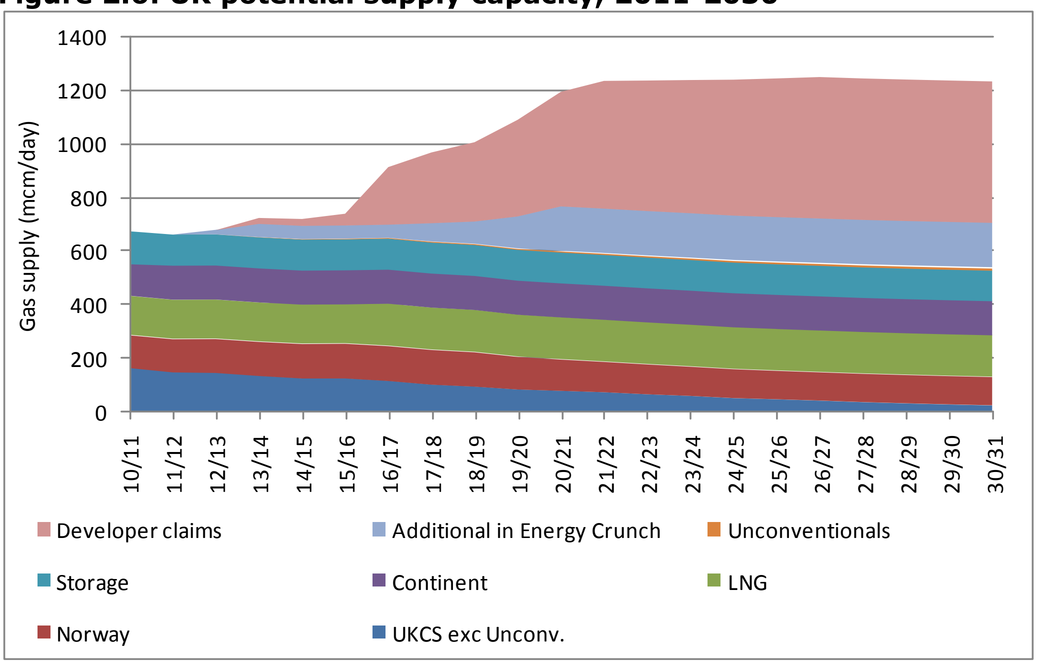
[30] Although definitions of proven reserves vary, a key element of this definition, in the context of gas reserves, is the requirement for the reserves to be considered commercially recoverable – ie there exists, or are plans for, suitable infrastructure to export to market.
[31] In 2010, the aggregate sum of proven, probable reserves and possible reserves was 781 bcm.
[32] Reserves/Production or R/P ratio is a common way of describing a country or region's production dynamics. R/P is normally calculated as proven reserves divided by annual production and listed in years.
[33] Chart 11 in the DECC's Statutory Security of Supply Report projects UKCS production at a level of 20 bcm in 2030.
[34] Pöyry (2011) The impact of unconventional gas on Europe. A report for Ofgem available at: http://www.ofgem.gov.uk/About%20us/PwringEnergyDeb/Documents1/033_PublicReport_UnconventionalGasOfgemLogo_v4_1.pdf

Peak gas supply

2.26. A key issue for GB gas supply security is ensuring sufficient gas is available on a daily basis to meet extreme gas demand. Peak gas supply is provided by a range of sources, currently GB has 715 mcm/day[35] of capacity supplying a maximum historic demand of 465 mcm/day, recorded on 9th January 2010.

2.27. Figure 2.6 provides an adapted version of National Grid's 2011 Ten Year Statement and Ofgem's in-house analysis. It shows that, assuming that all announced projects (in particular storage projects) are developed on time, there will be ample spare capacity. However, it would be unrealistic to assume that all these projects will be developed on time and to the scale assumed, or that all supply capacity will be available and able to operate at maximum levels on days when it is needed. The pale green section highlights the additional infrastructure assumed under the Energy Crunch scenario.

Figure 2.6: UK potential supply capacity, 2011-2030



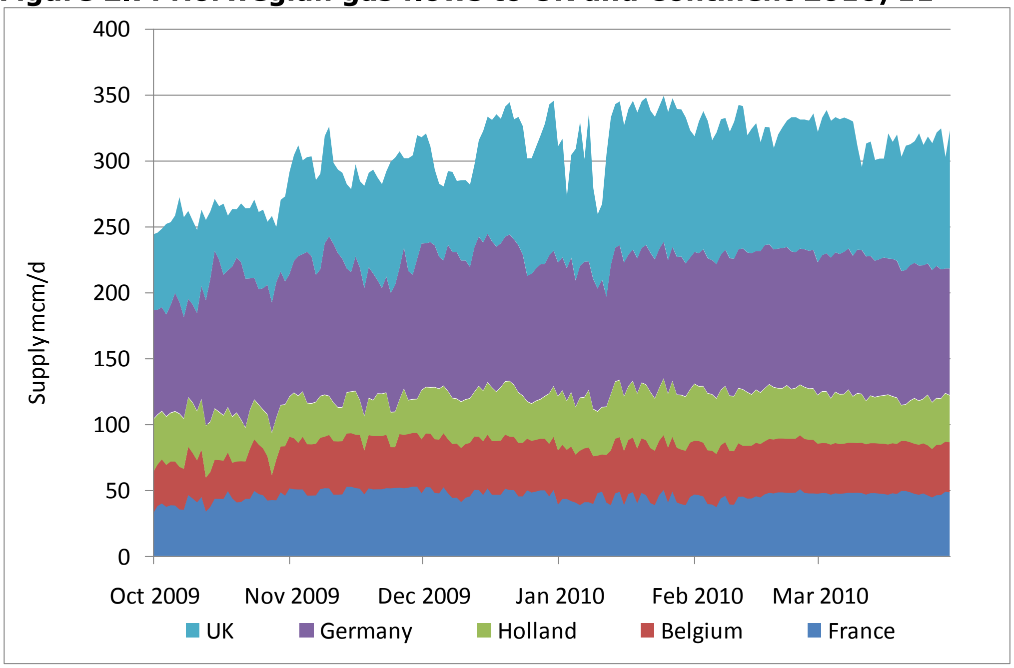
Source: National Grid and Ofgem analysis

2.28. With respect to the contribution to peak GB supply that Norway can provide, an important characteristic should be highlighted. There is evidence that at times of high demand and/or supply disruptions, flows to the Continent from Norway receive priority treatment over those to GB.

[35] This figure is the 12/13 peak supply figure from the National Grid Ten Year Statement 2011. In our resilience analysis, we de-rate this figure to 681 mcm/day at peak.

2.29. This is demonstrated in Figure 2.7 showing Norwegian supplies to the UK and the Continent during winter 2010/11. It highlights that there are drops in supply to the UK when supplies to Europe are stable. National Grid believe this to be a consequence of contractual commitments with flows to the UK having a lower priority than those to the Continent.

Figure 2.7: Norwegian gas flows to UK and Continent 2010/11



Source: National Grid Winter Consultation Report 2010/11, p. 25

2.30. This suggests there could be a risk associated with the certainty of Norwegian supplies in an emergency situation if this occurred at a time of high demand on the Continent. We explore further implications of the European market on GB in the following chapter.

3. European market developments

3.1. Taken together, the regional gas markets in Europe combine to form one of the largest consuming regions in the world. European natural gas consumption was over 450 bcm in 2011[36], just under 15% of total global consumption. However, the characteristics of the regional gas markets differ markedly: there are wide differences in how much gas is used and for what purposes, the supply mix varies in each of the markets and each country has its own market and regulatory arrangements.

3.2. The European gas market can broadly be categorised into three regions:

- North: This region has traditionally been reliant on indigenous production from Norway, the Netherlands and the UK with some imports from Russia. Production from the UK is now in decline and the region will become increasingly reliant on gas imported either as LNG or via pipelines from Norway and Russia.
- South: This region has been a net importer for many years and is reliant on a range of pipeline and LNG supplies.
- East: This region has been a net importer and almost exclusively reliant on Russia. It is now seeking to diversify its supply sources.

3.3. The European market influences the GB market in a number of ways. Europe provides a source of supply to the GB market. Pipelines from Norway and interconnectors from Belgium and the Netherlands can bring gas produced in Continental Europe or further afield (eg Russian gas) to GB, if market signals and commercial arrangements are right.

3.4. Europe can also provide a source of competing demand. For example, Norwegian gas can land in other north-west European countries, as well as GB; the interconnector between GB and Belgium (IUK) allows gas within the GB system to be exported, and a growing number of LNG regasification terminals across Europe will increasingly allow these countries to compete with GB in the global LNG market.

3.5. Also, there are uncertainties surrounding the future paths of European demand, indigenous supplies and the sources of imports. The main uncertainties affecting demand are related to the economic outlook, the achievement of renewable targets, the future investment climate and nuclear deployment. On the supply side, large uncertainties remain with respect to the potential for unconventional sources of gas and the extent to which Russia and/or other pipelines from Asia are constructed.

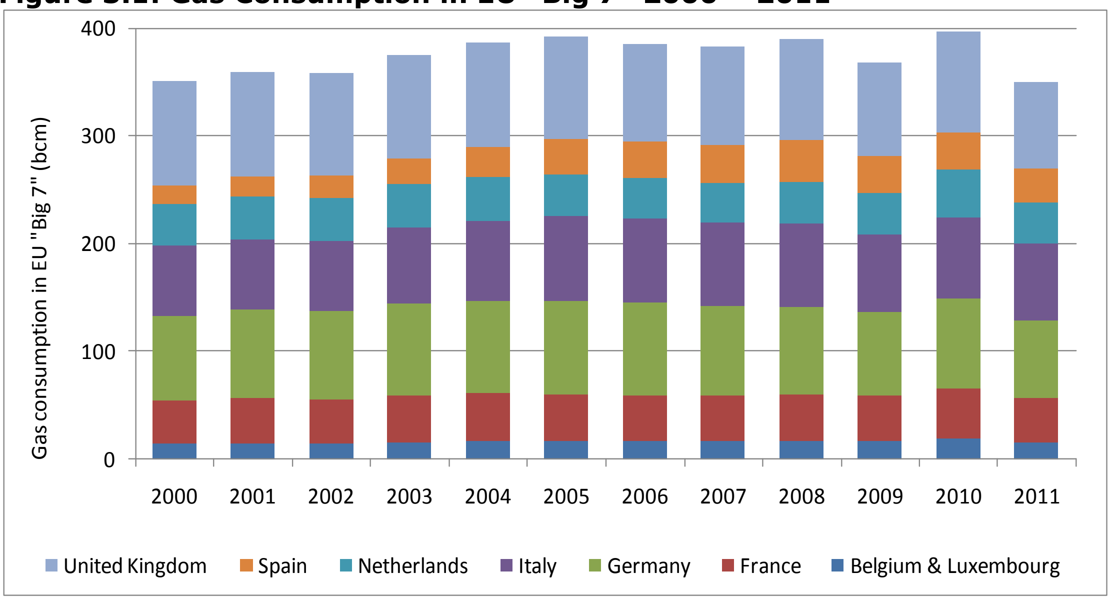
[36] BP Statistical Review of World Energy 2012: http://www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/reports_and_publications/statistical_energy_review_2011/STAGING/local_assets/pdf/statistical_review_of_world_energy_full_report_2012.pdf

European demand

Background and current market

3.6. On average across Europe, gas makes up 25% of primary energy consumption[37]. Gas penetration varies considerably across countries, with high gas penetration often linked to the presence of indigenous reserves (for example, in the Netherlands where the share is almost 50%[38]) and low penetration rates linked to relatively low heating loads (eg Greece where the share is around 10%) or the presence of abundant low-cost alternatives (eg Sweden where hydropower is plentiful the share is below 5%). Seven countries dominate gas consumption in Europe[39]. We plot the change in their gas consumption since 2000 in Figure 3.1.

Figure 3.1: Gas Consumption in EU "Big 7" 2000 – 2011



Source: BP Statistical Review of World Energy 2012

3.7. Figure 3.1 indicates that gas consumption in the EU "Big 7" countries, while showing growth in earlier years, has now returned to 2000 levels. After a small upturn in 2010, in part due to the economic recovery and cold weather at both ends of the year, 2011 saw the largest year-on-year decline on record in EU gas consumption (-9.9%), driven by a weak economy, high gas prices, warm weather and continued growth in renewable power generation[40].

3.8. In the short term, a combination of low coal prices (driven by increased exports from the US) and persistently low CO_2 prices has made burning coal more

[37] Eurogas Statistical Report 2011
[38] Ibid.
[39] In 2011, these seven countries represented 70% of total European gas demand. (Source: BP, ibid)
[40] BP, ibid

economic than gas in the European power sector[41]. This and the ongoing concerns over Eurozone GDP continues to put downward pressure on European gas demand.

3.9. Most European gas markets exhibit an "A" shaped demand profile during the winter months as cold weather leads to increased demand. According to the European Network of Transmission System Operators for Gas (ENTSOG)[42], the sources of supply that meet winter demand in Europe are: 28% indigenous production, 22% Russian imports, 16% Norwegian imports, 15% LNG imports, 12% storage and 7% North African imports.

Outlook to 2035

3.10. Future levels of European demand will depend on a number of factors such as the degree of gas use in power generation (which in turn will be affected by the cost of gas relative to other fuels, the impact of European legislation on fossil fuels[43], and the amount of renewables and nuclear capacity), the impact of carbon reduction policies in other areas and other factors that influence the price of gas (for example, demand and supply conditions in the global gas market and oil prices).

3.11. This uncertainty is illustrated by the wide range of gas demand scenarios for the EU. For example, two IEA scenarios[44,45] suggest annual gas demand in the EU will increase from around 508 bcm today to between 549 bcm and 592 bcm by 2020, increases of 8% and 17%, respectively. Between 2020 and 2030 these two scenarios show changes in demand of -4% and 23%[46]. On the other hand, two scenarios based on the European Commission's outlook on European demand growth, show demand will either fall or stay roughly the same. By 2020, their scenarios show gas demand will have either shrunk to 457 bcm, a -4% change from today, or grown to 514 bcm, a 1% change. Between 2020 and 2030 these two scenarios both show gas demand falling by -9% and -13%, respectively[47].

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[41] Medium-Term Market Report 2012 © OECD/IEA 2012
[42] Winter Supply Outlook 2011-12, Reviews 2010-11. Brussels: European Network of Transmission System Operators for Gas (ENTSOG).
[43] Such as the Large Combustion Plant Directive and Industrial Emissions Directive.
[44] Source: The New Policies scenario and 450 scenario. World Energy Outlook 2011.
[45] The IEA New Policies Scenario for Europe assumes existing commitments are honoured and renewables reach 20% of energy demand by 2020. The 450 Scenario is based on a 30% reduction in emissions compared with 1990 by 2020.
[46] Additionally, the IEA's 'Golden Age of Gas' scenario (as set out in a special report) indicates that EU demand in 2035 could be 16 bcm higher still than projected by the 'New Policies' scenario as a consequence of ambitious gas policy in China, low growth of nuclear power, and more use of gas in road transport.
[47] European Commission, 2010. EU Energy Trends to 2030 – Update 2009. Luxembourg: Publication Office of the European Union.
http://ec.europa.eu/energy/observatory/trends_2030/doc/trends_to_2030_update_2009.pdf

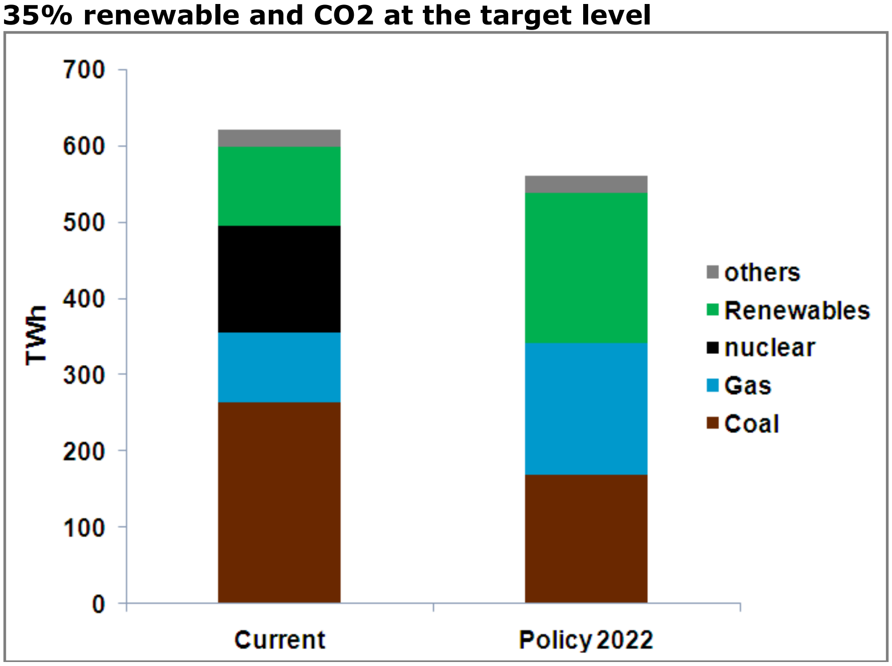
Figure 3.2: EU demand projection (bcm), 2009-2035

	2009 /10	2015	2020	2025	2030	2035
IEA– New Policies Scenario	508	571	592	608	626	628
IEA– 450 Scenario	508	-	549	-	490	448
MJM scenario based on EU Energy Trends - Baseline	507	508	514	503	488	-
MJM scenario based on EU Reference	502	484	457	451	437	-

Sources: World Energy Outlook 2011 © OECD/IEA 2011, Annex A,and European Commission, 2010; MJM analysis

3.12. There is also significant uncertainty regarding gas demand at a country level. A pertinent case study is Germany, where following the Fukushima disaster, the German Government swiftly decided to phase out nuclear generation by 2022. The IEA's initial view of the likely change in German generation mix is illustrated in Figure 3.3 below, which projects a larger share for gas generation than at present. Germany's current no nuclear policy is therefore likely to lead to higher gas demand in Germany than might have otherwise been the case. By contrast, the IEA highlights that gas demand in Germany has in fact decreased since the output of nuclear plants was reduced. This was accomplished by lower power demand, higher output from renewables and higher imports[48].

Figure 3.3: German electricity mix with 10% demand reduction, no nuclear, 35% renewable and CO2 at the target level



Source: Electricity: A Status Report © OECD/IEA 2011, page 10

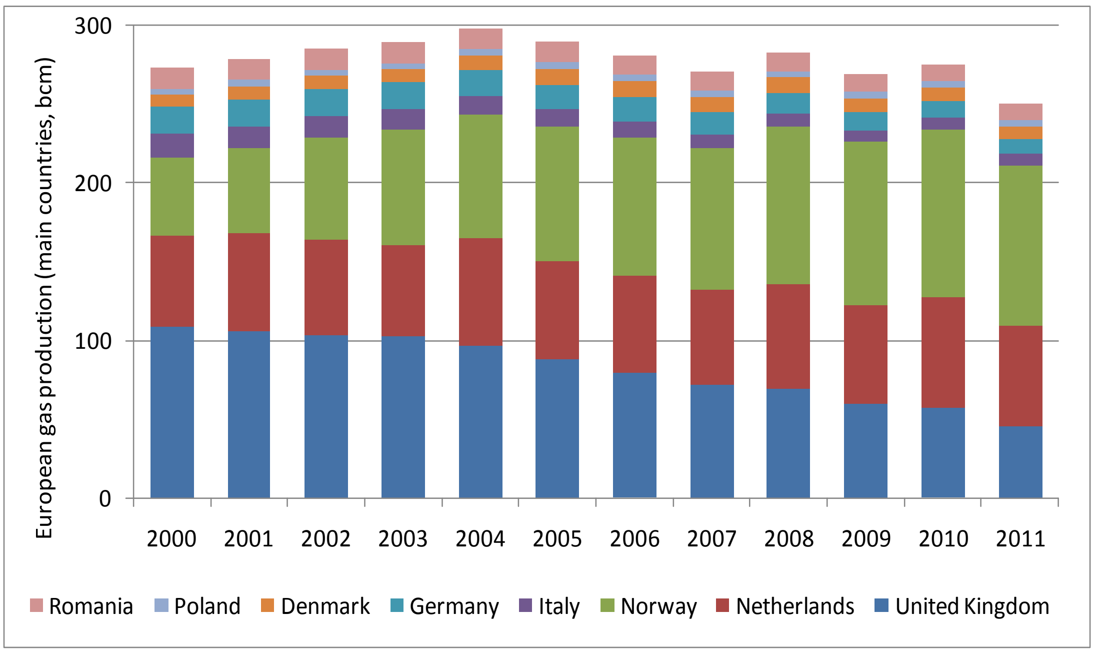
[48] Medium-Term Market Report 2012 © OECD/IEA 2012

European supply

Background and current market

3.13. In recent years, indigenous production in Europe has been dominated by the UK, the Netherlands and Norway[49]. Figure 3.4 shows the annual gas production in the main producing countries in Europe. It shows that supplies from the UKCS and some other countries (such as Italy and Germany) have fallen, and while in previous years this was in part offset by growth in Norwegian production, 2011 saw a record decline in EU gas production (-11.4%), due to a combination of mature fields, maintenance, and weak regional consumption.

Figure 3.4: Annual gas production in main producing European countries, 2000-2011



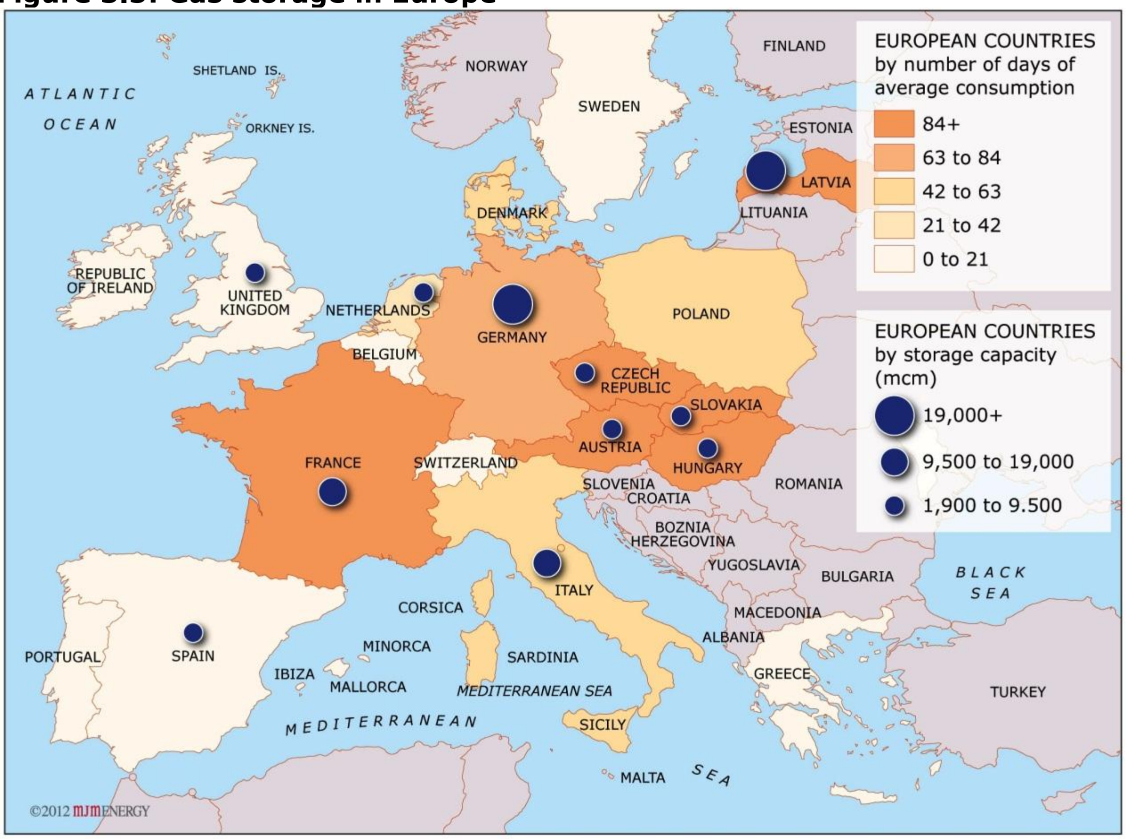
Source: BP Statistical Review of World Energy 2012

3.14. In terms of infrastructure, North West Europe is characterised by significant cross border pipeline capacity between Germany, the Netherlands, Belgium, France and the UK. In contrast, Spain has limited interconnection with France and relies largely on LNG to meet demand[50]. The EU has stated it considers increased interconnection in gas is crucial to both security of supply and further market integration[51]. The effectiveness (or otherwise) of cross-border flows is discussed in more detail later in this appendix.

[49] In 2011, indigenous production in Europe totalled around 250 bcm (BP Statistical Review of World Energy 2012)
[50] In 2010, Spain's share of gas supply from LNG was almost 80% (Eurogas Statistical Report 2011)
[51] Gas Pipeline Incidents, The 8th Report of The European Gas Pipeline Incident Data Group, EGIG NV

3.15. Historically, most European countries have not had large indigenous supplies of gas, and instead have tended to rely on imported gas using long-term, take-or-pay gas contracts (with certain flexibility to adjust gas flows) and gas storage facilities to provide additional flexibility and security of supply. Where geology allows[52], and where they have had need for it[53], this has tended to lead to larger volumes of storage space being developed in many European countries in relation to annual gas demand compared to GB. Figure 3.5 depicts the capacity of the storage infrastructure present across Europe. It also shows roughly the number of days at average consumption that storage could meet demand. GB stands out (as does Spain) as having a low level of storage capacity[54]. This reflects GB's historic position as a gas producer and the fact that there has been significant investment in non-storage supply in recent years.

Figure 3.5: Gas storage in Europe



Source: MJMEnergy

Nederlandse Gasunie: Groningen.

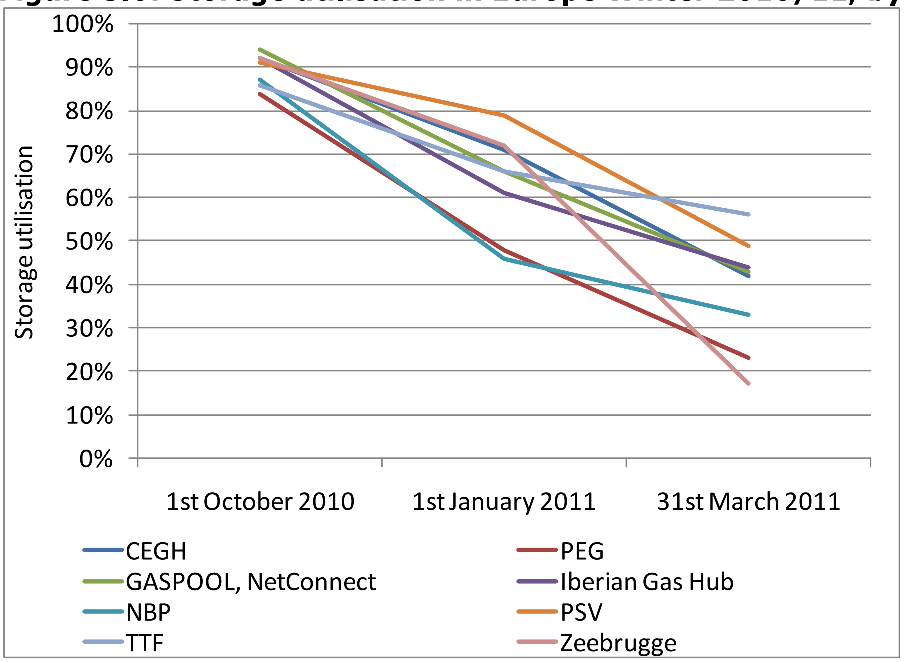
[52] For example, storage capacity in natural porous strata in Belgium is limited by geology.

[53] For example, Germany's gas demand is highly seasonal.

[54] These figures exclude storage at LNG importing facilities.

3.16. Storage utilisation is important in assessing its contribution to supply. Figure 3.6 shows the wide range of storage utilisation during last winter at major trading hubs. In different countries storage is similarly full at the start of winter (ranging from 84% to 94% in the hubs shown) though quite dissimilar by the end of winter (ranging from 17% to 56%).

Figure 3.6: Storage utilisation in Europe Winter 2010/11, by trading hub



Source: European Network of Transmission System Operators for Gas, 2011

3.17. Storage utilisation can be driven by a number of factors, including:

- market conditions such as the levels of demand and non-storage supplies,
- commercial factors such as contractual flexibility,
- the withdrawal and injection capability of the facilities. In some cases fast cycle storage facilities will inject gas during the winter months when circumstances permit, and
- regulatory requirements, such as required fullness levels at the start or during the course of the winter.

Outlook to 2035

Indigenous production

3.18. As shown in Figure 3.7, indigenous gas production in OECD Europe is projected to fall over the period to 2035. However, there are some production increases, namely from Norway, and later in the period, from unconventional sources in Poland. In the European Union, production drops by 55% between 2009 and 2035[55].

Figure 3.7: European gas supply forecasts, bcm

	2015	2020	2025	2030	2035	Annual % increase
UK	37	27	17	12	10	-6.9%
The Netherlands	83	67	54	41	28	-1.4%
Norway	109	117	122	124	120	0.5%
OECD Europe	279	259	240	222	204	-1.4%

Source: World Energy Outlook 2011 © OECD/IEA 2011, Table 4.4, page 165

3.19. Present forecasts exclude any material contribution from unconventional gas in Europe. In a study commissioned by Ofgem[56], Pöyry Management Consulting assessed the drivers behind and barriers to the development of unconventional sources in Europe. It finds that while there is potential for unconventional gas to be a major source of supply[57], constraints like environmental considerations may mean that no significant volumes may be developed. France, for example, has large reserves but has outlawed hydraulic fracturing on environmental grounds.

3.20. Investment in storage capacity continues in Europe. Natural candidates for facilities include depleted or partially depleted gas fields[58]. Much of continental Europe's gas fields are onshore and converting these fields to storage facilities is often more commercially attractive than converting offshore fields (offshore fields are characteristic of the GB market)[59]. Germany, Spain, Italy and Poland are seeing significant investment in storage capacity with around 15 bcm of additional space currently under construction[60,61].

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[55] World Energy Outlook 2011 © OECD/IEA 2011,

[56] http://www.ofgem.gov.uk/About%20us/PwringEnergyDeb/Documents1/033_PublicReport_UnconventionalGasOfgemLogo_v4_1.pdf

[57] Estimates of EU unconventional gas resources range from 1.4 tcm (Wood Mackenzie) to 4 tcm (Advanced Resources International), approximately equal to 8 years of EU27 demand. The latest EIA estimate, which includes more speculative potential plays, is over 18 tcm of technically recoverable resource.

[58] Salt caverns and aquifers can also be used to store natural gas, for example, for geological reasons France stores significant amount of gas in aquifers and Belgium's only storage facility is an aquifer. Natural gas can also be stored in liquid form, for example, Spain has a significant amount of LNG storage capacity.

[59] An example of an onshore field being developed into a storage facility in North-west Europe is the Bergermeer project which is 4.1bcm and is intended to roughly double Dutch storage capacity. This facility is located close to the interconnector between GB and the Netherlands. http://www.bergermeergasstorage.com/ How accessible this gas will be to GB shippers depends on how interconnected the GB and Dutch markets are, which is discussed elsewhere in the report.

[60] Germany 4.6 bcm, Spain 4.3 bcm, Italy 3.5 bcm and Poland 2.6 bcm. Source: Gas Storage Europe.

[61] Some EU countries (such as the UK, France and Germany) have negotiated third-party access as the default regulatory regime and returns to investment in storage are determined by market forces. Other countries have a regulated third-party access regime (such as Spain, Italy and Poland) where returns to investment in storage are regulated and the level of storage capacity that is developed is centrally controlled. Unless an exemption is in place, this means that storage facilities in Europe must be allocated to customers in a transparent, objective and non-discriminatory way.

3.21. Taken together, the implications of the demand and production projections above suggest that EU imports of gas are likely to increase significantly over the next two decades. Figure 3.8 shows the projected supply and demand balance for Europe in the IEA's New Policies scenario.Using separate projections for LNG, this has been used to disaggregate net imports into projections for LNG and pipelines imports. It shows that whilst pipeline imports remain larger than LNG imports over the period, LNG imports grow more rapidly.

Figure 3.8: OECD Europe supply and demand forecasts, bcm/a[62]

	2009	2020	2030
Demand	537	627	666
Production	294	259	222
Net Import Requirements	243	368	444
- Of which LNG	62	155	185
- Of which pipeline	173	213	259

Source: IEA World Energy Outlook 2011, MJMEnergy, Ofgem analysis

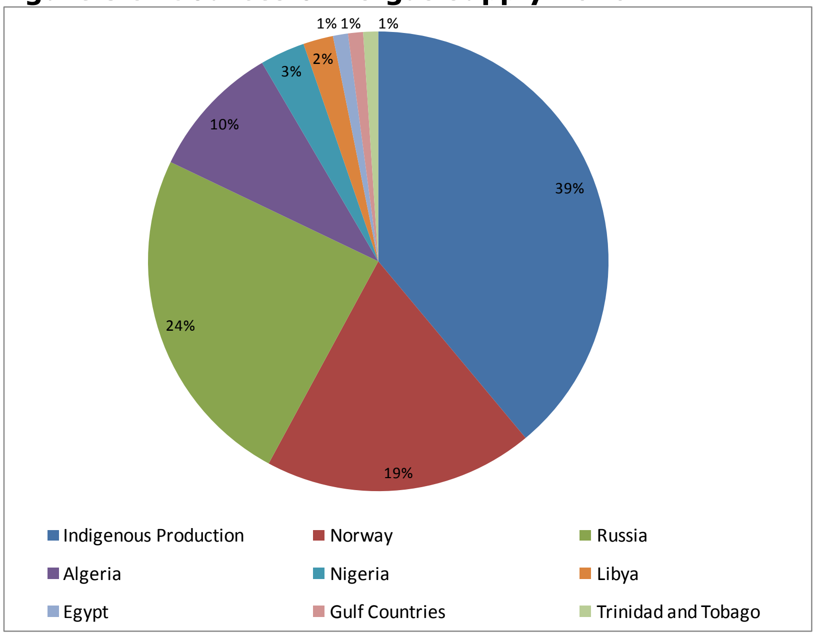
3.22. The IEA also show that projected gas flows from Russia to Europe will continue to grow, albeit at a slower rate. By 2030, the IEA predict Russian supplies to Europe to be around 200 bcm, up from around 150 bcm today[63]. We discuss the prospect for greater pipeline and LNG supplies in Europe in turn below.

Pipeline Supplies

3.23. In 2010, 76% of total European imports came through pipelines, with the remainder coming via LNG[64]. Russia is the main source of gas imports to Europe (though its share has declined in recent years due to new pipelines from North Africa and the increasing role of and competition from LNG)[65]. Figure 3.9 shows that Russia accounted for 24% of total EU gas supplies in 2010, although, this percentage varies between countries. For example, during the gas supply cut off caused by the dispute between Russia and Ukraine in January 2009, Bulgaria, Slovakia and Austria suffered a 100%, 97% and 66% import shortfall, respectively, whilst the figures for France and Italy were significantly lower at 15% and 25%, respectively[66].

[62] World Energy Outlook 2011 © OECD/IEA 2011, Table 4.2 and Table 4.4 are used for demand and production figures and net import requirements are calculated as the difference between the two. MJM analysis is used for LNG imports and pipelines imports are calculated for future years. LNG and pipeline imports for 2009 are taken from IEA Natural Gas Information 2010 (which also gives 28 bcm as unspecified imports) and do not sum to the calculated net import requirements taken from the WEO 2011.
[63] World Energy Outlook 2011 © OECD/IEA 2011,. p 338. Note: Europe in this context is the European Union, other OECD Europe and southeast European countries.
[64] Eurogas Statistical Report 2011
[65] Eurogas Statistical Report 2011
[66] Christie, E, H. et al., 2011. Vulnerability and Bargaining Power in EU-Russia Gas Relations. The Vienna Institute for International Economic Studies.

Figure 3.9: Sources of EU gas supply 2010



Source: Eurogas Statistical Report 2011

3.24. Figure 3.10 provides a schematic of Europe's pipeline routes. It shows the volumes of flows and remaining reserves supplying the pipelines. The main flows are:

- Norway: Pipelines carry gas from the Norwegian Continental Shelf to the UK, Germany, the Netherlands, Belgium and France.
- Russia: Historically, flows were via pipelines transiting Ukraine and Belarus with some smaller lines serving the Baltic countries directly. Russia, the world's largest holder of proven gas reserves, will increase its physical ability to supply Europe with the commissioning of the Yamal Bovanenkovskoye field in 2012. In addition, the non-Gazprom upstream producers in Russia have significant potential for production development often at lower supply costs than those of Gazprom's new projects[67].

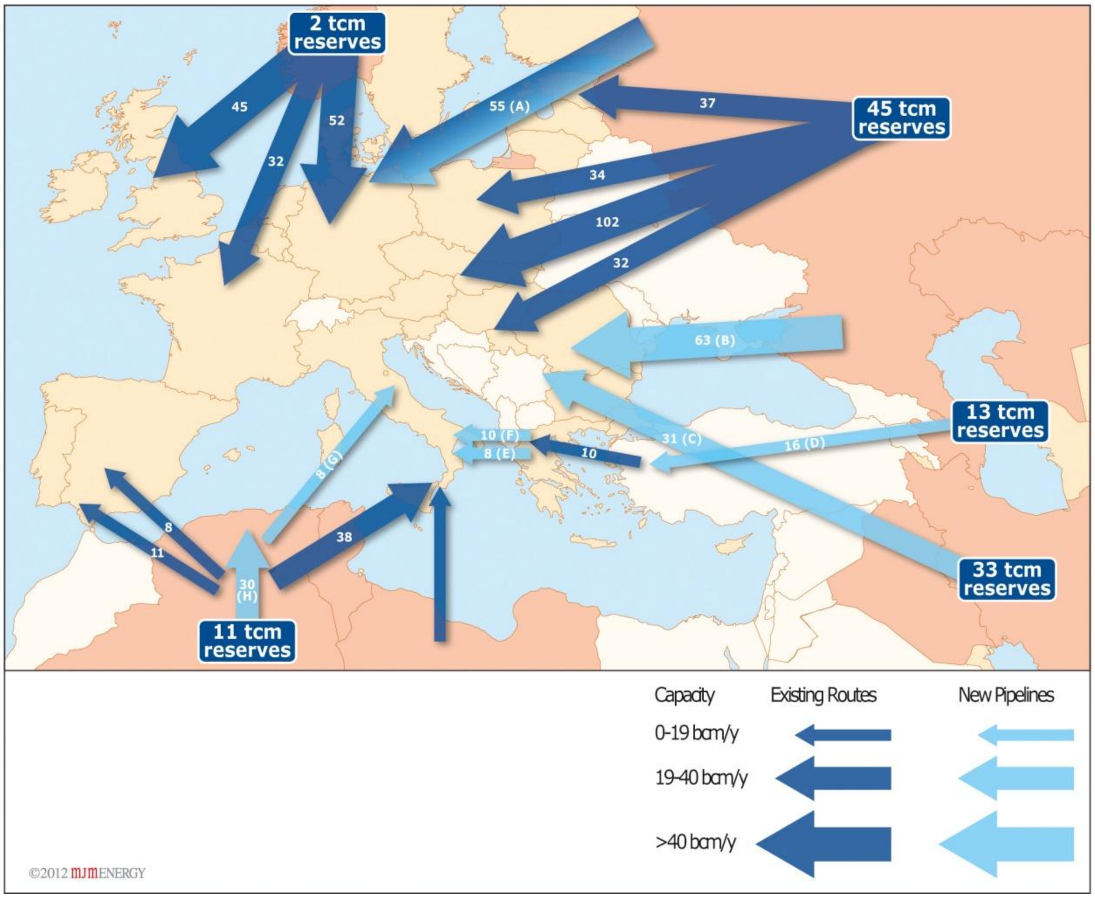
3.25. In November 2011 the NordStream pipeline (marked as A on figure 3.10) came on stream taking gas directly from Russia to Germany. The capacity of this pipeline is 55 bcm/a. Nordstream will avoid the cost and potential disruption associated with transiting Ukraine and Belarus and also provide Gazprom with direct control of the capacity serving its most important European customers[68].

3.26. A similar rationale underpins plans to build South Stream (marked as B in figure 3.10), a collection of up to 4 pipelines with a total capacity of 63 bcm which would cross the Black Sea to Bulgaria with onshore pipelines serving the countries of

[67] Henderson, OIES, http://www.oxfordenergy.org/2012/03/is-a-russian-domestic-gas-bubble-emerging/
[68] http://www.nord-stream.com/press-info/press-releases/nord-stream-pipeline-inaugurated-major-milestone-for-european-energy-security-388/

Central and Southern Europe. The final investment decision has yet to be made on South Stream. However, recent reports suggest this could happen as soon as early 2013[69].

Figure 3.10: Sources of EU gas supply 2010



Source: National Grid and MJMEnergy Research

3.27. Caspian and the Middle East: At present there are minor flows via the South Caucasus Pipeline and Turkey, though a number of projects are under discussion. Four projects are competing to bring additional gas from the Caspian and the Middle East into Europe:

- The Nabucco pipeline (marked as C) would connect production from the Caspian and Iraq through Turkey, Bulgaria, Romania and Hungary to Baumgarten in Austria. Nabucco would have a capacity of 31 bcm/a, and construction is planned to start in 2013 with full capacity available from 2019.

- IGI/Poseidon pipeline (marked as E) would comprise a 600 km onshore pipeline in Greece linking the existing Interconnector between Turkey and Greece (ITG) with

[69] http://www.euractiv.com/energy/south-stream-close-final-decisio-news-513952

a proposed 207 km line crossing the Ionian Sea to Italy. This 8 bcm/a pipeline is being promoted by Edison of Italy and the Greek gas company DEPA.

- The Trans Adriatic Pipeline (marked as F) would be an 800 km pipeline running from Komtini near the Greece/Turkey border to Italy via Albania and the Adriatic. The scheme is being promoted by EGL of Switzerland, Staoil and E.ON and has a planned capacity of 10 bcm/a. The line is due to open to coincide with Shah Deniz II in 2016/17.

- The Trans-Anatolian Gas Pipeline Project (marked as D) is a joint venture between the State Oil Company of Azerbaijan Republic (SOCAR) and Botas Petroleum Pipeline Corporation with a planned capacity of 16 bcm/a, of which 10 bcm/a is intended for the European market.

3.28. In the longer term (post 2020) Turkmenistan could export significant volumes to Europe, whilst the prospects for exports from Iraq appear limited due to domestic demand needs.

3.29. North Africa: Gas from Algeria, Tunisia and Libya is currently exported through 4 pipeline routes to Italy and Spain. A further pipeline (GALSI) is planned to take 10 bcm/a of gas from Algeria to Sardinia and Northern Italy and there is also the possibility of a trans-Saharan pipeline to take Nigerian gas via Algeria to Europe (NIGAL). Neither of these projects has been approved and NIGAL, in particular, is considered to be highly speculative. Some have also argued that due to a combination of upstream policy drift and fast growing domestic demand, the prospects for a significant increase in exports from Algeria, by pipeline or LNG, appear modest[70].

LNG Supplies

3.30. The IEA expect LNG imports to Europe to double between 2010 and 2020. Traditionally most of continental Europe’s LNG imports came into France, Belgium and Spain. As the market for LNG has grown, existing terminals have been expanded, and new terminals have been built and are under construction. For example, new terminals have recently opened in Italy and the Netherlands and terminals are under construction in Poland, Italy, France and Spain. Figure 3.11 below shows the LNG terminals that exist or are under construction. Total import capacity will exceed 180 bcm/a when all those terminals presently under construction come on stream.

[70] Natural Gas Markets of the Middle East and North Africa, Fattouh & Stern, OIES, 2011, Chapter 1.

Figure 3.11: LNG Terminals in continental Europe, existing and under construction

	Number	Capacity (bcm)
France	4	37
Spain	9	73
Netherlands	1	16
Italy	3	15
Belgium	1	9
Other	5	32
Total	23	182

Source: GLE LNG Investment Database

Uncertainties

3.31. There are a number of key uncertainties with respect to future gas supplies to Europe:

- Whether new gas from the Caspian and Middle East region will be piped to Europe, and if so by which route.
- The development of unconventional gas. There has been significant debate on the potential for unconventional sources of gas revolutionising European indigenous supplies. The largest resources are expected to be in Poland[71] followed by Germany, the Netherlands, and France, though estimates are subject to a high degree of uncertainty. There are still significant questions over the timing of the projects, their costs and resource accessibility. The latter point has been underlined with the withdrawal in June of ExxonMobil from drilling in Poland, claiming the shale is too tight to use standard hydraulic fracturing techniques[72].
- The development of the LNG market.

3.32. The last point on the future of the LNG market is discussed further in the next section on global gas market developments.

[71] Albeit less than initial estimates suggested. (Source: Pöyry, The Impact of Unconventional Gas on Europe)
[72] Ofgem commissioned Pöyry to assess the drivers and barriers to unconventional gas production in Europe, and impacts on gas prices and security of supply in GB and Europe. It finds that significant production of unconventional gas is not expected before the 2020s and thereafter the amount of production is highly uncertain. In addition, even moderate production in Europe could keep gas prices in GB lower from 2020 onwards than they would otherwise be.
http://www.ofgem.gov.uk/About%20us/PwringEnergyDeb/Documents1/033_PublicReport_UnconventionalGasOfgemLogo_v4_1.pdf

4. Global market developments

4.1. In this section we set out our analysis on medium and longer-term developments in the global gas market, drawing on the IEA's Medium-term Gas Market Report (MTGMR) 2012 for the period up to 2017 and thereafter, the IEA's World Energy Outlook (WEO) 2011, as well as other sources.

4.2. There are particular uncertainties around the market developments presented in this chapter. On the demand side, there is a chance that global gas consumption may be lower than presented in the scenarios in this section. This might come about if global consumption remains subdued due to the prolonged economic slump. On the other hand, in the long run, gas consumption might be even higher, as illustrated by the IEA's Golden Age of Gas (GAS) scenario[73].

4.3. On the supply side, the largest uncertainty surrounds the extent of the global development of unconventional gas and, in particular, whether the US will become a significant LNG exporter.

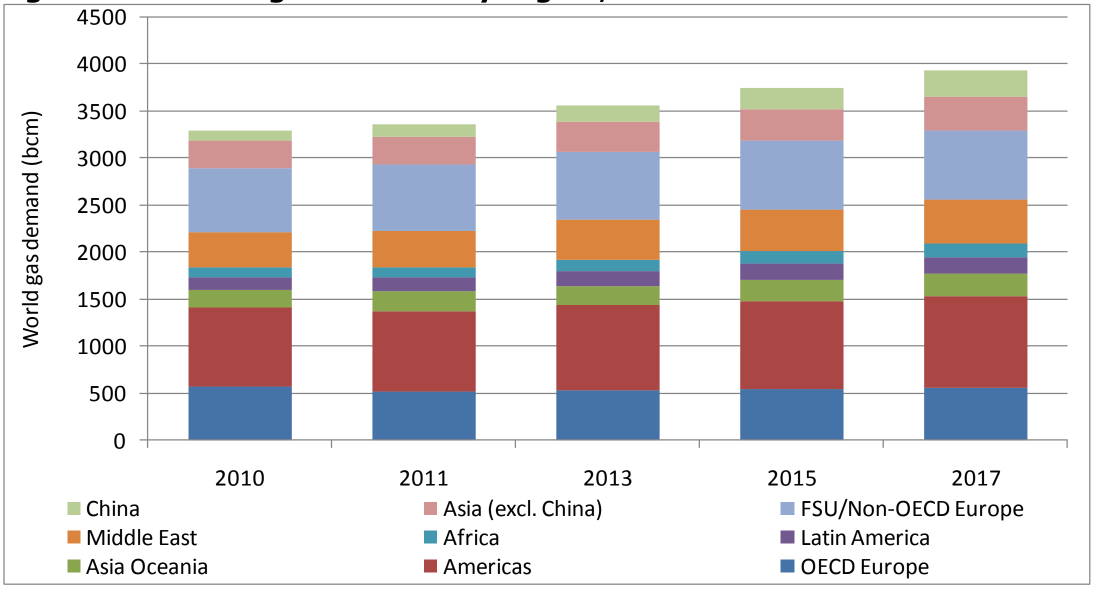
Global Demand

4.4. In the medium term the IEA suggest that global gas demand will grow by 17% to 2017, from 3.3 tcm in 2011 to approximately 4 tcm (see Figure 4.1). This gives an annual global growth rate of 2.7% and is similar to the level of growth seen in the last decade. In the coming 5 years, the IEA expect the strongest growth to come from China and Africa. Assumptions for US consumption show a faster growth rate than compared with previous IEA estimates, reflecting the consequence of sustained low gas prices.

4.5. The IEA's 2012 demand forecast for 2015 is around 3.76 tcm[74], just above the BP[75] forecast for the same year of 3.7 tcm. Interestingly, these figures are both above the 2015 forecasts from the IEA and EIA[76] in 2011, which are both around 3.5 tcm.

[73] This scenario shows a large increase in gas consumption to 2035 as a consequence of an ambitious gas policy in China, low growth of nuclear power, and more use of gas in road transport
[74] Medium-Term Market Report 2012 © OECD/IEA 2012
[75] BP Energy Energy Outlook 2030
[76] International Energy Outlook 2011, Energy Information Administration

Figure 4.1: World gas demand by region, 2010-17



Source: Medium-Term Market Report 2012 © OECD/IEA 2012, Table 2, page 31, adapted by Ofgem

4.6. In the longer term, the IEA use three scenarios to forecast changes in consumption: a high-demand case (the Current Policies scenario), a central demand case (the New Policies scenario) and a low-demand case (the 450 scenario).

4.7. The Current Policies scenario (called the Reference scenario prior to WEO-2010) shows how the future might look if there was no change in current energy and emissions-related policies across the globe. It includes all policies in place as of mid-2011.

4.8. The New Policies scenario is based on the broad policy commitments and plans that have been announced across the world to address energy security, climate change and local pollution, and other pressing energy-related challenges, even in cases where the specific details have yet to be announced.

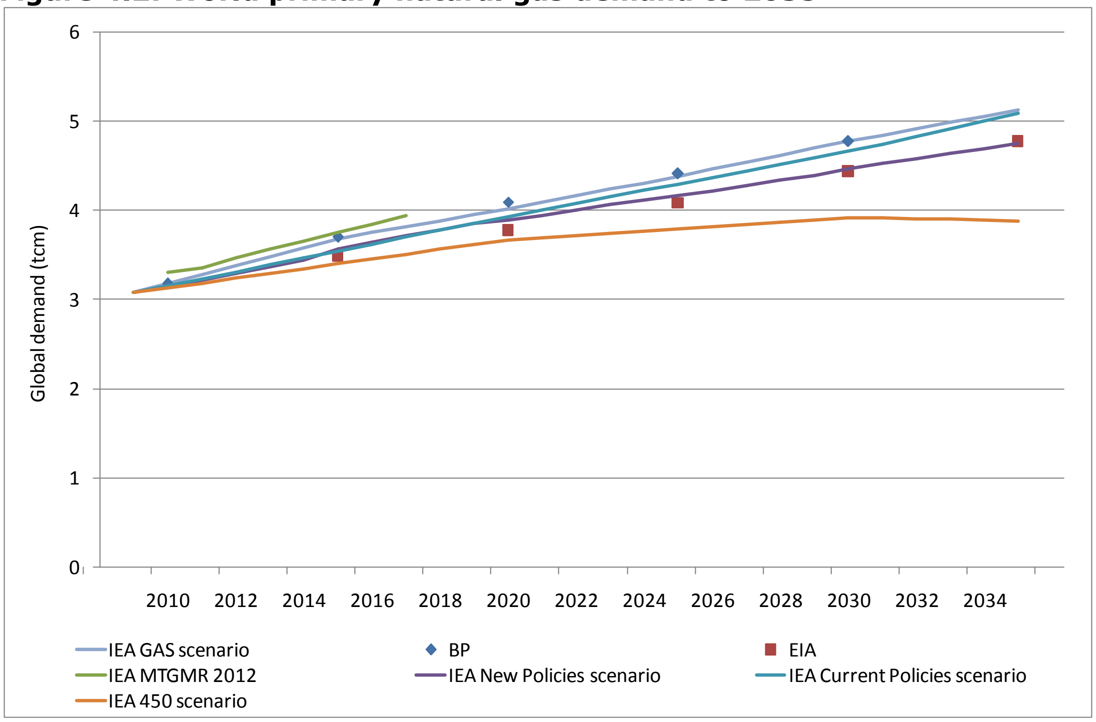
4.9. The 450 scenario assumes more vigorous policy action than is assumed in the New Policies Scenario. It assumes the Cancun Agreements are fully implemented and after 2020 OECD countries and other major economies are assumed to set economy-wide emissions targets to 2035 and beyond that collectively ensure an emissions trajectory consistent with the stabilisation of greenhouse gas concentrations in the atmosphere to 450 parts per million.

4.10. In all of the IEA's scenarios, global gas demand increases significantly in the period to 2035 (see Figure 4.2). In the New Policies Scenario (the central case), annual demand grows on average by 1.7% per year to reach 4.75 tcm by 2035. This increase is largely driven by new policies on emissions and pollutants which favour gas use over other fossil fuels. In the Current Policies scenario, average growth in demand is 1.95% per year, reaching just over 5 tcm by 2035. This is driven by fewer policies to reduce demand or the use of fossil fuels than in the New Policies scenario. In the '450' scenario, annual demand growth is only 0.9% on average, reaching 3.9

tcm in 2035. This is due to lower electricity demand and strong policies to reduce greenhouse gas emissions.

4.11. Figure 4.2 also shows longer-term outlooks from the EIA, BP and the IEA's Golden Age of Gas (GAS) scenario;the latter we discuss in more detail in the following section. While the EIA's long run forecast is largely in line with the IEA's central (New Policies) estimate, both the GAS and BP scenarios are more bullish, resulting in forecast values of around 4.8 tcm by 2030.

Figure 4.2: World primary natural gas demand to 2035



Source: IEA and Ofgem analysis
Note: IEA trend lines have been interpolated from data points every 5 years in most cases.

4.12. Looking at which countries drive this growth, most comes from China and the Middle East, with increases in annual demand of 410 bcm/a and 279 bcm/a in the New Policies scenario, respectively (equivalent to average annual growth rates of 6.7% and 2.3%)[77], between 2009 and 2035. To put these figures in context, the growth in annual demand in OECD Europe, over the same time period, is forecast to be around 130 bcm/a (or 0.9% on average). Growth in demand across the OECD is forecast to increase 0.7% on average to 2035, compared with 2.4% across non-OECD countries.

[77] World Energy Outlook 2011 © OECD/IEA 2011,p.160

Demand-side uncertainty

4.13. There is significant uncertainty around the outlook for global gas demand. “Are we entering a golden age of gas”, a special report by the IEA , devises a scenario that examines the conditions under which the future role of gas could be greater than expected. It uses the same assumptions on population and economic growth as the WEO 2010 New Policies scenario, but changes several other assumptions in favour of those driving gas use. This includes more ambitious policy on gas use in China, lower gas prices, lower nuclear deployment as a consequence of both policy and economics versus gas-fired electricity generation, greater use of gas in road transport, and more unconventional gas production.

4.14. Under these enhanced assumptions, global gas demand increases by an average of 2% per year to reach 5.1 tcm by 2035. This is around 380 bcm higher than in the New Policies scenario.

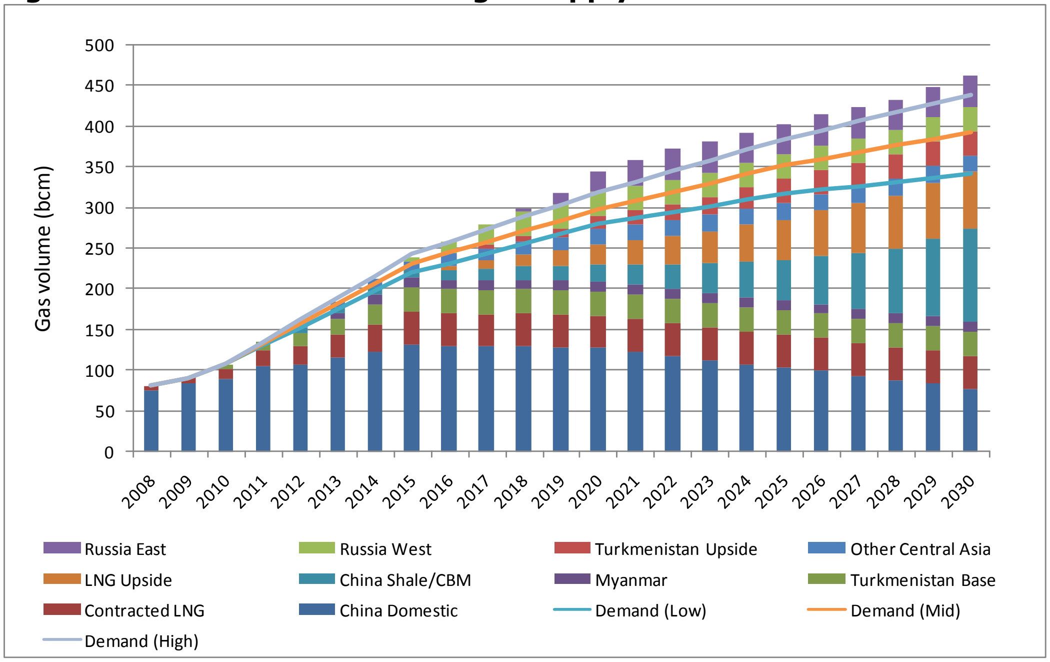
Asian demand growth

Looking in more detail at Chinese demand growth, Figure 4.3 presents one forecast for growth in Chinese demand to 2030. It shows that by 2030, Chinese demand could range between around 350 bcm/a and 450 bcm/a. The IEA forecast Chinese demand towards the high end of this range with 435 bcm/a in 2030, or around 10% of global gas consumption[78].

4.15. The figure also depicts how this demand might be met, for example through increased imports from Russia and Central Asia (e.g. Turkmenistan) and a significant proportion from indigenous, unconventional production. Since Chinese demand will be so large by 2030, even small percentage changes in its level will have significant implications for global gas markets. We look at global gas supply in more detail in the next section of this chapter.

[78] World Energy Outlook 2011 © OECD/IEA 2011,p. 159

Figure 4.3: Forecast of Chinese gas supply and demand



Source: Henderson (2011) The Pricing Debate over Russia Gas Exports to China, OIES

Nuclear generation

4.16. Additional uncertainty over future gas demand comes from the range of possibilities surrounding the development of nuclear power. For example, following the Fukushima disaster a number of countries are already reviewing their nuclear programs (see chapter 5 for further discussion). The IEA have looked at the impact of a reasonably pessimistic view of future nuclear build in their 'low nuclear' scenario, which assumes no new nuclear reactors are built in OECD countries beyond those already under construction, and only 50% of the capacity additions projected in non-OECD countries in the New Policies scenario[79] proceed as planned.

4.17. Under these assumptions, nuclear energy falls from a projected 13% share of global electricity generation to only 7% by 2035. The difference is made up from increases in coal, gas and renewables generation. The increase in gas generation capacity in this scenario is forecast to be 122 GW, which means the share of gas in power generation increases from 21% in 2009 to 24% in 2035 (compared to 22% in the New Policies scenario) and global gas demand increases by 130 bcm/a (roughly 3% of total demand in that year), with gas prices increasing by 4-6% as a result.

4.18. Sudden changes in the level of nuclear generation will also have significant short-run consequences on the gas market. For example, following the shutdown of nuclear stations in Japan after the Fukushima disaster, LNG demand increased by the equivalent of 11 bcm/a[80]. Future Japanese LNG demand will depend on the policy

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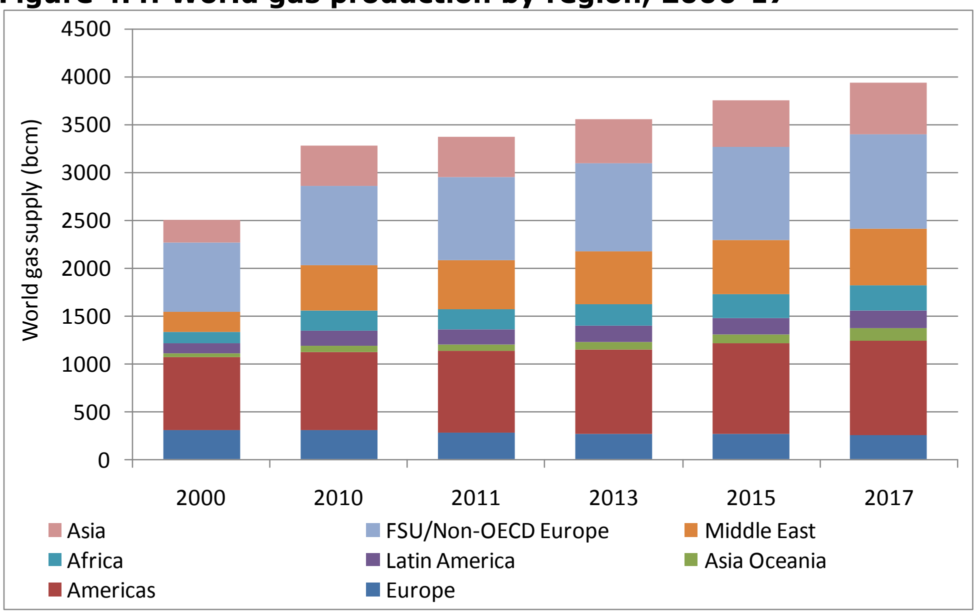
[79] The New Policies scenario
[80] Medium-Term Market Report 2012 © OECD/IEA 2012

decisions taken on whether and to what extent its nuclear power stations are restarted.

Global supply

4.19. The IEA's medium-term gas supply forecast is shown in Figure 4.4 below. In the period to 2017, production increases in all regions except Europe to reach just under 4 tcm/a. The Former Soviet Union is the largest contributor to increases in gas supplies over the period, increasing annual production by 16%. In the US, production from unconventional sources continues to increase, though the biggest increase in the OECD comes from Australia, which is expected to become the second largest LNG exporter, after Qatar, in 2016[81].

Figure 4.4: World gas production by region, 2000-17



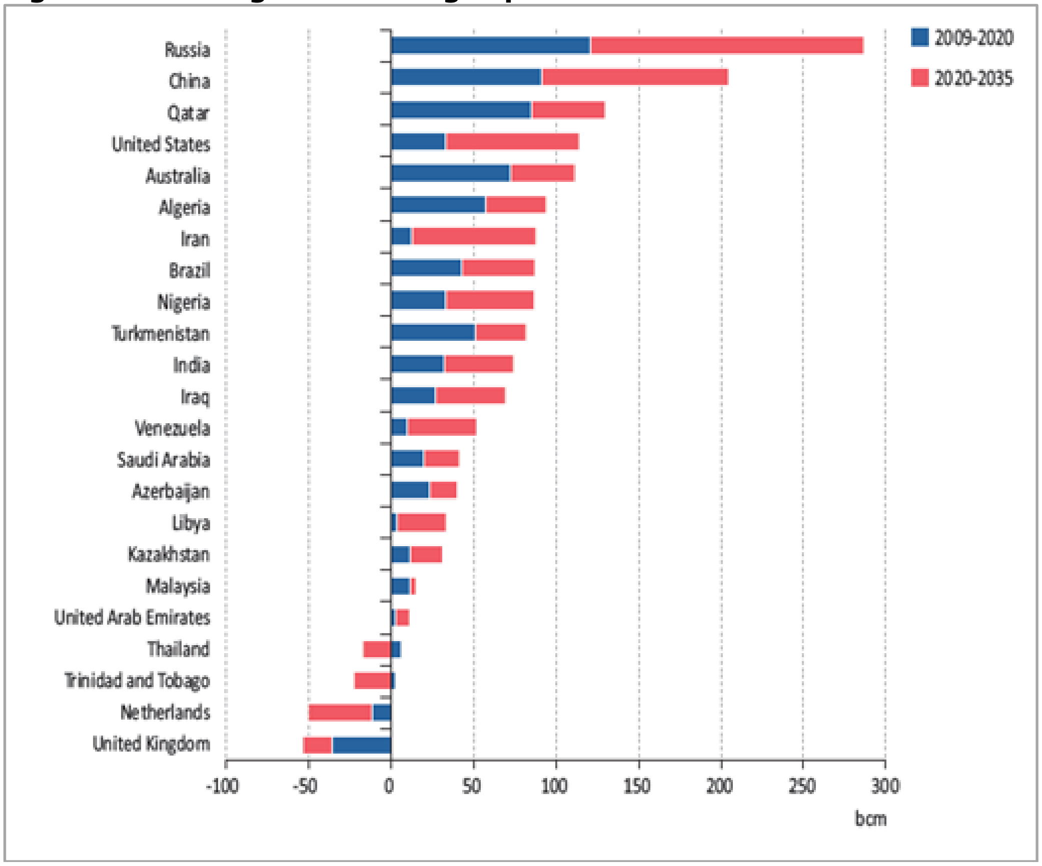
Source: IEA Medium-term Gas Market Report 2012

4.20. In the longer term, the IEA assess that global resources can comfortably meet demand to 2035 and beyond. Figure 4.5 shows how production changes in different countries in both the medium term (to 2020) and the longer term (to 2035).

4.21. It shows that the largest increases in production will come from Russia, China and Qatar, in that order. The IEA expect US production to increase more in the 2020s than in the decade before, largely because of future increases in unconventional gas production. In contrast, Australia, in fifth position, is due to increase production (of both conventional and unconventional gas) more in the coming decade than in the 2020s.

[81] This is based on an assumption that a significant proportion of the proposed liquefaction projects due to start in Australia are not delayed.

Figure 4.5: Change in annual gas production in selected countries



Source: IEA WEO 2011 p.166

Supply-side uncertainty

4.22. A significant supply-side uncertainty is the extent to which the US will continue to increase its shale gas production and whether the lessons in the US can be applied to the rest of the world, including Europe. With respect to the former, we note the following risks:

- There remain questions whether the increase in shale gas production in the US can continue, particularly in the context of much lower US gas prices. Capital costs of US shale gas production are generally estimated to be between $6-6.50/MMBtu[82], whereas currently US Henry Hub prices are below $4/MMBtu[83].

- In recent years there have been very large increases in estimated and recoverable US shale reserves. However, in a rapidly developing industry, there is considerable uncertainty about the accuracy of these estimates.

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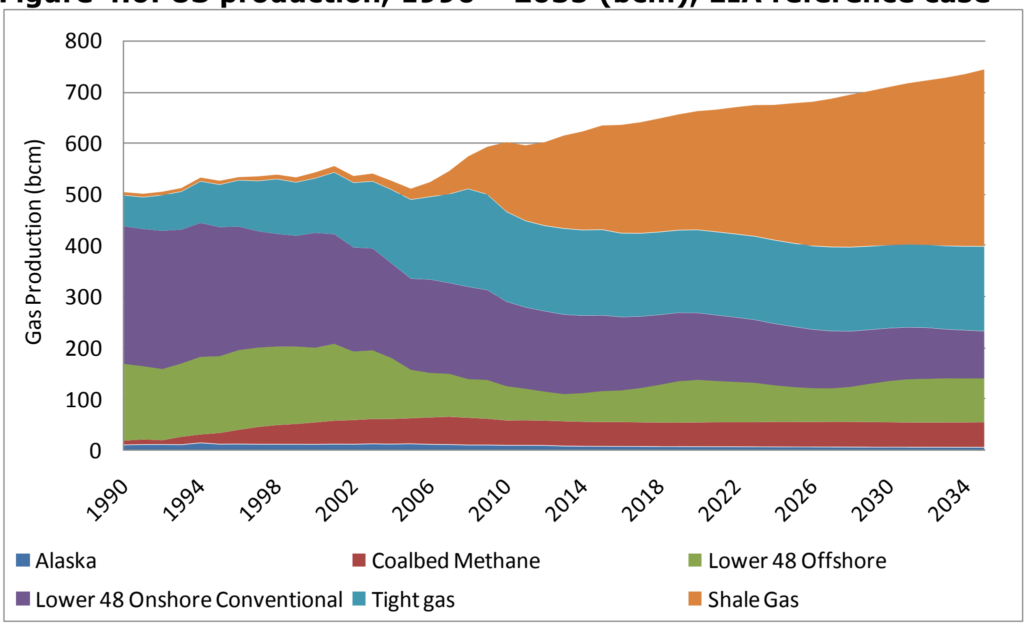
[82] Rogers, H., 2012. The Impact of a Globalising Market on Future European Gas Supply and Pricing: the Importance of Asian Demand and North American Supply, OIES
[83] Bloomberg, 2012 price up to September 2012

- Growing concerns, or a sudden incident, regarding environmental impacts of shale gas production may lead to higher costs for producers or restrictions on drilling for shale. This is discussed further in Chapter 5.

4.23. Nonetheless, current US projections show the shale boom to continue. Figure 4.6 presents the EIA's reference case for US production forecasts to 2035, in which shale gas production is forecast to increase almost threefold to 346 bcm/a[84]. By then, this will be nearly half of US production and just under 10% of the worldwide total, at a time of declining production elsewhere. Overall, the EIA's reference case is in line with the IEA's central case (shown in Figure 4.5), albeit slightly more bullish in the near term. The EIA forecast a net annual increase in US gas production of 1% to 2035, with production rising to over 740 bcm.

Figure 4.6: US production, 1990 – 2035 (bcm), EIA reference case



Source: Energy Information Administration

4.24. Figure 4.7 presents the EIA's range of estimated ultimate recovery (EUR) around the reference case. It shows the level of uncertainty surrounding forecast shale gas production: by 2035, US production is almost three times higher in the High Shale than in the Low Shale scenario.

Figure 4.7: US shale production forecast ranges, EIA

bcm/a	Low Shale EUR	High Shale EUR	Reference case
2035	156	484	346

Source: Energy Information Administration
Note: EUR: Estimated Ultimate Recovery

[84] EIA, *Annual Energy Outlook 2011*

4.25. The implications of the US shale revolution will depend on the extent the rest of the world, particularly Europe, can repeat this success. Unfortunately, there are a number of dissimilarities between the US and Europe that are likely to hinder the development of shale gas production. The following observations can be made:

- In the US mineral rights are often the property of the land owner, unlike in Europe, where these rights are often separated. For example, in the UK, ownership of subsurface minerals, including oil and gas is held by the Crown[85]. This reduces the incentive for land owners to grant access to companies to drill for gas.

- A long history of oil exploration in the US has created a large database of information, which provides detail of the geology of the subsurface and helps indicate whether an area is suitable for shale gas exploration before any wells are drilled. Without similar subsurface information in Europe, it is far more costly and time-consuming to establish where shale beds are located.

- The history of onshore drilling in the US also means it has a highly developed service industry, which is able to quickly and cheaply deploy drilling/exploration equipment. A similar infrastructure does not exist in Europe.

- Population density in Europe is much higher than in the US, leading to tighter environmental legislation and greater public interest in environmental protection. Similarly, extraction is likely to take place closer to large centres of population meaning there is a greater possibility of larger, more sustained NIMBY-ism.

4.26. Another country that could make a significant impact on global supply dynamics following developments in shale gas production is China. China has very ambitious targets for shale gas production: 6.5 bcm by 2015, with 60 bcm by 2020[86]. However significant technical challenges remain that may limit China's ambitions in this area. These include restrictions around water availability, shale that is buried deeply and located in densely populated areas and the lack of an extensive pipeline network to transport the gas from source to demand.

4.27. We end this chapter with a discussion on the future of LNG market developments, in particular how LNG supply and demand is expected to grow in the near future. We also provide some insight on the flexibility of LNG contracting and the implications for GB.

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[85] Under the Petroleum (Production) Act 1934
[86] See Country focus: China faces difficulties in shale gas production available at: http://www.ft.com/cms/s/0/3fcc49a4-71de-11e1-90b5-00144feab49a.html#axzz22IC4YCVk

Future LNG market developments

4.28. In 2011, global trade of gas by pipeline and LNG was around 1 tcm[87], approximately 35% of global gas demand. According to the IEA[88], this is set to increase by around a third by 2017 and, of this, 426 bcm will be traded as LNG.

4.29. Global LNG markets are currently well supplied. For this to continue, with increasing LNG demand, there will need to be extensive expansions of LNG liquefaction capacity. However, the degree of uncertainty surrounding the timing, size and likelihood of future capacity expansions is so great that a number of reports are pointing to increased supply tightness towards the middle of the decade. We discuss these reports in more detail below.

LNG supply and demand balance

4.30. Global LNG sales have roughly doubled every ten years since 1980, and in 2011, global LNG demand reached 327 bcm (approximately 10% of total global demand). Eighteen LNG-producing countries now supply 24 importing countries[89]. Going forward, there remains a significant degree of uncertainty surrounding the LNG supply and demand balance.

4.31. In their latest Medium-term Gas Market Report the IEA say that LNG markets will become "increasingly tighter" until mid-2014 as only three projects, totalling 25 bcm, are expected to come online over 2012 and 2013[90]. In the longer term, the market should loosen as the IEA report that a total of 114 bcm of additional liquefaction capacity is already under construction as of late April 2012 and a second wave of capacity should start to come on line from the end of 2014. Even so, the IEA note that many plants are expected to start later than originally planned due to a combination of workforce shortages and infrastructure bottlenecks, possibly leading to sustained tightness in the middle of the decade.

4.32. The IEA's short-term forecasts are echoed by Bernstein & Co. who state that spare capacity will reach historic lows in 2013. However, they report a more bullish longer-term forecast suggesting that by 2020, over 300 bcm/a of additional capacity could be added, leading to a global glut in LNG markets. Bernstein & Co. highlight, however, that there is significant uncertainty associated with these projects, as around 100 bcm/a is made up of projects that are yet to reach the final investment decision, while the remaining 200 bcm/a constitute projects that are at even more speculative stages of development[91].

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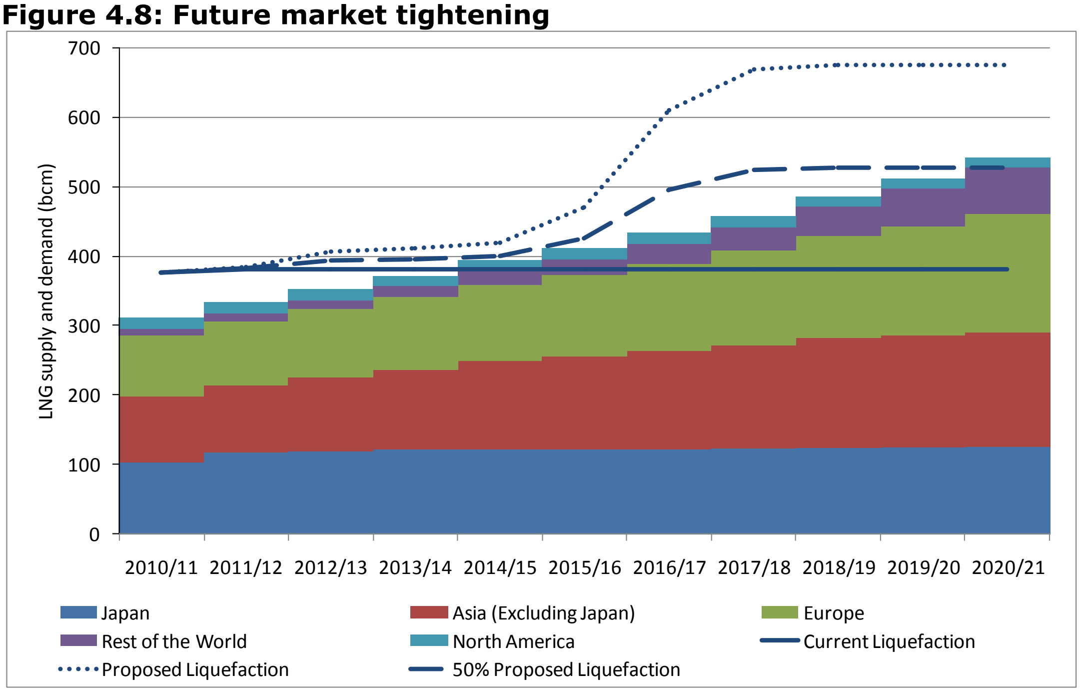
[87] BP Statistical Review of World Energy 2012
[88] Medium-Term Market Report 2012 © OECD/IEA 2012,p. 101
[89] BP Statistical Review of World Energy 2012.
[90] Medium-Term Market Report 2012 © OECD/IEA 2012
[91] http://www.bloomberg.com/news/2012-02-14/new-lng-supply-may-flood-gas-market-by-2018-bernstein-says.html and Ofgem calculations.

4.33. GDF Suez, drawing on a scenario by CERA, forecast global LNG markets to tighten earlier than the IEA, in around 2013/14[92]. In the longer term, their analysis shows market tightness in around 2020/21 when LNG demand would have outstripped the level of LNG liquefaction capacity in place by that year.

National Grid chose to present a range of possible market outcomes. Figure 4.8, (which reproduces figure 3.3K from National Grid's 2011 Ten Year Statement), shows low levels of new capacity coming online in the next few years, leading to market tightening in around 2014/15. However, in the years that follow, National Grid show two lines for the expected liquefaction capacity build going forward. The top line includes all projects that are currently proposed with no delays in addition to those that have already been announced, including the large Australian projects coming online around 2016. This results in global liquefaction capacities some way above the level of expected global demand for the last five years of this decade.

4.34. In addition, National Grid also present a line showing the level of liquefaction capacity if 50% of the total number of proposed liquefaction projects are delayed or cancelled. This line shows increasing market tightness towards the middle of the decade. Interestingly, it also leads to LNG market tightening by the end of the decade, similar to the analysis by GDF Suez. While this line does not have a probability associated with it, it goes to illustrate that an LNG liquefaction project success rate above 50% is required to avoid significant tightness during and at the end of this decade.

Figure 4.8: Future market tightening



Source: National Grid Ten-Year Statement

[92] http://www.gdfsuez.com/wp-content/uploads/2012/05/sg-oil-oil-services-lng-conference-april-3-2012-vdef3bis-1.pdf

4.35. Looking even further forward, another uncertainty is whether the US will become a significant LNG exporter. One LNG facility (Sabine Pass, 23 bcm/a export) has already received regulatory approvals to allow construction, and there are developers for seven other projects[93]. It should be noted though that even if large volumes of gas could be exported by the US, it does not follow that GB prices would fall to US levels, since a significant mark-up will be required to cover the export costs such as liquefaction and shipping.

How the spot LNG market will develop

4.36. Any tightness in the LNG market could lead to a disproportionately reduced availability of LNG on spot markets. This is important because a number of countries, GB included, rely on spot LNG markets for at least a proportion of their LNG imports. Currently, over 75% of LNG is traded on long-term contracts[94]. This has fallen significantly in recent years and there has been a large increase in short-term LNG trading from around 2-3% of total trade in 2000 to around 17% in 2008[95].

4.37. Looking forward, the IEA forecast that an additional 77 to 108 bcm of liquefaction capacity is expected to come online by 2018. However of that being commissioned after 2014 (between 53 to 84 bcm) only around 10 bcm has not been already contracted on a long-term basis.

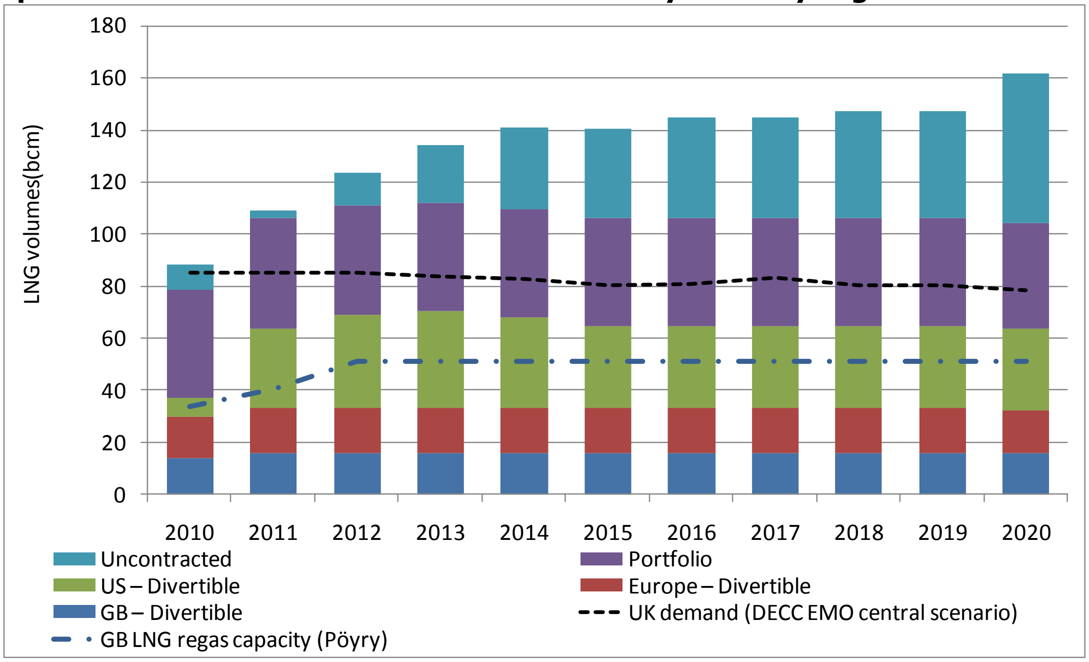
4.38. However, the IEA analysis does not distinguish between firm contracts and other forms of long-term contract. For example, Pöyry carried out analysis for DECC in 2010 that distinguishes between LNG that is regarded as potentially tradable and contracted firm[96]. This analysis shows that the market for potentially tradable LNG was around 100 bcm in 2010 (32% of total LNG production) and could grow to as much as 214 bcm in 2020 (55% of total LNG production)[97] depending on how much LNG that comes online turns out not to be contracted firm. For example, if all new LNG output is contracted firm, then the quantity of potentially tradable LNG would be towards the bottom end of this range.

Pöyry carry out further analysis using the top end estimate of this range and show how much could be accessed by GB. Figure 4.9 reproduces a chart from their report

[93] If all facilities were to be built this would allow 142 bcm/a of gas to be exported. Source: Medium-Term Market Report 2012 © OECD/IEA 2012
[94] Pöyry, Global Gas & LNG Markets & GB's Security of Supply
[95] Pöyry, Global Gas & LNG Markets & GB's Security of Supply
[96] Contracted firm LNG is the that which is contracted to buyers in markets which have limited or no access to alternative sources of supply. Buyers in these markets are unlikely to divert (or get sellers to agree to divert) cargoes. Potentially tradable LNG includes all LNG that is not classed as contracted firm and includes uncontracted, divertible and portfolio quantities. Uncontracted LNG is classed by Pöyry as any output from projects in excess of the volume contracted on a long-term basis; divertible LNG as LNG contracted to buyers who have access to alternative sources of supply and are likely to be prepared for cargoes to be diverted to other markets offering higher prices, and portfolio LNG as LNG contracted by companies such as BG, Shell, BP, GDF Suez, etc. who have an LNG trading business supplying LNG to a number of buyers and markets. This LNG is contracted on a flexible basis which allows diversions with a sharing of any additional revenues in many cases. Source: Pöyry (2010) Global Gas & LNG Markets & GB's Security of Supply
[97] Ibid

and shows the maximum potentially tradable volumes that could be accessible to GB, comparing the quantities to GB regasification capacity and total GB demand. Figure 4.9 highlights that the maximum forecasted volumes of potentially tradable LNG that could be accessed by GB are well in excess of total GB LNG import capacity.

Figure 4.9: LNG volumes potentially accessible to GB from capacity in operation and under construction in February 2010 by region



Source: Poyry, Global Gas & LNG Markets & GB's Security of Supply

4.39. Figure 4.9 only presents analysis based on the higher range of future potentially tradable LNG. Furthermore, it does not include any detail on the nature of the divertible contracts, nor does it include the demand of other LNG customers that could compete with GB for potentially tradable LNG. Even so, this analysis develops the arguments presented above. It shows that while forecasts for LNG demand suggest markets could tighten towards the middle and end of this decade, a significant (and possibly growing) proportion of customers do not purchase LNG on firm, long-term contracts. This increases the possibility of a price effect if markets tighten that could redistribute quantities of LNG from those customers that have alternative sources of gas supplies (assuming these supplies were priced below LNG at the time). Any redistribution of LNG quantities would alleviate, in part, LNG market tightness and would benefit countries who rely on spot markets for at least a proportion of their LNG supplies.

5. Shocks to the GB gas market

5.1. In addition to the potential future market developments already discussed, our review identified a number of key domestic and external shocks that could arise in the near term, with little or no notice, and could have a significant impact on the volumes of gas flowing into GB. The shocks identified can be of a geopolitical nature, such as the closure of a critical LNG shipping lane, a disruption in a key supply country, or a dispute between supply and transit countries. Shocks can also be domestic, for example a shutdown of a storage facility or a technical failure at an LNG terminal. This section discusses the domestic and external shocks that our review identified as having the most potential for significant impacts on GB security of supply.

5.2. All of the shocks we discuss below are, by their definition, difficult or impossible to predict. We highlight them because of the size of their impact on GB, not because we think they are more likely than others to occur. This list is not exhaustive, as a number of other (smaller) shocks to security of supply have also been identified in reports and interviews; these are listed in chapter 7 of this Appendix. We summarise the key shocks in Figure 5.1:

Figure 5.1: Key domestic and external shocks

Domestic shocks	External shocks
Outage at a key import terminal	Closure of critical LNG shipping lanes
Outage of a key pipeline	Some curtailment of Russian supplies
	An environmental incident associated with shale gas production
	Another nuclear disaster

5.3. In addition to understanding the types of shocks that the GB market might be susceptible to, this research also helped us revise the assumptions on infrastructure reliability which were then used in the probability modelling of further measures. The updated assumptions also reflect feedback we received from stakeholders. In the sections below on infrastructure reliability we present our assumptions on the likelihood, duration and magnitude of outages. A detailed explanation of these assumptions can be found in the separate Modelling Appendix, produced by Redpoint that covers the probability modelling.

Domestic shocks

5.4. During our interviews, some respondents highlighted that, in the past, the large number of fields and facilities on the UKCS provided GB with a high degree of infrastructure diversity and, as a result, resilience to problems and outages. In contrast, as pipeline supplies are becoming more concentrated (as a greater proportion of gas is being transported through a small number of large pipes) the risk associated with a major infrastructure failure is increasing. We consider the impacts associated with outages at key import terminals and on pipelines below.

Outage at a key import terminal

5.5. As shown in Figure 5.2, GB has nine entry points with a forecast peak deliverability of 576 mcm/day in 2010/11 (excluding medium-range storage and LNG storage). The terminals at Bacton, Easington and St Fergus together account for over 75% of total import capacity.

Figure 5.2: Peak supply forecast (mcm/d)[98]

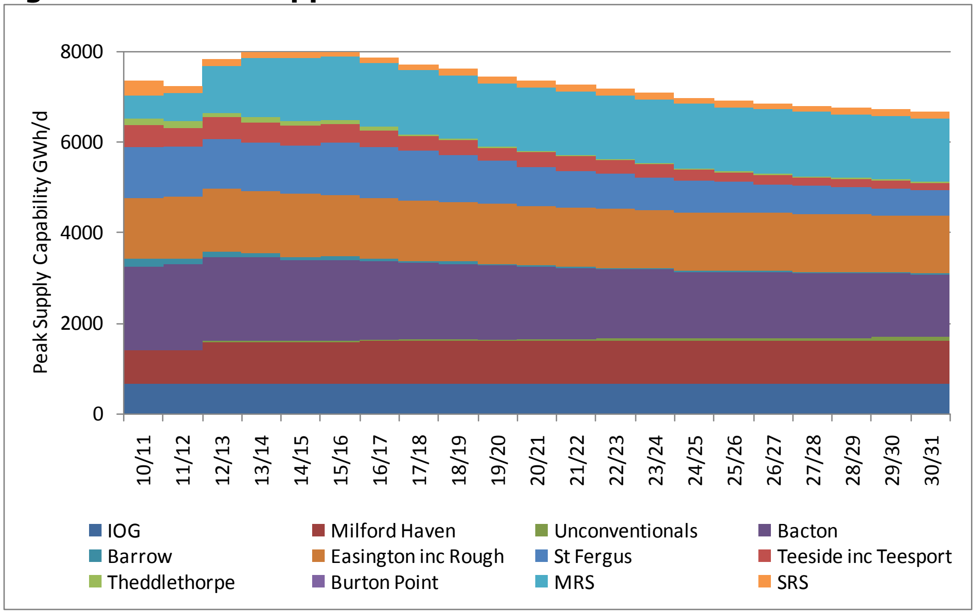
Terminal	2010/11 TYS Peak Forecast
Bacton inc IUK & BBL	159
Barrow	15
Easington inc Rough & Langeled	126
Isle of Grain (inc LDZ inputs)	56
Milford Haven	68
Point of Ayr	0
St Fergus	111
Teesside	25
Theddlethorpe	16
Total	**576**

Source: National Grid (2011) Ten Year Statement

5.6. Figure 5.3 shows the expected peak supplies through different entry points between 2010 and 2030 in National Grid's Gone Green scenario[99]. Unsurprisingly, and mirroring the decline in UKCS production noted elsewhere in this Appendix, there is a notable decrease in the quantity of supplies from St Fergus in meeting peak demand. On the other hand, no other source of GB supply is expected to decline significantly, and in the case of LNG and medium-range storage, their contributions are forecast to increase. The combined effect is that peak supply capacity is forecast to stay above 2010/11 levels for the majority of the coming decade.

[98] National Grid Ten Year Statement 2011
[99] The profile is the same as National Grid's Slow Progression scenario

Figure 5.3: Peak Supplies Gone Green scenario



Source: National Grid, Ten Year Statement 2011

5.7. There has never been a major long-term failure at a UK terminal, and indeed most terminals comprise a number of sub-terminals. However, a prolonged outage, were it to occur, could create problems.

5.8. Even outages of sub-terminals can be problematic. In 2008, a leak of highly flammable hydrocarbon liquid caused a large explosion and fire at the Shell-operated Bacton import sub-terminal on the Norfolk coast[100]. Shell pleaded guilty to seven charges, covering safety, environmental control and pollution-prevention failures at the plant which led to the accident.

5.9. While the fire was quickly and safely extinguished and the plant shut down safely, the incident removed 30 mcm/day of supply between 28 February and 3 March, 2008[101].

Specific issues with LNG terminals

5.10. GB has four LNG terminals, with a total capacity of 55.9 bcm/a:

- Isle of Grain 1-3 with a capacity of 20.3 bcm/a
- GasPort with a capacity of 4.1 bcm/a
- South Hook 1&2 with a capacity of 21 bcm/a
- Dragon 1 with a capacity of 7.6 bcm/a

[100] Health and Safety Executive, http://www.hse.gov.uk/press/2011/hse-shelluk.htm
[101] http://www.exeter.ac.uk/energysecurity/documents/Jim_Skea_presentation_April2012.pdf

5.11. This constitutes 35% of GB import capacity and the potential to supply approximately 60% of GB annual gas demand. Specific risks with LNG terminals could include:

- Problems with the regasification equipment in the terminal. This is mitigated by terminals usually having several LNG regasifiers.
- Problems with nitrogen ballasting equipment at the terminals could cause a sudden loss in supply if there were insufficient buffer stock at the terminal.
- Supplies from LNG terminals can also be affected by the weather. For example, rough seas stopped ships from docking at Rovigo in Italy in February 2012, affecting the berthing schedule for LNG carriers and reducing gas flows by roughly 25% from the normal 20 mcm/day rate[102].

5.12. The probability modelling undertaken for this work assumes that the likelihood of a loss of LNG supply is 12% in the warmest six months of the year and 25% in the coldest six months. It further assumes that the average duration of such an outage is 6 days, with a standard deviation of 20, and that the average impact is a 30% loss of LNG. These assumptions were updated in light of stakeholder feedback on LNG terminal reliability and further analysis. They are intended to reflect both physical outages and potential shocks further up the supply chain, such as geopolitical events (discussed further below). We discuss the probability modelling input assumptions for non-LNG terminals associated with pipelines in the next section.

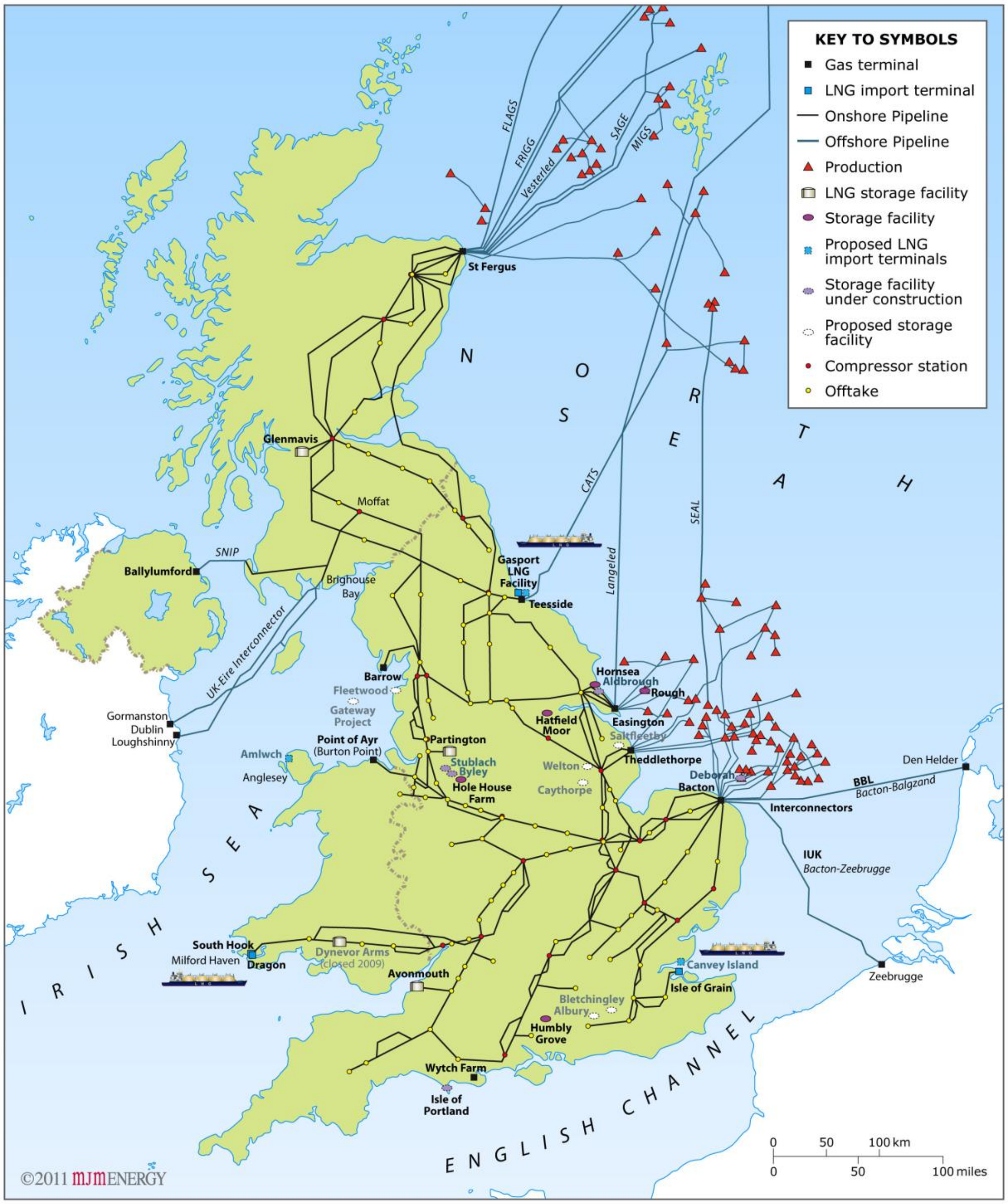
Outage of a key pipeline

5.13. While the capacity of import infrastructure, in particular LNG terminals, has increased dramatically over the last few years, pipeline supplies are becoming more concentrated, as a greater proportion of gas is being transported through a small number of large pipes. This decrease in diversity could increase the risk associated with GB pipeline infrastructure. We first discuss risks associated with interconnectors, and then discuss other pipeline risks.

5.14. Figure 5.4 provides a schematic of the import and transmission infrastructure and key gas fields that exists in and around GB.

[102] http://www.reuters.com/article/2012/02/10/markets-lng-idUSL2E8DAFAH20120210

Figure 5.4: GB gas import infrastructure and key gas fields



Source: MJM Energy

Interconnectors

5.15. Two interconnectors link GB to continental Europe:

- Balgzand-Bacton Line (BBL) with a capacity of 19.5 bcm/a that connects Bacton in (GB) to Balgzand (Netherlands), and
- Interconnector UK (IUK), a bidirectional pipeline connecting Bacton (GB) to Zeebrugge (Belgium) with a capacity of 20 bcm/a in forward flow (GB to Belgium) and 26.9 bcm/a in reverse flow.

5.16. In February 2009 the BBL line suffered a major failure in one of its three compressors – although this had minimal impact on flows (as there was sufficient back up) the damaged compressor took some months to repair and led to a major retrofit programme which has now been completed[103].

5.17. For IUK there were problems in 2002 when approximately 20 tonnes of hydrocarbon liquid flooded the line from the UK National Transmission System (likely to have come from one of the neighbouring gas processing facilities in the Bacton terminal complex). This necessitated a long shut down (some two weeks) to dry out the line, making it unavailable for either exports or imports[104].

Responsiveness and utilisation of gas interconnectors

5.18. In addition to the risks associated with interconnector outages, there are also concerns that gas interconnectors are less price-responsive than they could be, possibly limiting their effectiveness in an emergency. Ofgem has carried out initial analysis on the price responsiveness of gas interconnectors. It has looked at how day-ahead prices for gas compare between the markets, whether cross-border capacity was available on the day and to what extent cross-border flows reacted to this arbitrage opportunity.

5.19. Our initial analysis indicates that flows across the BBL and IUK interconnectors are not fully sensitive to price differentials. In particular we found the following:

- Short-term prices on Dutch, GB and Belgian hubs are closely linked on most days.
- There are days on which we observe significant price differentials between hubs (up to 10%), but some interconnection capacity remains unused. In fact, interconnector capacity is rarely fully used despite the existence of price differentials.
- On both IUK and BBL, on a large proportion of days, gas flows against the price signal, i.e. from the expensive to the cheap hub.

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[103] http://www.bblcompany.com/news/news/update-technical-problems-compressor.
[104] Mark Futyan, The Interconnector Pipeline: A Key Link in Europe's Gas Network, 2006 http://www.oxfordenergy.org/wpcms/wp-content/uploads/2010/11/NG11-TheInterconnectorPipelineAKeyLinkInEuropesGasNetwork-MarkFutyan-2006.pdf

- The take-up of virtual capacity products (such as interruptible reverse flow on BBL) has been very low, despite a zero reserve price and the existence of arbitrage opportunities.

5.20. Therefore, our initial analysis suggests that cross-border flows between GB, the Netherlands and Belgium are not entirely economically efficient, not always fully price-responsive and the market does not optimise the use of interconnection capacity in cross-border trades. This may cause concern with regard to GB security of supply, as it questions whether cross-border flows would respond accordingly to the high prices that would likely arise in a gas security of supply event.

5.21. These inefficiencies may be caused by market arrangements (in GB, adjacent markets or on the interconnectors themselves) or other factors. We are working closely with the Belgian and Dutch regulators and have published an open letter calling for evidence in this area[105].

5.22. For the purposes of the probability modelling, we have assumed that both BBL and IUK have a likelihood of interruption of 12% in summer and 25% in winter. These outages affect 45% of capacity and last for six days, on average[106].

Gas quality arrangements

5.23. Gas appliances and equipment in Great Britain and Ireland are designed to operate using gas with the quality of gas from the UK Continental Shelf (UKCS) - a different gas quality to that used in continental Europe. If significant quantities of gas were required quickly from Europe to meet GB demand (potentially in an emergency situation), this could mean that the rate of flow to GB from Europe is not as high as it could be, due to the time taken for gas quality changes to be made.

5.24. The Interoperability and Data Exchange Framework Guideline includes guidance on how TSOs should work together on mutually agreeable solutions in cases where gas quality differences are found across an interconnection point. The Framework Guideline (and subsequent Network Code) will not require gas quality harmonisation across Europe but instead will focus on ensuring that where gas quality differences are found, they are not permitted to become a cross-border barrier to trade.

5.25. Future gas quality related barriers to trade might be mitigated by Fluxys (the Belgian TSO) investing in new gas ballasting facilities (where gas quality can be changed) in Zeebrugge, which connects to the IUK interconnector. However, Fluxys has recently consulted on a charging regime that could decrease price responsiveness of gas flows into GB via Belgium. This is because the cost of gas

[105] See: http://www.ofgem.gov.uk/Europe/Documents1/120928_Interconnector_Open%20Letter%20Final.pdf

[106] In 2016, BBL is assumed to acquire reverse flow capability and trade like IUK, so we merge it into IUK in our model and adjust the interruption parameters accordingly (to have higher probability but lower average impact).

ballasting would be passed on to shippers, thus increasing the GB-Belgian price differential necessary to signal shippers to flow gas to GB. Ofgem will keep the progress of Fluxys's proposals under observation to monitor the potential for detrimental effects on security of supply.

Other pipeline infrastructure

5.26. In addition to interconnectors, we highlight the following concerns with the substantial quantity of pipeline infrastructure linking the UKCS and Norwegian continental shelf (NCS) to GB.

5.27. With respect to supplies from the NCS, around 20% of the UK's gas supplies are now imported along the Langeled pipeline. Additional imports of Norwegian gas also come via the Vesterled and TampenLink pipelines which link Norwegian fields into UK infrastructure in the Northern Basin of the North Sea.

5.28. In recent years, there have been issues with the reliability of Norwegian supplies. Problems have arisen either offshore on the NCS or with the processing facilities. For example, there have been a number of power losses at the Nyhamma and Kollsnes processing facilities [107].

5.29. During the cold snap in early January 2010, demand remained consistently above 400 mcm from 3-14 January and there was record peak demand of 465 mcm. At this time, there also occurred a 50 - 70 mcm/d supply disruption from Norway. The outages occurred at a number of Norwegian processing plants and gas fields over the period from 2 to 9 January and reduced gas flows through the Langeled pipeline. From 2 to 15 January, volumes averaged slightly over 50 mcm, compared to an average of just over 70 mcm during the week preceding the difficulties. Four within-day Gas Balancing Alerts (GBAs) were issued. This provided an incentive for additional supplies to come forward (from LNG terminals, IUK pipeline and storage) and for gas demand to fall (through coal being favoured over gas in the power generation sector). More recently, NCS supply was reduced by industrial action in Norway which reduced output by 12 mcm/day[108].

5.30. With regard to the UKCS, National Grid have noted in conversations that while long-term field outages are still a cause for some concern, the increase in the number of active fields in the UKCS means that problems with individual fields have less of an impact than in the past.

5.31. The main risk to UKCS production is therefore from an outage to a specific terminal (discussed above) or pipeline. Offshore lines have on occasion been hit by ships' anchors, requiring pressure reductions and emergency maintenance

[107] For example http://www.argusmedia.com/pages/NewsBody.aspx?id=780202&menu=yes
[108] http://www.reuters.com/article/2012/06/27/markets-britain-gas-power-idUSL6E8HRGIX20120627

shutdowns. For example, one such incident led the CATS pipeline to close for 64 days in 2007[109].

5.32. In our probability modelling, the chances of an outage for both NCS and UKCS is 3% in summer and 7% in winter, and both last for 10 days on average. The average size of the impact is a loss of 20% of supplies from UKCS, and 40% from NCS.

5.33. We also recognise that GB storage facilities have not been immune from problems in the past. In February 2006, a fire started at the Rough storage facility (GBs largest storage site). As a consequence, the facility was shut down for over a month. On March 13th, the Rough closure, combined with lower than normal interconnector flows and higher than expected demand, led to a simultaneous GBA and Notice of Insufficient Margin (NISM)[110]. Falling demand after the incident helped the system to recover quickly. However, high risks remained regarding supplies for the rest of the winter, as the Rough facility was only partially open.

5.34. We therefore model a storage infrastructure outage with a likelihood of 15% in summer and 30% in winter that lasts for ten days on average. An outage is assumed to affect an average of 20% of short-range storage and 50% of long-range storage.

External shocks

5.35. External shocks are geopolitical or natural events large enough to have a significant knock-on effect on GB. Historic examples include the Russia/Ukraine dispute over pipeline exports and the large increase in demand for LNG following the closure of Japanese nuclear plants after the March 2011 Tsunami. We list below those external shocks that our review identified as having the most significant potential impact on GB security of supply.

Closure of critical LNG shipping lanes

5.36. The most frequently quoted concern during our interviews related to LNG supply disruptions as a result of problems on critical LNG shipping lanes. The distance and time LNG travels raises the potential for disruption through natural hazards, accidents, or terrorism. For example, Qatari supplies go through the Gulf, past Somalia and through the Suez Canal.

5.37. The distance from Qatar to GB via the Suez Canal is 6290 nautical miles, with a journey time of 14 days for an LNG tanker. In the case that the Suez Canal was closed for any reason, LNG vessels would be diverted via the Cape of Good Hope, with an additional journey distance of 5440 nautical miles, or 12 days. This is likely to lead to some delays on UK LNG deliveries, but they would not cease. If the Canal

[109] Stern, H., 2010, UK Gas Storage: a case of market failure
[110] A notification to the market that generation operating margins are low.

remained closed for an extensive period, it is likely that, if shipping capacity was available, then LNG cargo deliveries could return to normal, albeit with the longer voyage time. It is worth noting, however, that the risk of closure to the Suez Canal is low. The Egyptian Authorities are mindful of the Canal's importance and even during the Arab Spring and the resultant civil unrest in Egypt, the Canal was kept fully open at all times.

5.38. In contrast, the situation in Iran may pose a far greater risk to LNG supplies from Qatar. Iran has already threatened to close the Strait of Hormuz in response to potential oil sanctions by the West[111,112]. If the Strait of Hormuz were closed, no LNG could leave Qatar or the United Arab Emirates (UAE). Countries reliant on these suppliers, including GB, would be forced to source their gas from elsewhere and competition for the remaining supplies would likely increase.

5.39. The IEA has examined the impact of a shipping lane closure long enough to require LNG buyers to seek alternative sources of supply. In 2011, 57 bcm of Qatari and UAE LNG went to Asia, with 43 bcm to Europe (with half of this going to the UK)[113]. If these supplies were no longer available, the countries supplied would be forced to seek alternative sources. The IEA explain that, in particular, those countries in Asia that rely solely on LNG to supply their needs would be forced to find alternative LNG supplies. This would increase the demand for uncontracted LNG, significantly reducing its availability and increasing its price. European countries would have to rely on alternative supply options and would probably source lost Qatari or UAE LNG from additional pipeline imports.

5.40. The IEA suggest the most likely candidates would be increases in pipeline exports from Russia, Norway or the Netherlands. Russia currently supplies around 150 bcm/a to Europe through six major supply routes with a total capacity of around 250 bcm/a[114]. Of this, around half must transit Ukraine. This suggests that pipeline capacity from Russia is currently sufficient to meet an increase in demand of the equivalent of around 75 bcm/a from Europe, enough to compensate a total loss of LNG supplies. However, it is not certain that Russia could make this additional volume of gas available at short notice, given its domestic demand requirements, the risk of transit disputes (see below) and possible constraints in pipeline and interconnector capacities across Europe.

5.41. Finally, piracy may be considered a threat to LNG tankers. As with oil tankers, LNG tankers regularly transit high-risk piracy areas. However, there is no evidence to date that a LNG tanker has been stopped as a result of pirate activity.

[111] http://www.bbc.co.uk/news/world-middle-east-16344102
[112] A disruption of supplies from LNG exporting countries would also have a significant impact on global and GB LNG supplies.
[113] BP Statistical Review of World Energy June 2012
[114] World Energy Outlook 2011 © OECD/IEA 2011, p 338 – listed as 225 bcm but has risen to roughly 250 bcm/a with the opening of Nordstream 2.

Some curtailment of Russian supplies

5.42. After the closure of shipping lanes, the second most referenced external shock during our interviews was a curtailment of Russian supplies to Europe. There are a number of reasons this could happen, for example civil unrest or deteriorating relations between Russia and the West; the most likely is a renewed dispute between Russia and Ukraine.

5.43. Russia currently supplies around 150 bcm/a to Europe through six major supply routes with a total capacity of around 250 bcm/a, and of this around half must transit Ukraine. Export capacity in the Ukraine system is around 140 bcm/a for pipes serving western and south-western Europe[115]. Capacity utilization is estimated at around 75% on average, though this is higher during the winter.

5.44. The most serious disputes over sales and transit have been the so-called gas wars between Russia and Ukraine in 2006 and 2009. The most severe, in 2009, resulted in supplies to Europe being disrupted when negotiations between the two countries over pricing and unpaid bills culminated in Russia suspending shipments to Ukraine (but, at this stage, not Europe via Ukraine) on January 1, 2009. Unlike in 2006, when flows were rapidly restored and exports to Europe unaffected, the dispute escalated on 5 January when Gazprom accused Ukraine of stealing 65 mcm of gas. Following this, supplies to Europe were completely cut off and only fully restored on 22 January. The supply loss was equal to 30% of EU gas imports at the time[116].

5.45. Countries in south-eastern Europe which were almost wholly dependent on Russian imports were completely without gas for 13 days, causing significant humanitarian problems[117]. The impact on Bulgaria and Serbia was particularly severe as they also had very limited gas storage or alternative fuel arrangements. Bulgaria suffered an estimated 9% GDP loss[118]. The impact on other Central European countries however was limited as they were able to draw on storage or import from other sources. The main responses to the cuts were:

- an increase in Yamal and Blue Stream flows by Russia,
- additional spot LNG to Greece and Turkey, and
- increased intra-EU flows[119].

5.46. The main impacts in GB were increased exports through the interconnectors (in response to higher prices in continental Europe) and some additional drawdown of UK storage.

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115 The European Network of Transmission System Operators for Gas
116 Risk assessment for the purpose of EU Regulation 994/2010 on security of gas supply, DECC
117 Pirani, S., Stern J. and Yafimava K., 2009. The Russo-Ukrainian gas dispute of January 2009: a comprehensive assessment. Oxford: OIES
118 Christie, E, H. et al., 2011. Vulnerability and Bargaining Power in EU-Russia Gas Relations. The Vienna Institute for International Economic Studies.
119 International Energy Agency, http://www.iea.org/stats/index.asp

5.47. Russia and Ukraine signed a contract in April 2010[120] in which Russia provided Ukraine with discounts on existing prices worth up to $40 billion under existing contracts that expire in 2019. In return, Ukraine extended the lease on the Sevastopol base used by Russia's Black Sea fleet from 2017 to 2042. Addenda to the contract provided for a price discount of 30% on most imports, increased annual contracted quantity and no change in base price or take or pay[121] provisions.

5.48. Whilst this deal brings some relief to Ukraine, some argue it still gives them record import prices and fails to deal with key "fault lines":

- Actual prices are higher than European prices (Ukrainian price levels during 2009 implied a base price that started more than $50/mcm higher than the Average German Import Price).
- Stringent take or pay requirements that do not recognise the reality of the fall in demand or daily variations, with no corresponding ship or pay[122] element for transit volumes.
- Tight payment deadlines.
- Lack of clarity of Gazprom use of Ukraine storage though it appears to still be paying a very low tariff.
- The persistence of penalties for failure to offtake, or to supply, monthly volumes.

5.49. The existence of these fault lines increases the risk of further disputes between Russia and Ukraine, and the potential for future contract renegotiations.

5.50. However, this risk is mitigated through the Nord Stream and potential South Stream pipelines, which do not have Ukraine as a transit country. The first phase of Nord Stream with capacity of 27.5 bcm came on line in November 2011, the second phase is due in late 2012, doubling its capacity to 55 bcm/year. Gazprom intends to build a new line – South Stream – across the Black Sea to Bulgaria with a total capacity of 63 bcm/year, though the final investment decision has not yet been made.

5.51. Depending on the timing of new capacity being built and the extent to which there is investment to maintain the operation of the existing Ukrainian transit network, Gazprom is expected to have spare export capacity of between 42 and 112 bcm in 2020 (see Figure 5.5 below). This spare capacity should allow Gazprom to arbitrage between routes and the power of individual transit countries becomes much reduced with a consequent improvement in European supply security[123].

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[120] Pirani, Stern and Yafimava 2010, The April 2010 Russo-Ukrainian gas agreement and its implications for Europe, OIES. http://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/05/NG_42.pdf

[121] A provision in gas contracts by which the seller obliges himself to supply contracted volumes of gas and the buyer obliges himself to pay for such contracted volumes regardless of whether he takes them or not. The buyer is entitled to take paid and not taken volumes of gas at a later date.

[122] A provision in gas contracts by which a buyer agrees to pay for contracted transportation capacity regardless of actually transported gas volumes

[123] Stern, J., *A Globalising Market: European, Asian, North American and Russian Impacts What does it mean for the UK?* Presentation to Ofgem, January 2012

Figure 5.5: Estimated Russian Export Pipeline Capacities

Capacity (bcm)	2005	2010	2015 projected	2020 projected
Existing Capacity – via Ukraine	145	145	95 – 145	60 – 145
Existing Capacity – via Belarus	48	48	48	48
Existing Capacity – total	211	214	145 – 198	145 – 264
Nord Stream	0	0	55	55
Blue Stream 2/South Stream	0	0	0 – 30	16 – 63
Total capacity	**211**	**214**	**214 – 285**	**200 – 332**
Exports to Europe[124]	154	139	150 – 200	158 – 250
Spare capacity	57	75	64 – 85	42 – 112

Source: Pirani, S. et al., 2010. The April 2010 Russo-Ukrainian gas agreement and its implications for Europe

Environmental shock reducing US shale gas production

5.52. Shale gas production in the US is growing fast, and the current market expectation is that growth will continue and lead to future LNG exports[125]. However, shale gas production remains controversial, particularly in the North East of the country. The main environmental concerns are outlined below.

Greenhouse gas (GHG) emissions

5.53. Compared to conventional gas, shale gas produces additional GHG emissions during extraction. These can be divided into three main sources:

- Combustion of fossil fuels to drive the engines of the drills, pumps and compressors, etc, required to extract natural gas onsite, and to transport equipment, resources and waste on and off the well site;
- Fugitive emissions of natural gas that escape unintentionally during the well construction and production stages; and
- Vented emissions resulting from natural gas that is collected and combusted onsite or vented directly to the atmosphere in a controlled way.

5.54. Figure 5.6 below gives a breakdown of the range of additional emissions from shale gas compared to natural gas. As a further benchmark the same study produced a figure for coal extraction of 93 gCO_2e/MJ.

[124] Based on estimated long term contract commitments
[125] Chapter 4 gives more detail on the US supply outlook

Figure 5.6: Direct emissions from natural gas extraction compared to the additional emissions of extracting shale gas

	gCO_2e/MJ
Natural gas	57
Additional emissions of shale gas extraction operations	0.14 – 1.63
Possible additional fugitive emissions from fracking flowback	2.87 – 15.3
Total possible shale gas additional emissions	**3.01 – 16.9**

Source: Adapted from paper by Broderick[126]

Water and sand

5.55. Fracking operations require a significant quantity of water which is enriched with chemical additives to give it the properties it needs for fracturing (eg viscosity and being bacteria free). There is a concern that these chemicals, or methane itself, may contaminate groundwater aquifers and cause local water quality issues. Additionally, spillages or other accidents could lead to the contamination of surface water by chemicals or other materials regularly used in fracking operations.

5.56. Fracking also requires a significant quantity of sand in its operations. The sand (or propant) is used to retard the closure of fractures once the fracking fluid stops flowing.

Seismic impacts

5.57. There were high profile seismic events at the Preese Hall well near Blackpool in April and May 2011. An independent report[127] confirmed that fracking was the most likely cause of the earthquake. The report makes recommendations to DECC to mitigate the risk of future earthquakes. However, a recent report by the National Research Council, which looked at the connection between energy extraction techniques (like fracking and oil well drilling) and earthquakes, found that while fracking and other similar activities do have the potential to cause earthquakes, so far only two, one in the US and one in the UK, can actually be attributed to fracking[128].

5.58. The IEA has recently studied these concerns in detail. A report[129], published earlier this year, recognises a number of environmental and social concerns associated with unconventional gas production (including shale). However, it also explains that mitigating these concerns is not beyond the scope of existing technologies or know-how. The report goes on to describe a set of 'Rules' for unconventional gas producers to limit environmental concerns.

[126] http://www.tyndall.manchester.ac.uk/public/Tyndall_shale_update_2011_report.pdf
[127] http://og.decc.gov.uk/assets/og/ep/onshore/5075-preese-hall-shale-gas-fracturing-review.pdf
[128] http://dels.nas.edu/Report/Induced-Seismicity-Potential-Energy-Technologies/13355
[129] IEA (2012) Golden Rules for a Golden Age of Gas

5.59. Even so, the political sensitivity is such that a serious environmental incident could trigger a significant clamp down on shale gas production in a relatively short time period. If this happened and the US had to switch to become a net importer of gas this would have a significant impact on the Atlantic LNG market, limiting available supplies and increasing the cost of LNG to Europe. It is likely that such a shock would also have the knock-on effect of downgrading the outlook for unconventional gas production in Europe, and elsewhere in the world, limiting supplies of unconventional sources in the future.

Another nuclear accident

5.60. As discussed above, the level of global nuclear generation is one of the major uncertainties surrounding future gas demand in the long term. However, in the shorter term, another nuclear-related accident was one of the key risks identified in our review. Such an event could lead to further reductions in the appetite of governments to pursue new nuclear programs, or to an acceleration of the closure of existing plants, leading to further increases in demand for gas across the globe.

5.61. For example, the Fukushima nuclear accident, in March 2011, led to the closure of a significant volume of nuclear capacity in Japan and as of September 2012 only two plants remain operational. The impact on gas demand so far has been a corresponding increase in LNG imports of 11 bcm/a[130]. The final government report into the accident does not argue for an accelerated restart of the Japanese nuclear fleet. It recommends a drastic shift in disaster management and raises doubts around whether Japanese nuclear facilities are sufficiently resistant to potential future earthquakes[131].

5.62. Even without a further nuclear-related incident, the Fukushima accident raised new doubts about the risks associated with nuclear energy, and its political consequences have been far-reaching:

- Just three days after the incident, the Secretary of State for Energy and Climate Change in GB requested a review of the accident to suggest lessons for the safety of the UK nuclear industry[132].
- In Germany, the Chancellor ordered a three month moratorium on the extension of life spans of German nuclear plants. By May, this policy had toughened to a plan for the full shutdown of nuclear facilities by 2022[133].
- Switzerland has announced its intention to phase out nuclear power by 2034[134].
- In Italy, a referendum in June 2011 resulted in the rejection of a proposal to lift the indefinite ban on nuclear power[135].
- The European Council issued a call for stress tests of all nuclear facilities in the European Union which began on 1 June 2011[136].

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130 Medium-Term Market Report 2012 © OECD/IEA 2012
131 http://www.irishtimes.com/newspaper/world/2012/0724/1224320709167.html
132 http://www.hse.gov.uk/nuclear/fukushima/interim-report.pdf
133 http://www.reuters.com/article/2011/05/31/us-germany-nuclear-idUSTRE74Q2P120110531
134 http://www.reuters.com/article/2012/09/28/switzerland-gas-idUSL5E8KSFFT20120928
135 http://uk.reuters.com/article/2011/06/13/uk-italy-nuclear-idUKTRE75C3P020110613

5.63. Elsewhere in the world, a further nuclear incident could tip the political scales further, leading to more widespread shut-downs and abandonments of nuclear programmes in Europe and possibly India, China and Taiwan (South Korea has announced that it is currently continuing with its nuclear power programme).

5.64. We discuss the IEA's own research on the impact of a 'low nuclear' generation mix and its impact on global gas demand in chapter 4. Another nuclear accident would increase the likelihood of such a scenario arising.

[136] http://ec.europa.eu/energy/nuclear/safety/stress_tests_en.htm

6. Modelling risks and resilience

6.1. In this chapter we look in further detail at the impact that market developments and shocks could have on GB. Our focus is on interruptions to physical supply. We discuss the two approaches we have taken to assess the potential impact that both gas market developments and shocks may have on physical gas supply to GB.

6.2. First, we have used probability analysis to investigate the possibility of outages based on the frequency and severity of historical events. Second, we have conducted a resilience analysis where we investigate the impact of losses of supply sources on different customer groups, without assigning probabilities to these losses. We discuss these approaches in turn below.

Probability analysis

6.3. We have investigated how some of the risks associated with infrastructure outages and global supply chain events, discussed in Chapter 5, might impact the GB gas market. To do so, we have used the same model that has been developed to test the effectiveness of the proposed reforms to cash-out arrangements. Detailed assumptions on the magnitude, duration and probability distributions of an outage event associated with the different infrastructure and global supply chain dynamics (informed by the frequency and severity of historical events, where data exists) can be found in the associated Redpoint Futher Measures Modelling Appendix.

6.4. Figure 6.1 presents the high-level results from our modelling exercise, showing the probability of facing an involuntary interruption for four different categories of customers. It indicates that while no category of customer is completely free from the risk of interruption, in most cases the probabilities of interruption are very small. The probabilities in the table have been presented as there being a once in x years chance of them occurring.

Figure 6.1: Revised Base Case- Probability of interruption (under reformed cash-out), Green Scenario[137]

	2012	2016	2020	2030	Mean
Firm DM gas	1 in 136	1 in 214	1 in 150	1 in 100	1 in 140
NDM gas	1 in 150	1 in 214	1 in 188	1 in 125	1 in 162
Firm I&C electricity	1 in 71	1 in 52	1 in 88	1 in 107	1 in 74
Domestic & SME electricity	1 in 500	1 in 136	1 in 375	1 in 1500	1 in 316

Note: Firm DM gas: daily metered customers are large industrial consumers. NDM gas: non-daily metered includes domestic consumers and some SMEs. Results for CCGT outages not shown. For full results please see the Redpoint Report published alongside this document.
Source: Redpoint Energy

6.5. The table shows the interruption probabilities for the different categories of domestic and non-domestic gas and electricity customers assuming Ofgem's cash-out reforms are enacted. Generally CCGTs[138] are the first firm demand to be interrupted by NGG in an emerging emergency. This can be seen in the difference between the results in 2016 and 2020. In 2016 we assume the proportion of electricity generated from gas-fired plants peaks over the period of our analysis. In this year, the probability of interruptions to firm DM and NDM gas customers is lowest, while the probability of an interruption to electricity customers is highest. This is because CCGT demand acts as a cushion to firm DM and NDM gas consumers, reducing the likelihood these customers will face an interruption. In 2020, on the other hand, fewer CCGTs contribute to electricity supplies. As a result, the cushion CCGTs provided to other gas customers decreases, resulting in a higher probability of firm DM and NDM interruptions. However, even in this case the chance of an interruption is very low (eg for firm NDM demand an interruption is expected once in every 162 years).

6.6. Overall the results show that domestic electricity customers are the least likely to face an outage, with an average probability of interruption of 1 in every 316 years. This is due to a number of mitigating factors in the electricity market, including distillate back-up for gas-fired generators[139], which would allow some CCGTs to continue to run in the face of low/no gas supplies. Furthermore, CCGTs are not always necessary to meet domestic electricity demand. An outage for domestic electricity customers would therefore only occur if CCGT curtailments were necessary at a time of high electricity demand. An assumed increase in demand side response

[137] We note that there are some minor differences between the results in the above table and the results that we published in the Gas SCR Proposed Final Decision. These have arisen due to an error in the modelling assumptions of the average frequency of supply outage of Long Range Storage. Further details are provided on page 19 of the Redpoint report published alongside this document. We have found that the error has little impact on the results, and no impact on the conclusions we draw from the results.
[138] Redpoint's analyse uses CCGTs as a proxy for all gas-fired generation capacity, we have mirrored this approach in our summary.
[139] In a 2010 analysis (available online) Poyry indicated that there was 8.1 GW of CCGT plant with distillate back-up connected to the GB grid. Based on recent permanent and temporary closure announcements, this could fall to as low as 3.3 GW by the end of 2013, although some of this capacity could return following a period of mothballing. Of the 10GW of proposed CCGT new build in 2010, just 1.3 GW planned to include distillate back-up.
http://www.decc.gov.uk/assets/decc/what%20we%20do/uk%20energy%20supply/energy%20markets/gas_markets/114-poyry-gb.pdf)

(DSR) for gas under reformed cash-out in the I&C sector also acts as a cushion to domestic electricity customers. Domestic gas customers are the second least likely group to face an interruption with an average probability of interruption of once in every 162 years.

6.7. As explained in footnote 137 there are some minor differences between Figure 6.1 and the results presented in the Gas SCR Proposed Final Decision. We have found that the error has little impact on the results, and no impact on the conclusions we draw from the results. Therefore to enable like-for-like comparison the results presented as the Counterfacutal for the rest of the report are consistent with those presented in the Gas SCR Report (ie they use the same assumptions as results presented in the Gas SCR). The Counterfactual results can be found on p.19 of the Redpoint Energy report.

6.8. We have also run two sensitivities to this modelling exercise. These look at how the likelihood of customer outages change when the severity and probability of infrastructure outages doubles and when the global GB LNG prices is set permanently high.

More severe infrastructure outages

6.9. The sensitivity on more severe infrastructure outages doubles the mean duration, magnitude and probability of outage associated with all GB import infrastructure in the model (see the Redpoint Further Measures Modelling report for more details). This sensitivity is used as a proxy to cover a wide range of possible risks, including heightened political instability affecting LNG supply chains and more significant and numerous technical failures to UK infrastructure. Figure 6.2 presents the summary results in the one year it was run, 2020.

Figure 6.2: Probability of at least one outage in a given year (Infrastructure outage sensitivity)

	Base case - 2020	Infrastructure outage - 2020
Firm DM gas	1 in 125	1 in 48
NDM gas	1 in 167	1 in 60
Firm I&C electricity	1 in 71	1 in 28
Domestic & SME electricity	1 in 300	1 in 125

Source: Redpoint Energy

6.10. The table shows that doubling the probability, magnitude and duration of infrastructure outages leads to more than a doubling in the probability of customer interruptions. For all customer categories the probability of interruption increases by around three times. Importantly, the results still indicate the chance of interruption to any one customer category is still very low, with the most likely being Firm I&C electricity customers due to interruptions of CCGTs from a gas deficit, at once in every 28 years.

Higher GB LNG price

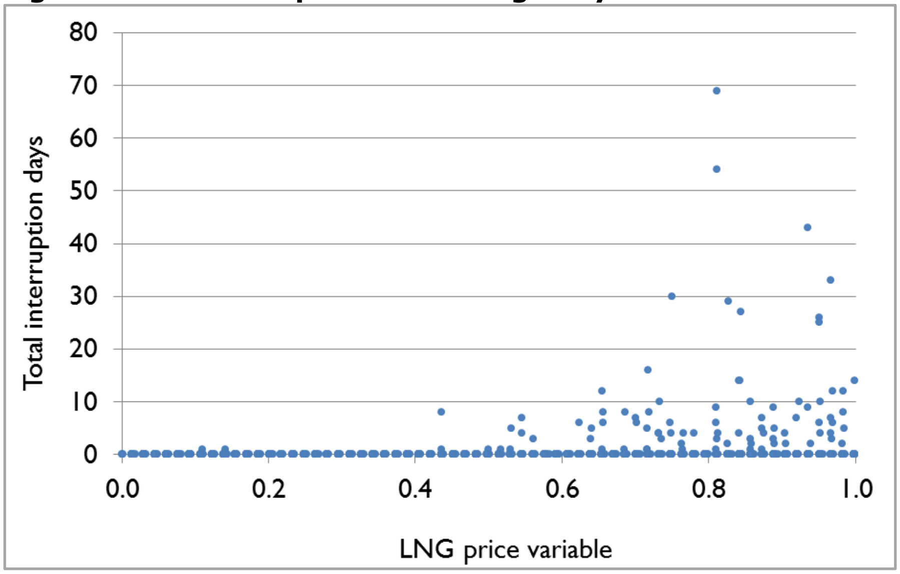
6.11. The base case assumption in the model for the GB LNG price is that it is a random mixture of the Henry Hub and the oil-linked Japanese Crude Cocktail (JCC) price (a proxy for the price of Asian LNG cargoes). We use these two values to reflect the wide range of uncertainty around future GB LNG prices, with Henry Hub acting as a future price floor and JCC the ceiling.

6.12. The level of the GB LNG price has a significant impact on the total number of interruption days (depicted by blue dots in Figure 6.3. The x-axis shows the extent the GB LNG price is driven by Henry Hub or JCC. A value towards 0 means the GB LNG price is driven more by the Henry Hub price, whereas a value towards 1 means the GB LNG price is driven more by the JCC price.

6.13. Figure 6.3 demonstrates that the model results in more interruptions when the GB LNG price is high (LNG price variable closer to 1)[140]. The reason for this is that when the GB LNG price is low (LNG price variable closer to 0), LNG imports into GB are high. This reduces GB dependence on other sources of supply such as imports from the Continent (via IUK and BBL) and storage, UKCS and NCS (via Langeled). This leaves these supply sources more able to respond to shocks by importing extra supplies if necessary. On the other hand, when the GB LNG price is high, LNG imports are low. This increases dependence on other sources of supply to bring gas to GB, and therefore makes them less able to respond to negative shocks if necessary[141].

[140] The chart plots the total number of interruption days in each simulation against the value of the LNG price variable in each corresponding situation. Interruption days are summed across all tranches of electricity and gas demand, and so interruption of two tranches of demand in a single day represent two interruption days.
[141] For example, in a scenario where both the IUK and BBL pipelines are importing gas from the Continent, due to low LNG imports and possibly very high demand a series of shocks might remove the import capacity of, for example, IUK and one or more other sources of supply. If this occurred, then without LNG supplies the remaining supply sources might not be able to increase imports at the volume required to avoid an outage to some customer categories.

Figure 6.3: GB LNG price and outage days



Source: Redpoint Energy

6.14. To test the impact of permanently high LNG prices, in this sensitivity, we artificially set the GB LNG price equal to the JCC price. This sensitivity acts as a proxy for the range of external shocks that could have significant implications on the price and availability of LNG. Figure 6.4 presents the summary results in the year 2020.

Figure 6.4: Probability of at least one outage in a given year (Higher GB LNG price sensitivity)

	Counterfactual - 2020	Higher GB LNG price - 2020
Firm DM gas	1 in 125	1 in 83
NDM gas	1 in 167	1 in 107
Firm I&C electricity	1 in 71	1 in 36
Domestic & SME electricity	1 in 300	1 in 188

Source: Redpoint Energy

6.15. As one would expect from figure 6.3 the higher GB LNG price sensitivity increases the probability of at least one outage over the year for all customer categories. However, comparing figures 6.2 and 6.4, the impact of the higher LNG price sensitivity on the probability of outages is less than in the infrastructure outage sensitivity. One broad implication of this result is that permanently very high LNG prices are a less significant driver of customer outages in our modelling than doubling the severity and probability of infrastructure outages. However, in both sensitivities the probabilities of customer outages remains very small and so drawing conclusions from the relativities of these results should be avoided.

Resilience analysis

6.16. This section outlines the methodology, assumptions and results of our resilience analysis. We compare levels of demand against varying levels of possible supply to understand the level of defence our supply and storage capabilities provide us against a range of extreme shocks.

6.17. We have looked at market resilience in two ways. First we investigate a number of stress tests. These tests have been designed to reflect a combination of extreme events (very high demand and infrastructure outages) to understand whether estimates around the levels of future import and storage infrastructure in GB would be sufficient to cover very high supply losses and high demand. This analysis makes no assumptions around the cause or the likelihood of the shock, just whether remaining supply and storage is sufficient to meet demand. Second, we present the findings of our critical loss analysis. This analysis has looked at the size of the outage required to result in an interruption to different customer types.

6.18. For our analysis we have used the two scenarios described in Chapter 2 of this appendix: Our Green scenario is broadly based on National Grid's Gone Green Scenario, and our Energy Crunch scenario is based on our internal analysis in which energy efficiency policies are less successful and gas plays a greater role in the generation mix. In this chapter, we first outline our demand and supply assumptions, and then present the results of our stress test and critical loss analyses.

Average and severe conditions

6.19. For each of our scenarios we have analysed demand under both average and severe conditions both over winter and on a peak day. Average conditions represent our demand assumptions should temperatures be in line with seasonal normal levels. Under severe conditions our demand assumptions reflect severe weather conditions. A peak day reflects a 1-in-20 peak day[142], and the winter profile is mapped to a 1-in-50 winter[143].

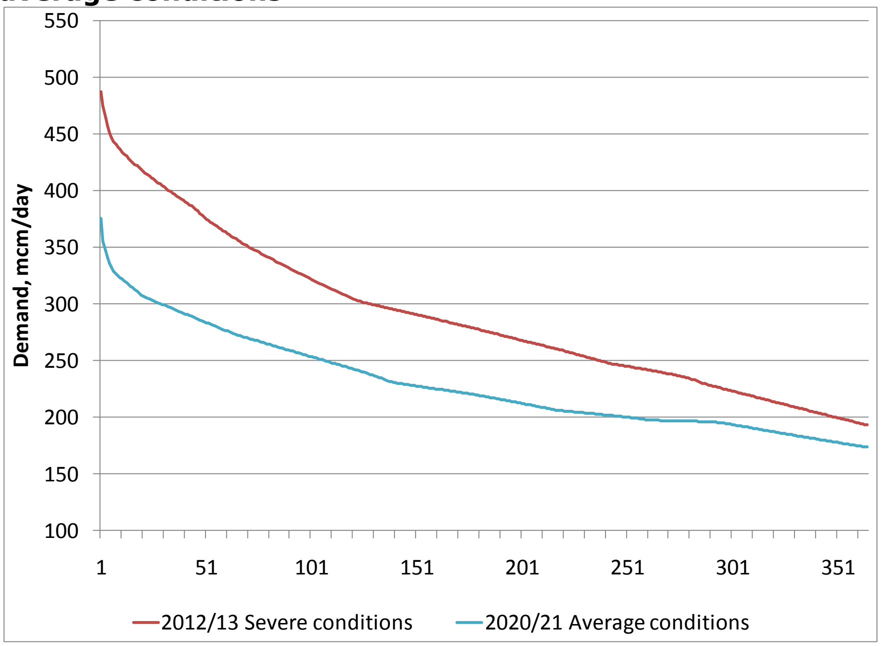
Demand assumptions

In the Green scenario, our overall demand assumptions are sourced from National Grid load duration curves (LDCs[144]) for both average and severe conditions and both non-daily metered (NDM) and daily metered (DM) demand. By way of producing a cautious demand forecast, power generation is not assumed to show any price response at times of high gas demand. Therefore demand for gas in the power generation sector is unchanged between National Grid's average demand forecast

[142] The volume of gas demanded on a peak day under which temperatures are in line with the coldest expected in a twenty year period.
[143] The volume of gas demanded over a winter period under which temperatures are in line with the coldest expected in a fifty year period.
[144] Based on the 2011 Ten Year Statement, available online: http://www.nationalgrid.com/uk/Gas/TYS/

and the 1-in-20 peak day forecast[145]. The range of demand forecasts can be seen in Figure 6.5 below, which shows the highest and lowest LDCs in our Green scenario.

Figure 6.5: Green scenario LDCs: 2012/13 severe conditions and 2020/21 average conditions



Source: National Grid, 2011

6.20. Our assumptions underlying demand in the Energy Crunch scenario are generated in house. Domestic and I&C demand are assumed to grow in line with GDP (from a 2011 base taken from the NG's 2011 Ten Year Statement), with the energy intensity of growth assumed unchanged from Ofgem's Project Discovery[146]. Growth assumptions are taken from HM Treasury's comparison of independent forecasts Document[147] up to 2013. Growth is then assumed to stay in line with trend growth as assumed by the OBR[148]. Reflecting the Green scenario, energy efficiency polices are enacted, but with less conviction than in the Green scenario. As a result, energy efficiency in the Domestic and I&C sectors are assumed to broadly follow DECC's 'pathway 2'.

6.21. In the Energy Crunch scenario, gas plays a key role in the generation mix; gas as a proportion of total generation slowly rises to around 60% of all output in the early 2020s. As in the Green scenario, demand from power generation is assumed to remain constant between average and severe conditions.

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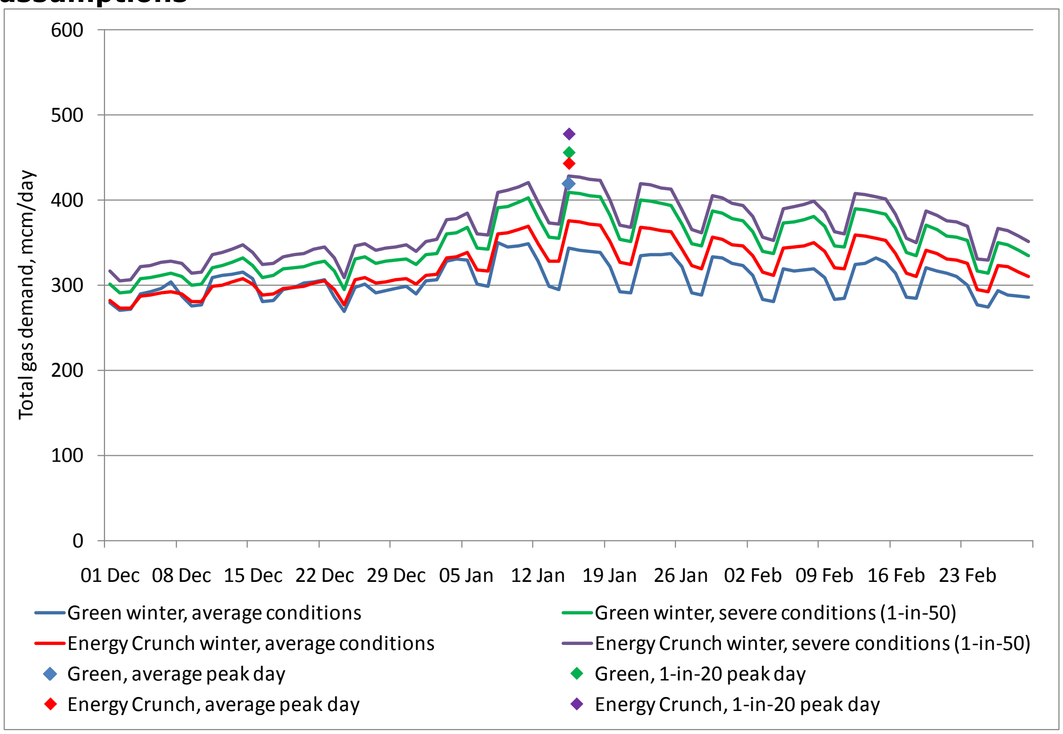
[145] National grid forecast a reduction in demand for gas from power on a 1-in-20 peak gas day, indicating some response by generators to price signals
[146] Available online: http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/Discovery/Pages/ProjectDiscovery.aspx
[147] Available online: http://hm-treasury.gov.uk/d/201111forcomp.pdf
[148] Available online: http://budgetresponsibility.independent.gov.uk/economic-and-fiscal-outlook-march-2011/

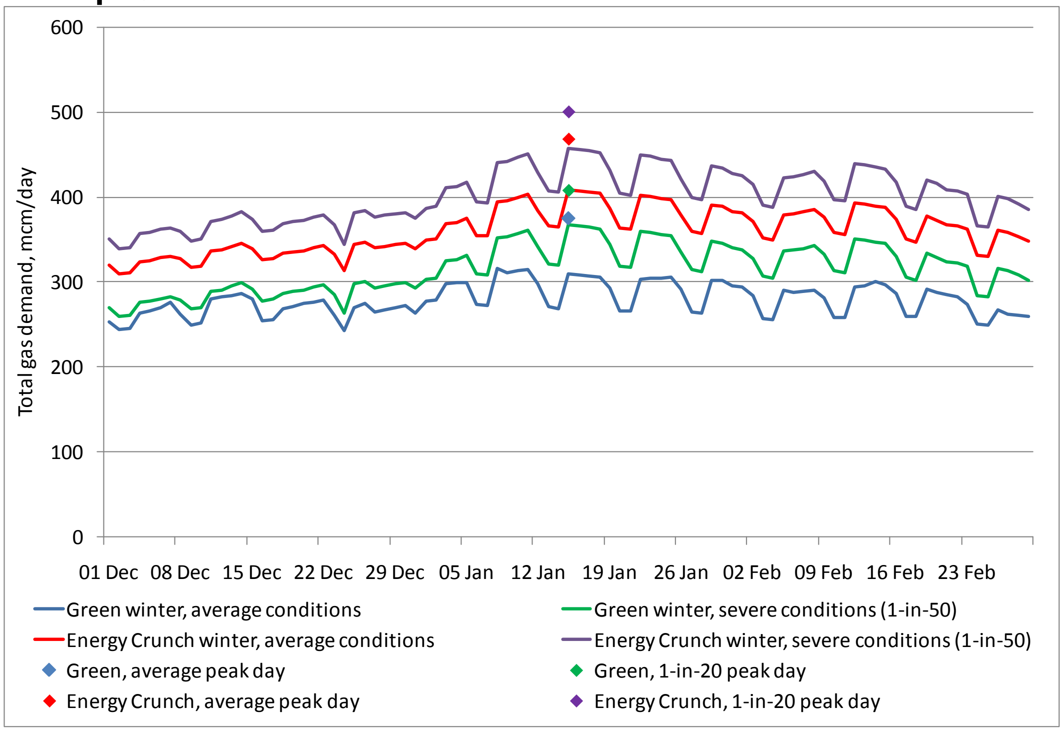
In the Green scenario, the LDCs are mapped against 2011/12 seasonal normal demand (SND) data published by National Grid to create a winter profile. We then assume that the shape of the winter demand profile does not change over time, instead it increases or decreases in line with our assumptions.
Figure 6.6 and Figure 6.7. below illustrate the winter demand profiles and peak day levels across our scenarios for 2015/16 and 2020/21, respectively.

Figure 6.6: 2015/16 winter demand profiles and peak day demand assumptions



Source: Redpoint, Ofgem analysis, National Grid

Figure 6.7: 2020/21 winter demand profiles and peak day demand assumptions



Source: Redpoint, Ofgem analysis, National Grid

6.22. The spread of the winter demand profiles in 2020/21 is greater than in 2015/16. This mirrors the trend in the demand described in Chapter 2 of this appendix for the two scenarios. Overall, across the years and scenarios, demand is lowest in 2015/16 for the Green scenario under average conditions and highest in 2020/21 for the Energy Crunch scenario under severe conditions.

Supply assumptions

6.23. Supply infrastructure in the Green scenario is assumed to stay broadly unchanged from current levels. UKCS and Norwegian imports decline in line with forecasts in the 2011 Ten Year Statement. Interconnector capacity remains unchanged throughout the period, with only a fractional increase in LNG regasification capacity. The only additional storage built in the Green scenario comes from that already under construction as recorded in the 2011 Ten Year Statement.

6.24. In the Energy Crunch scenario, supplies from UKCS and Norwegian fields are also expected to decline in line with National Grid's Slow Progression scenario. As in the Green scenario, interconnector capacity is assumed unchanged. In response to higher demand, large scale investment in storage and LNG facilities is assumed. After de-rating the deliverability of these new investments a total of 52 mcm/day additional LNG deliverability and 93 mcm/day of storage deliverability is assumed to come online by 2020/21.

6.25. A full tabulation of the demand and supply assumptions underlying this analysis is provided at the end of this chapter.

De-rating of declared infrastructure deliverability rates

6.26. As part of our resilience analysis we de-rate the declared deliverability of a number of pieces of gas infrastructure. Apart from adding a necessary caution to the analysis, de-rating is undertaken to reflect three factors that reduce the deliverability rates of GB supply infrastructure from maximum. First, that there may be physical issues getting gas onto the GB system. For example, LNG cargoes must travel thousands of miles from their sources with the possibility of diversions to higher priced markets[149]. Second, physical constraints on the NTS mean that all pieces of infrastructure cannot run concurrently. Third, it reflects the reality that some pieces of infrastructure have in the past not run at nameplate capacity despite GB being short of gas supplies.

6.27. The various de-rating factors used in this analysis are listed in Figure 6.8 below. Although this approach cannot fully reflect the three factors listed above, it provides a more balanced picture of potential sources of supply during a gas emergency than using nameplate capacities or historic deliverability rates alone.

Figure 6.8: Peak and winter de-rating factors

	Peak de-rating factor	Winter de-rating factor
UKCS	1.00	1.00
Norway	1.00	1.00
LNG	0.95	0.80
Imports	0.91	0.91
Storage[150]	1.00	1.00

Source: Ofgem

Stress tests

6.28. Our first approach to resilience analysis focuses on testing the availability of the GB gas network to deal with large scale outages. This stress test analysis consists of six tests of increasing severity. Test 1 studies the effect, under average winter conditions, of a loss of 70 mcm/d. This is equivalent to the loss of our single largest source of supply, the Langeled pipeline. Test 2 repeats test 1, but under severe weather conditions. Test 3 combines a loss of Langeled with a loss of the IUK interconnector and a 25% reduction in LNG from our supply sources. Test 4 repeats test 3, but under severe weather conditions. Test 5 combines a loss of Langeled with a loss of both the IUK and BBL interconnectors and a 50% reduction in LNG from our supply sources. Test 5 is our extreme interconnector stress test and effectively

[149] This explains the difference between the de-rating factors on LNG imports in Figure 6.8 between the winter and on a peak day.
[150] To reflect the uncertainty of storage new build, 15 mcm/day is de-rated from total SRS deliverability across the forecast period, compared with the 2011 TYS.

models the removal of around half of maximum GB non-storage supply. Test 6 repeats test 5, but under severe weather conditions. We summarise the six tests in Figure 6.9 below:

Figure 6.9: Stress tests

Test	Description	mcm loss
1	Average conditions, minus 70mcm/d (N-1)	70
2	Severe conditions, minus 70mcm/d (N-1)	70
3	Average conditions, minus 70mcm/d, minus IUK, minus 25% LNG	170 – 180
4	Severe conditions, minus 70mcm/d, minus IUK, minus 25% LNG	170 – 180
5	Average conditions, minus 70mcm/d, minus BBL, minus IUK, minus 50% LNG	260 – 285
6	Severe conditions, minus 70mcm/d, minus BBL, minus IUK, minus 50% LNG	260 – 285

Source: Ofgem

6.29. These tests represent extreme events to GB gas infrastructure, particularly as in the winter analysis we assume that the supply outages last the full three months of December, January and February. Since privatisation, the longest significant supply disruption recorded in GB was the Rough fire, which began in February 2006 and partly re-opened one month later. We have never seen a large piece of gas infrastructure outage for an entire winter period.

6.30. We have carried out each stress test in 2015/16 and 2020/21 and separately for our Green and Energy Crunch scenarios. We have also completed the analysis for a peak day and over the course of winter.

6.31. Figure 6.10 presents the results of the stress tests for total GB gas demand. "OK" refers to a situation where the capacity and deliverability of non-storage supply sources are sufficient to cover all customer demand either on the peak day or throughout the whole winter. "Storage needed" describes a situation where demand outstrips total levels of non-storage supply and storage is required to maintain supplies either on a peak day or over winter. "Interruption" means neither storage nor the remaining non-storage supplies are sufficient to meet total customer demand either on a peak day or over winter.

6.32. The results show that in all cases in the Green scenario, bar the peak day analysis in test 5 and the peak and winter analyses in test 6, storage plus remaining supplies are sufficient to meet total customer demand. The results for the Energy Crunch scenario are the same as the Green apart from in test 2 where storage is needed to meet demand over the winter.

Figure 6.10: Stress test results for all customers, Green scenario (and Energy Crunch), 2015/16

Test	Peak day analysis	Winter analysis
1	OK	OK
2	Storage needed	OK†
3	Storage needed	Storage needed
4	Storage needed	Storage needed
5	Storage needed	Interruption
6	Interruption	Interruption

Note: † indicates storage needed in Energy Crunch scenario.
Source: Redpoint, Ofgem analysis

6.33. The results for 2020/21 are shown in Figure 6.11 below. For the peak day analysis, the Green and Energy Crunch scenario show the same results, requiring storage supplies in tests 2, 3, 4 and 5 to meet customer demand. Interruptions only occur in test 6. For the winter analysis, tests 1 and 2 show "OK" for the Green scenario, but "Storage needed" for the Energy Crunch scenario. For tests 3 and 4 the Green scenario shows "Storage needed", for both tests, while under Energy Crunch an interruption is noted in test 4. Tests 5 and 6 show "Interruption" in both scenarios for the winter analysis.

Figure 6.11: Stress test results for all customers, Green scenario (and Energy Crunch), 2020/21

Test	Peak day analysis	Winter analysis
1	OK	OK†
2	Storage needed	OK†
3	Storage needed	Storage needed
4	Storage needed	Storage needed*
5	Storage needed	Interruption
6	Interruption	Interruption

Note: † indicates storage needed in Energy Crunch scenario, * indicate interruption in Energy Crunch scenario.
Source: Redpoint, Ofgem analysis

6.34. We also show the results looking specifically at non-daily metered (NDM) and daily metered (DM) customer demand. For the Green scenario, in all but the winter analysis for test 6 in 2020/21, our stress tests indicate that DM and NDM customer demand can be met by utilising storage supplies. In the Energy Crunch scenario, the interruption noted in the Green scenario becomes "Storage needed". This reflects the higher assumptions regarding storage and LNG capacity in the Energy Crunch Scenario.

Figure 6.12: Stress test results for NDM and DM customers, Green scenario (and Energy Crunch), 2015/16

Test	Peak day analysis	Winter analysis
1	OK	OK
2	OK	OK
3	OK†	OK
4	Storage needed	Storage needed
5	Storage needed	Storage needed
6	Storage needed	Storage needed

Note: † indicates storage needed in Energy Crunch scenario
Source: Redpoint, Ofgem analysis

Figure 6.13: Stress test results for NDM and DM customers, Green scenario (and Energy Crunch), 2020/21

Test	Peak day analysis	Winter analysis
1	OK	OK
2	OK	OK
3	Storage needed	OK
4	Storage needed	Storage needed
5	Storage needed	Storage needed
6	Storage needed	Interruption†

Note: † indicates storage needed in Energy Crunch scenario
Source: Redpoint, Ofgem analysis

6.35. Focusing on non-daily metered (NDM) customer demand, supplies would cover NDM demand throughout winter in all of the tests, but storage would be needed for the peak days in test 5 and 6 and winter in test 6 in 2015/16.

Figure 6.14: Stress test results for NDM customers only, Green scenario (and Energy Crunch), 2015/16

Test	Peak day analysis	Winter analysis
1	OK	OK
2	OK	OK
3	OK	OK
4	OK	OK
5	Storage needed	OK
6	Storage needed	Storage needed

Source: Redpoint, Ofgem analysis

6.36. In 2020/21 the results remain almost unchanged both on a peak day and during winter. In both the Green and Energy Crunch scenarios storage would be needed for tests 5 and 6 and no interruptions to NDM customers are recorded in any test.

Figure 6.15: Stress test results for NDM customers only, Green scenario (and Energy Crunch), 2020/21

Test	Peak day analysis	Winter analysis
1	OK	OK
2	OK	OK
3	OK	OK
4	OK	OK
5	Storage needed	Storage needed
6	Storage needed	Storage needed

Source: Redpoint, Ofgem analysis

6.37. The stress tests show that in all but the most extreme cases current and forecast levels of GB supply and storage infrastructure are sufficient to meet all customer demand. Only in the tests where non-storage supply losses reach 50% of total is storage insufficient to meet total demand and some (CCGT and large I&C) customers are interrupted. However, even in these cases NDM and DM demand is protected. It is important to note that no price response from CCGTs is assumed in this analysis. Historical evidence indicates that at times of tight gas supply (and high prices) CCGTs would self disconnect[151].

Critical loss analysis

6.38. Our second approach to test market resilience looks at the proportion of non-storage supply infrastructure needed to avoid interruptions to the following four classes of customer:

- CCGTs assuming they run at maximum levels[152]
- CCGTs running at normal levels
- Daily metered (DM) customers (proxy for I&C demand)
- Non-daily metered (NDM) customers (proxy for domestic demand)

6.39. As with our stress tests we have applied de-rating factors to supplies and carried out the critical loss analysis in 2015/16 and 2020/21 and separately for our Green and Energy Crunch scenarios. We have also completed the analysis for a peak day and over the course of winter.

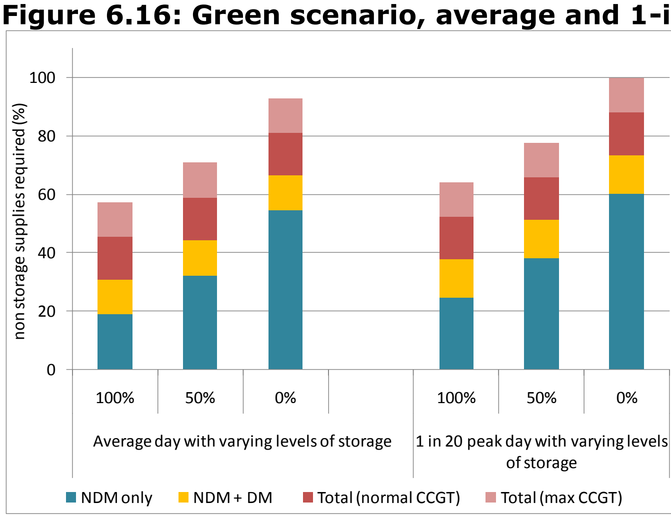
[151] The scope for demand side response from CCGTs may be appreciably less than shown in previous years as gas-fired power stations are assumed by National Grid in the latest Winter Outlook to run as the marginal source of power generation rather than base load.
[152] To provide a figure for maximum generation we estimate how much gas would be demanded by all gas fired generation connected to the system over a 24 hour period. First each generator on the system is given an efficiency rating based on data from Mott MacDonald and we assume availability of 85%. No distillate backup is assumed. This is an extreme test, assuming that all gas on the system is running as baseload power, and that either distillate backup has been used, or is not available. At a time of extreme gas prices, utilisation of distillate backup and running gas for just the peak 6 hours of the day could remove as much as 80% from these estimates.

Peak day analysis

6.40. **Figure 6.16** presents the results of the peak day analysis for an average and a 1-in-20 peak day in the Green scenario for 2015/16. Each bar represents the percentage of non-storage supply needed to ensure that the customer type does not risk interruption. For example, for the bar on the far left, which shows an average winter peak day with 100% storage availability, the non-storage supplies required to cover all NDM demand are only 20% of total. This implies that with full storage availability, the GB market could suffer a loss of 80% of its non-storage supply capacity before NDM customers were affected.

6.41. The other coloured bars present the percentage of non-storage supplies required to meet demand from the three other customer types. The top of the pink bar indicates the percentage of supplies required to cover CCGTs running at maximum capacity (just under 60% in the diagram); the top of the red bar indicates the supplies required to cover CCGTs running at normal capacity (around 45%), and the yellow bar indicates the supplies required to meet daily metered customers (around 30%).

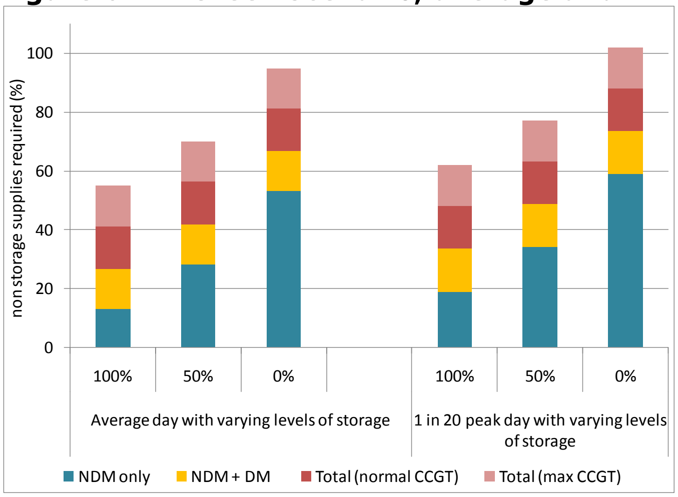
Figure 6.16: Green scenario, average and 1-in-20 peak day, 2015/16



Source: Redpoint, Ofgem analysis

6.42. In the 2020/21 analysis (see Figure 6.17), NDM gas demand in GB has fallen by about 20% compared with today's levels in the Green scenario. Unsurprisingly, in this scenario, a lower proportion of supplies is needed to cover NDM customer demand than in 2015/16. For example, on an average winter peak day with 100% storage, GB would need only around 10% of non-storage supplies to cover NDM customer demand (down from around 20% in 2015/16). Demand in the DM and power sectors in 2021/21 is broadly stable compared with 2015/16.

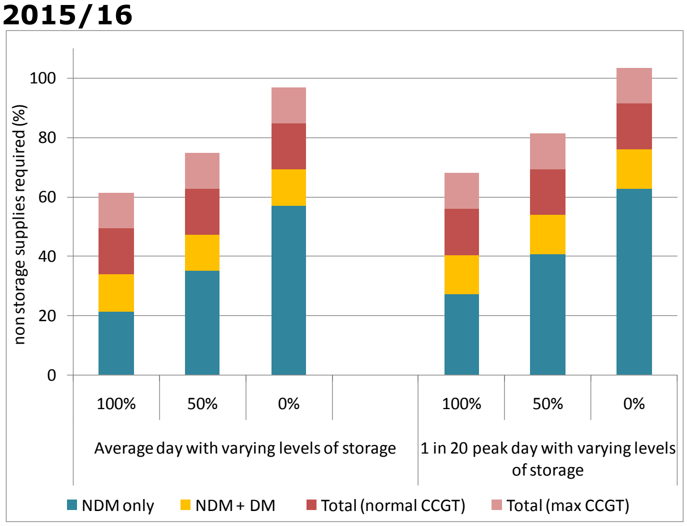
Figure 6.17: Green scenario, average and 1-in-20 peak day, 2020/21



Source: Redpoint, Ofgem analysis

6.43. Figure 6.18 shows the critical loss analysis for the Energy Crunch scenario in 2015/16. It shows a similar pattern to that in the Green scenario in the same year. However, demand is slightly higher across all four of the customer categories and, while we assume a small increase in LNG deliverability, it is not large enough to offset the increase in demand in this scenario. As a result, in all cases, a marginally higher proportion of non-storage supplies is needed to meet demand compared with the same years in figure 6.17. This is shown by slightly taller bars in figure 6.18 than in figure 6.16.

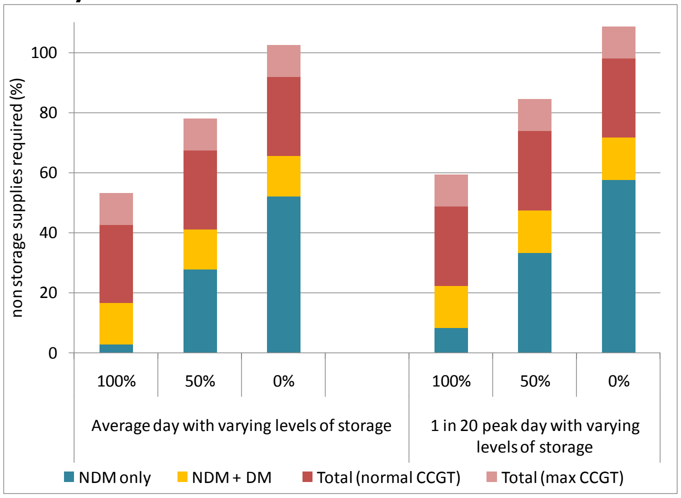
Figure 6.18: Energy Crunch scenario, average and 1-in-20 peak day, 2015/16



Source: Redpoint, Ofgem analysis

6.44. In the 2020/21 analysis, the picture for the Energy Crunch scenario has changed. With increased investments in storage and LNG facilities, NDM customers require only a small proportion of non-storage supplies to meet their demand levels. This is seen as the short bars for NDM customers in 2020/21.

Figure 6.19: Energy Crunch scenario, average and 1-in-20 peak day, 2020/21



Source: Redpoint, Ofgem analysis

6.45. One key feature of the Energy Crunch scenario in 2020/21 is the higher demand from the power sector. This is highlighted by the taller red bars in the 2020/21 analysis compared with 2015/16. Moreover there is a higher ratio of the dark red bars to the pink bars, indicating an increase in the load factors of gas-fired generators. The results show that if storage was 50% full, between 65 and 75% of non-storage supplies would be needed to cover demand from gas-fired generators depending on the severity of the weather. This suggests that, in 2020/21, a loss of only a quarter of supplies could result in a shortage of supply for power generators.

Winter analysis

6.46. Turning to the results of the whole winter analysis, this differs to the peak day approach, as it adds a constraint from storage capacity in addition to deliverability rates. The whole winter analysis has been run for a case where there is 100% storage available at the beginning of winter and where there is only 50% available[153].

6.47. Figure 6.20 presents the results for our Green scenario in 2015/16. In the case where storage is full at the start of winter, the required supplies are slightly above those for the peak day analysis with 100% storage availability (depicted by slightly higher bars in the chart). This is because, over winter, storage volumes decline and many MRS and SRS sites empty completely. This dramatically reduces the maximum deliverability of storage, resulting in higher bars on the charts. This means the proportion of supply that could be lost over winter before some customers might face interruptions is slightly lower than in the peak day analysis. However, where storage facilities start the winter at 50% capacity, the heights of the bars are similar to those in the peak day analysis. This indicates that in both winter and peak

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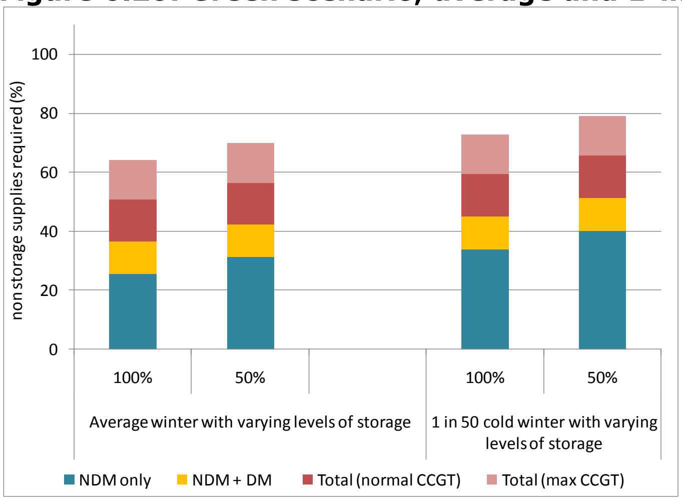
[153] On average over the past 6 years, GB storage has been 94% full on 1 October.

day analyses, with 50% storage availability, storage deliverability is the binding constraint, producing similar results for both peak day and winter analyses.

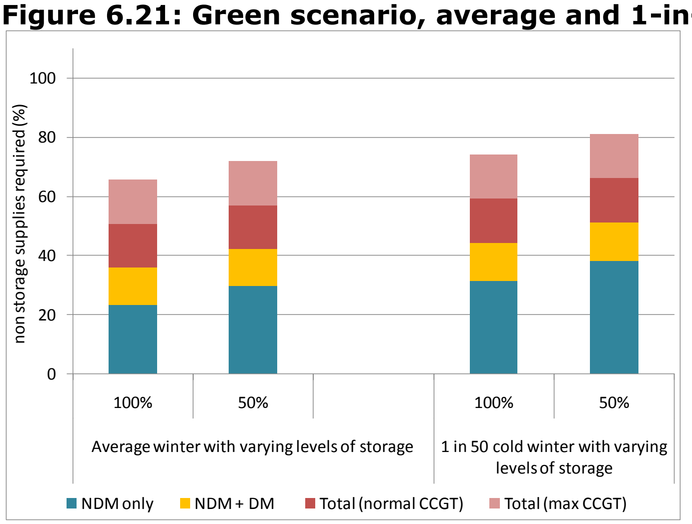
Figure 6.20: Green scenario, average and 1-in-50 winter, 2015/16



Source: Redpoint, Ofgem analysis

6.48. The 2020/21 Green scenario winter results are broadly in line with those recorded in 2015/16. However, as assumed storage levels are slightly higher in 2020/21 (due to the completion of storage projects currently under construction) and lower levels of NDM demand the results indicate a very slightly lower dependence on non-storage supplies. For example, in a 1-in-50 winter with storage 100% full at the start of winter, 66% of non-storage supplies can be lost before domestic customers are impacted in 2015/16, this rises to 69% in 2020/21.

Figure 6.21: Green scenario, average and 1-in-50 winter, 2020/21

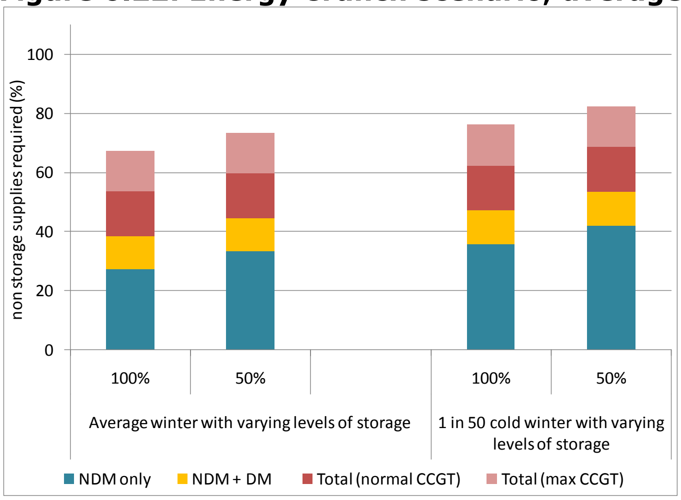


Source: Redpoint, Ofgem analysis

6.49. Mirroring the trend recorded in the peak day analysis, in 2015/16, the Energy Crunch analysis paints shows a similar level of resilience to shocks as the

Green scenario in the same year. The minor differences between the two scenarios generally reflect the higher demand assumptions the Energy Crunch scenario.

Figure 6.22: Energy Crunch scenario, average and 1-in-50 winter, 2015/16

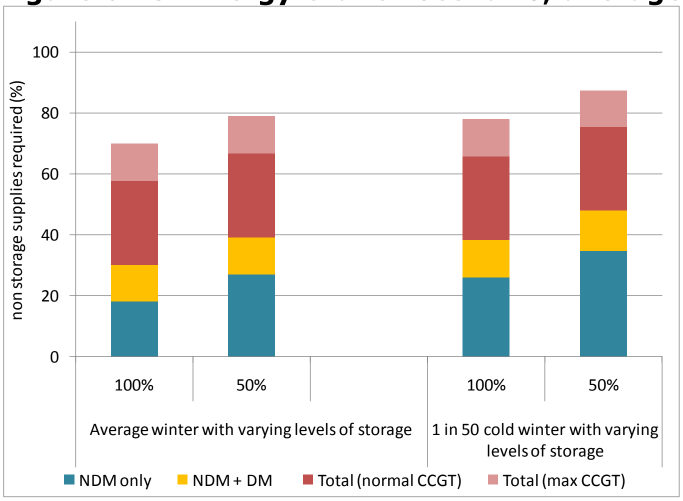


Source: Redpoint, Ofgem analysis

6.50. The Energy Crunch scenario, in 2020/21 (results in Figure 6.23), allows for slightly larger supply losses before non-daily metered customers are affected compared with the Green scenario. As in the peak day analysis this is owing to the fact that the Energy Crunch scenario includes higher forecast levels of storage154 and LNG regasification. However, as noted in the peak day analysis, the Energy Crunch scenario includes increased forecast levels of electricity demand which results in a higher supply requirement from CCGT demand. This can be seen by the wider red bars in Figure 6.23 compared with the Green scenario in Figure 6.21. Broadly, in the Energy Crunch scenario, across 2015 and 2020, a loss of gas supply of between 25% and 30% (again assuming storage to be 50% full at the start of winter) would probably result in a curtailment of gas supplies to power stations.

[154] The Green scenario assumes that only storage facilities currently under construction are built during this outlook period, in line with the timelines set out in the 2011 Ten Year Statement. As a result, no additional long-range storage facilities are constructed, while the completion of Stublach adds an additional 400mcm capacity and 32mcm/day deliverability to short-range storage by 2015. The Energy Crunch scenario assumes that market signals lead to the construction of an additional 2.5bcm of long-range storage capacity (49 mcm/day deliverability) by 2020, and an additional 100mcm of short-range storage capacity

Figure 6.23: Energy Crunch scenario, average and 1-in-50 winter, 2020/21



Source: Redpoint Energy, Ofgem analysis

Supply assumptions

Green

Peak day

mcm/day	2012	2015	2020
UKCS	147.1	126.5	79.9
NCS	127.4	130.2	117.4
LNG	145.4	145.4	149.6
Imports	115.7	115.7	115.7

Winter day

mcm/day	2012	2015	2020
UKCS	147.1	126.5	79.9
NCS	127.4	130.2	117.4
LNG	122.4	122.4	125.9
Imports	115.7	115.7	115.7

Storage capacity

bcm	2012	2015	2020
SRS	1.4	1.8	1.8
LRS	3.3	3.3	3.3

Storage deliverability

mcm/day	2012	2015	2020
SRS	108.0	140.0	140.0
LRS	45.0	45.0	45.0

Energy Crunch

Peak day

mcm/day	2012	2015	2020
UKCS	147.1	126.5	79.9
NCS	127.4	130.2	117.4
LNG	145.4	149.6	197.4
Imports	115.7	115.7	115.7

Winter day

mcm/day	2012	2015	2020
UKCS	147.1	126.5	79.9
NCS	127.4	130.2	117.4
LNG	122.4	125.9	166.2
Imports	115.7	115.7	115.7

Storage capacity

bcm	2012	2015	2020
SRS	1.4	1.8	1.9
LRS	3.3	3.3	5.8

Storage deliverability

mcm/day	2012	2015	2020
SRS	108.0	140.0	158.0
LRS	45.0	45.0	94.0

Demand assumptions

Green

Peak day

mcm/day	2012	2015	2020
NDM	302.8	282.2	246.0
DM	64.2	62.1	62.4
Power	68.0	75.7	67.5
Max. power	129.1	136.9	130.9

1-in-20 peak day

mcm/day	2012	2015	2020
NDM	335.5	312.6	273.0
DM	69.5	67.5	67.7
Power	68.0	75.7	67.5
Max. power	129.1	136.9	130.9

Energy Crunch

Peak day

mcm/day	2012	2015	2020
NDM	315.5	296.8	266.1
DM	67.5	65.3	67.9
Power	71.7	80.9	134.6
Max. power	129.1	143.1	188.9

1-in-20 peak day

mcm/day	2012	2015	2020
NDM	345.6	327.2	293.5
DM	73.3	69.4	72.5
Power	71.7	80.9	134.6
Max. power	129.1	143.1	188.9

7. Longlist of potential GB gas security of supply risks

7.1. This longlist of potential risks to GB gas security of supply is the result of our work with Baringa and MJM Energy, which draws on over 20 face to face interviews with key industry stakeholders, academics and market participants.

ID	Risk dimension	Sub-dimension	Risk description
Supply-side risks			
1	Commercial	GB	Force majeure terms in midstream/upstream contracts could limit liability in case of severe events, and may make assessment of risks for suppliers difficult.
2	Commercial	GB	Lack of direct Government involvement with supplying countries and NOCs becomes a barrier for parties aiming to securing new supplies. GB's political links with Middle East supply countries are critical. Could political pressure from Japan, Korea, India and China for LNG reduce volumes available for GB?
3	Commercial	GB credit issues	Potential for liquidity to dry up in near emergency situations due to concerns over potential counterparty default leads to inability for shippers to procure additional supplies.
4	Commercial	GB market structure	If LNG contracts negotiated to include greater volume and price flexibility (i.e. physical delivery vs. ability to trade), there is an increased threat that LNG cargoes will diverted away from GB. In this case NBP contracting may not be fully backed in advance by physical supply arrangements, leading to inability to meet obligations at times of sudden stress.
5	Commercial	GB market structure	Common risk management strategies that rely on short term contracting to cover demand peaks / supply failures, rather than longer term physical provisions, may lead to underinvestment due to a lack of sufficient demand signals.
6	Commercial	Hubs (EU), liquidity	If LNG prices continue to rise and move towards an oil based pricing methodology, there is the possibility that NBP prices could

			move towards rather than away from oil-based indexation, and together with a lack of liquid hubs (and gas-on-gas prices) this could lead to sustained higher prices due to exposure to oil-indexed pricing.
7	Commercial	LNG	Securing long-term and/or reasonably priced LNG supplies is a significant challenge facing GB gas supplies. Competition from locations where normal market dynamics do not apply perhaps provides the biggest threat."Firm" LNG markets are price inelastic due to limited competition and/or state interests and will "pay any price" in tight markets, and may limit supply to GB (lacking firm delivery contracts).
8	Commercial	LNG	New LNG supply projects do not take investments decisions due to demand and pricing uncertainty across the world; this prevents increased LNG trading, limiting flexible LNG availability for GB
9	Commercial	Pipeline	If gas trade is not increasingly hub-based, Russia could have market power to elevate prices in a tight supply environment.
10	Demand (for imported gas)	Continental Europe	Qatar has capacity in Zeebrugge and can access Gate (Rotterdam) – they will supply these terminals in preference to GB if prices are higher on the Continent, resulting in less LNG supply to the UK.
19	Financing	Global	Deterioriation in corporate balance sheets due to global economic conditions limits financing for projects and/or ability to procure long term contracts
20	Financing	Global	Delay or underinvestment in LNG liquefaction facilities due to difficulties in securing long term contracts with suppliers in competitive markets.
21	Financing	Global	New LNG supplies dedicated to home markets through direct upstream financing by Asian companies.
22	Financing	Local	Suppliers unwilling to take risk of long term contracts required for infrastructure development.
23	Geopolitics	Middle East/North Africa	Failure of co-ordinated EU state actions limits Western facing pipeline project progress from the Caspian. For example, Turkey holds up new projects to gain leverage on EU Accession (Armenia and Cyprus issues also).
24	Geopolitics	Middle East/North Africa	Civil unrest or geopolitical confrontation in Middle East or North Africa. For example, Iran closing the Strait of Hormuz would

			reduce LNG supply to UK and necessitate increased pipeline imports.
25	Geopolitics	Middle East/North Africa	Severe civil unrest / civil war in West Africa disrupts production.
26	Geopolitics	Middle East/North Africa	Strengthening environmental movements in Africa disrupt/reduce fossil fuel production.
27	Geopolitics	Other	Deterioration of relationships with NOCs leads to inability to secure new long term gas contracts.
28	Geopolitics	Other	Deterioration of relationships with NOCs leads to default on existing long term gas contracts.
29	Geopolitics	Other	Ukraine tilts towards Russia, limiting liberalisation and access to storage.
20	Geopolitics	Russia	Lower European gas availability if relations with Russia gradually deteriorate.
31	Geopolitics	Russia	Lower European gas availability if sudden breakdown in relations with Russia.
32	Geopolitics	Russia	Civil unrest / political disruption in Russia limit supplies.
33	Geopolitics	Russia	Further dispute between Russia and Ukraine could have a negative impact of gas supply to UK.
35	Infrastructure reliability	Pipelines/ interconnectors	Sudden failure of key part(s) of GB infrastructure for limited duration at times of stress. This could lead to price shocks and/or diversion of supplies.
36	Infrastructure reliability	Pipelines/ interconnectors	Failure of Ukrainian infrastructure leading to low imported gas availability for Europe.
37	Infrastructure reliability	Upstream	Sudden reduction in NCS supply (eg extreme weather) at a time of stress.
38	Infrastructure reliability	Upstream	Upstream accident leads to shut down and accelerated UKCS decline.
39	LNG supplies	Australia	Delay in LNG projects in Australia due to high costs. The current view is that 2015+ LNG demand will be covered from new Asian (mainly Australian) LNG projects. This would free up Qatari LNG for the Atlantic Basin and GB. If Qatar covers this new demand on a long-term basis, not new Australia supply, then new Australian projects will not be developed (NOTE: High costs of new Australia LNG projects may make this likely).
40	LNG supplies	Middle East	Limited Middle Eastern supplies could be redirected to Asia in response to higher price opportunities.
41	LNG supplies	Russia	Shtokman and Yamal do not proceed due to complexity/cost, leading to a continued delay in planned projects.

42	LNG supplies	US	"Energy island" politics - Political and regulatory risk that US will prevent or restrict the volume of LNG exports – leads to limited US exports.
43	LNG transport & regas	Cargoes / ships / ports	International events cause major disruption to transportation of LNG on global basis (e.g. natural hazards, accidents and terrorism).
44	Pipelines	Central Asian	Barriers to trans-Caspian link delay projects bringing gas west.
45	Pipelines	Other	Longer pipeline supply routes combined with higher demand volatility leads to inability to keep supply/demand within linepack tolerance. Disruption in flows from existing suppliers has knock on effect on GB volumes/prices.
46	Pipelines	Russia	Strategy for Russia to increase market diversification limits new supplies to Europe.
47	Policy	Climate change	Uncertainty about future role of gas in context of UK climate change policy leads to underinvestment in gas infrastructure.
49	Regulatory	Capacity allocation	Practical barriers to accessing network and storage capacity limit efficient flows at time of stress.
50	Regulatory	PSOs	Divergence between GB and other EU regulatory regimes with respect to supply security (eg PSOs) leads to inefficient restriction on flows to GB at times of stress.
51	Shale gas	N America	Environmental shock suddenly reduces US shale gas production, leading to rapid increase in US imports or decrease in exports (in the future), affecting supplies to GB.
52	Storage	GB	Planning issues as potential barrier to some new storage projects.
53	Storage	GB	Storage exemptions from TPA could lead to lack of efficient use.

ID	Risk dimension	Sub-dimension	Risk description
Demand-side risks			
11	Demand (for imported gas)	GB	Longer term annual gas demand from power generation higher than expected
12	Demand (for imported gas)	GB	Energy efficiency measures less effective than planned, leading to increase in demand
13	Demand (for imported gas)	GB	Failure to access DSR via smart metering fails to increase flexibility from demand side

14	Demand (for imported gas)	GB	Potential for extreme peak gas demand with increased intermittency in power generation.
15	Demand (for imported gas)	GB	Barriers to uptake of commercial interruption (eg lack of trust between customer and supplier) limit large customer DSR.
16	Demand (for imported gas)	Global	Further nuclear disaster leads to wide political response halting or closing plant on global basis
17	Demand (for imported gas)	North America	Abrupt change in US carbon policy drives rapid increase in coal-to-gas switching.
18	Demand (for imported gas)	North America	Higher than expected increase in industrial or transport demand in the US, triggered by low gas prices
34	Infrastructure reliability	Other	Type failure of AGRs leading to sudden closure of GB nuclear plant and increase in gas demand
48	Policy	Nuclear	Unexpected delays, downscaling or ending of GB new nuclear programme increases gas demand