GLOBAL GAS & LNG MARKETS & GB'S SECURITY OF SUPPLY

A report to Department of Energy and Climate Change

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EXECUTIVE SUMMARY

Despite major investments in gas pipelines and Liquefied Natural Gas (LNG) terminals in recent years, concerns remain that Great Britain (GB) is still exposed to disruptions to its gas supply. As gas is now being sourced from an increasingly diverse range of geographies and markets, it is important that GB is confident that in combination these sources provide adequate security of supply. Last year witnessed a step change in the volumes of LNG being brought to the country with the start-up of the South Hook and Dragon regasification terminals at Milford Haven, and LNG import flows now regularly represent over 15% of daily gas supplies.

Growing world trade in LNG exposes GB to the vagaries not only of the LNG market itself, but indirectly of regional gas markets elsewhere in the world. Any analysis of the adequacy of GB's gas supplies needs to understand not only the dynamics of the trade in LNG, but also the supply and demand situation, and political factors in the source regions. Furthermore, all of these factors are far from static: while political uncertainty has been a factor in energy supply for decades this is also a time when large amounts of new gas – so-called unconventional gas – are being realised in countries such as the US and Australia, and as the world economy recovers there is a wide range of views on the likely local needs for gas.

All of the above factors have an impact on gas supply into Britain, and this report provides an analysis of them, assesses the associated risks and recommends desirable policy options.

We briefly describe our review methodology below, but our analysis suggests that GB's gas supply is likely to be robust to even highly extreme combinations of possible events, and that current Government policy for LNG and the global gas market is appropriate. We do, however, suggest ways in which this could be further improved if required, such as further developing strategic relationships with LNG suppliers and continuing to ensure the effectiveness of Third Party Access arrangements.

While it might be expected that increasing dependency on non-indigenous gas supplies would lead to greater exposure to risks and events outside British control, our analysis suggests that the likely evolution of global gas supplies, particularly the likelihood of oversupply, and the behaviour of the resulting markets does not support this view.

The report outlines two base global supply/demand scenarios: 'Business as Usual', and 'Carbon Constrained' through to 2050, to capture the range of development of the global demand for gas, and then examines the impact of a series of severe stress tests involving binary events. We have assumed appropriate development of the GB gas infrastructure in these scenarios (e.g. some developments in storage and further regasification capacity) for full consistency.

By their very nature, such combinations of adverse events are very improbable – but our analysis suggests that the supply of gas is robust even to a combination of a 1 in 20 winter (i.e. extremely high demand), and the loss of both Milford Haven terminals for the entire winter. The minor amount of demand-side reduction that would be needed in this case could be provided by fuel switching by gas-fired power stations and some Industrial customers to distillate. Gas prices were affected in the stress-test situations, but in general remain below the level at which demand side response would be required.

Global trade in LNG is still relatively immature, and, in timescales of this analysis, the situation may change – but this report suggests that based on our view today, the gas security of supply will be more than adequate.

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1. INTRODUCTION

1.1 Background

Gas security of supply is a significant issue that faces the government, industry participants and consumers. Significant investments in pipeline and LNG import capacity, have taken place in recent years. However, some concerns remain that GB may not have adequate security of supply to mitigate supply disruptions, particularly in light of increasingly diverse sources of gas.

A key issue, when considering GB's gas security of supply, is the increasing dependence on imported supplies, in particular in the form of LNG. In 2009, LNG imports increased significantly, with the start-up of the South Hook and Dragon terminals in Milford Haven, and LNG import flows now regularly represent 15-20% of daily GB gas supplies. However, there still remain questions around the future contractual liquidity and physical flexibility of the global LNG market, and hence the consequent level of reliability of LNG deliveries to GB

In addition, there are a number of other factors affecting the wider global gas market which may also have a material impact on the security of imported gas supplies to GB. These include the recent developments in relation to unconventional gas, in particular the recent significant production of US shale gas, and the continuing political uncertainty affecting some of GB's import sources.

Pöyry Energy Consulting, using as an Associate the global LNG expert Andy Flower, have been commissioned by DECC to examine the key factors affecting the development of these markets and to assess the circumstances under which market developments might put LNG supplies to GB at risk. The study will then consider whether are any suitable policy options for the UK government to implement in order to influence the key market factors, with a view to maintaining LNG supplies to GB.

1.2 Approach and report structure

A summary of the approach we have adopted for the study is as follows:

- we have identified and analysed the key factors affecting the development of the LNG and global gas markets e.g. those relating to supply, demand, regulation, etc, and prioritised the factors in terms of those which have the greatest potential impact on GB's gas security of supply, in particular relating to GB LNG flows;
- we have defined two gas market scenarios – Business-as-usual, in which gas demand follows similar trends to historic demand – and Carbon-constrained, in which carbon abatement is more effective on a global basis;
- for the two main gas market scenarios, we have modelled the global gas supply/demand position using our Perseus model and determined the impact on the GB's security of supply;
- on the basis of the analysis of the key factors analysed previously, we have designed stress tests which test the security of GB's gas supply under defined extreme circumstances e.g. the loss of LNG supplies or a key piece of LNG infrastructure; and
- we have assessed the outputs of our analysis to determine what factors, or events, might prejudice GB's gas security of supply, and then consider what potential policy

options might be considered by the UK government to mitigate the risks of such developments or events occurring.

Section 2 of the report provides an overview of the global LNG market. This includes descriptions of the market structure, operation and other key characteristics such as pricing.

Section 3 of the report describes the analysis undertaken of the key factors affecting the development of the global gas and LNG markets. The section concludes by identifying which factors are likely to have the greatest potential impact on LNG flows to GB. The output from this analysis has been used to formulate the various sensitivities and stress tests used in the modelling.

Section 4 describes the development of the base gas market scenarios – Business-as-usual and Carbon-constrained – and explains the key assumptions underlying the scenarios. The model results for the two scenarios are described.

Section 5 describes the stress tests designed to test those factors, or potential events, which it has been determined are most likely to represent risks to GB's security of gas supply. The model results for the stress tests are described.

Section 6 describes the potential policy options which might be adopted by the UK government with the objectives of reducing the risks to the supply of LNG to GB.

1.3 Conventions

1.3.1 Europe

Throughout this report reference to Europe should be taken to mean the European countries covered by our Perseus model, more details of which can be found in Annex A. Within the Perseus structure gas flows to Northern Ireland and the Republic of Ireland are treated as being in the same zone and separate from GB.

1.3.2 Exchange rates

In many places we have converted costs and costs per unit from internationally quoted currencies, usually $ or € and $/mmbtu to £ and p/therm using exchange rates of 1.65 $/£ and 1.1€/£. Full assumptions of exchange rates are included in Annex B.

1.3.3 Sources

Where tables, figures and charts are not specifically sourced they should be attributed to Pöyry Energy Consulting.

2. LNG MARKET OVERVIEW

2.1 The LNG chain

Bringing LNG to market involves the development of a chain of activities, each of which requires the investment of large sums of money and the skills and expertise of people from many disciplines. Table 1 shows the links that make up the chain with an estimate of the capital cost and the revenues required to remunerate the investment and cover the operating costs. These costs are indicative and the range is necessarily wide since there are considerable differences amongst projects depending on such factors as the composition and location of the gas reserves, the design of the liquefaction plant and the distance to the market.

Table 1 – LNG chain analysis

	Upstream	Liquefaction	Shipping	Regasification
Gas use (%)	-	10 - 14	1.5 - 3.5	1 - 2
Capex ($bn)	2 - 6	6 - 10	1 - 2.5	1 - 1.5
Full cost (p/th)	6 - 18	18 - 27	5 - 9	2 - 5
Marginal cost (p/th)	0 - 3	2 - 3	4 - 5	0.3 - 0.6
Lead time (months)	30 - 48	45 - 54	27 - 36	36 - 42

The total capital cost of the LNG chain is estimated to range from US$10 billion (bn) to US$20bn for a chain producing 8 million tonnes per annum (mtpa) equivalent to 10.6 billion cubic metres per annum (bcm/a). The price needed to remunerate the capital investment and cover the operating cost ranges from US$5.2/MMBtu (32p/th) to US$9.8/MMBtu (59p/th). An LNG chain with costs at the bottom end of the range would be based on low cost gas reserves possibly with significant condensate content in the gas which would generate additional revenues to remunerate the upstream investment, a low cost plant and a location close to the market. There are very few projects that enjoy these advantages and costs are generally in the mid or upper part of the range.

The largest element of cost is the liquefaction plant which represents around 50% of the total for the entire chain. An 8mtpa (10.8bcm/a) plant could consist of a single process unit (liquefaction train), as is the case with the latest developments in Qatar, but is more likely to have two 4mtpa (5.4bcm/a) trains. The facilities in the producing country (the liquefaction plant and upstream gas production) account for around 80% of the total chain costs with shipping accounting for 10% to 15% and the receiving plant in the importing country 5% to 10%. The total use of gas in the chain from the inlet to the liquefaction plant to the outlet from the receiving terminal is between 12.5% and 19.5%. The main use is in the liquefaction plant where gas is consumed in the turbines which drive the refrigeration process and for the production of the power required by the plant. In the receiving (regasification) terminal 1% to 2% of the gas is used in the vaporisers and to produce power. On the ships the gas which boils-off during transit, which typically amounts to 0.1% to 0.15% per day, is used by the ship's engines, although around 15% of the world fleet (mainly the Q-Flex and Q-max vessels used by Qatar) has on-board reliquifiers. These ships burn fuel oil in their engines.

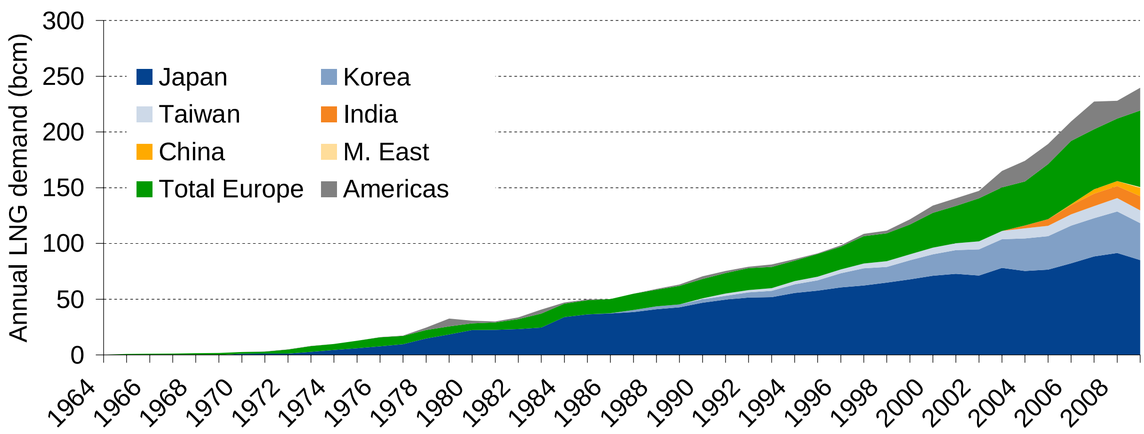
Constructing a liquefaction plant currently takes between 45 and 54 months from the Final Investment Decision (FID) to the loading of the first cargo and generally determines the time taken to implement an LNG chain. In most projects, the upstream facilities are developed in parallel with the construction of the liquefaction plant. LNG ships can be built in around 27 months using an existing design with up to nine months extra being required if a non-standard capacity or design is required. The time frame for an LNG receiving terminal is 36 to 42 months from FID. However, the planning for a new LNG project can add many years to the time required.

2.2 The development of the LNG business

The first international LNG trade consisted of seven trial cargoes transported from a small liquefaction unit in Louisiana on the Gulf of Mexico in the USA to a temporary terminal at Canvey Island in the Thames Estuary in GB using a converted bulk carrier with a capacity of around 5,000 cubic metres (cm) of LNG. These voyages demonstrated that transporting natural gas LNG over long distances was a technically viable option and it led to the development of the world's first commercial LNG project, which delivered product from a small (0.9mtpa) plant at Arzew in Algeria to GB. The first cargo was delivered to Canvey Island in October 1964 using a purpose built LNG ship.

Over the forty-five years since that first cargo, LNG has developed into a global business with a total of 181.4mtpa (245bcm) transported in 2009 (Figure 1). Although the UK was the world's first LNG importer, the discovery of natural gas reserves in the North Sea in 1965 resulted in the country becoming self-sufficient in gas supply and, except for a few spot cargoes in the late 1980s, LNG imports ceased in 1980 when the contract with Algeria expired. They restarted in 2005 when the Isle of Grain terminal in the Thames estuary was converted from a peak-shaving to an import facility after North Sea gas production went into decline.

Figure 1 – LNG trade by importer



2.2.1 European LNG trade

France joined GB as an LNG importer in 1965 and subsequently Spain, Italy, Belgium, Turkey, Greece and Portugal began to import LNG. As Table 2 shows, in 2009 Europe's eight current LNG importers received a total of 51.9mtpa (70.1bcm/a), an increase of 22.1% compared with the previous year. Over three-quarters of the increase came from GB as a result, largely, of the flow of cargoes from Qatar into South Hook and spot cargoes into Isle of Grain (Table 3). Qatar supplied 55% of GB imports in 2009 with

Trinidad & Tobago (21.4%) and Algeria (16.2%) the other major suppliers. Six cargoes came from Egypt, two from Norway and a single cargo was sourced from Australia. GB accounted for 15.1% of European imports and just over 4% of total global imports in 2009.

Table 2 – European LNG imports – 2008 and 2009

Country	mtpa		bcm/a		% change	%
	2008	2009	2008	2009	2009/08	Share in 2009
France	9.5	9.9	12.5	13.1	4%	19%
Spain	22.1	20.1	29.1	26.5	-9%	39%
Portugal	2.0	2.1	2.6	2.8	8%	4%
Turkey	4.1	4.5	5.4	5.9	9%	9%
Belgium	2.1	4.7	2.7	6.1	127%	9%
Italy	1.3	2.3	1.7	3.1	75%	4%
Greece	0.7	0.6	0.9	0.8	-14%	1%
GB	0.8	7.8	1.1	10.4	857%	15%
Total	42.5	51.9	56.1	68.6	22%	

Table 3 – GB LNG imports – 2008 and 2009

Source	mtpa		bcm/a		%
	2008	2009	2008	2009	Share in 2009
Qatar	0.1	4.3	0.1	5.7	55%
Trinidad	0.4	1.7	0.5	2.2	21%
Algeria	0.3	1.3	0.4	1.7	16%
Egypt	0.1	0.4	0.1	0.5	5%
Norway	-	0.1	-	0.2	2%
Australia	-	0.1	-	0.1	1%
Total	0.8	7.8	1.1	10.4	

2.2.2 Asian LNG trade

Imports of LNG into Asia commenced in 1969 with deliveries from a small plant at Kenai in southern Alaska to Japan, whose need for LNG was driven by a policy of reducing the dependence on oil for strategic and environmental reasons. In 2009, Asia imported a total of 114.1mtpa (154bcm) of LNG, which represented 62.9% of the global total. However, the recent economic recession hit industrial production in the export-led economies of Japan, Korea and Taiwan hard, and Asia's imports fell for the first time in the forty years since the first cargo arrived to Japan.

Japan has only limited reserves of natural gas. Historically, importing gas from Russia was not an option due to the complex geopolitical relations between the two countries, the lack of gas production in Russia's eastern regions and deep-water stretches that complicate pipeline construction. LNG was the only way for Japan to access natural gas supplies. The country quickly became the world's largest importer of LNG accounting for over 70% of world imports in the mid-1980s. It has remained the largest importer, receiving 35.6% of global LNG production in 2009. South Korea became the second LNG importer in Asia in 1986 and is now the world's second largest importer after Japan. It was followed by Taiwan (1990), India (2004) and China (2006). Thailand and Singapore are both constructing LNG receiving terminals and are set to start importing in 2011 and 2013 respectively.

An addition to the countries in Asia importing LNG is the Middle East where Kuwait started to receive LNG in 2009 and Dubai is scheduled to follow in 2011. Both countries require LNG in the summer months to meet the rapidly increasing demand for power for air-conditioning. The lack of a pipeline network in the Gulf region means they have had to turn to LNG and both have opted to use a ship with on-board regasifiers as a Floating Storage and Regasification Unit (FSRU) since it took a much shorter time to activate than would have been the case with a conventional onshore facility. In 2009, Kuwait imported 11 cargoes of LNG.

The development of LNG terminals in the Middle East mirrors the dynamic in other emerging markets, such as Latin America, as described in Section 2.2.3. It reflects the rising demand for electricity, which is coupled with the lack of willingness in importing states to rely on their neighbours. They therefore prefer to import LNG, even at a higher price, which they regard as a premium to be paid for the enhanced security of supply. Regional disputes, gas shortages and politically motivated supply disruptions have led countries to seek to diversify supplies by building LNG regasification terminals.

An additional factor behind the build-up of LNG regasification terminals in emerging markets has been the under-development of the sometimes abundant domestic resource base. This applies to countries, such as Brazil where development is currently underway, but also Saudi Arabia, which has the fourth largest proven gas reserves in the world (of which 57% is in the form of associated gas) but which decreed in 2006 that all of the country's new coastal power plants, previously expected to run on gas, would now be oil fired. In the absence of such gas supply limitations, it may have been possible for Saudi Arabia to supply pipeline gas to Kuwait, with which it has strong political ties and with which it cooperates within the framework of such institutions as OPEC and the Gulf Cooperation Council. Kuwait has recently expressed interest in buying gas from Iraq; however, it is likely that LNG will be preferred to imports from the large neighbour, which has been regarded with suspicion since the Iraq invasion in 1990.

On the other hand, producer states often prefer to export their gas to the rest of the world rather than to the neighbouring countries because the former are both more profitable and politically expedient. Exports outside the region help Middle Eastern producers raise their international profile and advance their political interests in the global arena. Qatar is a case in point. This country has diversified its geographic reach by moving from supplying its LNG only to Japan in 1997 to delivering it (on short, medium and long-term basis) to other markets in Asia, Europe (including GB) and North America.

2.2.3 The Americas LNG trade

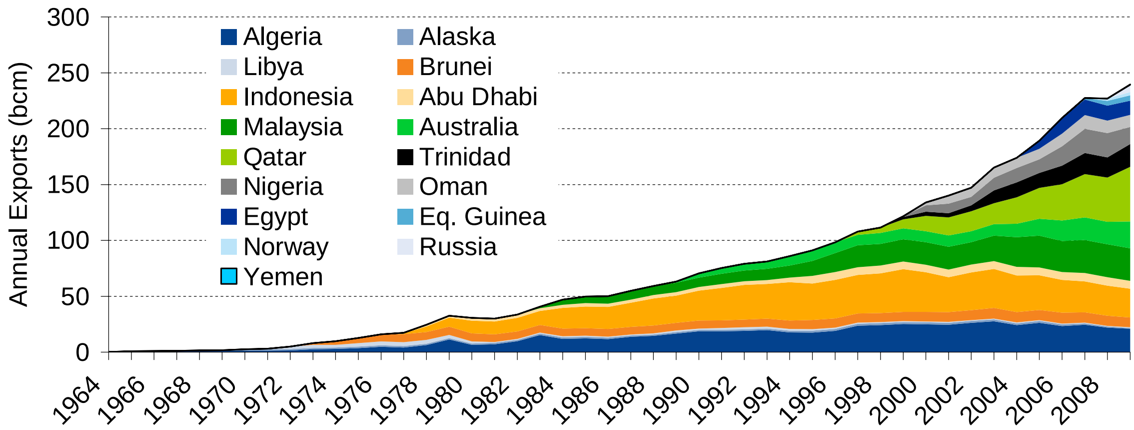
The Americas accounted for 8.4% of global LNG imports in 2009. Until 2000, the US was the only importer of LNG in the region but it was joined by first Puerto Rico and then the Dominican Republic, Mexico, Argentina, Brazil, Canada and Chile. The new importers accounted for over 50% of the total LNG received by the Americas in 2009.

The US has experienced something of a roller-coaster ride in terms of the role of LNG in overall natural gas supply. In the 1970s, LNG was seen as being required to meet growing natural gas demand as domestic production levelled-off. Four LNG receiving terminals were built and long-term contracts were signed with Algeria. However, increasing prices and deregulation boosted indigenous and Canadian supply and LNG imports were no longer needed. Three of the terminals were moth-balled for extended periods and just a few cargoes were imported, generally in the winter months when prices spiked. Around 2000, there was a second wave of interest in LNG to meet the forecast growing gap between increasing demand and declining domestic production. The existing terminals were reopened and eight new terminals were built (six of which were in operation by February 2010 and two were still under construction). The unexpected surge in the production of natural gas from shale has resulted in forecasts of the volume of LNG imports needed to balance supply and demand being considerably scaled back from 120bcm by 2020 in the 2004 Energy Information Administration's 2004 Annual Energy Outlook to 40bcm in the same year in the latest 2010 Annual Energy Outlook. The size of the US natural gas market, its flexibility and the amount of underground gas storage it can offer mean that it is expected to play a balancing role in global LNG supply and demand, taking in additional cargoes when there is a surplus and releasing cargoes when they are required by other markets around the world.

2.2.4 LNG supply

Figure 2 shows the sources of LNG supply by country. Qatar, which started producing LNG at the end of 1996, is now the world's largest producer by a wide margin and will retain this position for the foreseeable future. The output from the six 7.8mtpa mega-trains now being commissioned will boost its production to 77.5mtpa (102bcm/a) by 2012 or 2013.

Figure 2 – LNG trade by exporter



Malaysia is currently the world's second largest producer with output of 22.1mtpa (29bcm) in 2009. Indonesia was for many years the world's largest producer but its output has been in decline since 1999 as the gas reserves in fields supplying its two liquefaction plants at Arun in the north of Sumatra Island and at Bontang on Borneo Island are depleting. Furthermore, the Government has given priority to domestic gas use over LNG exports for the remaining reserves. This is becoming an increasing trend around the world as Governments question whether exporting their natural gas as LNG is the best option for limited reserves when they face challenges in creating jobs for their growing work-force. As a result, in 2009, LNG production from Oman, Egypt, Nigeria and Algeria was below the available capacity.

A feature of the last decade has been the increasing role played by producers in the Middle East and in the Atlantic Basin (including the Mediterranean) in global LNG supply. In 2000, the Pacific Basin was the dominant producer accounting for 57% of total output (Table 4). By 2009 its share had fallen to just below 40%. The share of the Middle East increased over the same period from 17.3% to 28% largely as a result of the growing output from Qatar. The Atlantic Basin's contribution also increased from 25.7% to 32.3% as production from Trinidad and Tobago and Nigeria, which commenced in 1999, built-up and plants in Egypt, Equatorial Guinea and Norway came into operation. The increasing role of the Middle East has added new flexibility to global LNG supply since producers in the region are approximately equidistant from markets in Europe and north-east Asia allowing cargoes to be switched between destinations without a major disruption to shipping programs.

Table 4 – Regional share of LNG supply – 2000 and 2009

Region	**supply in mt**		**supply in bcm**		**% share**	
	2000	**2009**	**2000**	**2009**	**2000**	**2009**
Pacific Basin	57.9	72.0	76.5	95.0	57%	40%
Middle East	17.6	50.8	23.2	67.0	17%	28%
Atlantic Basin	26.1	58.7	34.4	77.5	26%	32%
Total	101.6	181.4	134.0	239.5		

In 2008, the last year for which reliable data on pipeline gas is available at the time of writing, 7.6% of world gas production was delivered to market as LNG. A further 23% was traded internationally by pipeline with the remaining 69.4% being consumed in the country in which it was produced. When the data for 2009 becomes available, it is likely that LNG's share will have increased possibly to around 8% since production has increased at a time when overall gas consumption has fallen. The natural gas industry is very different from the oil industry where around two-thirds of production is traded internationally, largely by ship. As a result oil has become a global commodity whereas the more limited international trading of natural gas has meant it is a regional and often national business with prices varying widely amongst markets across the world.

2.3 Liquefaction

At the end of February 2010, the installed liquefaction capacity globally was an estimated 256mtpa (338bcm/a). However, actual output is running significantly below that level. In the four month period October 2009 to January 2010, production was at an annualised rate of 210mtpa (277bcm). The difference between available capacity and actual production is partly explained by some plants being in build-up mode but it is also due to the shortfall in gas supply to a number of facilities as discussed above.

A further 64.8mtpa (85.5bcm/a) of capacity was under construction at the end of February 2010 (Table 5). The new facilities, which are in Qatar, Peru, Algeria, Angola and Australia, will come into operation by 2015 taking the installed world liquefaction capacity to just over 307mtpa (406bcm/a), after taking into account facilities that will probably be shut-down permanently in Alaska, Algeria and Indonesia.

Table 5 – Global liquefaction capacity – February 2010

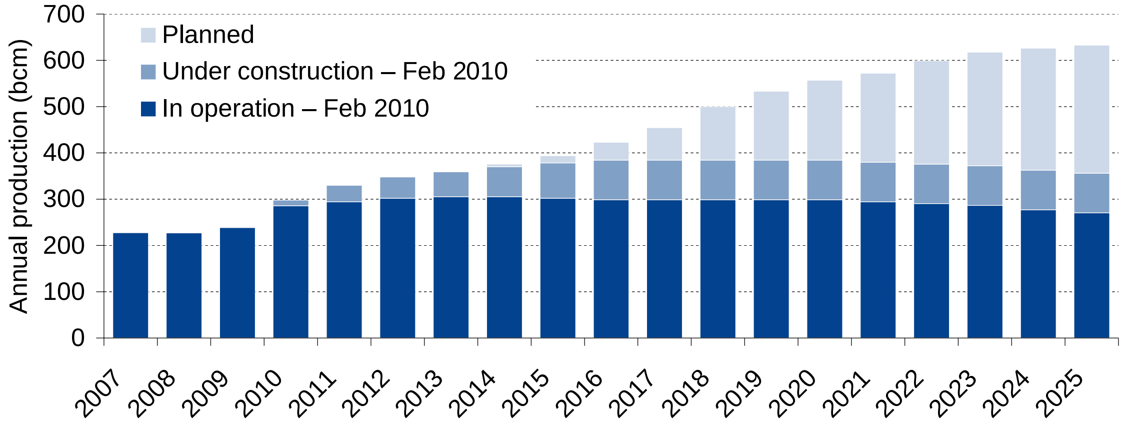
Region	in Operation		Under Construction		Planned		Total	
	mtpa	bcm/a	mtpa	bcm/a	mtpa	bcm/a	mtpa	bcm/a
Pacific Basin	95.3	125.8	31.5	41.6	130.4	172.1	257.2	339.5
Middle East	82.0	108.2	18.9	24.9	48.0	63.4	148.9	196.5
Atlantic Basin	78.7	103.9	14.4	19.0	129.2	170.5	222.3	293.4
Total	256.0	337.9	64.8	85.5	307.6	406.0	628.4	829.5

Production over the period to 2013 will be predominantly determined by the plants currently in operation and under construction, since it typically takes a minimum of four years to build a new liquefaction facility. Even if Final Investment Decisions (FID) are made in 2010 for plants currently at the planning stage the earliest they will begin to contribute to supply is 2014. Global LNG production looks set for a record increase of around 40mtpa (53bcm) in 2010 as new trains commissioned in 2009 build-up to full capacity and additional trains come on stream. The rate of increase will slow over the following three years because of fewer commitments to the construction of new capacity between 2006 and 2008. Production in 2013 is expected to reach 272mt (359bcm), 50% above the level in 2009. This represents an annual growth rate of 10.7% over the period 2009 to 2013, significantly faster than the 7.7% recorded between 1980 and 2009.

Beyond 2014 the expansion of global LNG supply will depend on the rate at which new liquefaction capacity is commissioned. As Table 5 shows, a similar amount of new capacity is being planned as is in operation and under construction. The total planned capacity shown in Table 5 excludes some of the more speculative projects in Russia, Iran and Alaska. There is considerable uncertainty over just how many of the planned projects will be developed and when they might come on stream. Furthermore, more projects will almost certainly be added as new reserves are discovered by exploration companies, who are increasingly focussing on drilling for natural gas. However, FIDs on new liquefaction capacity have slowed since 2006 through a combination of escalating costs, a shortage of qualified people, governments prioritising domestic gas use over LNG exports and more challenging locations for the construction of new plants. In particular, the decline in prices since mid-2008 which has not been matched, as yet, by a fall in costs has put the economic viability of some planned projects under significant pressure. This is especially the case in the Atlantic Basin where market-based prices (see below) have fallen further than oil-indexed prices in the Pacific Basin.

The outcome is likely to be a slow-down in the rate at which liquefaction capacity and supply grows after 2014. Figure 3 shows that the rate of increase in supply could average just under 5% per annum from 2014 to 2025, which would take it to 480mtpa (634bcm/a) by the end of the period.

Figure 3 – LNG liquefaction capacity – 2007 to 2025

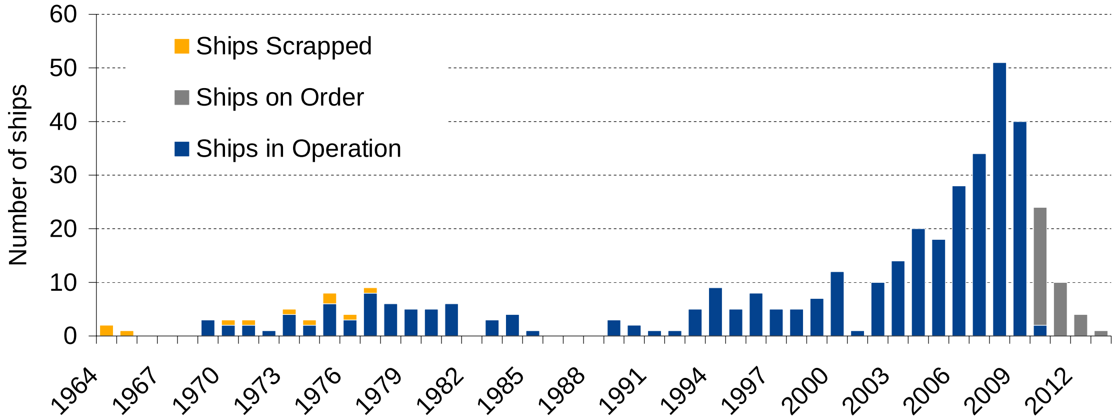


2.4 LNG shipping

The shipping industry responded rapidly to the increase in LNG activity, with the delivery of new ships into service increasing to record levels (Figure 4). In fact, the global LNG shipping fleet nearly tripled in number to 339 vessels as of January 2010.

The orders for ships were boosted by ship-owners commissioning ships on a speculative basis for the first time since the early-1980s, when they incurred major losses as new ships failed to find employment and were laid-up for many years. Oil and gas majors such as Shell, BP and BG also ordered ships after 2000 to support their trading activities. These orders were in addition to those by projects and by LNG buyers to support sales and purchases under long-term contracts, which had been the mainstay of ship orders pre-2000. The number of ships entering service peaked at 52 ships in 2008 and is currently on a downward trend. Nevertheless, the excess global fleet capacity created over the past decade will not begin to disappear until the surge in LNG production expected from 2010.

Figure 4 – New LNG ships entering service each year



Further details on the development of LNG shipping are presented in Section 3.1.3.

2.5 LNG receiving (or regasification) terminals

Receiving (or regasification) terminal capacity has also been increasing more rapidly than liquefaction capacity over the past decade as new terminals are built and existing terminals expanded for a number of reasons:

- Countries which lack access to pipeline gas, expanding the capacity to import LNG to meet growth in demand (e.g. Japan, Korea, Taiwan).
- Countries seeking access to LNG to increase security of supply (e.g. Singapore, Brazil, Poland).
- New importers needing LNG to meet growing demand which cannot be satisfied by domestic production or pipeline imports (e.g. China, India).
- Countries where domestic production is in decline (e.g. GB, Malaysia).
- The need of LNG traders for access to flexible markets (e.g. GB, US, the Netherlands) to support their activities.

The capacity of each receiving terminal depends on a combination of the size of the regasifiers, the number of berths, the size and number of storage tanks and the characteristics of the market into which the LNG is delivered (seasonality, daily swings in demand, the role of LNG and the availability of pipeline gas). Most terminals have sufficient regasifiers to meet the peak in demand for gas and, as a result, there can be wide variations between the base-load and the peak capacity and it may not be clear which is being referred to when capacities are quoted. The International Energy Agency (IEA) in its Annual Natural Gas Review published in March 2009, estimates that 472mtpa (623bcm/a) of receiving terminal capacity was in operation in March 2008 and a further 130mtpa (172bcm/a) was scheduled to come on stream by 2010, taking the total available to 602mtpa (795bcm/a). This is more than double the expected LNG production in 2010 of around 225mtpa (297bcm/a). Even if it is assumed that on average the effective capacity of an LNG terminal (after taking into account seasonality, sub-optimal use of unloading berths and storage capacity etc.), is 60%, a figure that has been quoted by some terminal operators, there is still ample receiving capacity available.

Despite the current excess of capacity, the IEA identified potential projects that would increase the total to over 1,000mtpa (1320bcm/a), more than outpacing the planned liquefaction capacity. New terminals are proposed in some of the 22 countries that currently import LNG and in countries planning to join them. There are four countries currently building their first receiving terminals and plans in several more countries are at the advanced stage.

A large part of the increase in receiving terminal capacity has been in the flexible markets of the US and GB. The US has ten terminals in operation with a further two under construction and due on-stream later this year and in 2011. In addition, the Canaport terminal in New Brunswick, Canada and the Costa Azul Terminal in Baja California, Mexico were built, in part, to supply demand in New England and in California respectively. At the end of February 2010, US terminals had an estimated capacity of over 100mtpa (132bcm/a) of capacity with a further 40mtpa (53bcm/a) to be added by 2011. GB now has four terminals in operation with a capacity of 25.8mtpa (34.0bcm/a). The completion of phase 3 of the Isle of Grain should add a further 5.3mtpa (7.0bcm/a) by the end of 2010, with South Hook phase 2 adding a further 7.9mtpa (10.5bcm/a) on a similar timescale.

LNG receiving terminals in the US and GB were in part built to meet the expected gap between available domestic production and pipeline imports and the expected demand and partly because companies wanted access to terminals on both sides of the Atlantic to allow them to take advantage of the arbitrage opportunities between prices in the two markets. As a result, the excess of terminal capacity can be expected to continue and new capacity may be built if there is an expectation that the existing terminals may be filled up to meet market demand.

Most of the receiving terminals built before 2005 were designed to receive the largest ships then in operation which was less than 150,000cm. Qatar's decision to use much larger ships has prompted a number of these terminals to modify their berthing facilities to receive the Q-Flex and even the largest Q-max ships. In GB, the Isle of Grain, Dragon and South Hook terminals can receive Q-Flex ships and both the Isle of Grain and South Hook have already done so. The South Hook terminal was designed for ships up to the Q-max size and a number have already discharged at the terminal.

2.6 LNG prices

There are two basic ways in which LNG is priced:

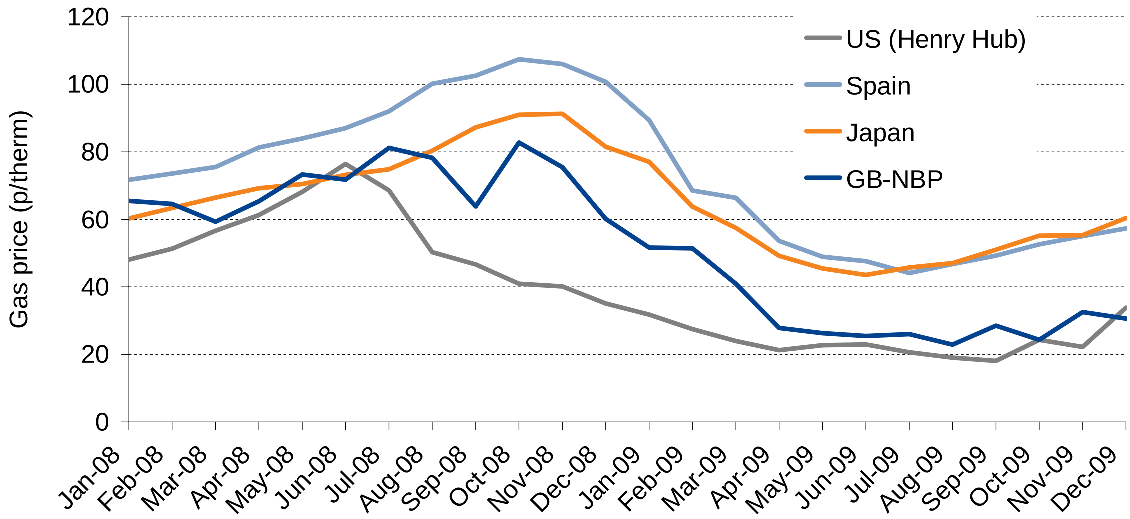
- Formula based pricing: The LNG is linked to the price of another commodity, typically the crude oil price or the price of oil products. This approach is used in markets where there is no gas-on-gas trading to set a price based on the supply and demand for natural gas. It is used in Asia and in Europe outside GB, Belgium and the Netherlands (from 2011 when the Gate terminal in Rotterdam is scheduled to be commissioned).
  - In Asia the linkage is generally to JCC - the Japanese Custom Cleared Crude Oil price often referred to as the Japanese Crude Cocktail. It is the average price of crude oil imported into Japan each month and is published by the Japanese Ministry of Finance. It was first adopted in contracts with Japan but is now used in contracts with buyers in Korea, Taiwan, China and India, since it is based on the large volume of crude oil imported into Japan each month and is seen as being a good measure of crude oil prices in Asia. The main exceptions to the use of JCC are Indonesian contacts, where the average Indonesian Crude Price (ICP) has been preferred, although more recent contracts with buyers in Japan have moved to the use of JCC. There are also now at least two contracts with Asian buyers that use the Brent crude oil price.
  - In Europe pipeline natural gas prices have traditionally been linked to a mix of gas oil and fuel oil prices, the main products competing with natural gas in the domestic and commercial and industrial sectors respectively. LNG had to adopt the pricing approach used by pipeline gas. However, more recently, the linkage in LNG contracts has increasingly been to Brent crude oil, which is widely traded allowing buyers and sellers to manage the price risk using the forward prices on the trading exchanges.
  - Approximately 75% of LNG sales are currently on some form of oil-linked basis.
- Market based pricing: In markets where natural gas is actively traded, the price of LNG is linked to market (or hub-based price) to ensure it is competitive with other sources of natural gas supply.
  - In the US, prices are linked to the Henry Hub price. Buyers in the rest of the Americas have generally adopted some form of linkage to Henry Hub prices in their contracts. Natural gas is actively traded at Henry Hub, a physical trading hub in Louisiana, which is used as the reference point for futures contracts that

are bought and sold on the New York Mercantile Exchange (NYMEX) futures market.

– In GB, the linkage is to the National Balancing Point (NBP) price. The NBP is a virtual point in the GB gas network which is used as the basis for the trading of natural gas on the Inter-continental Exchange (ICE). The Zeebrugge hub, a physical hub in Belgium, is used for LNG delivered to the Zeebrugge terminal, while the Dutch Title Transfer Facility (TTF) price will be the basis for pricing LNG delivered to the Gate terminal in Rotterdam, when it is commissioned in 2011.
– Approximately, 25% of LNG production is currently sold linked to prices at a trading hub.

Figure 5 compares the monthly prices in GB, USA, Spain and Japan in 2008 and 2009. GB prices are the average NBP prices and for the US they are the average Henry Hub prices. The Japanese prices are the monthly average LNG import price as reported by the Ministry of Finance and the Spanish prices are the average monthly natural gas prices as reported by the weekly publication, World Gas Intelligence. The Spanish prices are for both LNG and pipeline gas imports, but, since LNG accounts for around 70% of the total, they provide a good representation of LNG prices.

Figure 5 – LNG natural gas and natural gas prices – 2008 and 2009



In the first half of 2009, oil-linked prices in Spain and Japan and hub-based prices in GB and the US moved reasonably closely together. However, following the collapse in oil prices in mid-2008, a significant divergence has developed between oil-linked and hub-based prices as the latter fell by much more than oil-linked prices. In the last quarter of 2009, oil-linked prices averaged over 54p/th while hub-based prices averaged under 30p/th. This difference is putting pressure on oil-linked prices, especially in Europe where some buyers paying the higher oil-linked prices for their LNG supplies can purchase natural gas at NBP prices at the trading hubs. In Asia, the lack of pipeline connections between the markets and the lack of any trading hubs which could provide an alternative to oil-linked prices has meant that there is less pressure for a change in the pricing principles. Long-term deals for LNG supplies from new projects in Papua

New Guinea and Australia (Gorgon) signed in late 2009 by buyers in Japan, Korea, China, India and Taiwan are all understood to have retained the traditional oil-linkage.

3. KEY FACTORS AFFECTING GLOBAL GAS AND LNG MARKETS

In this part of this study we have identified the key factors associated with the global gas and LNG markets which might impact the supply of LNG to GB. We have also assessed whether the factors should be used as the basis for the modelling sensitivity analyses or stress tests, or indeed whether the effect of the factor should be built in to our base modelling scenarios.

There are a large number of factors that we have grouped into the following categories:

- supply;
- demand;
- flexibility;
- markets;
- technology; and
- regulatory.

The following sections describe the potential risk to GB.

3.1 Supply

We have considered a range of factors relating to gas supply, namely reserves, investment, shipping, gas quality and geopolitical issues.

3.1.1 Total gas reserves

The International Energy Agency (IEA) projects plentiful global gas reserves in its 2009 World Energy Outlook (WEO). It projects more than enough reserves to meet global gas demand through to 2030 and well beyond.

Proven gas reserves (i.e. those with at least a 90% probability of economic extraction), at end 2008 amounted to 180tcm, representing around 60 years of production at current rates. It should be noted that over half of these reserves are located in just three countries – Russia, Iran and Qatar.

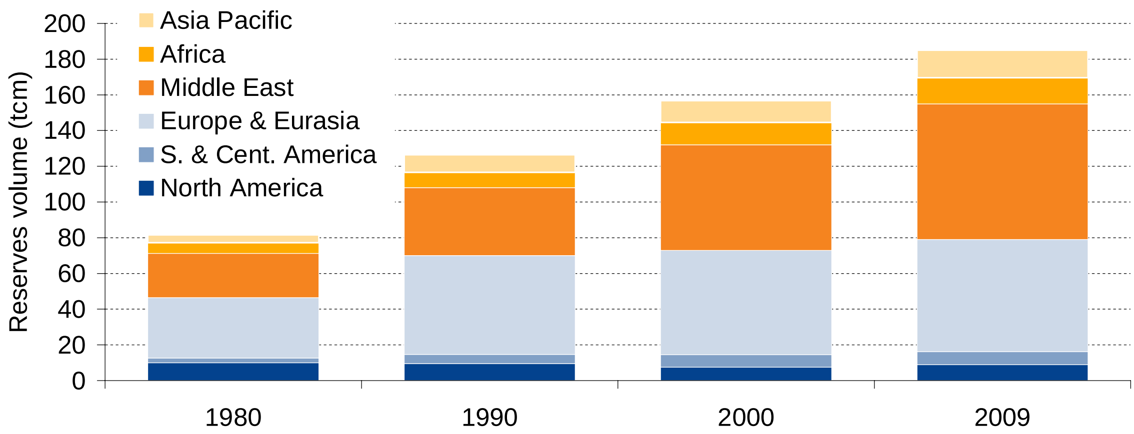
The location, and trend since 1980, of proven gas reserves are summarised in Figure 6.

Proven reserves have more than doubled since 1980 and have increased by 20% since 2000. They are typically categorised into conventional and unconventional gas types:

- Conventional gas – produced from higher permeability rock, often held in conjunction with oil (known as associated gas) and extracted using vertical drilling. This has been the predominant type of gas extracted to date on a global basis.
- Unconventional gas – produced from less permeable rock typically using horizontal drilling, and has historically been more expensive to extract than conventional gas. Unconventional gas includes shale gas, coalbed methane, tight gas and gas hydrates.

It should be noted that 96% of proven reserves as at 1 January 2009 are from conventional gas sources.

Figure 6 – Proven gas reserves



Source: IEA, Cedigaz

Estimated recoverable reserves are significantly higher than proven reserves at 850tcm on a global basis.

In addition, the IEA also concludes that the majority of new gas supplies will need to come from newly developed sources, with around 50% of the world's existing production capacity needing to be replaced by 2030 as current gas fields are depleted.

3.1.1.1 Unconventional gas

Unconventional gas, whilst still representing only 4% of the world's proven gas reserves, has seen significant production growth over the last decade. This growth has been underpinned by the adoption of specific extraction technology, notably horizontal drilling – which provides access to greater areas of reserves – and hydraulic fracturing – the high-pressure injection of water, chemicals or sand to fracture the rock and thereby release gas.

The main types of unconventional gas, and summaries of their key characteristics, are as follows:

- **Tight gas** – produced from natural gas reservoirs (sometimes referred to as 'tight gas sands') with low permeability. Such reservoirs cannot produce gas economically using conventional technology and require the use of hydraulic fracturing (injection at high pressure) with water, chemicals and sand. Tight gas has been produced for more than 40 years in US, with the associated extraction technologies evolving over this period to improve production rates, quantities of gas recovered and financial returns. It should be noted that some countries do not explicitly separate tight gas from conventional gas when classifying reserves.
- **Coalbed methane** – produced from typically inaccessible i.e. too deep, or poor quality coal beds. The coal beds typically have high water content and therefore water extraction and disposal are important environmental considerations. Extraction technology can include hydraulic fracturing (for less permeable beds) and horizontal drilling, which provides access to a larger area of potential reserves and also assists in water drainage. Coalbed methane is produced in more than a dozen countries including the US (since the late 1980s), Canada, Australia, India and China. In addition, trials and pilots are underway in range of other countries

including Chile, Italy, UK, France, Germany, Poland, Russia and the Ukraine. The gas extracted is normally transported to market using existing pipelines. In Australia it has been proposed to feed LNG exports.

- **Shale gas** – this is gas held in 'shale' rock (albeit this is a loose classification), often overlying already exploited conventional gas reserves. Gas is extracted by massive hydraulic fracturing (using large volumes of water) and horizontal drilling to provide access to a larger area of potential reserves. In shale gas extraction, the treatment and disposal of the water are major economic and environmental challenges. The main global production of shale gas is in the US and Canada, where production has expanded significantly since 2000, although the first commercial production dates back to the 19th century.
- **Gas hydrates** (or gas methane hydrates) – gas hydrates are the least well-developed source of unconventional gas. Gas hydrates are held as an ice-like solid of water and gas, typically in cold northern sediments or offshore deepwater sediments. Total reserves estimates are many times those of conventional gas reserves, though not commercially exploitable using current technologies. Extraction technologies for gas hydrates are likely to be similar to conventional extraction, for example vertical drilling to much greater depths. Gas hydrate extraction has the additional uncertainty around the potential carbon implications of large scale commercial development – some commentators believe that gas hydrate exploitation could cause the uncontrolled release of vast quantities of methane (which is a more powerful greenhouse gas than carbon dioxide) thereby increasing the rate of climate change. However, gas hydrate research and development programmes have been established in the US, Canada, China, India, Japan and Korea, with successful production tests taking place in the US and Canada.

Unconventional gas reserves (covering tight gas, shale gas and coalbed methane) are thought to be enormous, despite the considerable uncertainty around reserves estimates due to the lack of authoritative and comprehensive assessments. Table 6 provides an assessment of the reserves of unconventional gas 'in place' – these estimates do not include consideration of what might be economically recoverable.

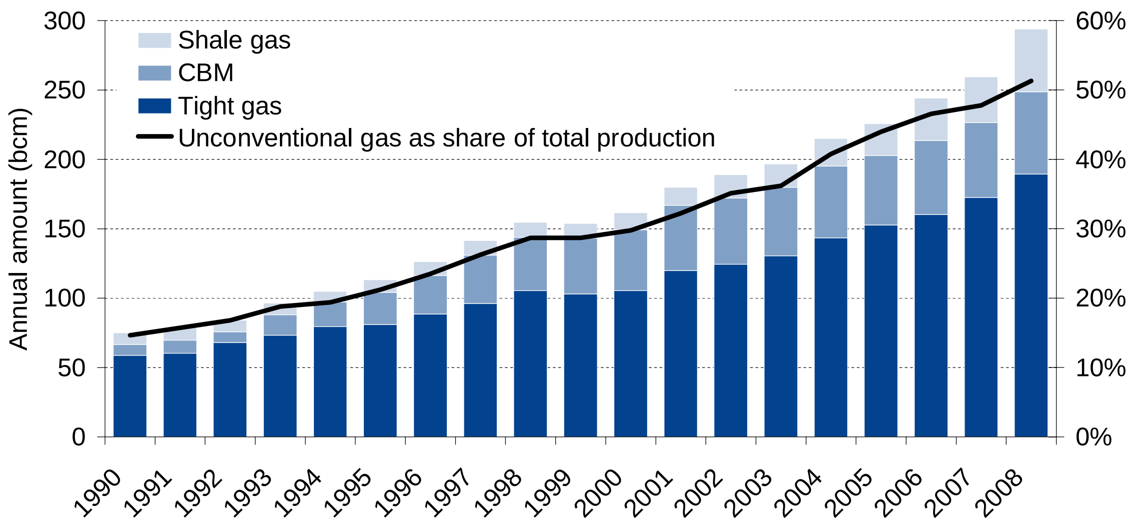
Table 6 – Unconventional gas reserves (tcm)

	Tight gas	Coalbed methane	Shale gas	Total
Middle East and North Africa	23	0	72	95
Sub-Saharan Afirica	22	1	8	31
Former Soviet Union	25	112	18	155
Asia Pacific	51	49	174	274
Central Asia and China	10	34	100	144
OECD Pacific	20	13	65	98
South Asia	6	1	0	7
Other Asia-Pacific	16	0	9	24
North America	39	85	109	233
Latin America	37	1	60	98
Europe	12	8	16	35
Central and Eastern Europe	2	3	1	7
Western Europe	10	4	14	29
World	210	256	456	921

Source: IEA, World Energy Outlook (2009)

As shown in Figure 7, in the US, unconventional gas production has expanded four-fold since 1990 to just under 300 bcm in 2008; this constitutes 75% of global production.

Figure 7 – Unconventional gas production in the US (bcm)



Source: IEA, World Energy Outlook (2009)

The IEA projects that global unconventional gas output will rise from 367 bcm (2007) to 629 bcm (2030), though this only represents an increase from 12% to 15% of total global gas production. Growth is projected to be highest in China, India, Australia and Europe.

Examples of unconventional gas developments in Europe include

- France – shale in the Southeast;
- Germany – tight gas in Ostfriesland;
- Germany – shale gas in Lower Saxony;
- Hungary – tight gas in Mako Trough;
- Poland – shale gas in Baltic Basin;
- Romania – shale gas in Transylvanian Basin;
- UK – coalbed methane in Wales, Cheshire, Yorkshire and Staffordshire; and
- Ireland – tight gas in Lough Allen.

Whilst the potential for unconventional gas developments is being pursued actively in a number of locations, there are a number of reasons why unconventional gas production may not expand rapidly on a worldwide basis, as follows:

- Impact on local communities – large scale unconventional gas extraction will have a range of impacts on local communities, including the need to secure access rights to land, disruption to infrastructure e.g. transport, and issues such as noise pollution. Whilst such issues have been directly addressed as part of developments in the US, for example, by means of education programmes, there is no guarantee that local communities elsewhere will accept such developments, particularly if the direct benefits are not communicated effectively.

- Environmental impact – unconventional gas extraction, and in particular that for shale gas, will typically result in disruption to a large area of landscape as a result of the high number of wells required to maximise gas production. In this respect, the environmental impact would typically be greater than for other energy infrastructure projects such as a gas storage facility or a power station. In addition, the extraction technique of hydraulic fracturing will require very large volumes of water, whose treatment and disposal are likely to provide significant environmental challenges. In addition, where chemicals are used in conjunction with the water, there is the potential for the water table to be affected and the risk of contaminating the supply of drinking water. Given these environmental implications, projects may be subject to delay or additional cost as a result of the licensing and permitting processes, particularly in ecologically sensitive areas.
- Geological uncertainty – in many cases, the potential for significant unconventional gas reserves is yet to be conclusively proven. In addition, some resource areas are likely to provide only limited reserves which prove to be either technically or commercially unexploitable.
- Proximity to existing pipeline infrastructure – this has proved to be an important factor in the rapid development of unconventional gas in the US. Where potential new reserves are remote from existing pipeline infrastructure, this may deter the necessary level of investment to exploit the unconventional gas sources.

Unconventional gas production could have a material effect on the global supply/demand picture going forward, including affecting potential demand for LNG. This effect could be modelled as a sensitivity – under-production against forecasts will have the effect of potentially tightening global LNG flows.

3.1.1.2 Russian reserves and Shtokman LNG

Russia has the world's largest proven gas reserves. Its total reserves, considered to be fully extractable, stood at 47.8tcm as of 31 December 2008 (latest data available), of which Gazprom's share was 33.1tcm. Russia is a key supplier to Europe, providing some 42% of gas imports to the EU. Since the mid-2000s, Russia has sought to diversify into LNG, with some policy documents stating that the country would supply up to 25% of the global LNG market by 2030. In February 2009, Russia launched the Sakhalin-2 project with 9.6mt/annum (12.7 bcm/annum) of capacity. Almost all of its gas has been contracted on a long-term basis and will be supplied to customers in the Pacific basin, most notably Japan and Korea.

In the Atlantic basin, Russia pinned its hopes for developing LNG exports on the super-giant Shtokman field, estimated to contain some 3.9tcm of gas. The official schedule for bringing Shtokman online – 2013 for pipeline gas and 2014 for LNG – was highly ambitious given the technical challenges at this Arctic field and Gazprom's lack of experience in developing offshore LNG. Market changes, such as the current 'gas glut' and the development of shale gas in the US, together with the worldwide recession, have reduced the need for Shtokman gas.

In February 2010[1], Gazprom decided to delay the project in the light of the uncertainty over LNG demand. The Final Investment Decision (FID) has now been delayed until late 2011, but even that deadline is understood to be subject to improved market conditions.

[1] Platts European Gas Daily – 8 February 2010

The new schedule for bringing Shtokman online has been moved to 2016. The start of LNG production is expected a year later, in 2017.

Maximum production from the field is expected at 71bcm/annum. Of this, until recently, 1.2bcm/year was to be sent to the local market, 47bcm/year was to be liquefied and 23bcm/year was to be piped to Europe. However, this split may be altered due to changed market conditions or out of political considerations.

On the one hand, delaying Shtokman's development – which was to produce 7.5mt/annum (9.9 bcm/annum) of LNG from Phase I – shows Gazprom's ability to adapt to market changes. But it is notable that just a week before delaying FID, Gazprom rejected the earlier plan to build an LNG loading terminal near Teriberka (close to Murmansk). It proposed an alternative site at the larger Orlovka bay, on the grounds that there would be more space for LNG carriers to manoeuvre and more scope for future expansion (i.e., in Phases II and III). This suggests that Gazprom is concerned that the planned infrastructure covers only Phase I of the project's development, and the burden may prove excessive for Gazprom Dobycha Shelf, which is due to operate Phase II and III. The fact that the Teriberka site was rejected when the front-end engineering design (Feed) study was almost complete suggests that Gazprom has been using the period of market oversupply not only to delay the Shtokman project but also to make foreign shareholders take into account its long-term interests when designing infrastructure.

The development plan assumes a time lag of three years between each phase. If production starts in 2016, and a three-year build-up period is applied to production, the plateau production of 71bcm/annum could be reached in 2024.

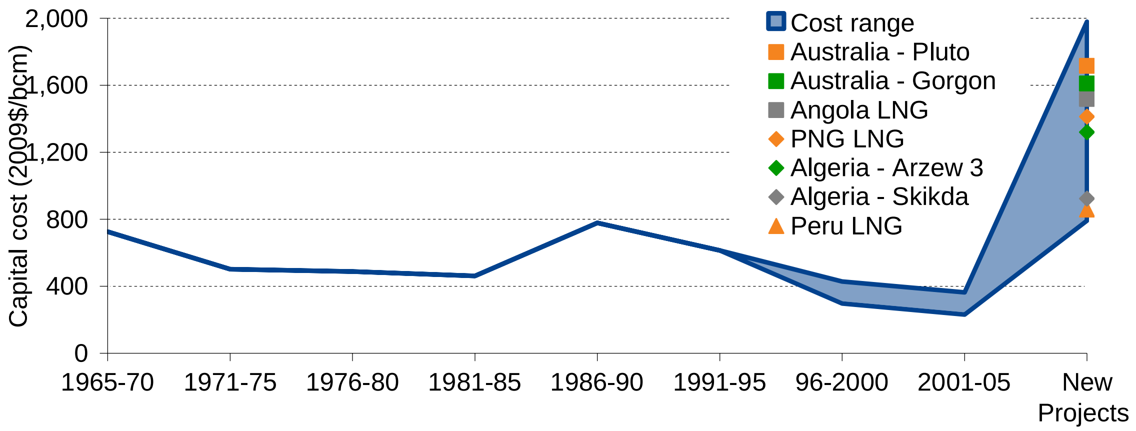
3.1.2 Investment

Substantial levels of investment have been made in recent years, both in the development of LNG supplies and in the development of unconventional gas production.

Current cost ranges for the various parts of the LNG chain are shown in Table 1. This chart also shows the average gas use in the various parts of the LNG chain, and the typical lead time range for the various infrastructure elements.

Significant increases have been experienced in the capital costs of projects, particularly for LNG liquefaction capacity where costs have increased from an average of around \$300/tonne (\$400/bcm) per annum to anything in the range \$600 to \$1400/tonne (\$800 to \$1850/bcm) per annum over the decade to 2009. The trend of estimated capital costs of liquefaction projects, together with some cost estimates for specific projects, is shown in Figure 8.

Figure 8 – Estimated capital cost of liquefaction capacity



This trend was caused by a range of factors including the following:

- increased cost of raw materials - steel, nickel and aluminium;
- higher labour costs as a result of a shortage of skilled and semi-skilled people;
- increased costs and longer lead times for the delivery of equipment (pumps, valves, etc);
- plant construction times increasing from around 36 months to 48 months; and
- more difficult locations for the liquefaction plants.

Whilst some of these factors have now reversed e.g. steel prices have halved during 2009 and skilled resources are being released from Qatari projects, there has been no sign thus far of significant project cost reductions.

These cost increases, coupled with the uncertain economic and financial climate, have led to a dearth in new LNG projects coming forward. The project in Papua New Guinea (with an estimated cost of $14bn) has been the only project funded on the basis of project-finance since the financial crisis. A range of recent LNG projects (e.g. Yemen, Sakhalin, Qatar) were financed pre-crisis, whilst others, for example, in Australia, Pluto (Woodside) and Gorgon (Chevron, ExxonMobil, Shell)), have been financed via the balance sheet of project partners.

There is a range of estimates quoted for the gas selling price required to bring forward projects for both LNG and unconventional gas development. We consider that, for LNG projects, this range is from US$5.2/MMBtu (32p/th) to US$9.8/MMBtu (59p/th)[2](with Atlantic Basin projects generally at the lower end of the range and Pacific Basin projects at the higher end of the range, although there are individual exceptions to this rule e.g. the Algerian Arzew 3 and Angola LNG projects will be nearer the top end of this range), whilst for shale gas the range is $3 to $10mmBtu (18p/th to 60p/th), with the lower end of this range representing the latest (early 2010) cost estimates produced for the very large scale shale projects in the US.

[2] $1.65=£1

3.1.3 LNG shipping

The global LNG fleet has expanded rapidly since 2000. Over 60 orders for new ships were placed in 2004, but, as a surplus of ships has developed, companies have begun to refrain from placing new orders. No new ships were commissioned between May 2008 and January 2009, when a single ship was ordered from China's Hudong yard. By the end of February 2010, the order book had fallen from the peak of over 130 ships to just 36 ships, four of which are preliminary orders for vessels to be used as floating liquefaction plants and will not, therefore, be available to trade LNG.

The average capacity of vessels has increased from 112,000 cubic metres (cm) for those entering service before 2001 to 160,000cm for ships entering service between 2001 and early 2010. The average has been boosted by Qatar's 31 Q-flex (capacity 210,000cm to 217,000cm) and 11 Q-max (capacity 263,000cm to 266,000cm) vessels, with a further three Q-max ships scheduled for delivery in 2010. The total capacity of the fleet has increased from 14.2 million cubic metres (mcm) at the end of 2001 to 49.2mcm at the end of February 2010. The breakdown of the shipping fleet by size is shown in Table 7.

Table 7 – LNG shipping fleet – January 2010

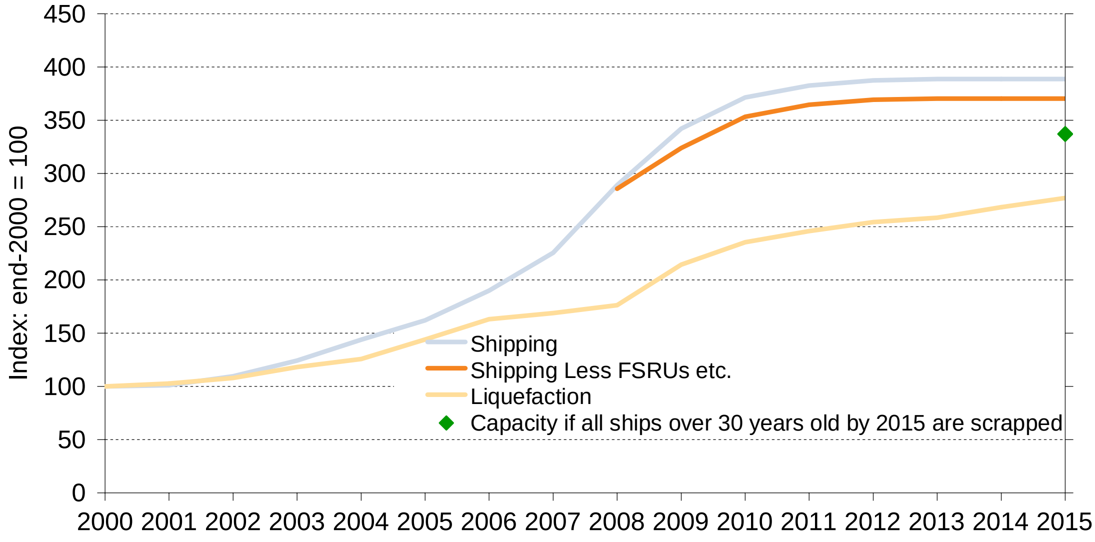
In Operation	
18,900 to 41,000 cubic metres	11
65,000 to 89,800 cubic metres	18
122,000 to 165,500 cubic metres	268
210,100 to 217,330 cubic metres	31
263,000 to 266,000 cubic metres	11
Total	339

On Order	
145,000 to 177,000 cubic metres	31
263,000 to 266,000 cubic metres	3
Floating Liquefaction	4
Total	38

The number of new ships entering service peaked at 51 in 2008. Ship construction times are typically around three years, so the market can react quite quickly to demand changes.

The expansion of the global fleet has outpaced the expansion of liquefaction capacity, as is shown in Figure 9. Taking the end of 2000 as a base, the capacity of the global fleet will have increased by close to 390% by the time the last ship on order has been delivered in 2013. In contrast, the liquefaction capacity, based on plants in operation and under construction in February 2010, will have increased by 280% by 2015, when Australia's Gorgon plant comes on stream, the last of the plants currently under construction to do so.

Figure 9 – Comparison of shipping vs. liquefaction capacity



There has been some reduction in the availability of ships as fourteen older vessels (and two newly built vessels) have been put into lay-up. The older ships will probably never be employed in active trading again and will either be scrapped or converted to floating storage and regasification units (FSRUs). Furthermore, a number of ships are already being used as FSRUs which takes them out of the fleet available for trading. However, even if these ships are assumed to go permanently out of active service, the shipping capacity will still have increased by 3.7 times between 2000 and 2013.

In part, the faster expansion of the global fleet has been needed to support longer shipping distances. According to the International Energy Agency the average distance over which a cargo of LNG is transported increased from around 5,000 kilometres in 2000 to 7,000 kilometres in 2007. Furthermore, more ships are needed to support the growth in the short-term trading of LNG, which inevitably makes less efficient use of ships than deliveries under long-term contract when regular voyages between the liquefaction plant and a receiving terminal can be planned well in advance.

However, one effect of the rapid expansion of shipping capacity has been the increasing availability of ships for short-term charter since around 2004. Delays in the start-up of new trains for which ships had been ordered and delivered on time have added to the ships available for short-term charter. One consequence has been a fall in charter rates at times to levels which only just covered operating costs and made little contribution to the repayment of the capital costs incurred by ship-owners. This has been part of the reason for the slow-down in the placement of new orders.

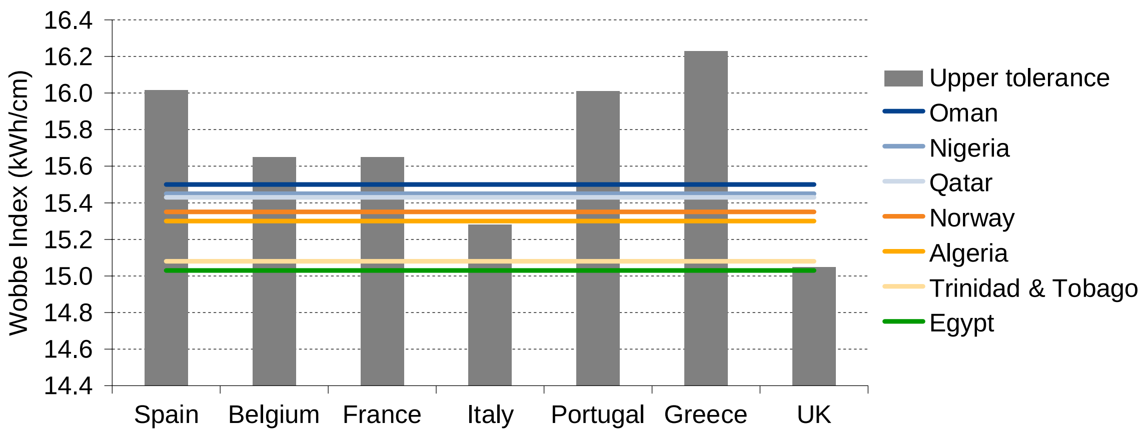
The expected surge in LNG production at a time when the delivery of ships into service is slowing will tighten the shipping market from 2010. Papua New Guinea LNG and Gorgon will probably need to order new ships to support contracts entered into before FID, as will other new projects reaching FID in and after 2010. However, shipyards in Japan, South Korea and China have the total building capacity of over 50 ships per year. With the construction of a new ship taking a maximum of 36 months from the placing of an order, it is unlikely that shipping capacity will be a constraint on the expansion of the LNG business in the foreseeable future.

3.1.4 Gas quality

The key gas quality requirement applying to the delivery of LNG into gas pipelines is the Wobbe Index (a measure relating to the heating, or calorific, value of the gas). The GB gas system has a narrow range of acceptable Wobbe Index (WI), primarily as a result of the continuing need to supply older GB gas appliances. Gas with a WI that is outside the specified acceptable range can cause combustion problems, formation of soot and excessive production of carbon monoxide. The WI of LNG varies significantly, depending on the source of the LNG and the liquefaction process (in particular, whether higher hydrocarbons are removed as part of a separate liquids production process), but, in almost all cases, will have a WI which is unacceptably high for GB's requirements.

A comparison of the range of WI for LNG sources against the upper limits of the acceptable WI range of selected EU countries is shown in Figure 10. It should be noted that the source LNG WI values represent a typical value and that there will be a range of potential WI values for each LNG source (specified in the LNG supply contract). There is also a recommended acceptance range of WI for EU entry and interconnection points of 13.60 to 15.81kWh/cm, set by EASEE-gas (the industry association set up to develop common, streamlined business practices for gas operations and trading), which should be implemented by EU countries by October 2010.

Figure 10 – Upper limits of the WI ranges in LNG importing countries in Europe and typical WI of LNG by source



Source: MVV Consulting Report (May 2008)

The DTI, Ofgem and HSE carried out a cost benefit study in 2006 which concluded that a large number of appliances would need to be modified to accept a wider range of WI at a prohibitive cost – it would therefore be more cost effective to keep the narrower limits and require gas to be ballasted before entering the GB system. The study further proposed that the existing arrangements should persist until 2020 at least, and that there was no intention to change the current regime post-2020.

In line with this, all the GB regasification terminals have been equipped with nitrogen ballasting facilities. Isle of Grain, Dragon and Teesside Gasport have sufficient ballasting to be able to accept LNG from most sources. We understand that South Hook will be supplied by relatively lean Qatari LNG i.e. with a lower WI value than the 'typical' line shown in Figure 10, and therefore the terminal has installed a reduced nitrogen ballasting capability, and therefore cannot accept higher Wobbe LNG, without a regasification capacity reduction.

Use of nitrogen ballasting adds extra cost to the gas supplied, but this is unlikely to be material in terms of the cost of gas supplied to the market. For example, information from GB terminal developers suggests that the cost of a ballasting facility designed for a 6 bcm terminal over 15 years would be of the order of £20m, which translates to an additional cost of less than 0.2 p/th at 50% load factor for the delivered gas.

GB terminals can therefore receive the vast majority of global LNG. Given this position, gas quality is unlikely to be a material constraint on LNG flows to GB.

3.1.5 Geopolitical

The diversity of GB gas sources raises a range of geopolitical factors potentially affecting LNG flows worldwide, including the push in some exporting countries to prioritise their own domestic use of gas at the expense of LNG exports, political unrest that inhibits new investment or may affect flows, or development of an international cartel that may manage output in order to manage prices. These are discussed individually below.

3.1.5.1 Exporters prioritising gas for domestic use

In recent years, there has been increasing evidence of some national governments pursuing policies of 'resource nationalism'. One of the forms of resource nationalism has been prioritising indigenous gas resources for domestic use, thereby potentially reducing quantities available for LNG export - other forms have been restricting foreign ownership in the gas sector, which is perceived as strategic. Examples include:

- **Indonesia** – the proposed 3bcm Donggi Senoro project has been delayed by uncertainty. Its future was first thrown into doubt in June 2009 when then Indonesian Vice President Jusuf Kalla ordered LNG output from the project to be slated for the domestic market, with only the surplus exported, claiming that Indonesia could not export gas at a time of domestic shortages. The Indonesian authorities are yet to dispel doubts and present a cohesive strategy for the project. The project was initially expected on line in 2012, but is now likely to be delayed until at least 2015. Although Donggi Senoro is still on the table, the project's majority shareholder, Mitsubishi, could lose interest as a result of protracted indecision or if the potential export ban on LNG is confirmed.
- **Oman** – in the light of strong domestic demand, Oman is planning to restrict its potential LNG exports. Oman's current levels of production are insufficient to satisfy the rapidly rising indigenous consumption and fill the Qalhat LNG facility, which therefore produces below capacity. Oman produces only the 11bcm/y it needs to meet long-term supply contracts, while the plant's liquefaction capacity stands at 15bcm/y. In 2008, Oman signed a contract to import by pipeline 10bcm/annum of gas from Iran's South Pars field. The deal also included joint development of the Kish and Hengam gas fields in the Gulf. Some of this gas could be processed for LNG. However, Iran's lack of spare gas production capacity means that it is unlikely to fulfil its export plans and the plan to export to Oman has now been delayed, while negotiations on the joint development proceeded throughout 2009.

The maturation and depletion of fields that have traditionally accounted for large volumes of output in producer states, such as Indonesia and Oman, is an additional factor that leads them to reconsider the balance between domestic consumption and exports. For instance, 90% of the reserves of Indonesia's Arun gas field, the largest gas field in Asia, are now depleted, with reserves projected to run out by 2018. But Arun will stop LNG exports in 2014, diverting supplies to the domestic market. Similarly, the Bontang project, which has been experiencing LNG shortfalls since 2004, is expected to stop producing by 2020. Together, these two projects produced around 25.9 bcm of LNG in 2009.

3.1.5.2 Qatar and the moratorium on production

Qatar is the world's third largest holder of proven gas reserves, which in 2009 were estimated at 26tcm. A notable feature of Qatari reserves is that 99% of them are located in only one field, North Dome (also known as North Field), which is part of the larger structure that crosses over into Iran's territorial waters (where it is called South Pars). Even individually, these two fields are by far the largest in the world. The IEA estimates that, together, North Field and South Pars could continue to produce at the current rates for over 300 years. These fields will account for a significant rise in production in the future.

North Field has been developed sequentially, with early developments geared towards meeting Qatar's domestic market. However, the vastness of North Field reserves has enabled the country to grow output rapidly and emerge as the leader in LNG production.

Qatar's LNG production rose quickly from 21.6bcm in 2005 to 70.8bcm in 2009. This is set to expand further to over 100bcm in 2010. We expect this volume to be sustainable for several years before gradual declines begin to take place at older production sites.

An important factor that will influence production in the medium and long term is the moratorium imposed by the Qatari government in 2005 on new gas development projects at the North Field. The fact that the moratorium does not affect projects approved or underway before its imposition has enabled Qatar to continue growing LNG production. But in 2009, Qatar extended the moratorium from 2010 to 2014. It emphasised that after 2014, Qatar would decide on whether to have more development. In the words of Saad Al Kaabi, Director of Oil and Gas Ventures at Qatar Petroleum: 'This is an important point, as most people think or state that we will open up after the moratorium. Year 2014 is a decisive point, a time where QP will decide what is in the best interest of the country and the field.'

The sustainability of production has featured prominently on the agenda of the Qatari government, which has indicated the importance it attaches to creating a lasting legacy for future generations. The moratorium was imposed to assess the impact of the development of the North Field, focusing on the layers that support current production and the factors behind the unexpected differences in gas quality found across different blocks. In addition to these factors, global market conditions will play a role. If the current oversupply of gas persists, it could contribute to the extension of the moratorium beyond 2014, as Qatar may not approve large-scale projects that would keep prices depressed prices further. Therefore, the moratorium on new developments, and not other factors – such as Qatar's participation in a 'gas cartel' (Section 3.1.5.6) – remains the main source of uncertainty for the country's future LNG production.

We have not included any expansion of Qatari LNG production (beyond the expansion to around 100 bcm in 2010) in our modeling scenarios.

3.1.5.3 Iran's reserves vs. production

Iran holds the world's second largest gas reserves, but it is also the world's third largest consumer of gas, after the US and Russia. Its domestic demand almost doubled over the period 2000 to 2008 – from 62bcm to 122bcm – and is expected to continue to grow rapidly, albeit at a slower pace. Despite its massive reserves, estimated at 29tcm, Iran is a net importer of gas and has sought to ensure the opening of new pipelines from Central Asia, such as the Turkmenistan-China line. Iran has been exporting around 4-6bcm to Turkey since 2003 and importing some 6bcm from Turkmenistan, but this capacity has been raised to 14bcm and could be raised further to 20bcm.

Iran has a very significant potential for growing production. The IEA estimates that only 5% of the country's total reserves have been produced to date. Over half of its gas reserves are in dry gas fields and up to 14tcm of the country's reserves are located in the South Pars field, which it shares with Qatar, as described in Section 3.1.5.2. The field, which came online in 2004, is currently responsible for over a third of Iran's gas production. Additions to production capacity at South Pars reached 45bcm during 2000-08, but all phases of the project have been dogged by delays.

Problems in the upstream development include insufficient investment, politically motivated decisions in the choice of contractors, the inability to install LNG trains without external technical expertise and financial burden-sharing. The situation is complicated by Iran's political isolation and the weight of US and international sanctions. Gas export schemes have often been stifled by Iran's international isolation. In addition, Iran has traditionally prioritised oil production over gas. As a result, long-range sour gas pipelines have been built to transport gas for re-injection at oil fields, although oil output gains have been relatively small.

An increase in exports, especially LNG, is unlikely in the short to medium term. In mid-2008, Iran officially postponed LNG projects led by Total/Petronas and Shell/Repsol, leaving in place only the Iran LNG project led by the National Iranian Oil Company. The situation with the growing domestic demand, in part the result of subsidies, is compounded by the application of sanctions, which preclude large-scale international investment in the country.

We do not expect LNG exports from Iran before 2019. However, Iran's geographical location, coupled with large reserves, will enable it to become a significant exporter of gas in the long term.

3.1.5.4 Political unrest, piracy and terrorism

Political unrest, terrorism and piracy are among potential sources of disruption to global LNG supplies. Some examples include:

- **Domestic political conflicts** – the conflict in the Niger Delta region arose in the early 1990s over tensions between Nigeria's ethnic groups and foreign oil companies. It continues to the present day. Frequent attacks have meant that oil and gas facilities have worked to about two-thirds of capacity**.** In 2006, Shell withdrew over 300 workers from four sites following a gunboat attack. Ceasefires, if negotiated, are often violated. In late January 2010, the militant Movement for the Emancipation of the Niger Delta announced that it would end the ceasefire negotiated in October and that the companies had to prepare for an 'all-out onslaught' on installations and personnel, as 'nothing will be spared'.
- **Piracy in the Gulf of Aden** – the Gulf of Aden, located in the Arabian Sea between Yemen and Somalia, is a vital waterway for shipping but one where piracy has

become a threat. According to the International Maritime Bureau, pirate attacks off the coast of Somalia rose from 19 in 2008 to 80 in 2009. The total number of attacks reported in the Gulf of Aden last year stood at 116.[3] The hijacking of an LPG tanker by Somali pirates in January 2009 has raised concerns for the safety of LNG shipments, especially as Yemen emerged as an LNG exporting country. Indeed, any form of traffic disruption in the Gulf of Aden could mean longer journeys for LNG supplies to the Atlantic, putting pressure on shipping and increasing costs. It should, however be noted that LNG ships are considered more difficult to attack since they sit higher in the water, and that the overall risk of piracy is considered to be relatively low.

- **The threat of terrorism** – in late 2009, Yemen's Foreign Minister estimated that several hundred al-Qaeda members were operating in Yemen and could be planning terrorist attacks. He stated that Yemen had launched major operations against al-Qaeda but appealed for more assistance from the US, EU and individual European states, as he admitted that his country was 'very short of helicopters'. Yemen has been trying to expand its counter-terrorist units amid concerns that it is becoming a major training centre for militants. Yemen's success in the war against terrorism on its territory is particularly important given its strategic location on the Gulf of Aden, and as a LNG producer.
- **Piracy in the Straits of Malacca** – the vulnerability of the Straits of Malacca, Sunda and Lombok is highlighted by the increasing volumes of LNG that have been passing through South-east Asian sea lanes from producers in the Middle East and Australia. At its narrowest point, the Strait of Malacca is just 2.7 km, which makes it vulnerable to disruption by terrorism, accidents or piracy. The volume of oil and LNG that pass through these straits will continue to rise in the future. In recognition of the risks and in the attempt to reduce piracy and armed robbery in the lanes, the three regional states – Indonesia, Malaysia and Singapore – have engaged in maritime and air patrols. In a report published in early 2009, the International Maritime Bureau reported a reduction in the number of piracy attacks in the Straits of Malacca for the fourth year running to 2008. It applauded the efforts of the littoral states in improving surveillance and operating procedures, and noted that precautionary measures taken onboard the ships were paying off. Nevertheless, the straits remain vulnerable and still rank number three in the world for the frequency of armed attacks – after the Gulf of Aden and Nigeria.

3.1.5.5 The vulnerability of the Strait of Hormuz

The Strait of Hormuz is a key route for transporting large quantities of Middle Eastern – most notably, Qatari – LNG. The Strait of Hormuz represents a narrow bend of water that separates Oman and Iran, and connects the biggest oil producers in the Gulf, including Saudi Arabia, with the Arabian Sea (Figure 11). It is the only waterway leading out of the Persian Gulf. Iran controls the strait's northern coast, while Oman and the United Arab Emirates control the southern coast. The entire strait is only 180 km long, and, at its narrowest point, only about 45 km wide. It contains two shipping lanes used for large vessels. The channels are each just over 3-km wide, separated by a 3-km buffer zone. The northern channel is within a few dozen kilometres of the Iranian coast.

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[3] 'Thwarting pirates – Securing Asia-Pacific infrastructure', *E&P,* 19 February 2010.

The strategic importance of the strait cannot be underestimated. A potential Iranian closure of the strait has featured prominently on the list of global energy security problems, inviting further scrutiny and even contingency planning.

Figure 11 – The Strait of Hormuz – key LNG transport route

Source: tenpercent.wordpress.com

The strategic, geopolitical and military significance of the Strait of Hormuz is underpinned by several factors:

- Some 90% of all Gulf oil exported to international markets is shipped through the strait. This is approximately 40% of all seaborne oil traded in the world. The volume of oil passing through the strait is expected to increase in the future from the current 15 million barrels/day today to some 24 million barrels/day by 2020.
- The world's largest LNG exporter, Qatar, ships a total of 71bcm/annum through the strait to Asia and Europe. This volume is expected to rise to over 100bcm by the end of 2010, as the planned expansion in exports takes place.
- The United States uses the waterway to move armour and military supplies for US armed forces in Iraq. These are transferred aboard US naval ships, US-flagged ships or foreign-flagged ships. The US Fifth Fleet, stationed in Bahrain, patrols the Gulf to ensure free traffic.
- Merchant ships loaded with grain, sugar, iron ore, various perishable foods and manufactured commodities also pass through this strategic corridor en route to Gulf countries and ports such as Dubai.

Thus, there is little doubt that the Strait of Hormuz is both a waterway of strategic international importance and a major chokepoint.

Iran currently represents the main, if not the only, potential threat to unimpeded traffic to and from the Strait of Hormuz. The international situation around Iran's nuclear programme and the escalation of tensions between Tehran and Washington, mean that the Strait of Hormuz has become even more vulnerable than before. This is because:

- Iran could attempt to physically barricade the Strait in response to a real or perceived provocation/threat from either the US or Israel.
- It could attempt to barricade the Strait *in order to* provoke the US and/or make its influence felt internationally;
- The US, which has staked its credibility on responding to any possible closure of the strait by Iran, may be pressured into responding to any mine laying or other hostile military activity in the Gulf.
- The US may seek to take military action in the face of Iran's continued nuclear defiance.

It is clear that an offensive from either side would quickly lead to an escalation of the military conflict in the region. Diplomacy, early detection and preventive action (through, for example, close surveillance of Iran's submarine activity in the Gulf) are critically important to avoid this situation. Persuasion and credible threats are already part of the diplomatic effort. The US continuously seeks to convince Iran that the cost – military, economic and political – of any attempted closure of the strait would be prohibitively high and therefore counterproductive for Iran.[4]

Although the repercussions from any attempt to block the strait would be tremendous and self-destructive for Iran, this scenario cannot be dismissed altogether. A desperate or adventurous political leadership in Iran could consider military action in the strait. Indeed, precedents of military conflicts in the Gulf exist, such as the 'tanker war' from 1984 to 1987, where Iran and Iraq fired on each other's tankers, while the vessels of other states were caught in the crossfire. Some 239 tankers were attacked, of which 55 were sunk or damaged beyond repair. As a result, shipping in the Gulf fell by a quarter. Episodic military confrontation took place in the Gulf between Iran and the US throughout 1988, but no serious conflict has occurred in the area since. However, political tensions began to rise again in late 2007 and 2008, when a series of naval standoffs took place between Iranian speedboats and US warships.

The escalation continued throughout summer 2008 when a commander of Iran's Revolutionary Guard said that any attack on his country by Israel or the US would lead to the sealing of the Strait of Hormuz. A similar statement was made by Iran's oil minister, who warned about the consequences of an attack on the international oil markets. Responding to these threats, US Vice Admiral Kevin Cosgriff stated that if Iran choked off the Strait of Hormuz, it would be 'saying to the world that 40% of oil is now held hostage by a single country', and the US would not allow that to happen. For the US, precluding the closure of the strait would become a major political and military objective not only because it would be interested in providing free passage to oil and LNG tankers passing through the Gulf but also in order to prevent the disruption of the military supply lines to the troops in Iraq. Reputational losses from inaction would also be tremendous.

In brief, non-intervention by the US in case of the closure of the strait by Iran is unlikely to be considered as a serious policy option. It is highly unlikely that Iran possesses the capability to seal the Strait of Hormuz altogether. Rather, the question is whether Iran is willing *and* able to harass traffic in the strait for a sufficiently long period of time to

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4 William D. O'Neill and Caitlin Talmadge, 'Costs and Difficulties of Blocking the Strait of Hormuz', Correspondence, *International Security,* vol. 33 (3), Winter 2008/09, pp. 190-98.

provoke a US response in defence of the lanes.[5] Assuming that Iran possesses adequate physical assets to try and barricade the strait, it is unlikely to be able to carry out such activities for long without being detected. The real question under this case scenario would be the time it takes for the US (and its allies) to destroy Iranian assets and de-mine the Gulf, making it sufficiently safe to reopen the strait.

Although a large-scale closure of the strait is unlikely – short of a full-fledged military conflict between the US and Iran – scenarios must be considered in which Iran successfully disrupts traffic in the strait. Under these scenarios, disruptions of up to a month could occur, prompting a military response, which, in turn, could lead to further delays in reopening the strait. A military conflict between Iran and the United States could result in a prolonged period of traffic disruption and at least a partial closure of the strait, although in the past, tankers have proved to be resilient targets, especially if escorted by warships, and their captains have been prepared to accept the high level of risk in return for financial remuneration.

In our modelling, we have included a stress test where there is a loss of LNG from Qatar during a severe winter in North-West Europe. We extend the period of closure to four months in order to accentuate potential repercussions of any prolonged closure of this vulnerable chokepoint. It should be noted that this is considered to be an extreme situation, which will have a bigger effect on world oil markets than gas markets, and we have not modelled the consequences for oil prices.

3.1.5.6 'Gas OPEC'?

The Gas Exporting Countries Forum (GECF) has been often referred to as a potential 'gas OPEC'. Set up in Tehran in 2001, this grouping remained informal until December 2008 when, at a meeting in Moscow, it transformed itself into a structured international organisation with a fixed membership structure, charter and secretariat. The signatory states include Iran, Russia, Algeria, Qatar, Egypt, Nigeria, Libya, Trinidad &Tobago, Equatorial Guinea, Venezuela and Bolivia. All except the latter two are either current or probable future gas suppliers to the EU markets. The role and influence of GECF should therefore be considered in greater detail.

None of the key suppliers to consumers in the Pacific basin – such as, Indonesia, Malaysia, Brunei and Australia – joined the organisation. This is particularly notable for Indonesia, Malaysia and Brunei, as they had attended previous meetings of the Forum. The formal membership of the organisation will inform GECF's primary focus, which can be expected to be on the markets of the Atlantic basin, particularly Europe.

Can GECF become a gas cartel? There is little doubt that deteriorating conditions in the gas market since mid-2008 have provided the stimulus for gas producers to set up a structure that would enable them not only to consult but also coordinate their actions. At the December 2008 meeting in Moscow, Prime Minister Vladimir Putin stated that the era of 'cheap gas' was over and that producers needed the security of demand in order to invest in new, difficult-to-access regions, such as Russia's Yamal peninsula. The oversupply in the gas market, caused by the combination of factors, such as the large number of LNG projects coming online in 2009-12, the development of unconventional gas in the US and reduced global demand for gas as a result of recession, have further contributed to the members' perceived need to coordinate their actions. Gazprom's

5 Caitlin Talmadge, 'Closing Time: Assessing the Iranian threat to the Strait of Hormuz', *International Security,* vol. 33 (1), Summer 2008, pp. 82-117.

CEO, Alexei Miller, has characterised the primary function of GECF as a forum that would 'jointly analyse and form the global gas balance as well as consider the issues related to production volumes in order to avoid an oversupply of gas to the market'.

However, the objectives of gas producers vary widely, as do their views about the role and future influence of GECF. While some members prefer to participate in the Forum without arousing international concern, others use it as a vehicle to raise their international profile. For instance, Russia used the December 2008 meeting on its territory to seize the political initiative and gain visibility as a leader of an international structure that is alternative to the organisations of the Euro-Atlantic basin.

Furthermore, there is little consensus as to the influence GECF members aspire to have over gas pricing. Algeria is considering urging GECF members to adopt a policy of production cuts in order to support gas prices in liquid markets.[6] Because of the current long-term structure of gas contracts (both pipeline and LNG), any such initiative would target only the gas traded on the spot market and under short-term contracts. The relative liquidity of the markets of North-Western Europe would make them the main targets. However, most LNG is currently sold on the basis of long-term contracts with fixed pricing arrangements (usually oil linked), and little opportunity to manipulate market prices through spot volumes. There is no single, global market for gas, compared to oil (around 65% of oil is traded globally). GECF cuts would be restricted mostly to the volumes of LNG that are currently not covered by long-term contracts. This is around a fifth of the LNG market. A key LNG producer, Qatar, has so far shown no enthusiasm for the proposal. Indeed, it has been one of the producer states most reluctant to consider any cartel-like price manipulation, as it has traditionally placed long-term relationships ahead of short-term gains. Furthermore, it is unlikely that any LNG producer will want to shut-in production for economic reasons. But even assuming that price-support measures are implemented, they would have only a marginal impact given the current oversupply in the market.

For the above reasons, GECF is unlikely to emerge as a structure capable of influencing prices in the short or medium term. However, with political will from key states, such as Russia and Algeria, and the growth in LNG volumes that are not subject to long-term contracts, GECF has the potential to become more significant in the long term.

3.2 Demand

We have considered a range of factors relating to gas demand and by inference demand for LNG. The most important of these are:

- in the short term, the rate of recovery from the current recession;
- in the longer term, the moves towards decarbonisation; and
- the effect of global warming and climate change itself.

These are discussed more fully below with an assessment of the risks to the supply of LNG to GB and our thoughts on how they can be modelled.

[6] Alex Forbes, 'A gas cartel looms', *The European Energy Review,* 24 March 2010.

3.2.1.1 Recovery from global recession

The global recession has affected gas demand worldwide, and in Europe and North America in particular, since mid-2008, through lower industrial and commercial demand, and also through the power sector as the demand for electricity has also reduced.

Almost every country in the world has been affected by the downturn in the global economy; with demand for gas in the UK in 2009 being 8% lower than 2008 and demand in the EU27 countries falling by an average of around 6%. Estimates for declines in Russian and US demand in 2009 are 20% and 2%, respectively.

The question is how will the different markets recover and how will this affect gas demand? A number of propositions have been put forward regarding how countries will recover, including a gradual increase back to 2008 levels over time due to temporary reductions in consumption, particularly in the more developed countries, where industrial output was in decline. The latest OECD economic forecasts[7] are actually showing a relatively rapid return to growth in industrial production in Russia, Brazil, China and India (although industrial production for the latter two countries did not actually shrink during the recession). The European zone is also moving back into positive growth in industrial production during 2010, albeit at a more modest rate.

How such industrial growth translates to overall gas demand will, however, be determined by the interaction of a number of factors. We believe that a significant proportion of the industrial plant that has closed in the last two years will be replaced by more efficient plant and that much of this may be moved to lower cost centres, thereby resulting in a certain amount of permanent demand destruction. This will, however, take place mostly in the developed economies and we would still expect industrial demand growth to be relatively high in the developing world, once the effects of the recession have passed. We expect domestic and power sector gas demand to be more resilient during the recession.

The aggregated effect across all gas sectors is therefore likely to show a short period of demand reduction (probably of two to three years maximum) followed by steady growth thereafter, with developing countries experiencing higher gas demand growth rates.

However, gas demand will be impacted by carbon abatement measures, which are addressed next.

3.2.1.2 Environmental pressures to minimise climate change

We anticipate there will be a strong drive to reduce greenhouse gas emissions worldwide over the coming decades. The EU has taken a lead by setting its own 2020 targets and the annual rate that the cap in the EU Emissions Trading System will be reduced beyond 2020. Further, some Member States have set their own ambitious longer term targets, including the UK which has a target of an 80% reduction in 1990 level greenhouse gas emissions by 2050.

Despite the failure of the December 2009 conference in Copenhagen to produce a legally binding document covering emissions beyond 2012, China and the US did agreed to targets and monitoring mechanisms in the Copenhagen Accord. A large number of countries have accepted this Accord and submitted their own target reductions, and there

1.1. [7] OECD Interim Assessments – April 2010 are expectations that it could form the basis for a legally binding document at a subsequent conference.

However, whilst carbon reduction targets may have been set, extensive effort will be required to actually decarbonise the economy, including the power and transport sectors. A large range of new technologies is being developed to achieve this aim, including renewable power generation (from wind, wave, tidal, biomass and solar), renewable heat, biofuels, nuclear, and carbon capture and storage (CCS).

A challenge with many of these technologies is that they are more expensive than conventional forms of energy, a number are intermittent and will require some form of backup, some have never been used in a commercial context at scale, and there are supply side constraints in their widespread deployment. A range of measures are being designed and implemented to speed up the process of developing these technologies to a point where they become economically viable and can be deployed at scale. However, it is difficult to envisage this happening in a material way before the early to mid 2020's.

Until such time as these technologies can be deployed at scale, gas is widely seen as an interim measure to reduce emissions, as it is a cleaner fuel than coal and oil.

In terms of future gas demand therefore, we consider that, in the developed countries e.g. Europe and the US, we would expect to see demand increases as economies return to growth, and there is fuel-switching from coal to gas-fired generation. Looking further into the future, and probably beyond 2030, we would expect to see an increasing impact of new carbon abatement technologies and energy efficiency measures leading to demand reductions through to 2050. We are slightly more cautious about the impact in the US of such carbon reduction measures given its reluctance hitherto to sign up to binding reduction targets and also the strength of the US coal lobby.

We expect the impact of carbon abatement in the developing countries such as China and India to have a reduced effect on gas demand, which would continue to grow as the economies continue to expand, and fuel switching from coal to gas-fired generation becomes more prevalent. Although there remain significant uncertainties in projecting far into the future, given the complexity of the factors involved, we consider that demand for gas (or, in this case, LNG) will continue to grow in the developing countries through to 2050.

3.2.1.3 Fundamental demand changes because of climate change

A key risk factor in the long term is the effect of global warming and climate change on the demand patterns for energy and perhaps, through rising sea levels, the loss of certain ports. Pöyry is not a climate change consultancy, so we refer to other pieces of work that have looked at potential impacts of climate change. One of the biggest risks to the UK is through the possible movement in ocean currents, which could mean the Gulf Stream moving further south and NW Europe being thrown into a much colder environment. Our winters would be much more severe and the impact on heating demand would be significant. Alternatively there could be mass migration to other parts of the world which have become more temperate, thereby changing the balance of gas demand between different geographies.

It should be noted that consideration of the longer term effects of climate change is outside the scope of this study, and it has therefore not been covered by the modelling.

3.3 Flexibility

LNG producers prefer to operate their facilities at a relatively constant level throughout the year to optimise their use. As a result, production is usually very flat and does not provide seasonal swing. The surplus of regasification capacity compared to liquefaction capacity means that LNG can provide flexibility to one market by delivering cargoes there when demand and/or prices are high and then to another market which has more demand or can offer cheaper storage when demand elsewhere is low.

We have seen evidence of this in recent years between the liberalised markets of the US and GB where price signals in the different markets have meant more cargoes are delivered to GB in the winter than the summer and more cargoes delivered to the US in the summer than the winter. The US has very large volumes of gas storage compared to Europe; over 100bcm in working gas, which is equivalent to around 18% of US annual gas demand. Furthermore, US storage tariffs are generally lower than those in NW Europe. In addition, the US has reduced seasonality in its gas demand when compared with NW Europe, due to the relatively high summer air-conditioning gas demand. These factors taken together usually mean that the seasonal spread of prices in the US is not as high as in NW Europe.

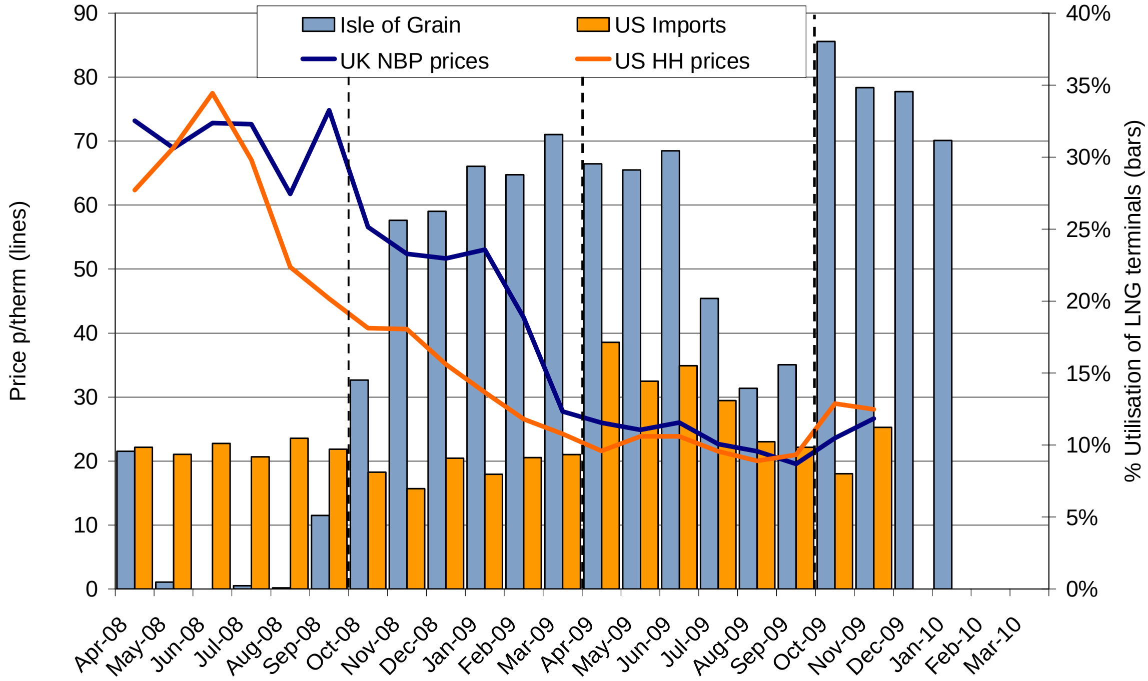
Figure 12 shows how in summer 2008 prices in the US and GB were very similar and there was virtually no output from the Isle of Grain terminal at that time, while LNG continued to flow to the US. Whereas, in winter 2008/9 flows to the US were less than the summer but flows into GB were significantly higher. Similarly in 2009 US flows were higher in the summer than the early part of the winter and Isle of Grain was utilised to a greater extent in the winter than the summer. At the same time the orange line in Figure 13 represents the amount of gas in storage facilities in the US compared to the five-year range. This indicates that the LNG helped to fill US storage to near record levels in 2008 and to record levels in 2009.

We have also seen how this flexibility has operated on a worldwide basis, when LNG provided support to the Japanese market in 2007/8 when some of its nuclear power stations were affected by an earthquake and it had to use gas-fired power plants to produce electricity, increasing its demand for LNG. At the same time, Japanese buyers were prepared to pay a premium over prices in the US and NW Europe to secure the LNG that they needed, so flows to the US, GB and Belgium were reduced as cargoes were redirected to Japan. We note that there were a number of other factors, such as a very mild winter in Europe and high oil prices that came into play during this period to assist with this arrangement.

The LNG market is able to provide flexibility to GB due to:

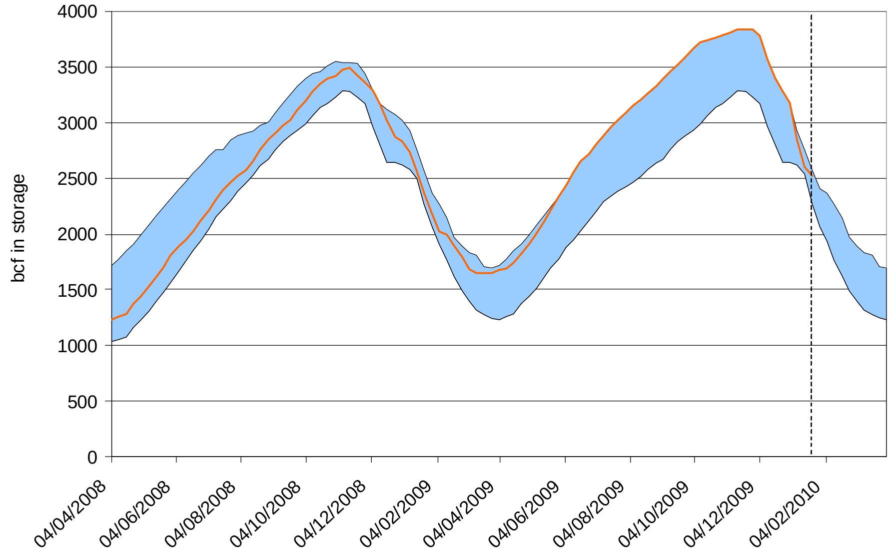
- an excess of regasification capacity globally compared to liquefaction which allows LNG to be moved between markets to meet variations in demand;
- a source of plentiful and cheaper storage in the US; and
- the increasing liquidity of the global LNG market as short-term trading takes an increasing share of total activity.

Figure 12 – LNG import utilisation and average monthly prices in US and UK



Note: the chart shows the average utilisation of LNG regas capacity rather than absolute levels, as new facilities were commissioned in the US and at Isle of Grain in this period.
Sources: ICIS Heren, National Grid, EIA

Figure 13 – Gas volumes in US storage



Source: EIA

At the moment, all three exist and have proven themselves to be able to provide flexibility to GB to meet seasonal demand patterns, and to Japan in order to meet an unexpected increase in demand caused by the shutdown of nuclear power plants. The first two points are physical and will persist for a long time into the future. There is more uncertainty over the third point, which is discussed in more detail in Section 3.4.1.

We expect LNG to continue to provide flexibility in the medium and long term, as there are increasing quantities of LNG coming to the market, as discussed in section 3.4.1, and an increasing proportion of this is not dedicated to a specific market, also as discussed in Section 3.4.1, which can be diverted between markets according to price. In the longer term, improved access to, and reduced prices of, storage in Europe may undercut and reduce the role of US storage and LNG trading to provide flexibility, but the ability of these factors to provide the flexibility will still be there.

3.4 Markets

As discussed in Section 2, the trade in LNG has grown significantly in recent years. In this section we have considered a range of factors relating to gas market and liquidity issues, namely:

- LNG contracts, both in terms of types of contracts used and the future developments in contracts;
- market players; and
- competition from pipeline supplies.

3.4.1 LNG contracts

A key feature of the global market for LNG is the ability to agree between the contracting parties to deliver cargoes into terminals at short notice. The contracts will determine whether this is at the discretion of the buyer, or whether it can be agreed between both the buyer and the seller.

Over 75% of LNG is still traded on long term contracts. There are three main types of LNG contract, varying by the treatment of the delivery point for the LNG:

- Free-on-Board (FOB) – in FOB contracts, the buyer takes title and risk of the LNG as it is loaded on the ship. The buyer therefore generally has more control over the destination of the LNG, although some FOB contracts have destination clauses, particularly in the Pacific Basin, which require the buyer to transport the LNG to a terminal in its own market. In many of these contracts there is no provision for diversions to alternative markets. Where diversions are allowed they generally require the approval of seller and a sharing of any upside in revenues that result.
- Cost-Insurance-Freight (CIF) – in CIF contracts, the buyer takes title and risk of the LNG somewhere between loading and before the arrival of the ship in the territorial waters of the buyer's country. Any request by the buyer to divert a cargo will require the agreement of the seller, since the seller is responsible for transporting and delivering the LNG and any lengthening of the voyage time may adversely affect the seller's shipping programme and potentially its ability to meet its contractual commitments.
- Delivered-Ex-Ship (DES) – in DES contracts, the buyer takes title and risk of the LNG as it leaves the ship at the specified destination port. The position with regard to diversions to alternative destinations are the same as for a CIF contract.

In the Pacific Basin, contracts generally have rigid destination clauses, and CIF and DES contracts predominated until about 10 to 15 years ago when buyers began to look for FOB deals which gave them more flexibility to trade cargoes. The buyers in the established markets in the Pacific Basin (Japan, Korea, Taiwan) were prepared to accept these conditions since they had no alternative sources of gas supply. As a result of the lack of contractual flexibility, the Pacific Basin market was much less liquid than the Atlantic Basin market. However, as the supply/demand balance in their markets has become more uncertain buyers are now looking for more flexible contracts that allow them to vary quantities at short notice. They have also increasingly purchased Atlantic Basin cargoes on a short or medium term basis when demand has increased more rapidly than expected or there has been a short-fall in production from regional producers (for example the failure of Indonesia to meet its contractual commitments over the last few years)..

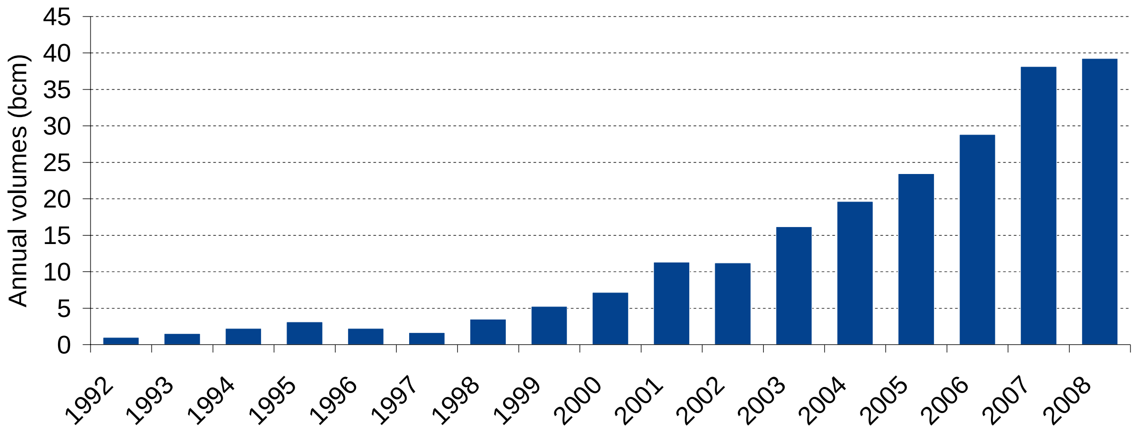
In the Atlantic Basin, LNG contracts are more flexible in terms of the rights of buyers to divert cargoes, mainly when they are purchased under an FOB contact but diversions of CIF and DES cargoes have also become more common. . There are a number of FOB contracts that allow diversion at the sole discretion of the buyer, whilst others (FOB, CIF and DES) give the buyer the right to divert, but only having obtained seller's permission. In addition, some contracts allow destinations to be altered by agreement between buyer/seller with a sharing of the 'upside profit'.

In addition, some regasification terminals, e.g. Zeebrugge, have reloading facilities allowing the buyer to divert LNG (following initial unloading) without reference to the seller, i.e. no upside sharing. This has happened a number of times in the last two years. There is even the example of Qatari LNG being delivered to Zeebrugge and then the LNG re-loaded onto a different ship and taken to Kuwait. In this case the buyer was able to add value to the LNG and probably avoided having to share the benefit with the seller.

The contracting position for LNG delivered to GB is quite flexible. For the South Hook terminal, the main LNG supply contract is between Qatargas and ExxonMobil Gas Marketing Europe. However, given the shared project interest (ExxonMobil is the largest foreign shareholder in the Qatargas II project which delivers the LNG to South Hook) cargoes can be diverted if it makes economic sense for the project, and there is evidence of at least one having been diverted to the US in the first 6 months of operation. For the Dragon and Isle of Grain terminals, there are currently no dedicated sources of LNG supply. The LNG capacity holders at these terminals (BG, Petronas, BP, Sonatrach, Centrica, GDF Suez, Iberdrola and E.On) have the ability to deliver LNG on their own ships or receive FOB cargoes from different sources.

The trend in the increased flexibility of contracts can be seen in the growth in short-term LNG trading (defined as two-year or shorter contract duration) in Figure 14, from around 2-3% of total trade in 2000 to around 17% in 2008.

Figure 14 – Growth in short term LNG trading



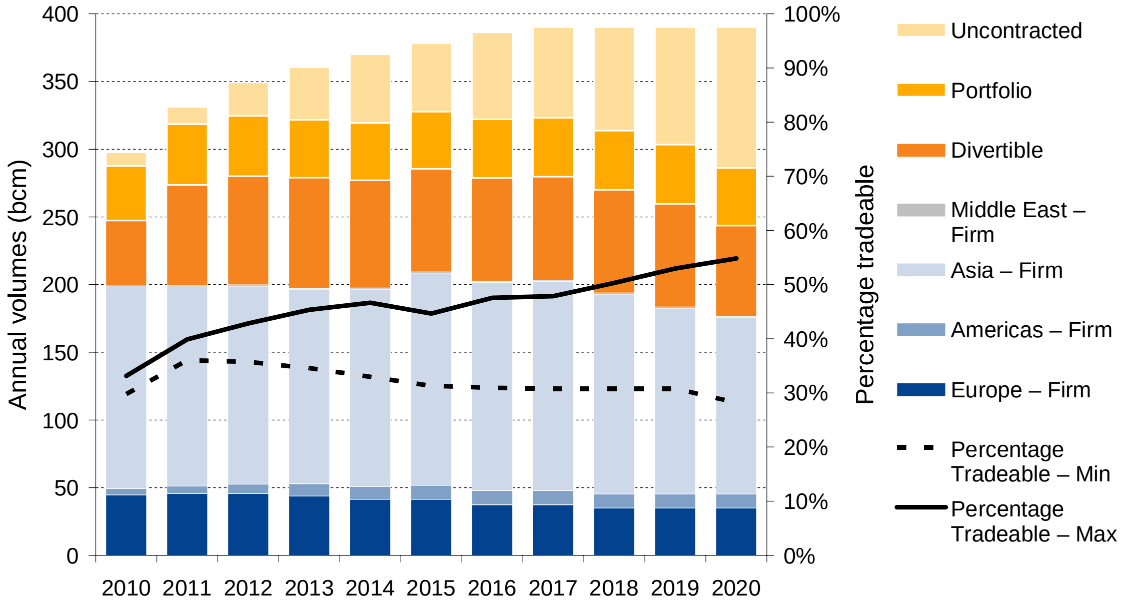
Looking forwards, we expect this trend to continue. We have analysed future contracted (and uncontracted) volumes to assess the potential LNG volumes that might be available from a contractual perspective to be divertible or tradable and hence potentially available to GB importers. We have defined the contracts into the following categories:

- **Firm** – LNG contracted to buyers in markets which have no or have limited access to alternative sources of supply, for example contracts with Japanese power and gas utilities, with Korea Gas or CPC in Taiwan. Buyers in these markets are unlikely to divert or agree to sellers diverting cargoes except when their demand is weaker than expected.
- **Divertible** – 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, for example:
  - LNG contracted to GB and the US from Qatar, where the main buyers are the partners of Qatar Petroleum in the liquefaction trains in Qatar (ExxonMobil, Total, ConocoPhillips and Shell) who can source alternative gas supplies at the trading hubs and will benefit as shareholders from any additional revenues generated by diversions; and
  - LNG from Atlantic LNG in Trinidad contracted to European or US buyers.
- **Portfolio** – 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. The LNG is contracted on a flexible basis which allows diversions, in many cases, with a sharing of any additional revenues generated but in some with no sharing, for example:
  - BG's purchases from Equatorial Guinea and Egyptian LNG; and
  - BP, BG and Repsol's equity LNG from Trinidad.
- **Uncontracted** – Potential output from projects in excess of the volume contracted on a long-term basis. It includes LNG from contracts which expire from 2010 to 2020. This volume of uncontracted LNG is likely to be reduced as contracts are extended or the LNG contracted to alternative buyers, but includes:

- LNG from the Arzew 3 train in Algeria which is scheduled to come on stream in 2013; and
- LNG from Brunei LNG where contracts with Japanese and Korean buyers expire in 2013.

We consider the total of divertible, portfolio and uncontracted LNG as potentially tradable, thereby giving an indication of LNG volumes that could be available on a global basis. Figure 15 shows how the volume of potentially tradable LNG from existing and under construction plants is increasing over the period. This volume will depend on how much of the currently uncontracted LNG is contracted over the period – the potentially tradable volume therefore increases from around 100 bcm (32% of total LNG production) to between 110bcm (28% of total) and 214bcm (55% of total).

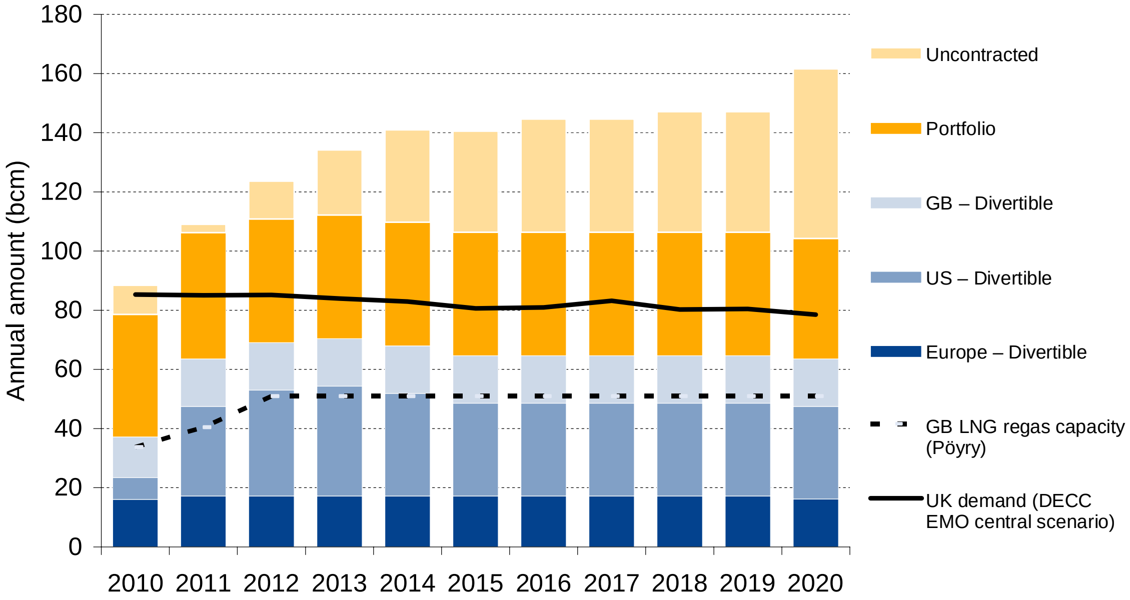
Figure 15 – Firm v potentially tradable LNG from capacity in operation and under construction February 2010



Looking in more detail, Figure 16 shows the potentially tradable volumes (including uncontracted volumes) as identified from the above analysis, broken down between contract destinations, i.e. GB, rest of Europe and the US. This chart also excludes production volumes from the Pacific Basin to give a more realistic view of volumes likely to be available to GB. It shows an increase in contracts to the US in 2011, but the majority of the growth will be from LNG production which is still uncontracted. We consider that GB will be in a good position to attract additional LNG volumes in this period, for example if pipeline supplies are interrupted.

In addition, Figure 16 shows the UK demand profile from the DECC Energy Markets Outlook (which has been used in the modelling for the study), and the projected GB regasification capacity, for comparison with the potentially tradable LNG volumes. This shows that the potentially tradable volumes of LNG exceed total projected GB demand over the period, and also exceed projected GB regasifcation capacity by an even greater margin.

Figure 16 – LNG volumes potentially accessible to GB from capacity in operation and under construction in February 2010 by region



3.4.2 *Market players*

LNG production and supply is characterised by Joint Ventures (JVs) between National Oil Companies (incumbents) and oil majors. There is therefore the potential for differences in strategic objectives of the JV partners. For example, in relation to Qatargas, ExxonMobil may wish always to go to the highest priced market, while Qatar Petroleum may see wider strategic value in continuing to supply GB (for example) even if this is not the most favourable short-term economic solution.

In addition, the variety of players involved in trading LNG gives increasing depth and liquidity to the market. LNG players include ExxonMobil, BP, BG, Shell, Repsol, GDFSuez, Sonatrach, Petronas, Gazprom, Statoil, Sempra, Vitol, Mitsui, Mitsubishi, Morgan Stanley, Barclays Capital and Citibank.

3.4.3 *Pipeline competition*

LNG supplies to Europe and the US face competition from supply by pipeline, from both conventional and unconventional sources, and so must be priced to compete with these alternatives. In the case of NW Europe this would be notably from the uncontracted or flexible contractual elements (the contracted volumes in excess of the take-or-pay obligations) of Norwegian supplies and new Russian supplies.

In terms of the competitive position of pipeline gas vs. LNG flowing to NW Europe, the key points to note are:

- LNG from existing sources can be supplied within a marginal cost range estimated at between $1.2 to $1.7/mmBtu (7 to 10p/th), as discussed in Section 2.1, which would undercut Russian and Caspian pipeline supplies;

- Norwegian and Algerian gas can provide potentially competitive supplies compared with most LNG sources; and
- new LNG supplies need a long term price of between $5/mmBtu (30p/th) and $10/mmBtu (60p/th), as discussed in Section 2.1, for development to be economically viable; new pipeline supplies may be cheaper and may come on earlier.

We consider that LNG will be competitive with pipeline gas, particularly with gas on long-term oil-indexed contracts and will arrive in GB when prices are competitive.

3.4.4 Risks to GB

Even though there are no firm (i.e. non-divertible) long-term contracts to GB, we do not consider this to be a major issue for GB in the next decade, as the increasing volume of LNG, in particular uncontracted and portfolio LNG, available to trade and the number and variety of participants in the market will provide sufficient liquidity for GB importers to trade. The surplus of potentially tradable LNG volumes over likely GB LNG requirements is illustrated in Figure 16 in Section 3.4.1.

The risk is that gas prices remain so low that investment in new supplies does not take place until it is too late, meaning global gas supply becomes tighter. If this happens, LNG importers are likely to take up the currently uncontracted LNG from existing projects (as discussed in Section 3.4.1 above) before new gas supplies become available. It is too early at this stage to assess whether this is a realistic risk, as there are plentiful reserves in the world, as discussed in Section 3.1.1, which will come to market if the long-term price signals/contracts are there.

3.5 Technology

Both the global LNG and unconventional gas markets feature a range of technological developments.

For the LNG market, these include:

- Floating regasification – this has been implemented for a range of projects, including Excelerate Teesside (UK), Gulf Gateway (Louisiana, US), Guanabara Bay (Brazil) and is being developed for Offshore Tuscany (Italy). The technology provides benefits in terms of faster start-up, potentially easier environmental compliance and flexibility to maximise seasonal use. Floating regasification projects are characterised by lower capital costs, but higher operating costs (to cover ship leasing & offshore operation).
- Floating liquefaction – this technology allows plant construction to be undertaken remotely and, it is claimed, at lower cost. However, the technology is not yet in operation anywhere so any claims of lower costs will only be verified when projects are developed and brought into service. There are several companies pursuing developments in a range of countries with offshore gas reserves e.g. Australia, Indonesia, Malaysia, Nigeria, Equatorial Guinea, Brazil, Eqypt.
- New ship designs – the latest Q-Max and Q-Flex ships provide lower unit transportation costs. In addition, they are able to reliquefy gas which boils off onboard, thereby allowing more LNG to be delivered (around 3 to 4% on a four-week round voyage from the Middle East to GB). However, the new ships can limit operational flexibility e.g. ability to divert since there are a limited number of terminals that can receive these ships for operational reasons or because additional storage would be required.

For the unconventional gas market, technological developments include:

- Hydraulic fracturing – this is a key technological characteristic of unconventional gas extraction. The approach is used for shale gas, tight gas and coalbed methane (for less permeable beds). The technology involves high pressure injection of water (with chemicals or sand) into rock thereby fracturing the rock to release gas. Use of this approach requires the disposal of large quantities of contaminated water, and there are claims that this process can affect the water table.
- Horizontal drilling – this approach is commonly used in unconventional gas extraction and provides access to greater area of potential reserves. The approach can also facilitate drainage of water from coalbed methane.
- Gas hydrate extraction – there is currently no commercial production of gas from hydrates, although initial trials indicate that conventional vertical drilling may be used but at higher cost to reflect the deeper and more remote location of reserves.

In relation to unconventional gas extraction technology, there still exist some doubts as to the ease with which the technology can be transferred from areas such as the US where it has been successfully deployed, due to the variability in geological characteristics across geographies and the potential reactions of the affected communities to the social and environmental impacts in the areas of reservoir development.

In terms of incorporating technological factors into the modelling, should these factors be regarded as significant in terms of the potential impact on GB's gas security of supply, the approach would be to build technological developments into the two core scenarios as follows:

- For LNG, this would be achieved by reducing, over time, project development costs and shipping transportation costs.
- For unconventional gas, the use of appropriate technology e.g. hydraulic fracturing, is assumed as integral part of the projected growth of unconventional gas production.

3.6 Regulatory

In relation to regulatory factors, we have considered environmental issues and Third Party Access arrangements, as described below.

3.6.1 Environmental

Both the global LNG and unconventional gas markets face a range of environmental challenges.

For the LNG market, these include:

- Difficulties in finding suitable sites for liquefaction and regasification due to the environmental impact and, in the case of regasification terminals, objections from the local community. This may drive demand for some of the new technological solutions e,g, floating liquefaction and regasification.
- Planning and permitting processes – historically this has been a significant issue for LNG developments, causing delays and cancellations e.g. to planned regasification facilities in Italy and the US (West Coast). Steps are being taken in some countries e.g. UK, Italy, to streamline the applicable permitting processes, although the effect of these measures is yet to be proven. Delays to liquefaction projects could present

a problem for GB in accessing LNG supplies, however, delays to regasification projects (outside GB) could be a benefit to GB.

- Requirements for CO_2 sequestration can add significant cost to LNG projects. For the Gorgon LNG liquefaction project in Australia the sequestration cost is reported to be around $2bn (5% of the total project cost). Thus far, this has not been a requirement for projects in the Middle East and Africa.

For the unconventional gas market, environmental considerations include:

- Hydraulic fracturing – as discussed in Section 3.5, hydraulic fracturing requires the disposal of large quantities of contaminated water, and can affect the water table of the local environment.
- Water extraction and disposal – this is a requirement of coalbed methane extraction, which normally requires the drainage of significant quantities of water before gas production begins.

Environmental requirements for both LNG and unconventional gas are quite well established and there are no anticipated new 'step change' environmental requirements (although this may depend on how decarbonisation is incentivised in the longer term).

The obvious way to model the effect of increasing the environmental burden is to delay the start dates of projects or increase project costs (potentially making them uneconomic and therefore less likely to proceed).

An additional environmental consideration is the treatment of gas flaring from oil production. As regulations are tightened to prohibit flaring, this could result in additional gas production being available which could be exported as LNG (e.g. from Nigeria) or exported as pipeline gas (e.g. from Russia).

3.6.2 Third Party Access arrangements

The process of obtaining Third Party Access (TPA) to both LNG regasification terminal capacity and to pipeline transmission capacity could potentially affect the speed, or ease, with which the LNG market might develop.

In relation to access to regasification terminal capacity:

- In GB, access is typically obtained via long-term capacity contracts, where a TPA exemption has been granted by the regulator (Ofgem). This arrangement applies to the South Hook, Dragon, and Isle of Grain terminals. Capacity may then be traded by capacity holders to other users via bilateral contracts. GB has an additional regulatory requirement to offer short-term Use-It-Or-Lose-It capacity, in the event that the long-term capacity holders are not using the capacity.
- In Europe, the access arrangements typically feature a mix of long-term capacity contracts (TPA exempt) and a percentage (for example, in Italy, 20%) of capacity offered on TPA basis.
- In the US, for pre-2003 terminals, capacity has typically been booked on a long term basis via an open access process. For post-2003 terminals, developers are able to hold the capacity for their own use or sell it to third parties on a long or short-term basis. There are no incentives for the companies to maximise the use of the terminal or offer it to third parties. However, the Federal Energy Review Commission has said it will review these arrangements if it believes they are not working in a way which benefits the wider community.

In relation to access to the transmission system:

- For LNG, access (i.e. connecting regasification terminals) to the GB gas transmission system has not proved to be a material obstacle. In addition, GB and the US have well tried mechanisms for allocating short-term entry capacity. Transmission access for LNG terminals could be more of an issue for Europe (and other places) where the access regimes are less well developed. This gives the UK an advantage as spot cargoes are more likely to arrive in UK and US than other countries without reliable TPA arrangements. This could be a reducing problem in Europe as the markets are harmonised.
- For unconventional gas developments, access to pipeline capacity appears not to have been a problem in the US given the recent rapid growth in production. This is also consistent with the well-developed mechanisms for allocating capacity in the US. As for LNG, transmission access for unconventional gas development could be more of an issue for Europe (and other places) where the access regimes are less well developed.

If access was considered a significant issue, it could be modelled by delaying the start dates for projects.

3.7 Key factor analysis summary

On the basis of the preceding analysis, we have categorised the factors according to their potential impact on GB's gas security of supply.

This summary analysis is shown in Figure 17.

We have used this analysis to feed into the determination of appropriate modelling sensitivities and stress tests.

Figure 17 – Summary of key factor analysis

Factor		Summary findings	Criticality*
Supply	Reserves	Reserves are plentiful and unlikely to be an issue for GB security – potential for modelling under-production of unconventional gas	🟢
	Investment	LNG investment costs, particularly liquefaction, have spiralled and will affect projects in the near term – the longer term position is unclear	🟡
	Shipping	Shipping capacity far exceeds liquefaction capacity and is unlikely to be a constraint	🟢
	Gas quality	Gas quality (from LNG) is unlikely to be a constraint – the GB terminals can accept the vast majority of global LNG	🟢
	Geopolitical	Geopolitical issues could be significant – disruption to LNG supplies e.g. from Qatar should be modelled as a stress test	🔴
Demand		Demand assumptions will be important – key elements will be the impact of severe weather and the impact of carbon abatement	🔴
Flexibility		The flexibility provided by the large quantities of US storage could affect potential LNG flows to Europe, and could be modelled by assuming higher costs for US storage use	🟡
Markets	Contracts & liquidity	LNG contract flexibility and liquidity is increasing and should provide greater availability of LNG volumes – a dedicated GB LNG contract could be modelled as a sensitivity	🟡
	Pipeline competition	LNG supplies will face competition from pipeline gas supplies – different price relativities between LNG and pipeline gas could be modelled as a sensitivity	🟢
	Market players	The LNG market has a wide range of players of various types, increasingly adding to market depth and liquidity – there is no direct modelling impact	🟢
Technology		Technology is likely to have a gradual impact on the LNG and unconventional gas markets, rather than major step changes effects – this could be modelled by incorporating cost reductions over time	🟢
Regulatory	Environmental	No 'step change' environmental requirements anticipated for the LNG and unconventional gas markets, any effects could be modelled by delaying projects or increasing project costs	🟢
	Third Party Access	Third Party Access arrangements are unlikely to be a significant constraint affecting GB – difficulties with access could be modelled by delaying start dates for projects	🟢

Criticality

🔴 High/moderate impact potential
🟡 Moderate/low impact potential
🟢 Low/no impact potential

4. SCENARIO ANALYSIS

In this section, we describe:

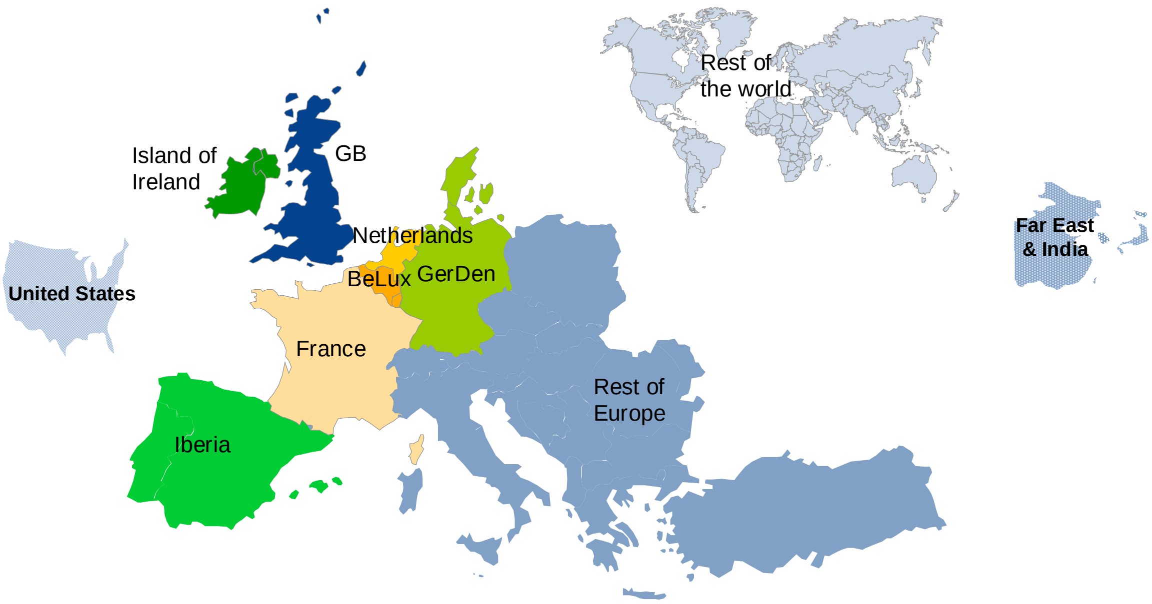
- the key modelling features of our gas model Perseus;
- the basis for our two base gas market scenarios – Business-as-usual (BAU) and Carbon-constrained;(CC); and
- the outputs from the analysis of the Business-as-usual and Carbon Constrained scenarios.

4.1 Modelling approach

For this part of the project we have used our international gas model Perseus, which examines the interaction of worldwide supply and demand, pipeline imports, LNG, storage usage and interconnections between the different zones on a daily basis without perfect foresight to match uncertainty of volatile demand. Great Britain, Ireland, and Continental NW Europe are modelled in detail, alongside all existing and proposed LNG terminals worldwide and their interaction with the global LNG market.

Perseus models supply from a number of sources flowing gas to a number of demand zones. The demand zones modelled by Perseus are summarised in Figure 18 below.

Figure 18 – Geographical coverage of Perseus



In our modelling using Perseus, we (manually) build additional supply capacity as required to meet demand. This reflects the premise from 3.1.1 that the 'worldwide gas market' will not run out of gas within the timescales of this study.

New gas supply investment coming on line will always make sufficient returns, as Perseus will ensure that prices remain above the long run marginal cost (LRMC) of new investment.

Any overbuild or underbuild of new capacity will be reflected in the modelled gas prices (and hence revenues to facilities):

- If too much new supply capacity is built, gas prices collapse and returns drop.
- If too little new supply capacity is built, gas prices will increase.

In terms of the modelling of global LNG supplies, Perseus models the limited foresight of future demand in dispatching LNG cargoes and flow from LNG tanks. We assume that the market has to take an LNG dispatch decision a few days in advance (a week for example), but that there is an element of flexibility with the LNG tank that can be dispatched day-ahead. The LNG tank in this context works like a very short range storage supplied by the cargo and withdrawing into the market. The LNG cargo dispatch decision is made with only a reasonable estimate of actual demand in the future, and in this way reflect the fact that LNG may not be able to respond to a short cold spell or unplanned supply outage.

The worldwide LNG market is very complex, and we make a number of simplifying assumptions in Perseus in order to be able to run the optimisation of supply and demand within an acceptable timescale. We capture the interaction between the continental gas markets by defining the US, Far East, and 'Rest of the world' zones which act as competing demand zones for LNG.

Perseus normally assumes that all cargoes can go from any liquefaction plant to any regasification terminal, and that cargoes are fully 'market determined'.

Further details on how Perseus works are provided in Annex A.

4.2 Base scenario definitions

In this section we describe the key assumptions that have been made for the two base modelling scenarios – the Business-as-usual and Carbon-constrained scenarios.

It should be noted that the modelling has been undertaken for gas years 2009/10, 2014/15, 2019/20, 2029/30 and 2049/50, as agreed with DECC.

4.2.1 Business-as-usual

The Business-as-usual scenario has been developed to reflect the view that some carbon reduction actions to mitigate against climate change will take place but will not result in the EU 2020 or 2050 targets being met. More details of the supply and demand assumptions used in the scenario are summarised below.

4.2.1.1 Demand

We have made a range of assumptions covering the key elements of gas demand, namely:

- domestic demand;
- powergen demand; and
- demand profiles.

In this section we describe our key demand assumptions.

Summary of demand assumptions

A summary of the main demand assumptions for this scenario is as follows:

- GB shows a significant demand reduction through to 2050 as carbon abatement measures become increasingly effective. We have set GB demand in 2050 at 20 million tonnes of oil equivalent i.e. 22bcm, as provided by DECC.
- Europe shows steady growth in demand through to 2030, followed by demand reduction to 2050 as carbon abatement and energy efficiency measures become effective – resulting in a demand reduction of 9% over the period 2030 to 2050.
- US demand shows a modest increase over the period through to 2050 – carbon abatement measures are resisted by a strong coal lobby – we have projected to 2050 based on the IEA WEO demand growth rate (2020 to 2030) – resulting in a demand increase of 4.5% from 2030 to 2050.
- The Far East (including China and India) demand for LNG increases through to 2050, whilst the Rest of World demand for LNG shows a demand increase to 2020 and is then flat through to 2050. For the Far East and Rest of World (LNG demand only) we have extrapolated the 2020 to 2030 trend through to 2050, giving an increase of 24% for the Far East and flat demand for Rest of World.

Great Britain

The annual gas demand projections for GB we have used are those in DECC's Energy Markets Outlook publication[8]. These annual figures have been profiled to create a daily demand profile based on within year weather patterns. For the central scenarios (Business-as-usual and Carbon-constrained), the weather patterns from a typical weather year (the year 2000) were used. In addition to the predominantly temperature-related impact on non-power sector demand, the weather patterns also have an effect on the power sector demand as the amount of intermittent generation increases.

In addition to the typical weather demand profile, a severe weather daily demand profile has been created, based on weather patterns from 1985. In comparison to the typical weather demand profile, the severe weather demand profile is characterised by higher annual demand, and higher peak day demand. This is illustrated in Figure 19 and Figure 20. In our modelling, the severe weather demand profile is used in conjunction with infrastructure outages to create stress tests.

As a high demand sensitivity, we have also used a 'high demand' projection for GB gas demand as the basis for a more severe set of stress tests, described more fully in Section 5. These projections are taken from the 'high case' sensitivity used by National Grid in its 2009 Ten Year Statement. In keeping with the methodology applied to the DECC demand projections, a typical and severe weather daily demand profile have been created from the National Grid projections. These are also shown Figure 19 and Figure 20.

[8] DECC Energy Markets Outlook – December 2009

Figure 19 – GB annual demand profiles

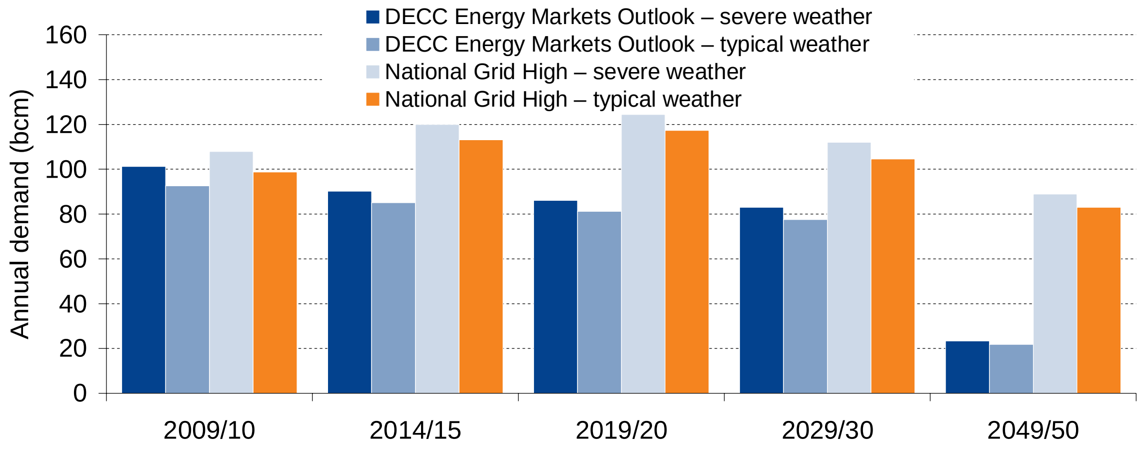
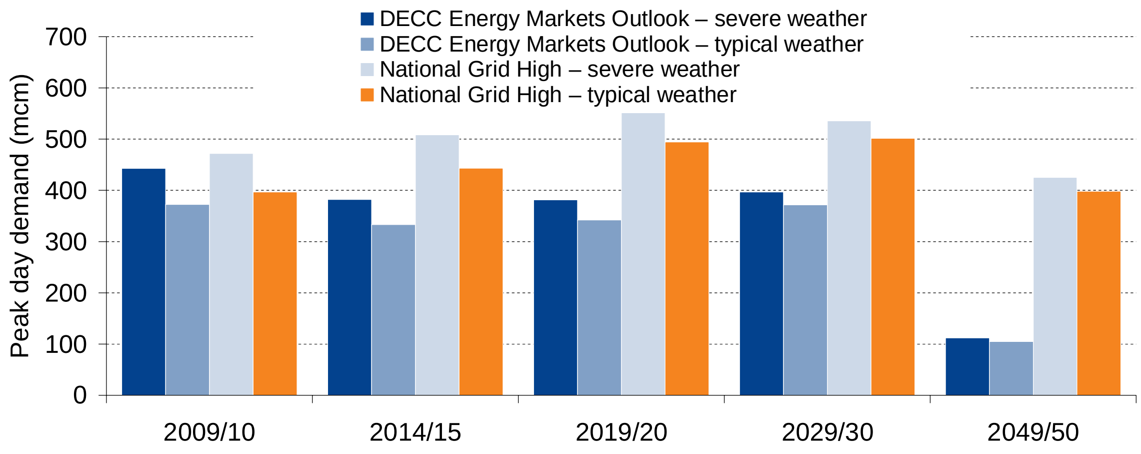


Figure 20 – GB peak demands



Other zones

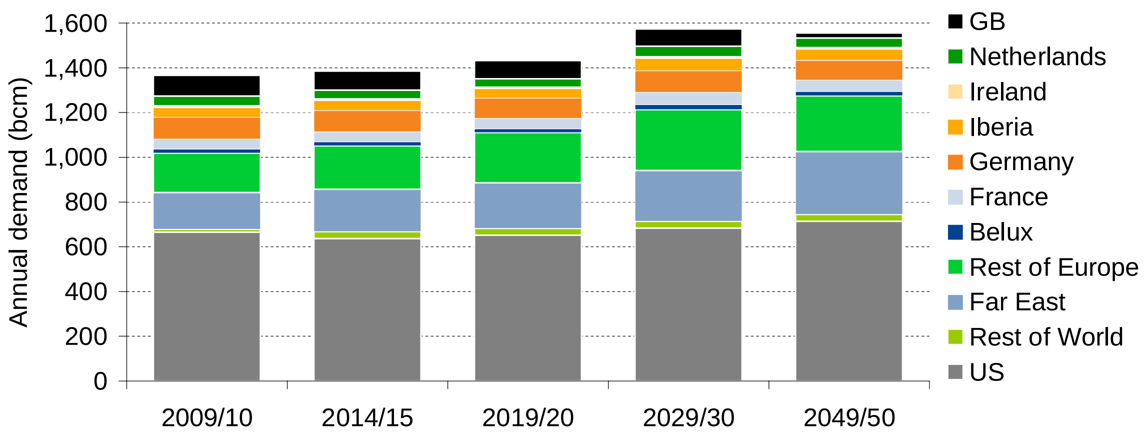
Annual demand projections for all other Perseus zones are based on Pöyry's own central case demand projections, which are summarised in Annex B.

For all European zones (covering GB, Ireland, France, Belgium, Luxembourg, Netherlands, Germany and Denmark) apart from 'Iberia' and 'Rest of Europe', daily demand profiles have been created for both typical and severe weather conditions from the same historical weather years as for GB (2000 and 1985). In this way, the effect of severe weather in a stress test is replicated across much of North West European demand, creating additional and realistic competition for gas supplies from those areas linking directly with GB.

In the remaining Perseus zones (Iberia, Rest of Europe, US, Far East and Rest of World), the daily demand profiles used are weather insensitive and have been created using 'seasonal-normal' demand variations within a gas year.

The resulting global demand profile for the BAU scenario is shown in Figure 21.

Figure 21 – Global gas demand – BAU scenario

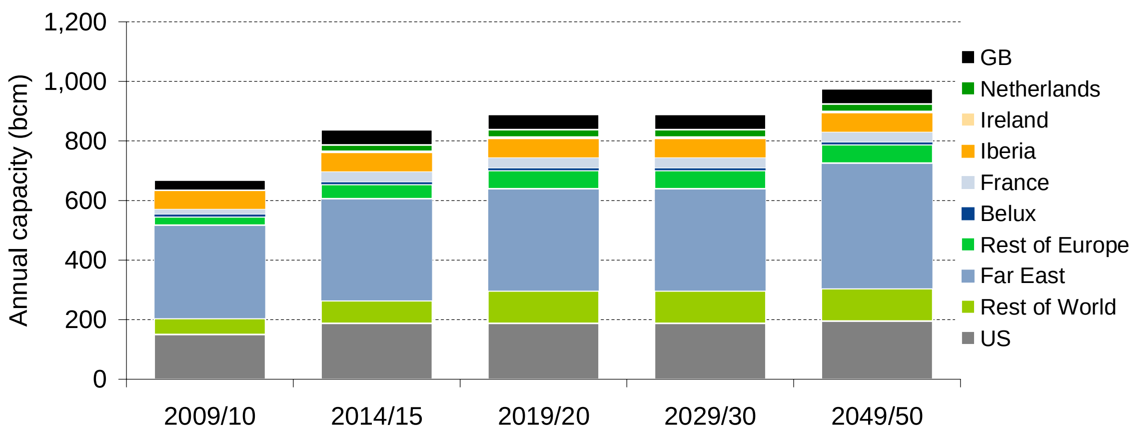


The detailed assumptions used for the Perseus demand zones for the Business-as-usual scenario are provided in Annex B.

4.2.1.2 Infrastructure

We have made a range of assumptions covering the key elements of gas infrastructure, and, in particular, for LNG regasification capacity. The LNG regasification capacity profile used in the Business-as-usual scenario is shown in Figure 22.

Figure 22 - LNG regasification capacity – BAU scenario



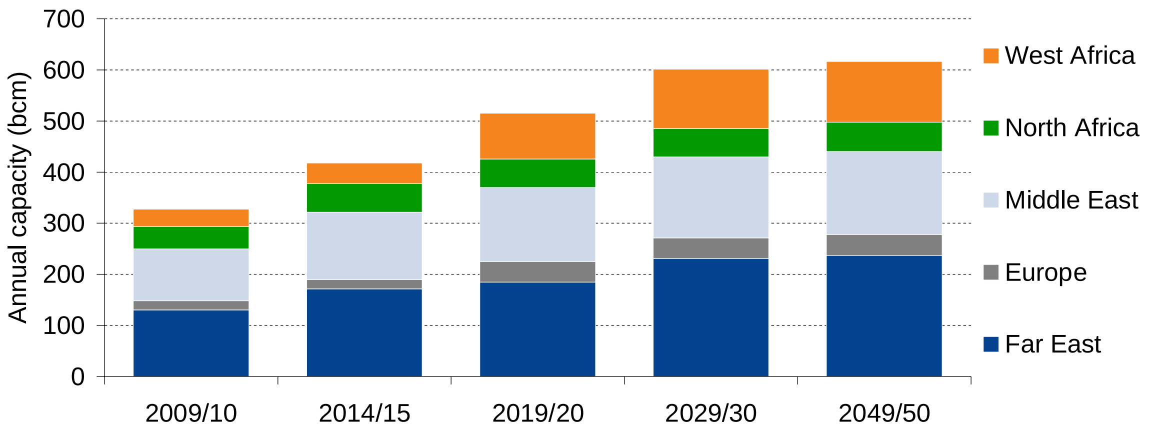
4.2.1.3 Supply

We have made a range of assumptions covering the key elements of gas supply, namely:

- gas reserves;
- gas volumes available for export i.e. potential gas production less indigenous demand;
- minimum gas production rates;
- export pipeline capacities;
- liquefaction capacity;
- gas production cost; and
- interconnector capacities.

The liquefaction capacity profile used in the Business-as-usual scenario is shown in Figure 23. This profile has been based on the liquefaction projections described in Section 2.3, using the projects that were in operation or under construction in February 2010. For years 2029/30 and 2049/50, we have assumed additional LNG liquefaction comes on stream sufficient to meet the projected growth in global demand for LNG.

Figure 23 – LNG liquefaction capacity – BAU scenario



The detailed assumptions used for the Perseus supply sources and interconnectors for the Business-as-usual scenario are provided in Annex B.

4.2.1.4 Summary of GB infrastructure assumptions for Business-as-usual scenario

We have summarised the key GB infrastructure assumptions for the Business-as-usual scenario over the five modelled years in Table 8. Full details of all the demand, supply and interconnector assumptions are provided in Annex B.

Table 8 – Capacities of GB infrastructure for BAU scenario (bcm/year)

	2009/10	2014/15	2019/20	2029/30	2049/50
Indigenous production (UKCS)	68	45	24	13	0
Norwegian pipeline	42	46	46	46	46
NL to GB interconnector	14	17	17	17	17
GB to NL interconnector	0	0	17	17	17
Bel to GB interconnector	24	24	24	24	24
GB to Bel interconnector	20	20	20	20	20
GB to Ire/NI interconnector	11	11	11	11	11
LNG regasification	34	51	51	51	51
Storage	5	10	11	11	11

4.2.2 Carbon-constrained

4.2.2.1 Demand

As for the Business-as-usual scenario, we have made a range of assumptions covering the key elements of gas demand, namely:

- domestic demand;
- powergen demand; and
- demand profiles.

A summary of the main demand assumptions for the Carbon-constrained scenario is as follows:

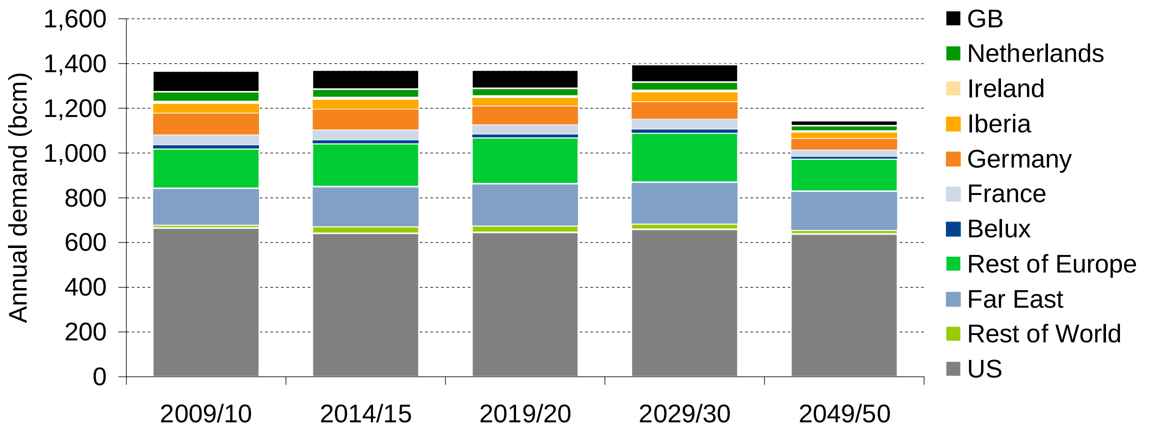
- GB demand assumptions for the Carbon-constrained scenario are the same as those for the Business-as-usual scenario – showing a significant demand reduction through to 2050 as carbon abatement measures become increasingly effective (see Figure 19 and Figure 20).
- Future demand levels for other regions under this scenario are based on the International Energy Agency (IEA) World Energy Outlook (WEO) 450 scenario – the IEA forecasts have been used to scale down the Business-as-usual scenario demand.
- Under the IEA 450 scenario, there are increased incentives for carbon abatement as a result of the carbon pricing in cap-and-trade scheme. There is a gradual migration of generation from fossil fuels to renewables and nuclear, and increased energy efficiency savings relating to building developments.
- In terms of meeting national emissions-reductions commitments, the IEA 450 scenario assumes that the OECD+ countries i.e. the OECD countries plus EU countries that are not members of the OECD, comply with such commitments for 2020. After 2020, emissions reduction commitments are extended to other major economies, including China, Russia and the Middle East.
- In relation to the modelling of demand through to 2050, for all regions we have projected the change in BAU/CC scaling factor from 2025 to 2030 through to 2050.
- As a result, there is a mix of demand increases and decreases across the regions from 2019/20 to 2029/30, and then a more pronounced and consistent demand decrease across all regions from 2029/30 to 2049/50.

- Demand reductions in comparison with the Business-as-usual scenario are up to 50% in 2050.

The detailed assumptions used for the Perseus demand zones for this scenario are provided in Annex B.

The resulting global demand profile for the Carbon-constrained scenario is shown in Figure 24 below.

Figure 24 – Global gas demand – CC scenario



4.2.2.2 Supply

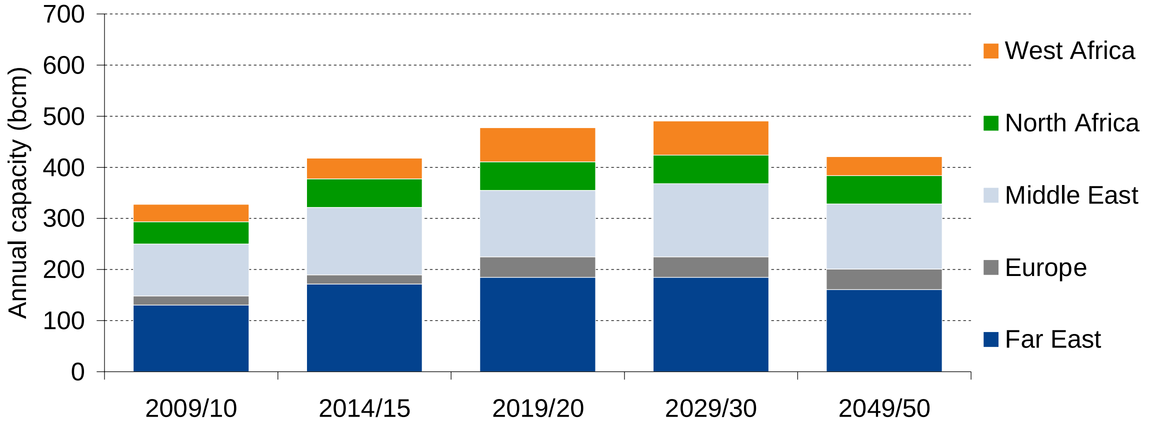
As for the Business-as-usual scenario, we have made a range of assumptions covering the key elements of gas supply, namely:

- gas reserves;
- gas volumes available for export i.e. potential gas production less indigenous demand;
- minimum gas production rates;
- export pipeline capacities;
- liquefaction capacity;
- gas production cost; and
- interconnector capacities.

Where gas demand is projected to reduce significantly we have made adjustments to the profile of supply capacity coming on stream to match the demand reductions.

The LNG liquefaction capacity profile used in the Carbon-constrained scenario is shown in Figure 25.

Figure 25 – LNG liquefaction capacity – CC scenario



The detailed assumptions used for the Perseus supply sources and interconnectors for the Carbon-constrained scenario are provided in Annex B.

4.3 Base scenario analysis

By analysing the two base scenarios in our model we are able to ascertain the likely flows of gas and LNG from all the sources to all the demand zones and the projected price of gas in each zone. These results are presented in the following sections.

4.3.1 Monthly gas flows to GB

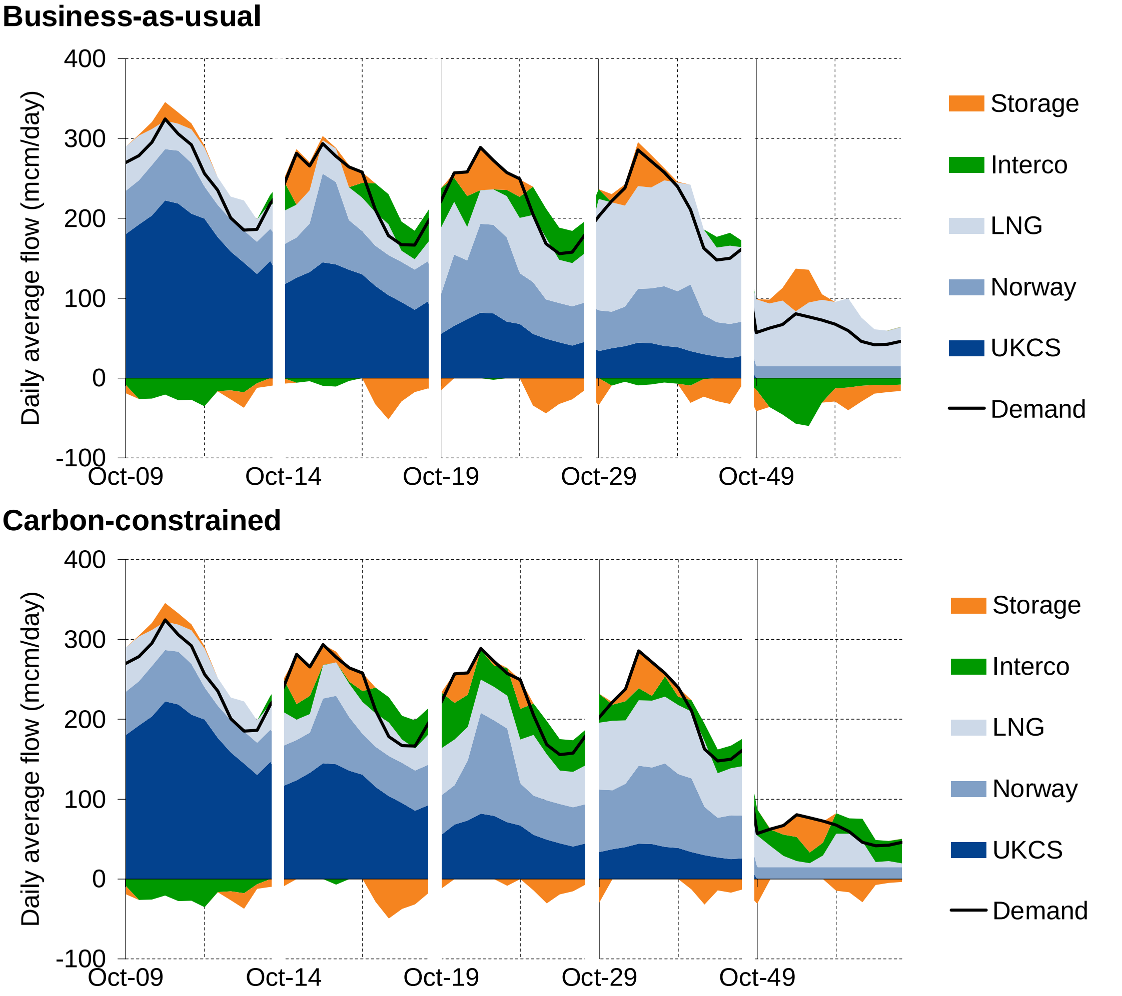
Figure 26 shows the gas flows to GB under the Business-as-usual and Carbon-constrained scenarios, with no outage. The main observations from this analysis for the Business-as-usual scenario are:

- There are plentiful gas supplies available to meet GB demand.
- UKCS flows to GB decline steadily over the period, reflecting the declining availability of GB's indigenous reserves, and Norwegian supplies are gradually displaced by LNG flows, particularly in 2029/30 and 2049/50.
- Storage is used in the standard seasonal fashion, with injections occurring predominantly during the summer, followed by withdrawals during the winter.
- The relative costs of GB gas supplies are such that, under certain circumstances, it makes economic sense to import gas into GB and export the gas through the GB-Europe interconnectors.

Focusing on the main differences from the Business-as-usual scenario, the main observation for the Carbon-constrained scenario is:

- Due to the reduced global demand for gas, there are surplus gas supplies available in Europe, and this increases cheaper gas flows to GB from Europe (notably from the Netherlands via the BBL interconnector and from Norway) from 2019/20 onwards, displacing LNG supplies to GB.

Figure 26 – Monthly gas flows to GB



4.3.2 LNG flows to GB

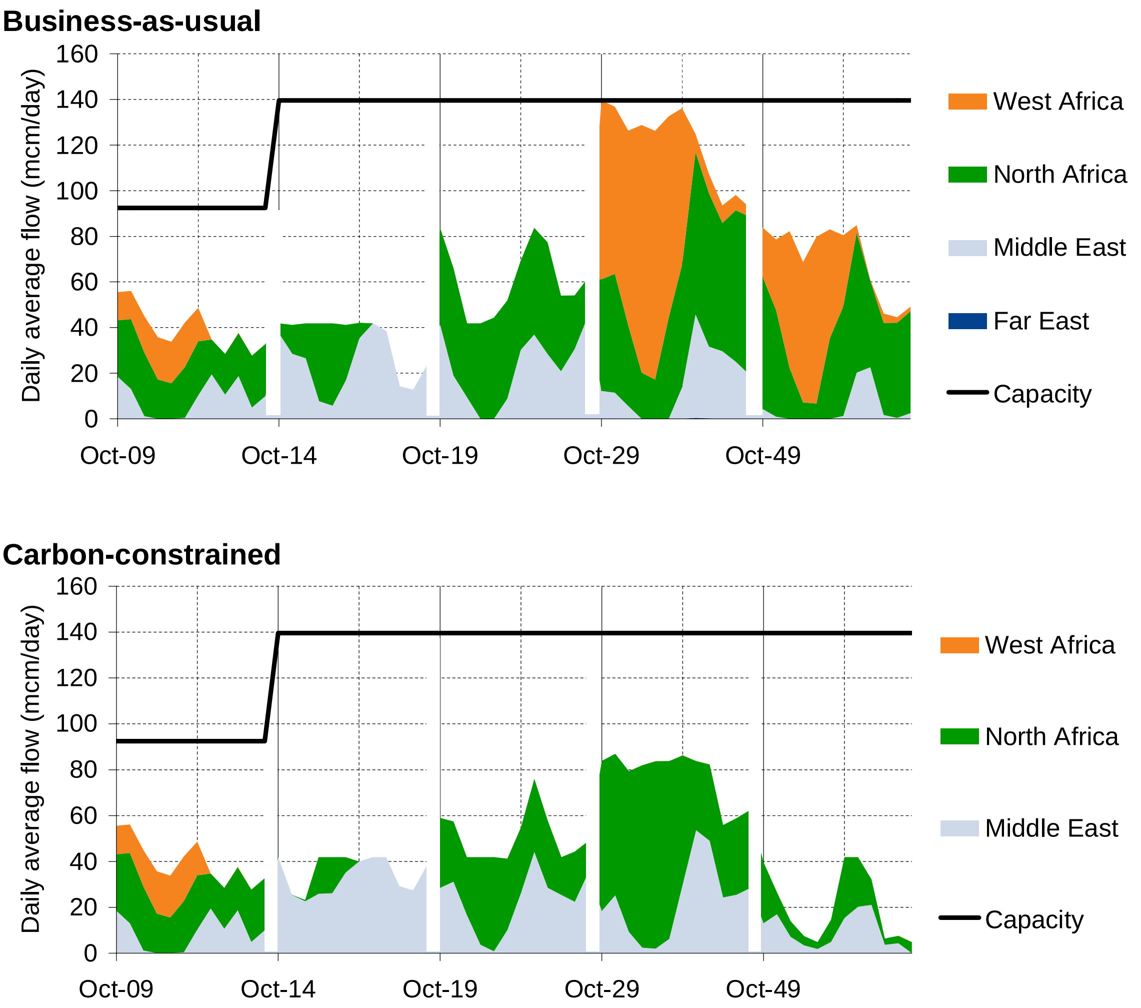
Figure 27 shows the LNG flows to GB and the utilisation of GB regasification terminals under the Business-as-usual and Carbon-constrained scenarios. The main points arising from this analysis relating to the Business-as-usual scenario are:

- In the years through to 2019/20, the GB terminals are utilised around or below a 50% load factor, whilst there remains reasonable supply availability from the UKCS.
- In 2029/30, the further decline in UKCS supplies results in a near 100% LNG regasification at certain times during the winter, with reductions during the following summer.
- In 2049/50, the much-reduced GB demand results in a much lower (around 50%) regasification utilisation level; some gas imports to GB are exported to the continent via the GB-Europe interconnector.
- In terms of LNG sources, GB is primarily sourced from 2029/30 by cheaper African supplies, although it also maintains a fairly steady supply over the period from the Middle East.

The key difference relating to the Carbon-constrained scenario is as follows:

- Due to the reduced global demand for gas, surplus gas supplies from Europe displace LNG supplies to GB, thereby reducing the utilisation of the GB regasification terminals from 2019/20 onwards.

Figure 27 – LNG flows to GB



4.3.3 *Storage use in GB*

Figure 28 shows the storage use in GB under the Business-as-usual and Carbon-constrained scenarios. The main points arising from this analysis relating to the Business-as-usual scenario are:

- Storage use in 2009/10 is relatively low, reflecting the supply flexibility which continues to be provided by UKCS supplies.
- In 2014/15, the volume of storage used increases due to new storage capacity coming online combined with a decline in UKCS supplies, making it cheaper to source gas from more expensive non-UKCS sources during the summer, inject this

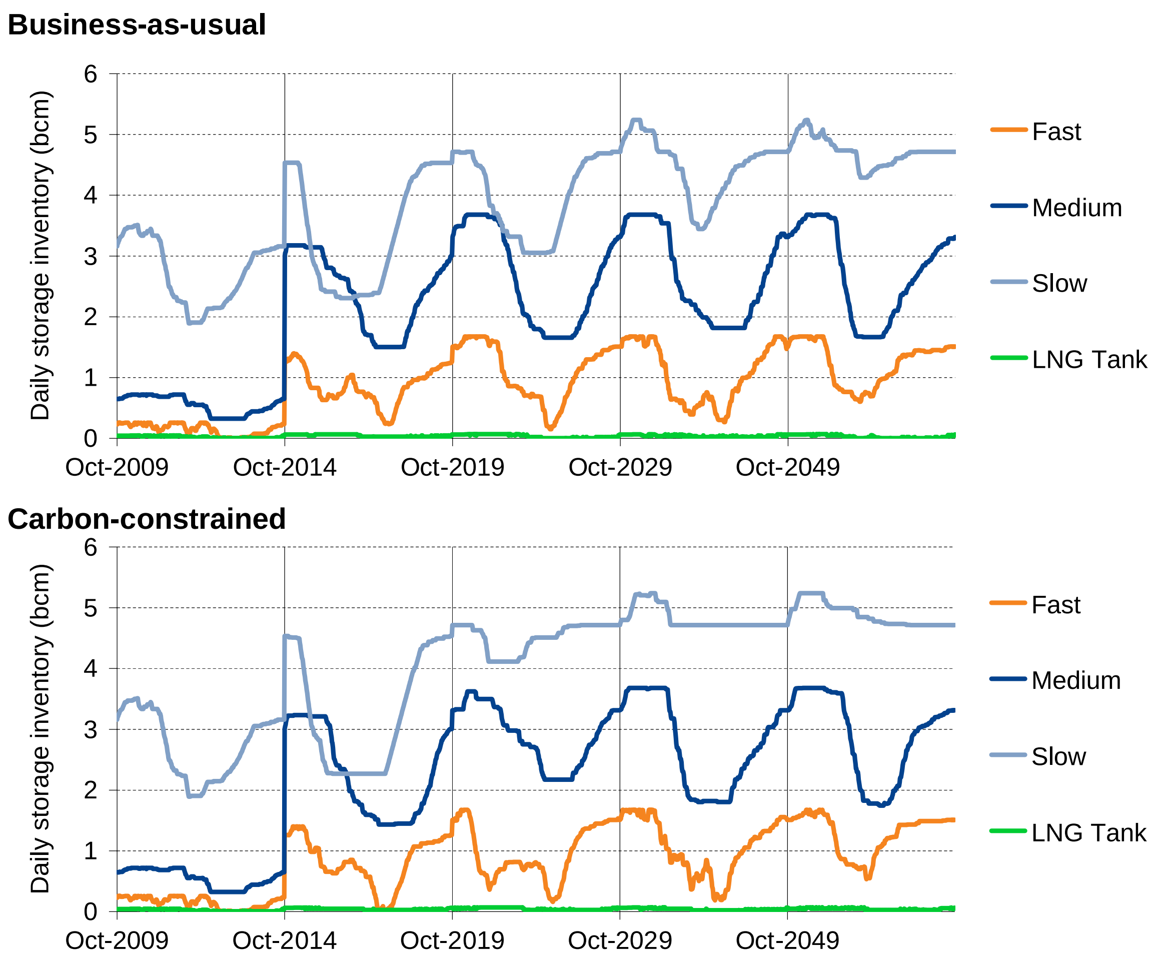
gas in store and withdraw it during the winter, than the alternative of sourcing more expensive gas from outside GB during the winter.

- From 2019/20 onwards, storage use decreases as demand decreases in GB.

The main point arising from this analysis for the Carbon-constrained scenario is:

- Storage use is generally dampened in comparison with the Business-as-usual scenario from 2019/20 onwards, reflecting the fact that GB has access to cheaper sources during winter from European imports, as demand (outside of GB) reduces.

Figure 28 – Storage use in GB



4.3.4 Gas prices

Figure 29 shows the applicable gas prices for GB, the US and the Far East under the Business-as-usual and Carbon-constrained scenarios. The main points arising from this analysis relating to the Business-as-usual scenario are:

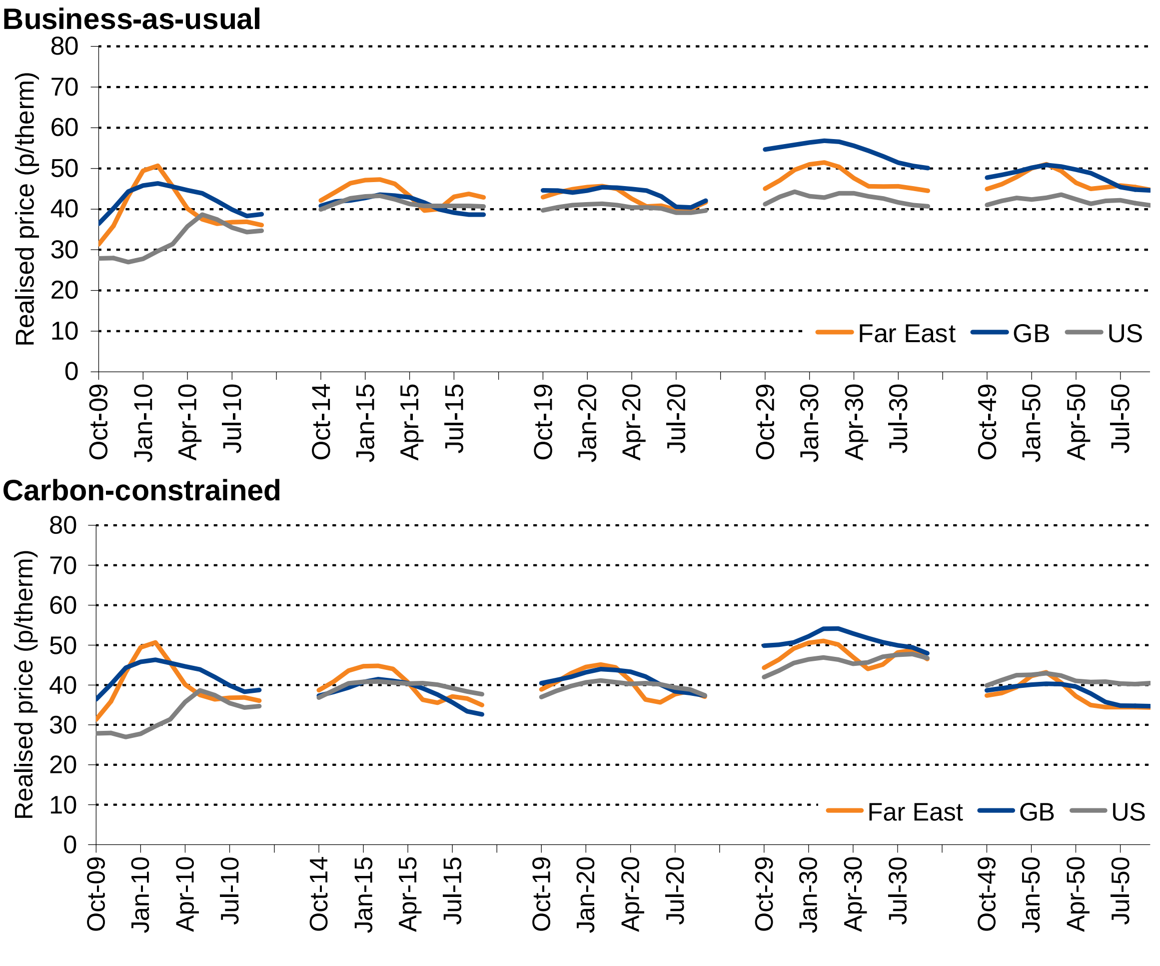
- GB prices are slightly higher than US and Far East prices from 2029/30 onwards, due to GB having to source increasing volumes of LNG in a tightening supply position.

- Far East prices show a more pronounced seasonal profile due to the fact that the Far East gas market is totally dependent on LNG, and prices therefore reflect the fact that the market has no alternative other than to source more expensive LNG during the winter when there is increased gas demand.

The key differences between the Carbon-constrained and the Business-as-usual scenario are:

- Prices are generally lower in the Carbon-constrained scenario due to the reduced worldwide demand – this effect is most pronounced in 2050, with the exception of the US which experiences a more modest demand reduction.
- Prices are identical in the two scenarios in 2009/10 as they have the same supply and demand in this year.

Figure 29 – Gas prices (2009 money)



4.4 Base scenarios – modelling conclusions

The main conclusions from the analysis using the Business-as-usual scenario are as follows

- There are plentiful supplies of gas available for GB, and no shortages are experienced.
- UKCS flows to GB decline steadily over the period, reflecting the declining availability of GB's indigenous reserves, and Norwegian supplies are gradually displaced by LNG flows, particularly in 2030 and 2050.
- The GB LNG terminals increase in utilisation to 2030, when the further decline in UKCS supplies results in a near 100% LNG regasification utilisation at certain times during the winter; GB LNG is primarily sourced by cheaper African supplies, although it also maintains a fairly steady supply over the period from the Middle East.
- Storage use in 2009/10 is relatively low, reflecting the supply flexibility which continues to be provided by UKCS supplies – from 2014/15 onwards, storage use increases as more storage becomes available, and then reduces slightly as demand falls.

The main conclusions from the analysis of the Carbon-constrained scenario are as follows

- There are plentiful supplies of gas available for GB, and no shortages are experienced.
- The reduced demand (outside of GB) in this scenario has the impact of reducing gas prices, by making cheaper surplus gas available to GB.
- Due to the reduced global demand for gas, surplus gas supplies from Europe displace LNG supplies to GB, thereby reducing the utilisation of the GB regasification terminals from 2020 onwards compared with the Business-as-usual scenario.
- Storage use is generally dampened in comparison with the Business-as-usual scenario, reflecting the fact that GB has access to other seasonally competitive sources, e.g. from European imports, as demand (outside of GB) reduces.

5. SENSITIVITIES AND STRESS TESTS

5.1 Introduction

In this section we describe the main assumptions behind the sensitivities and stress tests we have developed to further test GB's gas security of supply. Based on the risk factor analysis discussed in Section 3 we have constructed a set of tests designed to model the effect of those factors with the greatest potential impact.

The set of tests were agreed with DECC and are listed in Table 9.

Table 9 – Sensitivities and stress tests

		Scenarios		Sensitivity
Weather severity	Events	Business-as-usual	Carbon-constrained	High GB demand (National Grid)
2000 ('typical')	None	Yes	Yes	Yes
1985 ('severe')	Qatar LNG outage	Yes	Yes	Yes
1985 ('severe')	Milford Haven outage	Yes	Yes	Yes
1985 ('severe')	None	Yes		
1985 ('severe')	Unconventional gas increase	Yes		
1985 ('severe')	Unconventional gas decrease	Yes		
1985 ('severe')	Use of flexibility (US storage)	Yes		
1985 ('severe')	Dedicated GB LNG supply contract	Yes		

In relation to the weather severities used, and their effect on demand:

- Under typical weather (2000), annual demand in all zones matches the projections described for the base scenarios. Accordingly, the within-year profiles for all European zones in Perseus apart from Iberia and Rest of Europe exhibit a peak day demand level which would be expected in a typical year.
- Under severe weather (1985 – which represents a near 1-in-20 severe winter) the annual gas demand is increased in accordance with 1985 weather patterns, resulting in a corresponding increase in peak day demand. This effect applies to demand in all European demand zones in Perseus apart from Iberia and Rest of Europe.
- Iberia, Rest of Europe, US, Far East and Rest of World use seasonal normal demand for both the typical and severe weather cases.

In relation to the outages:

- The Qatar LNG outage results in the loss of all Qatar liquefaction for the winter months of December to March inclusive – applicable to all study years 2009/10, 2014/15, 2019/20, 2029/30, 2049/50.
- The Milford Haven outage results in the loss of both the South Hook and Dragon regasification terminals for the winter months of December to February inclusive – applicable to all study years 2009/10, 2014/15, 2019/20, 2029/30, 2049/50. This

outage has been chosen due to GB's increasing dependence on LNG over the modelled period.

In relation to the 'High GB demand' scenario:

- GB demand is increased to the high case sensitivity projections used by National Grid in its 2009 Ten Year Statement.
- Demand in all other zones is the same as for the Business-as-usual scenario.
- In response to the increased GB demand level (both in terms of annual volume and peak day demand), we have:
  - increased the available GB LNG regasification capacity by 12bcm from 2029/30 onwards (when GB becomes increasingly dependent on LNG imports); and
  - increased GB storage by adding 5.1bcm of storage space, with 124mcm/d of additional deliverability (comprising 2.9bcm and 78 mcm/d from salt caverns and 2.2bcm and 46 mcm/d from depleted fields) from 2019/20 onwards.

In relation to the US unconventional gas 'events':

- These sensitivities examine the effect on GB of an increase and a decrease in unconventional gas production in the US.
  - In the increased production scenario we assume a 7% increase on Business-as-usual US unconventional gas production.
  - In the decreased production scenario we assume a 7% decrease on Business-as-usual US unconventional gas production.
  - The increase (and, conversely, decrease) in unconventional gas production amounts to 20bcm (of around 300bcm total unconventional gas production) in 2009/10 through to 23bcm (of 340bcm total) in 2049/50.

In the US storage flexibility 'event', we increase the cost of storage use in the US to the same level as that used for GB and North West Europe, in order to examine the effect of a change in the usage of US storage on the LNG flows to the UK.

In the dedicated GB LNG supply contract 'event', we examine the effect of an LNG supply contract dedicated to GB, and the consequent displacement of other gas supplies to GB

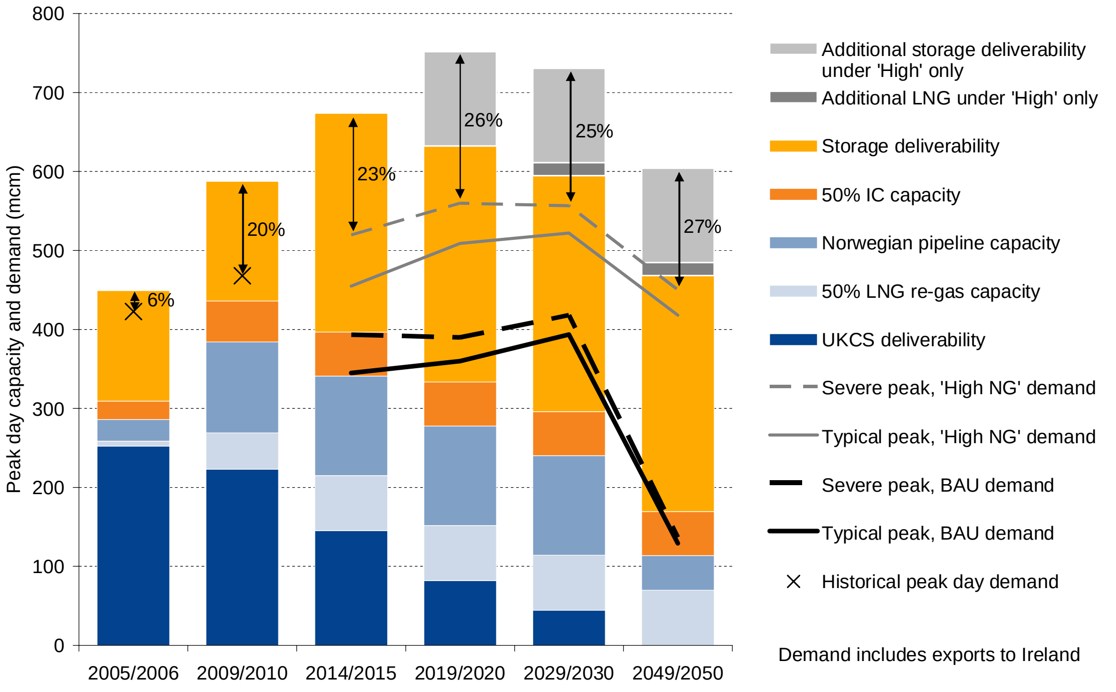
5.2 Capacity margin analysis

Prior to describing the results of the sensitivities and stress tests described in Section 5.1, in this section we examine the capacity margins (i.e. the comparison between the supply capacity available and the projected peak day demand) both for the historically very tight winter of 2005/6 and for the modelled future years. We consider the capacity margins for the various GB demand profiles included in the modelling, namely the Business-as-usual profile and the National Grid high demand profile, each under typical and severe weather conditions.

Since 2005/6 there has been a large increase in LNG regasification and interconnector import capacity to GB. In order to reflect the likelihood that not all of this import capacity will be utilised on a peak day, only 50% of the total LNG regasification and interconnector capacity is included in the derived capacity margins. Obviously, this is a simplification and the actual utilisation of LNG regasification terminals and interconnectors is uncertain.

Figure 30 shows the capacity margin assuming 50% of LNG re-gasification capacity and 50% of interconnector capacity are available - the percentage capacity margin is shown in each year.

Figure 30 – Historical and projected capacity margins



In the case of the National Grid high demand profile, as indicated in Figure 30 and described in Section 5.1 above, we have added in additional storage capacity (5.1bcm of space and 120mcm/day of deliverability) from 2019/20 onwards and additional LNG regasification capacity (12 bcm) from 2029/30. This is to reflect the increasing annual and peak demand levels. We would expect the market to realise such additional capacity, in the event that such high demand levels were anticipated.

The tightness in the GB gas market in 2005/6 is clear and at no point does the projected capacity margin get as low as that again in any of the scenarios modelled.

It should also be noted that the relative peakiness of demand i.e. the ratio between the peak day demand and the average day demand, increases over the period modelled, reflecting the increased volatility of demand, as a result of the increasing proportion of intermittent generation present in the generation mix.

5.3 Business-as-usual stress test

5.3.1 Monthly gas flows to GB

This section compares the monthly gas flows between the Business-as-usual scenario with 2000 typical weather and no outages and the outages of Qatari LNG and Milford Haven, each with 1985 severe weather. This is shown in Figure 31 on page 67.

In respect of the Qatari outage, the key points arising are:

- There are reduced LNG flows to GB during the outage period, reflecting the tighter global LNG supply/demand position.
- Storage is used in greater volumes to balance the seasonal supply/demand position and make up the lack of supply during the outage.
- In 2049/2050, GB continues to export gas to the continent during the outage as GB demand is severely reduced in this year, allowing it to provide support to Europe whose demand is at a higher level.

In respect of the Milford Haven outage, the key points arising are:

- There are reduced LNG flows to GB, reflecting the unavailability of the Milford Haven terminals during the winter.
- Storage is used in greater volumes to both balance the seasonal supply/demand position and make up for the lack of LNG during the outage.
- The relative costs of GB gas supplies are such that, under certain circumstances, it makes economic sense to import gas into GB through the GB-Europe interconnector, and, at other times, export gas to Europe via this route.

5.3.2 Demand side response

No demand side response is used in GB under either the Qatari outage or the Milford Haven outage.

However, for the Qatari outage, a small amount of demand side response was used in Europe in 2009/10 totalling 46mcm.

5.3.3 LNG flows to GB

In this section we compare the LNG flows to GB between the Business-as-usual scenario with 2000 typical weather and no outage and the outages of Qatari LNG and Milford Haven, each with 1985 severe weather. This is shown in Figure 32 on page 68.

In respect of the Qatari outage, the key points arising are:

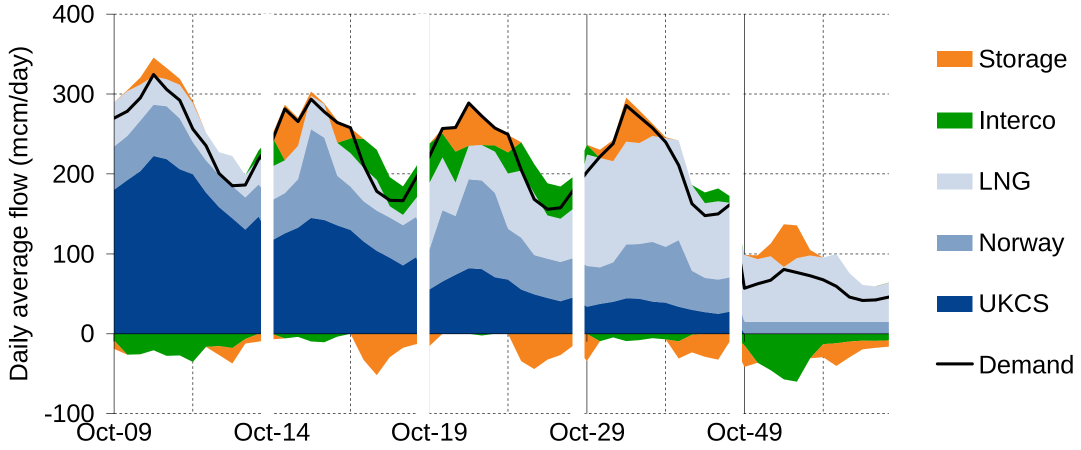
- The Qatari outage restricts the LNG available for GB imports, particularly in 2029/30 and 2049/50, when winter supplies are made up by the use of storage.
- The principal sources of LNG to GB continue to be from Africa (on a least cost basis).

In respect of the Milford Haven, the key points arising are:

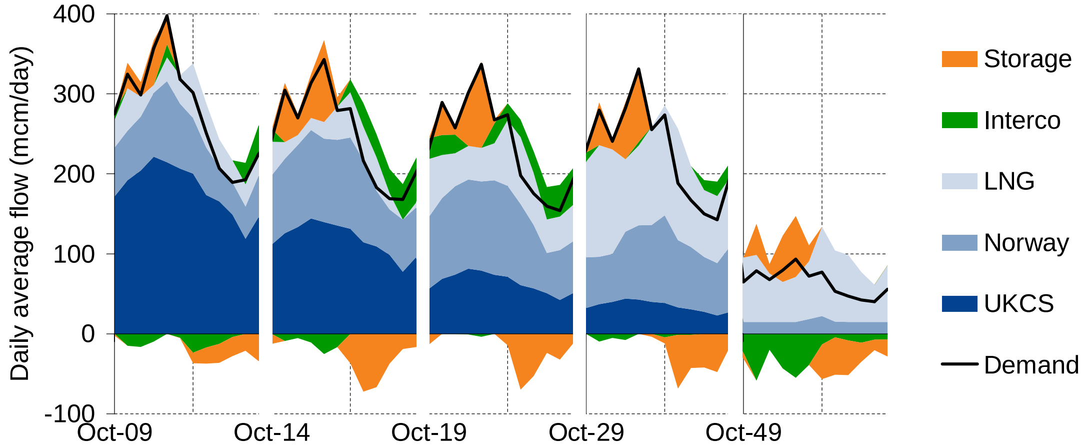
- There are reduced LNG flows to GB, reflecting the unavailability of the Milford Haven terminals during the winter. LNG flows peak in the April/May period in order to fill storage as shown in Figure 33.
- Middle Eastern LNG flows to GB continue during this stress test, in comparison with the Qatari outage stress test.

Figure 31 – BAU stress test – monthly gas flows to GB

No outage and 2000 typical weather



Qatar outage and 1985 severe weather



Milford Haven outage and 1985 severe weather

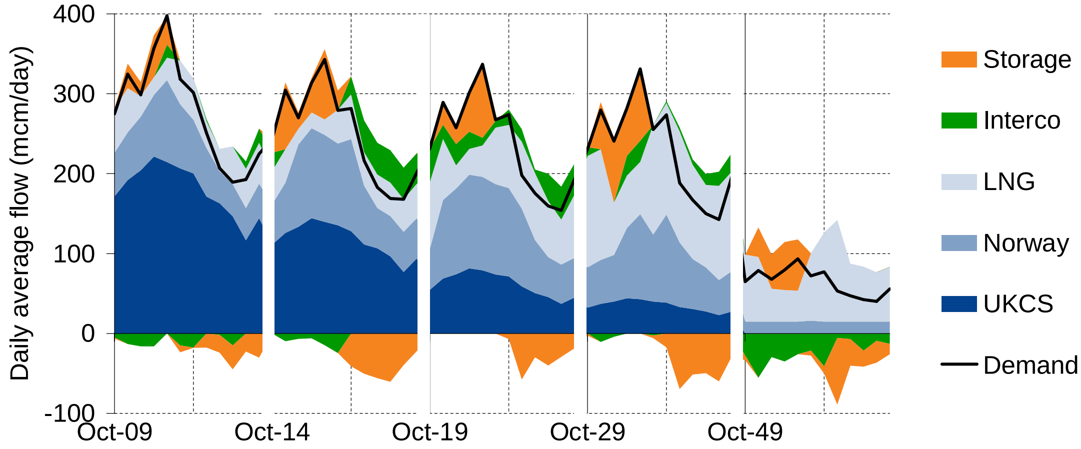
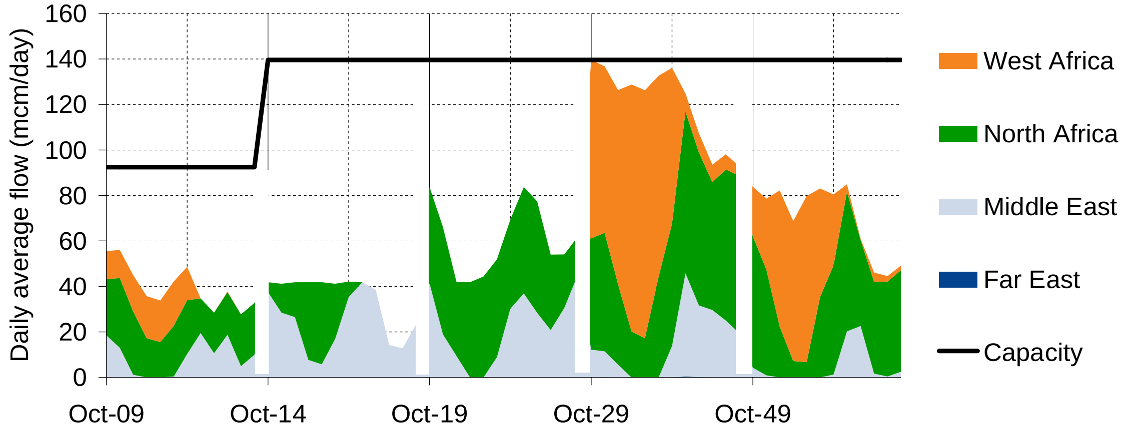
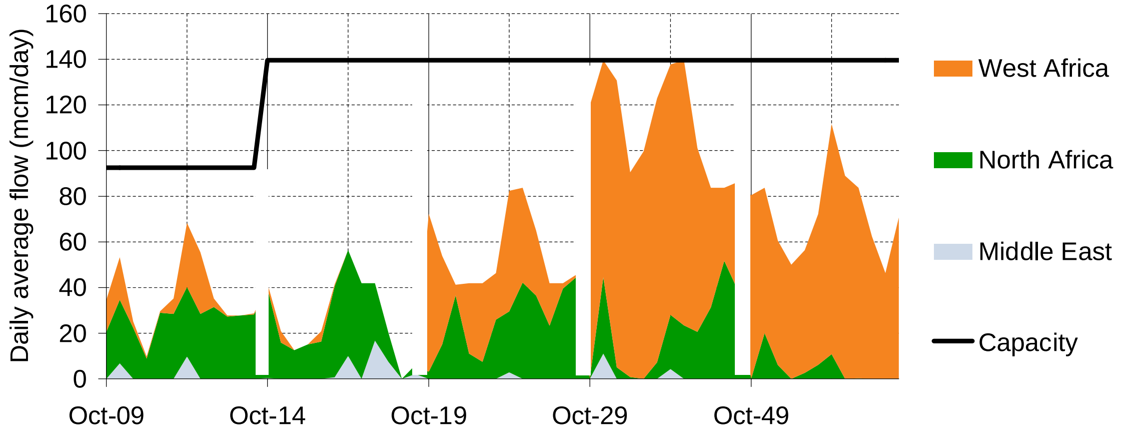


Figure 32 – BAU stress test – LNG flows to GB

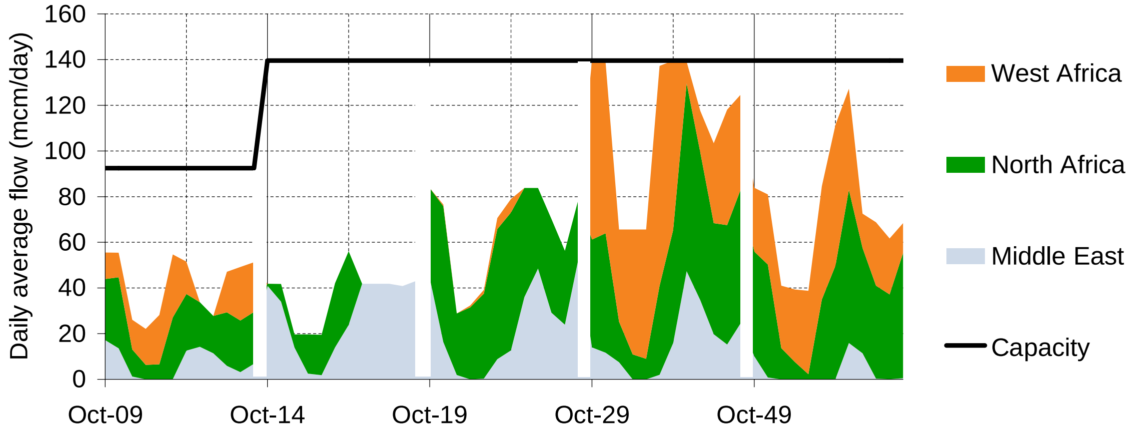
No outage and 2000 typical weather



Qatar outage and 1985 severe weather



Milford Haven outage and 1985 severe weather



5.3.4 Storage use in GB

This section compares the use of GB storage between the Business-as-usual scenario with 2000 typical weather and no outage and the outages of Qatari LNG and Milford Haven, each with 1985 severe weather. This is shown in Figure 33.

In respect of the Qatari outage, the key points arising are:

- There is significant use of storage across the five studied years. All three storage types (slow, medium and fast) are heavily utilised.
- The use of storage reflects the stressed position of GB's supply/demand balance during the outage.
- In 2049/50 GB storage is drawn on heavily during the outage, despite the low demand level in GB, in order to supply gas to Europe during the outage whose demand in this year has not decreased to the same extent.
- Storage is, however, not used to the maximum extent for this outage since the US makes increased use of its storage in preference to LNG imports, thereby making additional LNG available to GB (and elsewhere).

In respect of the Milford Haven outage, the key points arising are:

- There is significant use of storage across the five studied years.
- In comparison with the Qatari outage, storage is generally used to a greater extent, reflecting the need for additional flexibility due to the loss of the Milford Haven infrastructure and the consequent reduced LNG flows to GB.
- Storage is fully depleted in 2014/15 as this is the cheapest way to meet GB's demand, but this does not lead to demand side response being required as LNG supplies are still available during the shoulder periods.

5.3.5 Prices

In this section we compare the gas prices for GB, the US and the Far East between the Business-as-usual scenario with 2000 typical weather and no outage and the outages of Qatari LNG and Milford Haven, each with 1985 severe weather. This is shown in Figure 34 on page 71.

In respect of the Qatari outage, the key points arising are:

- There is a rise in prices in comparison with the no outage case, with GB and Far East prices showing a similar trend.
- Prices in GB and the Far East show the most pronounced spike in 2009/10, when the global supply/demand margin is tight under such an extreme outage; the US makes use of its storage flexibility and does not experience the same level of price increase.

In respect of the Milford Haven outage, the key point arising is:

Prices rise in comparison with the Business-as-usual scenario with no outages, but are reduced in comparison with the Qatari outage, reflecting the reduced impact of the GB-based outage as compared to the global LNG supply nature of the Qatari outage.

Figure 33 – BAU stress test – Storage use in GB

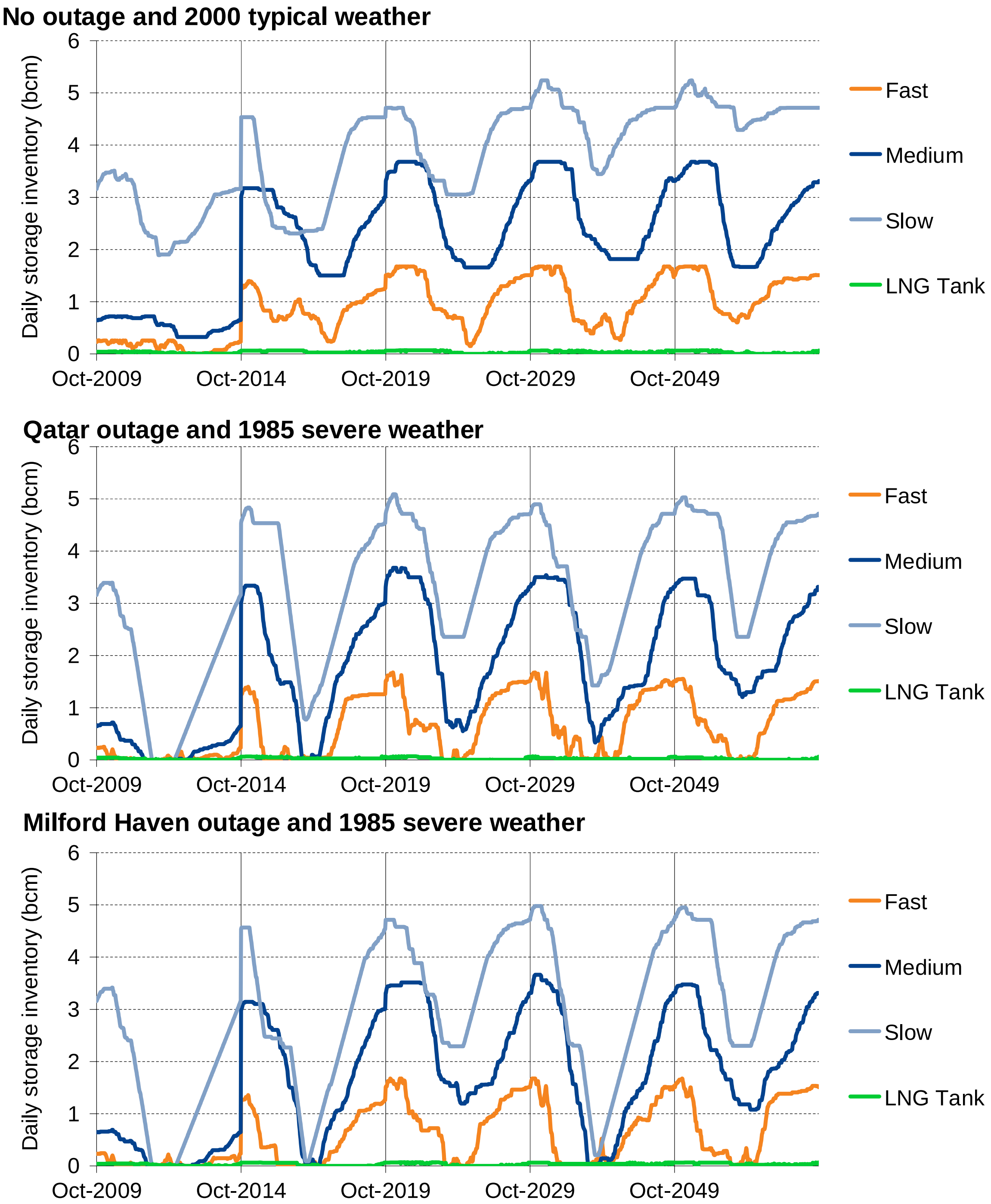
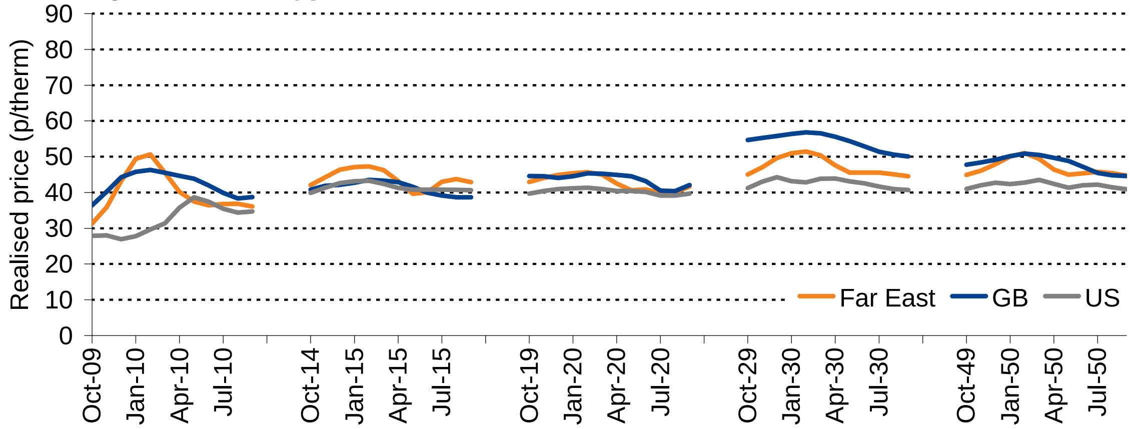
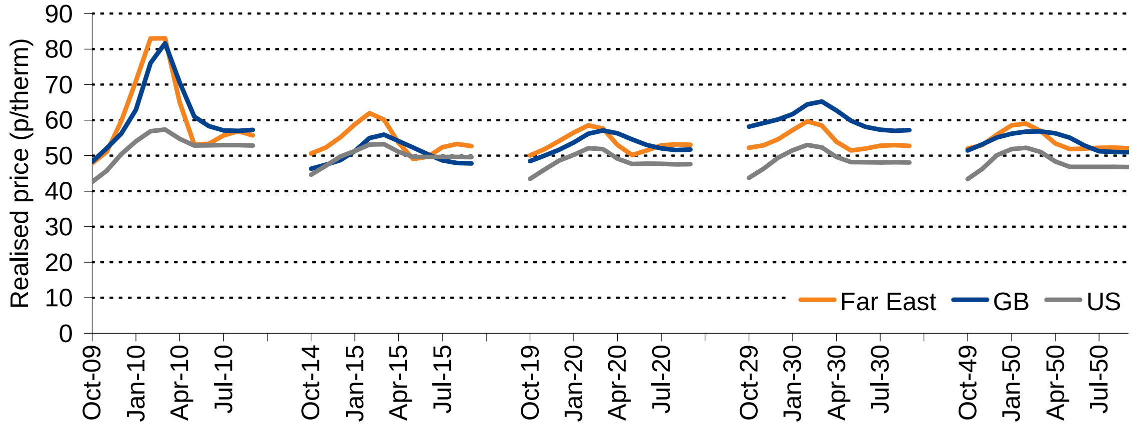
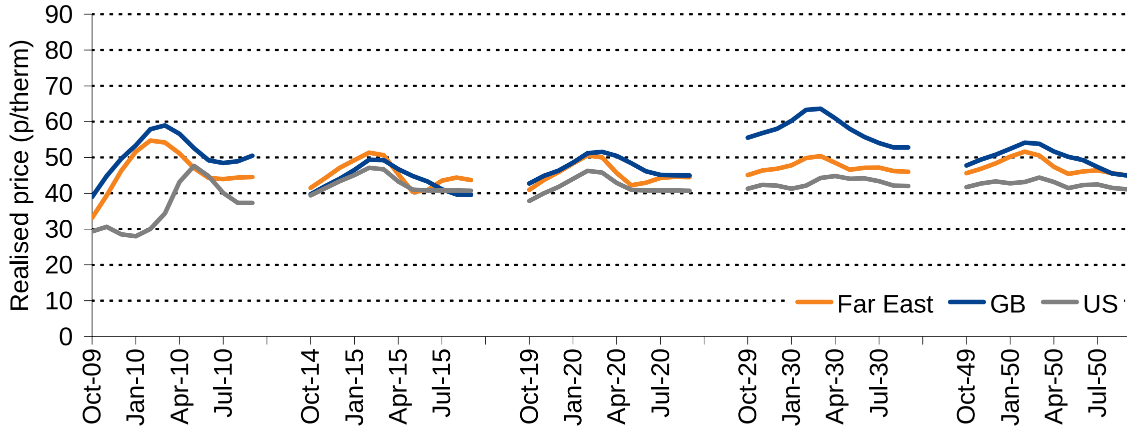


Figure 34 – BAU stress test – gas prices (2009 money)







5.4 Carbon-constrained stress test

5.4.1 Monthly gas flows to GB

This section compares the monthly gas flows to GB between the Carbon-constrained scenario with 2000 typical weather and no outages and the outages of Qatari LNG and Milford Haven, each with 1985 severe weather. This is shown in Figure 35.

In respect of the Qatari outage, the key points arising are:

- There are reduced LNG flows to GB compared to the Carbon-constrained scenario with no outages, reflecting the tighter global LNG supply/demand position. As UKCS production falls off from 2030, GB secures additional LNG from non-Middle Eastern sources at slightly higher cost (see Section 5.4.5).
- The use of storage is reduced in comparison with the Business-as-usual version of this stress test, reflecting the reductions in peak supply/demand requirement (see Section 5.4.4).
- The relative costs of GB gas supplies are such that, under certain circumstances, it makes economic sense to import gas into GB through the GB-Europe interconnector, and, at other times, export gas to Europe via this route. This is shown where the interconnector flows are below the horizontal axis.

In respect of the Milford Haven outage, the key points arising are:

- Flows are broadly similar to those for the Qatari outage case.
- There is a slight reduction in the use of storage (as compared with the Qatari outage) reflecting the ability to use other gas sources for peak demand requirements and there still being sufficient supply capacity to the GB market.

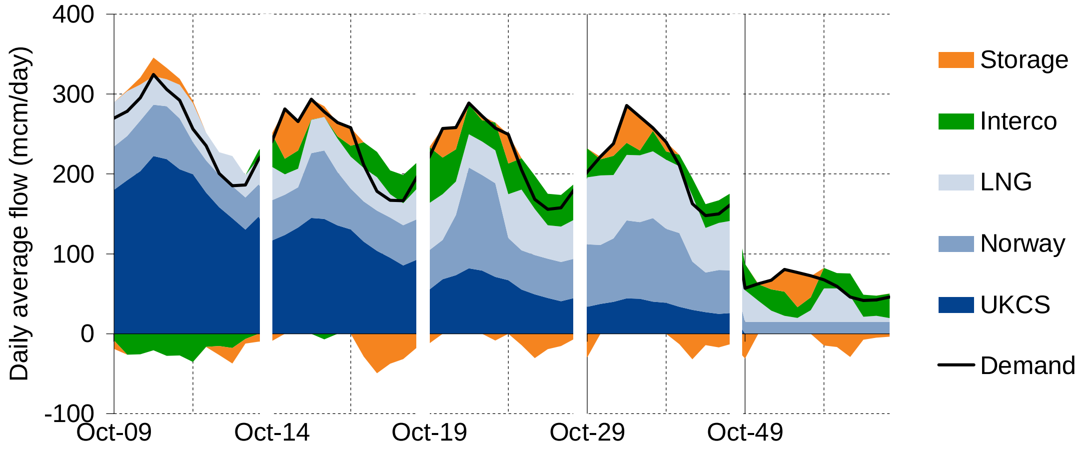
5.4.2 Demand side response

No demand side response is used in GB under either the Qatari Outage or the Milford Haven outage.

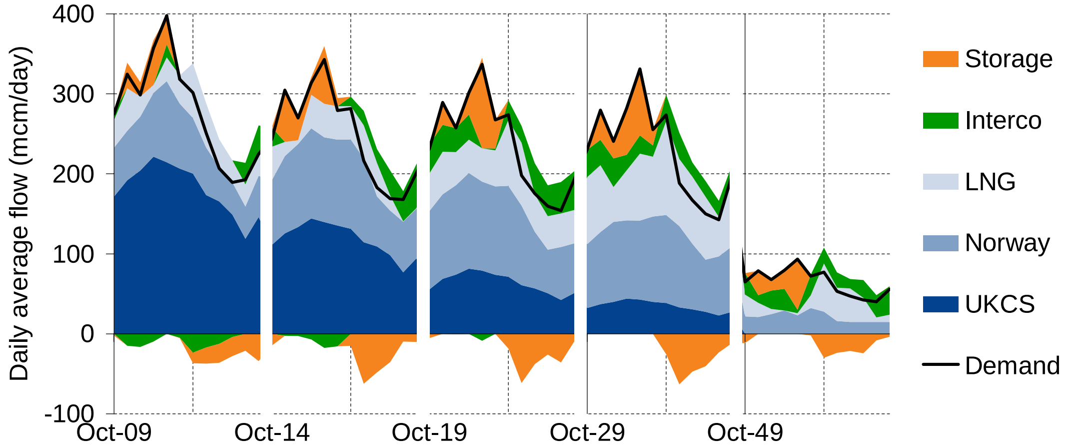
However, for the Qatari outage, a small amount of demand side response was used in Europe in 2009/10 totalling 46mcm.

Figure 35 – CC stress test – monthly gas flows to GB

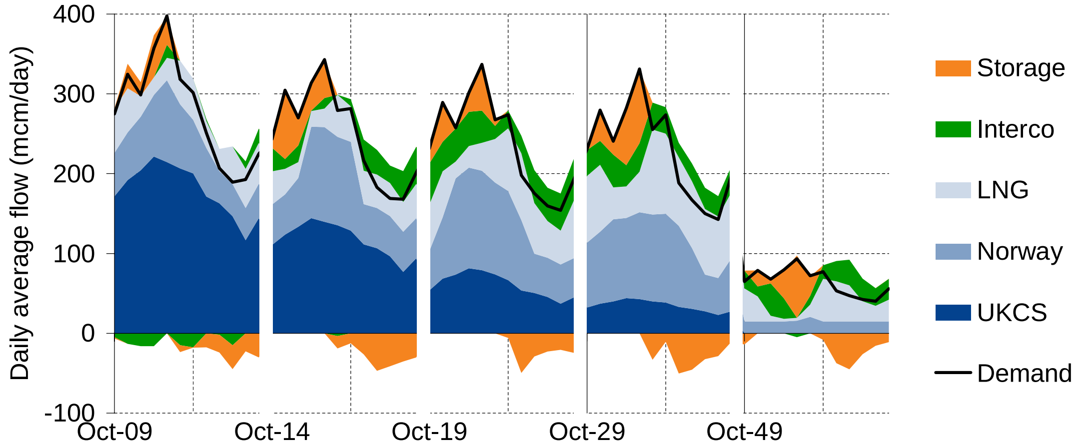
No outage and 2000 typical weather



Qatar outage and 1985 severe weather



Milford Haven outage and 1985 severe weather



5.4.3 LNG flows to GB

In this section we compare the LNG flows to GB between the Carbon-constrained scenario with 2000 typical weather and no outages and the outages of Qatari LNG and Milford Haven, each with 1985 severe weather. This is shown in Figure 36.

In respect of the Qatari outage, the key points arising are:

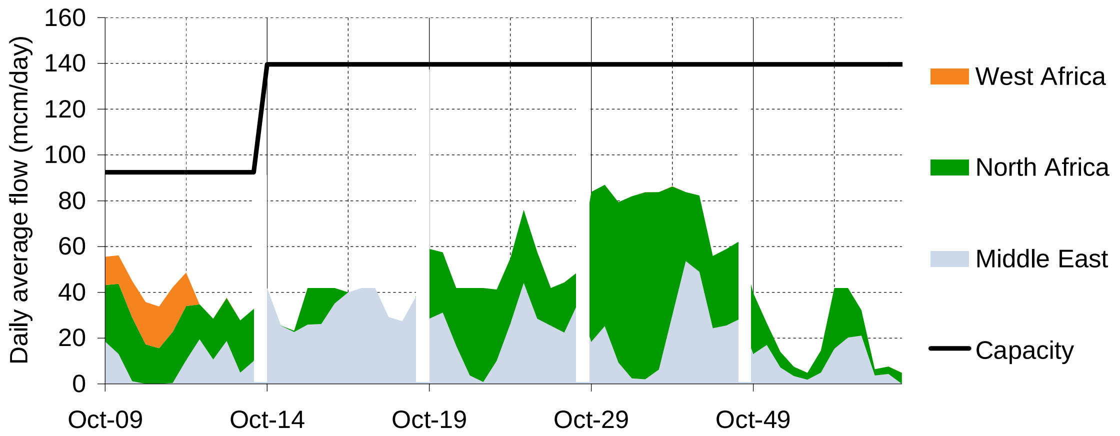
- There are reduced LNG flows to GB during the period of the outage, reflecting the tighter global LNG supply/demand position.
- As soon as the outage is over, LNG flows to GB increase markedly, primarily in order to fill storage (see 5.4.4).
- LNG is sourced principally from North Africa.

In respect of the Milford Haven outage, the key points arising are:

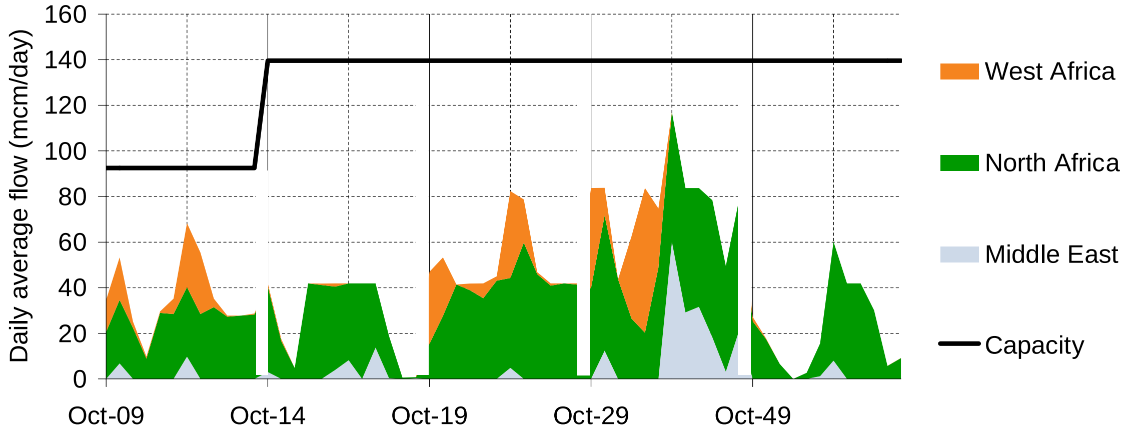
- There are slightly reduced LNG flows after the outage, compared with the Qatari outage, reflecting the ability of GB to source gas from elsewhere.
- Middle Eastern LNG flows continue during this stress test, utilising other GB regasification capacity.

Figure 36 – CC stress test – LNG flows to GB

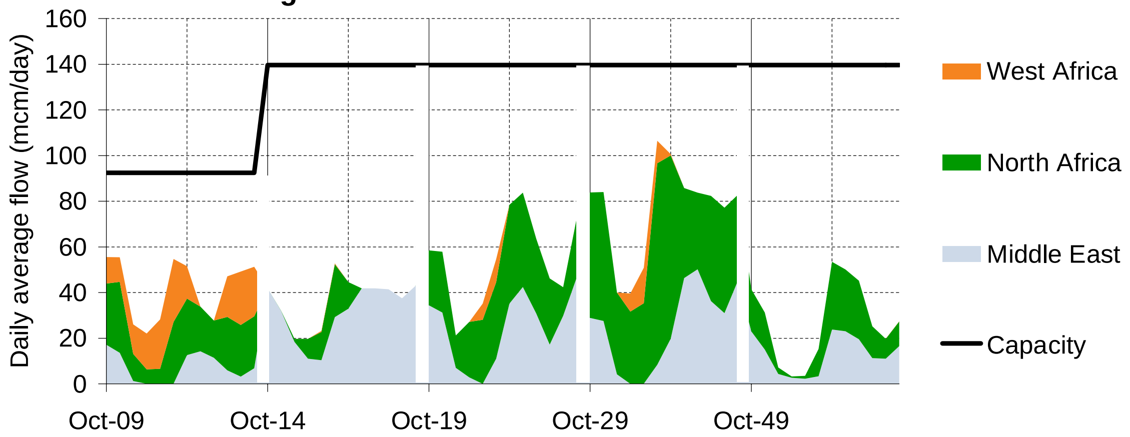
No outage and 2000 typical weather



Qatar outage and 1985 severe weather



Milford Haven outage and 1985 severe weather



5.4.4 Storage use in GB

This section compares the use of storage in GB between the Carbon-constrained scenario with 2000 typical weather and no outages and the outages of Qatari LNG and Milford Haven, each with 1985 severe weather. This is shown in Figure 37.

In respect of the Qatari outage, the key points arising are:

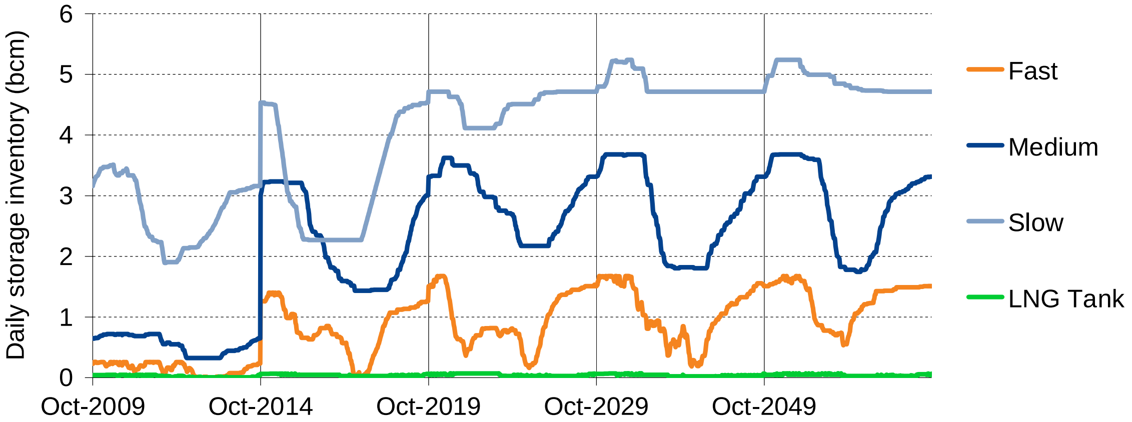
- There is significant increase in the use of storage across the five studied years. All three storage types (slow, medium and fast) are heavily utilised.
- Storage is fully depleted in 2009/10 as this is the cheapest way to meet GB's demand, but this does not lead to demand side response being required as LNG supplies are still available during the shoulder periods.
- There is a reduction in storage use in 2019/20 relative to 2014/50 as additional LNG liquefaction comes online and reduces the impact of the outage. In 2029/30, GB is much more heavily reliant on LNG and hence uses storage much more heavily during the outage. In 2049/50, there is a reduction in storage use as demand in GB has fallen significantly by this year, reducing the relative need for gas from storage during the outage.

In respect of the Milford Haven outage, the key points arising are:

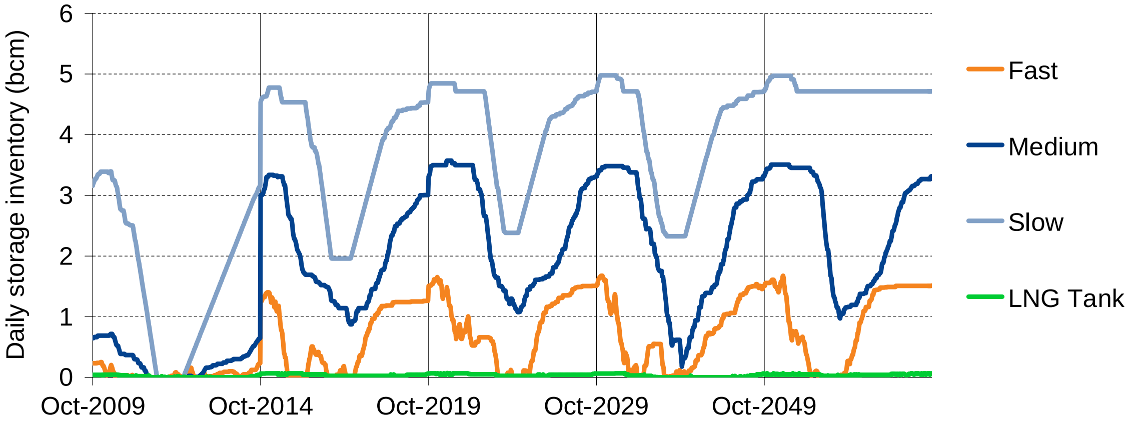
- There is significant use of storage across the five studied years. However, the use of storage is slightly reduced in comparison with the Qatari outage case, reflecting the lower stress on the GB system resulting from the Milford Haven outage in this scenario due to the reduced dependence on LNG compared to the Business-as-usual scenario.
- As for the Qatari outage, storage is fully depleted in 2009/10 as this is the cheapest way to meet GB's demand, but this does not lead to demand side response being required as LNG supplies are still available during the shoulder periods.
- There is a slight reduction in storage use in 2049/50 as reduced global gas demand (outside of GB) reduces the stress on the GB system, and releases additional flexibility from other sources for use by GB.

Figure 37 – CC stress test – storage use in GB

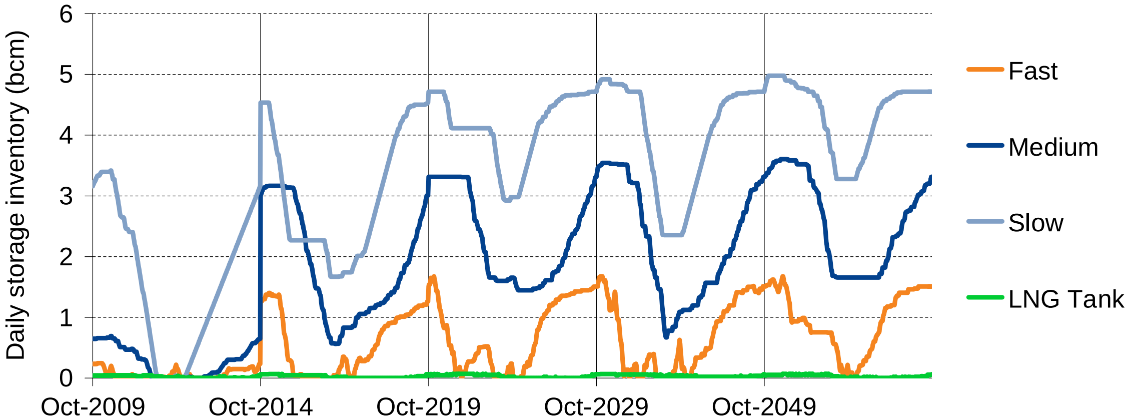
No outage and 2000 typical weather



Qatar outage and 1985 severe weather



Milford Haven outage and 1985 severe weather



5.4.5 Prices

In this section we compare the gas prices for GB, the US and the Far East between the Carbon-constrained scenario with 2000 typical weather and no outages and the outages of Qatari LNG and Milford Haven, each with 1985 severe weather. This is shown in Figure 38.

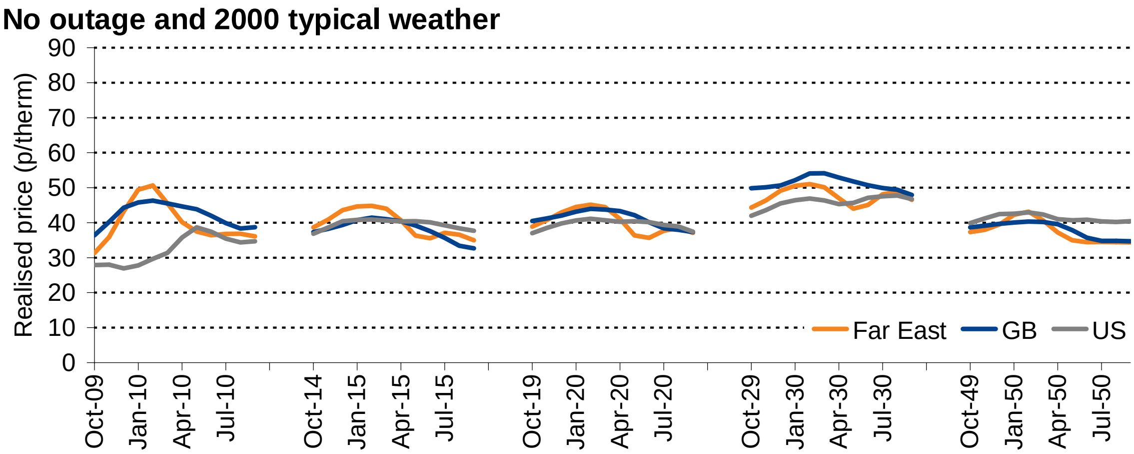
In respect of the Qatari outage, the key points arising are:

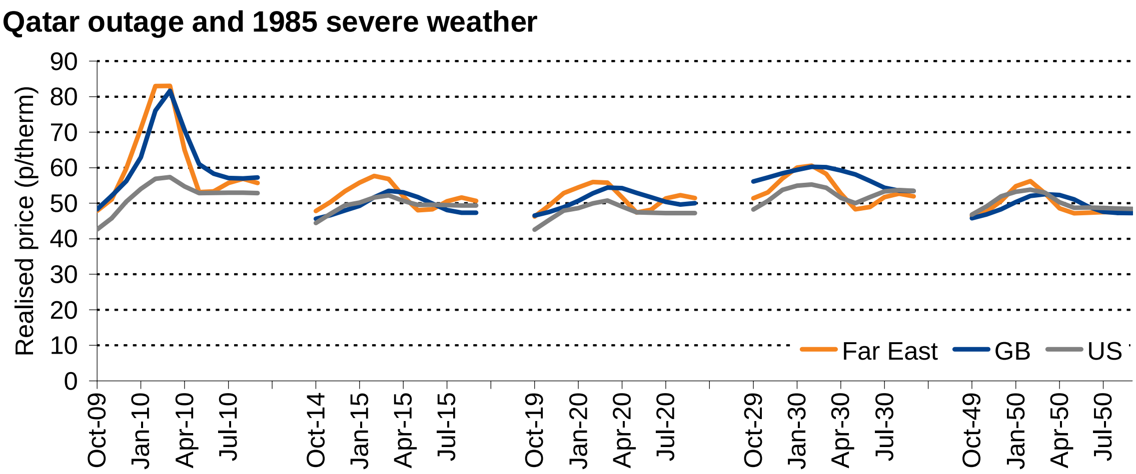
- There is a significant rise in prices in comparison with the no outage case, with GB and Far East prices showing a similar trend. Prices for 2009/10 are the same as those shown in the Business-as-usual scenario due to the supply/demand positions of the two scenarios being identical.
- Prices show further rises in comparison with the no outage case from 2014/15 onwards, although the rises are less than in the Business-as-usual scenario, reflecting the more relaxed supply/demand position due to the reduced demand.

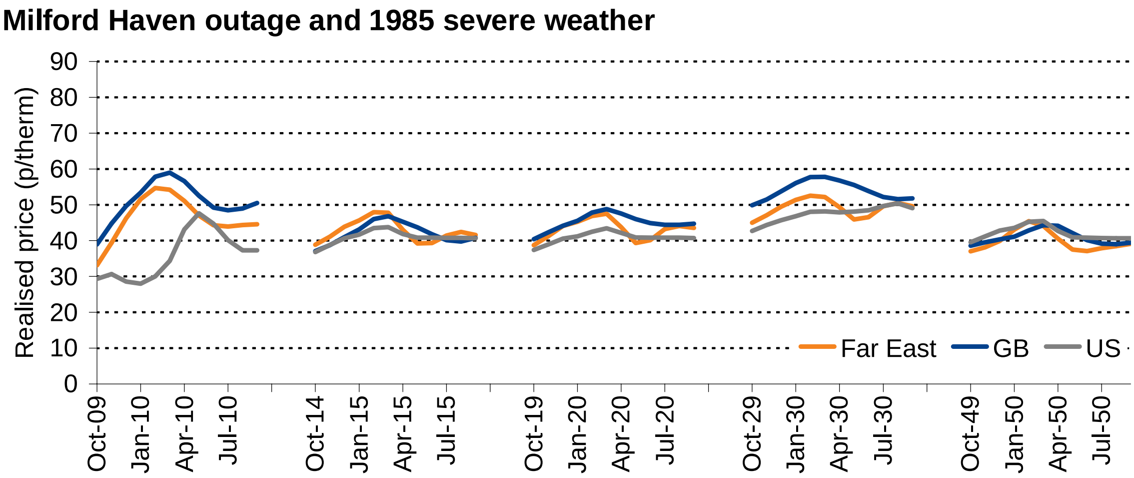
In respect of the Milford Haven outage, the key points arising are:

- Prices show a minimal increase in comparison with the no outage case, and are reduced in comparison with the Qatari outage, reflecting the reduced impact of the GB-based outage as compared to the global LNG supply nature of the Qatari outage.

Figure 38 – CC stress test – gas prices (2009 money)







5.5 National Grid high demand stress tests

In relation to this stress test:

- GB demand is based on the high case sensitivity used by National Grid in its 2009 Ten Year Statement.
- All other demand zones have Business-as-usual demands.
- In response to the increased GB demand level, we have:
  - increased the available GB LNG regasification capacity by 12bcm from 2029/30 onwards (when GB becomes increasingly dependent on LNG imports); and
  - increased GB storage by adding 5.1bcm of storage space, with 124mcm/day of additional deliverability (comprising 2.9bcm and 78 mcm/day from salt caverns and 2.2bcm and 46 mcm/day from depleted fields) from 2019/20 onwards.
- During the Milford Haven outage, 6bcm of the additional 12bcm capacity is included in the outage (reflecting the proportion of total regasification capacity that Milford Haven represents).

5.5.1 Monthly gas flows to GB

This section compares the monthly gas flows to GB between the National Grid high demand (2000 typical weather) case with no outage and the National Grid high demand (1985 severe weather) combined with the outages of Qatari LNG and Milford Haven. This is shown in Figure 39.

In the no outage case, the key points arising are:

- Despite the significant increase in GB demand for this scenario over the Business-as-usual and Carbon-constrained GB profiles, GB is still able to source sufficient gas supplies, without experiencing any demand side response.
- Significant gas volumes are imported from Europe in 2014/15 and 2019/20, and extra volumes of LNG, particularly from 2019/20 onwards.

In the Qatari outage case, the key points arising are:

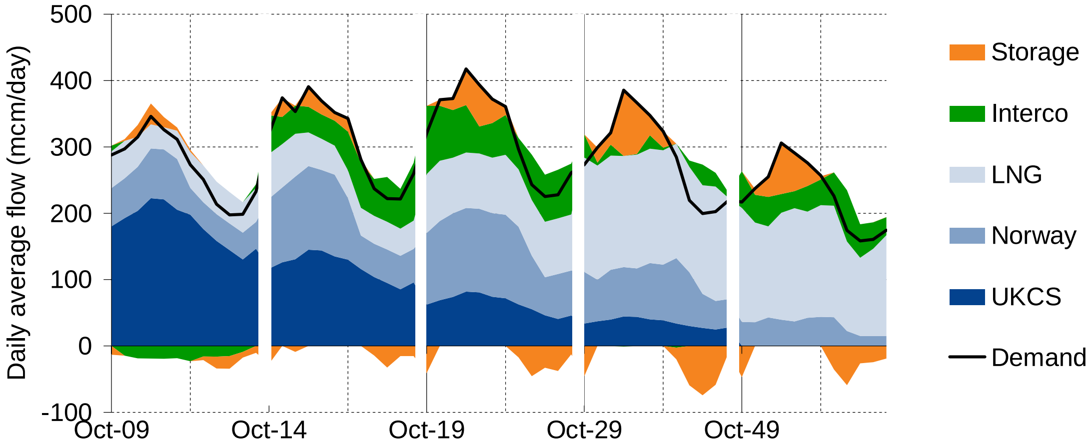
- The GB system is operating at full capacity and there is a very small amount of demand side response in 2009/10, reflecting the tightness in the global LNG supply/demand position.
- Significant use is made of storage for supply/demand balancing and large volumes are imported to GB from Europe.

In the Milford Haven outage case, the key points arising are:

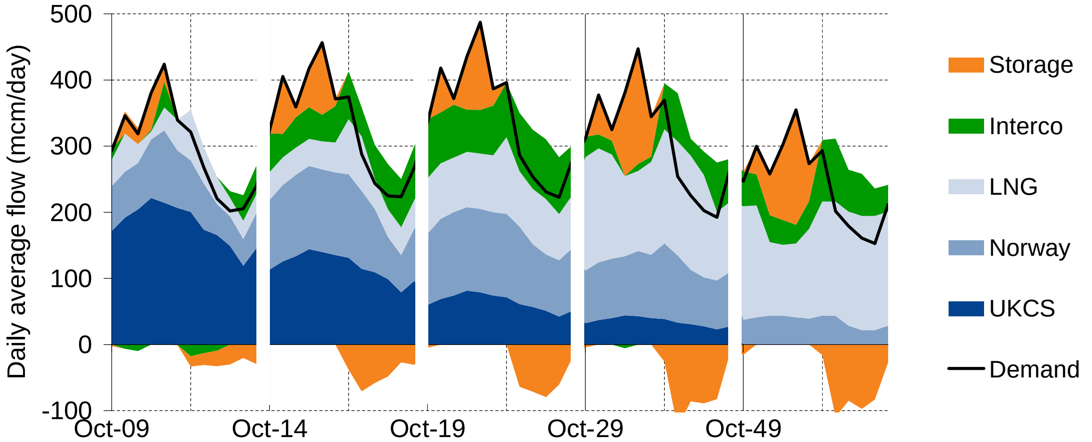
- Although the GB system is operating at full capacity there is no demand side response experienced.
- Significant use is made of the expanded storage for supply/demand balancing and large volumes are imported to GB from Europe.

Figure 39 – NG high demand stress test – monthly gas flows to GB

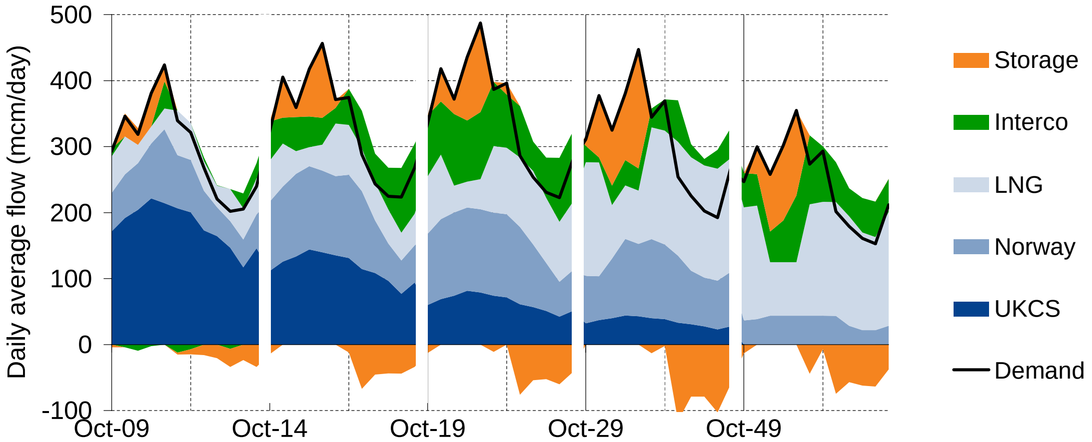
No outage and 2000 typical weather



Qatar outage and 1985 severe weather



Milford Haven outage and 1985 severe weather



5.5.2 Demand side response

A very small amount of demand side response is used in GB in the Qatari Outage stress test in order to meet demand, as shown in Table 10. This level of demand side response will be met by the use of CCGT distillate and I&C interruption.

Table 10 – GB demand side response – Qatari outage

	2009/10	2014/15	2019/20	2029/30	2049/50
GB – Annual	0.053 bcm				
GB – Max daily	27 mcm				

Demand side response is also used in Europe in 2009/10 under the Qatari outage totalling 0.7bcm, and in the Far East totalling 3.5mcm.

No demand side response is required under the Milford Haven outage, although in 2009/10 and 2029/30 storage is completely depleted. The availability of LNG through other GB regasification capacity allows GB demand to continue to be met.

5.5.3 LNG flows to GB

This section compares the LNG flows to GB between the National Grid high demand (2000 typical weather) case and the National Grid high demand (1985 typical weather) combined with the outages of Qatari LNG and Milford Haven. This is shown in Figure 40.

In the no outage case, the key points arising are:

- Significant volumes of LNG are attracted to GB due to the high GB demand, with the existing GB regasification capacity being highly utilised in 2029/30 and 2049/50.
- The LNG sources are predominantly from Africa and the Middle East.
- Due to the strength of GB's requirement for LNG a small quantity is attracted from the Far East LNG market in 2029/30.

In the Qatari outage case, the key points arising are:

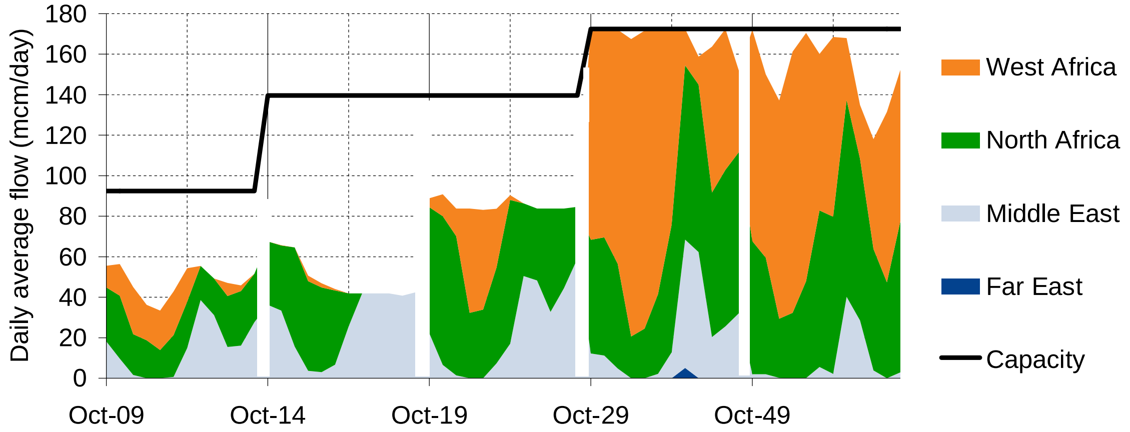
- LNG imports increase after the outage period to make up the shortfall, and are used to fill storage (see Figure 40)
- The LNG sources are predominantly from Africa.

In the Milford Haven outage case, the key points arising are:

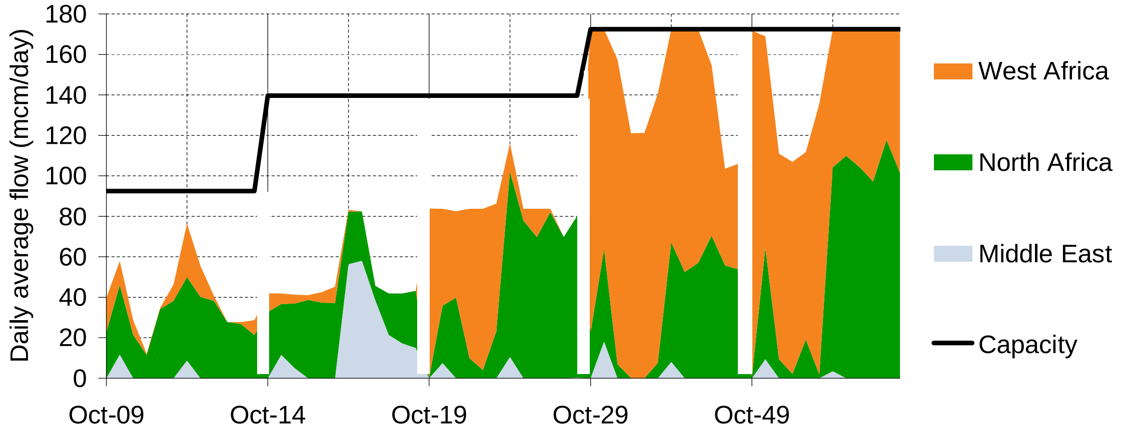
- LNG imports increase after the outage period in order to help refill storage (see Figure 40).
- The LNG sources are predominantly from Africa and the Middle East.
- Due to the strength of GB's requirement for LNG a small quantity is attracted from the Far East LNG market in 2029/30.

Figure 40 – NG high demand stress test – LNG flows to GB

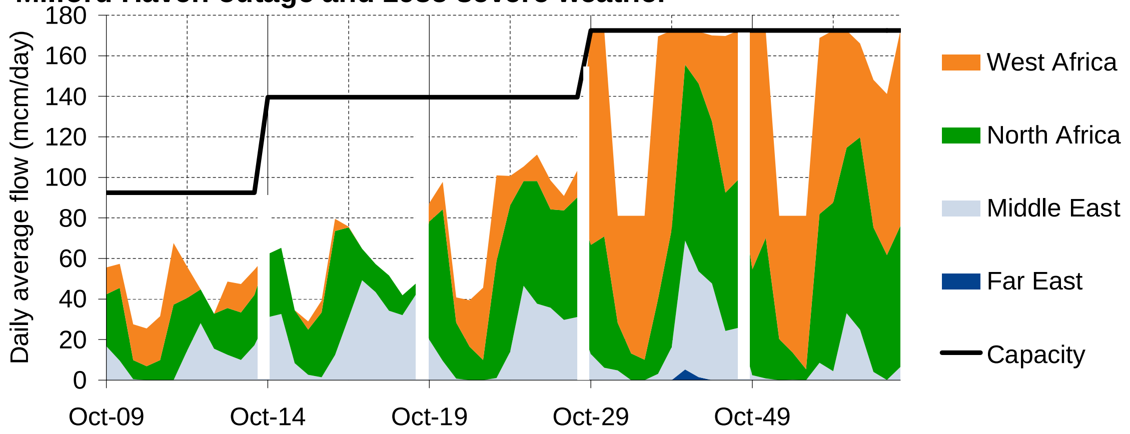
No outage and 2000 typical weather



Qatar outage and 1985 severe weather



Milford Haven outage and 1985 severe weather



5.5.4 Storage use in GB

In this section we compare the use of storage in GB between the National Grid high demand (2000 typical weather) case and the National Grid high demand (1985 severe weather) combined with the outages of Qatari LNG and Milford Haven. This is shown in Figure 41.

In the no outage case, the key point arising is:

- Storage use increases over the five studied years, reflecting the increasing practice of accessing non-UKCS supplies during summer (when they are cheaper than during the winter) and injecting into storage for use during the winter.

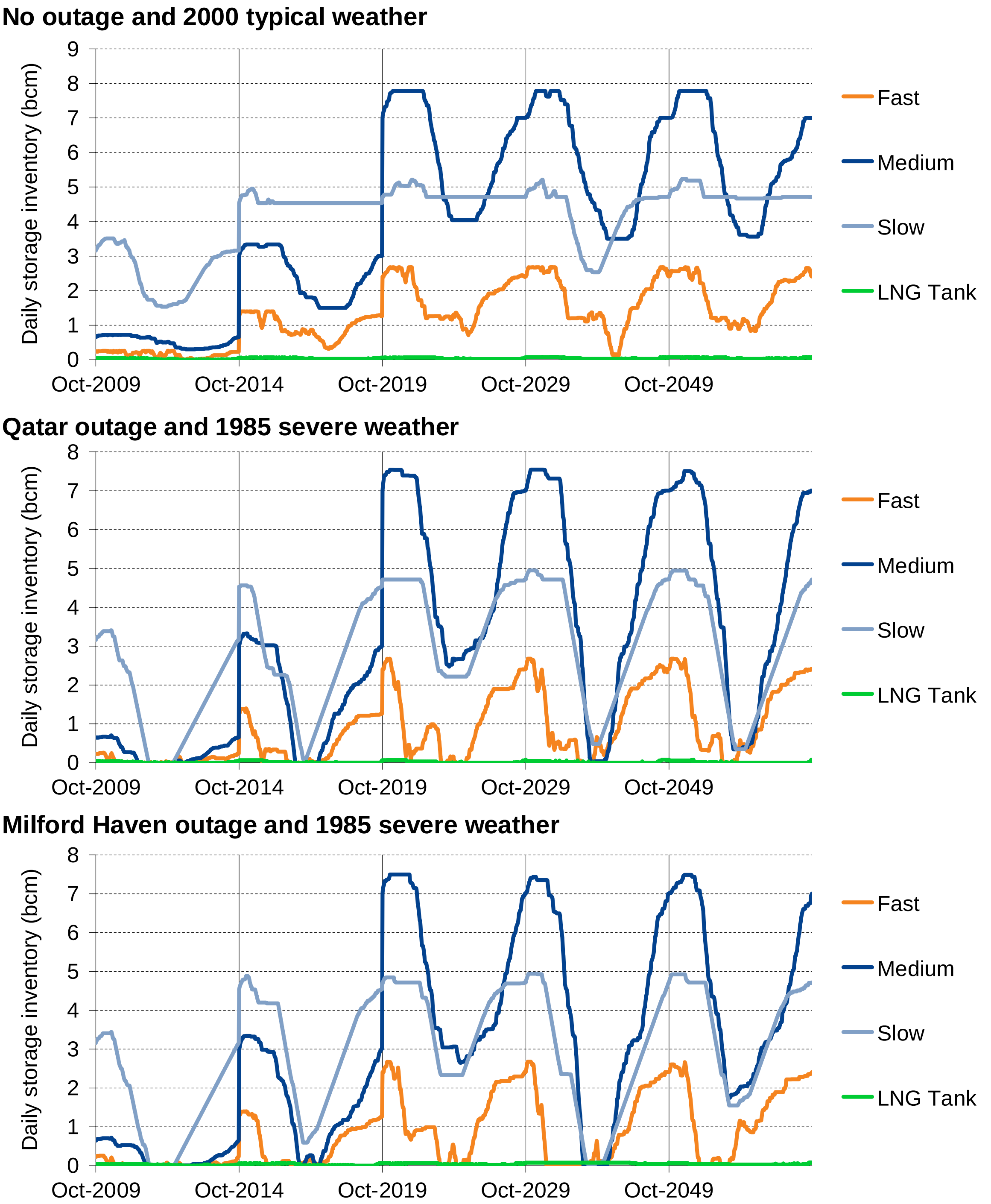
In the Qatari outage case, the key points arising are:

- There is significant use of storage in four of the five modelled years, during which storage is almost fully depleted. This reflects the increasing practice of accessing non-UKCS supplies during summer (when they are cheaper than during the winter) and injecting into storage for use during the winter.
- In 2009/10 and 2014/15 storage is fully depleted. In 2009/10, a very small amount of demand side response is required which can be met via the use of CCGT distillate and I&C interruption. In 2014/15 GB demand can continue to be met via the availability of LNG.

In the Milford Haven outage case, the key points arising are:

- There is significant use of storage in three of the five studied years. This reflectis the increasing practice of accessing non-UKCS supplies during summer (when they are cheaper than during the winter) and injecting into storage for use during the winter.
- In 2009/10 and 2029/30 storage is fully depleted, but GB can continue to be met via the availability of LNG.

Figure 41 - NG high demand stress test – storage use in GB



5.5.5 Prices

This section compares gas prices in GB, the US and the Far East between the National Grid high demand (2000 typical weather) case and the National Grid high demand (1985 servere weather) combined with the outages of Qatari LNG and Milford Haven. This is shown in Figure 42.

In the no outage case, the key points arising are:

- GB prices are slightly higher than those for the Business-as usual scenario (see Figure 34), reflecting the higher GB demand profile.
- US and Far East prices are very similar to the Business-as-usual scenario.

In the Qatari outage case, the key points arising are:

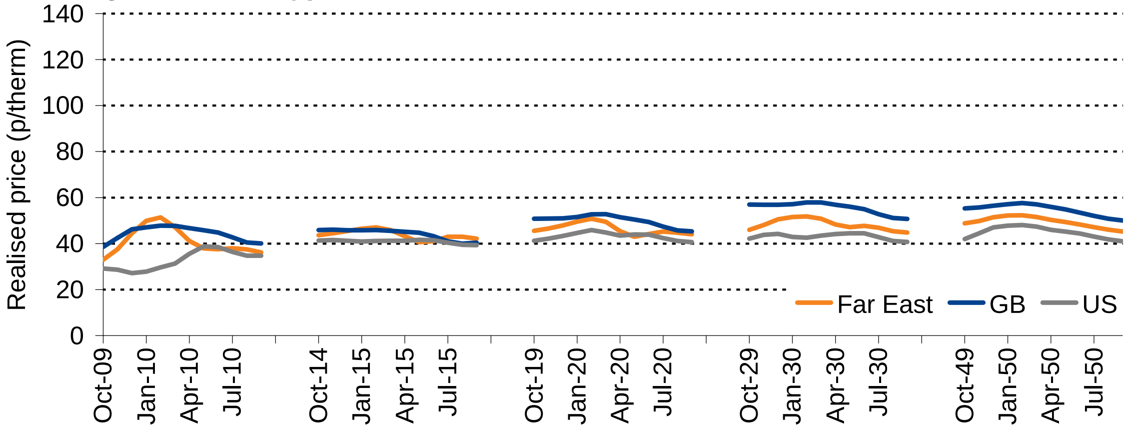
- GB prices spike more under this stress test than in the no outage National Grid high demand case.
- Far East prices are also higher than in the no outage National Grid high demand case, reflecting the global impact of the Qatari outage and the impact of GB's additional demand (an increase of around 70 bcm in 2049/50 compared with the Business-as-usual scenario).
- The price spikes in GB and the Far East are particularly pronounced in 2009/10 due to the tighter LNG demand in this year. As additional LNG liquefaction comes on stream in later years this position is eased.
- US prices show a much reduced impact, as the US is able to use its own cheap storage instead of needing to access more expensive LNG supplies.

In the Milford Haven outage case, the key points arising are:

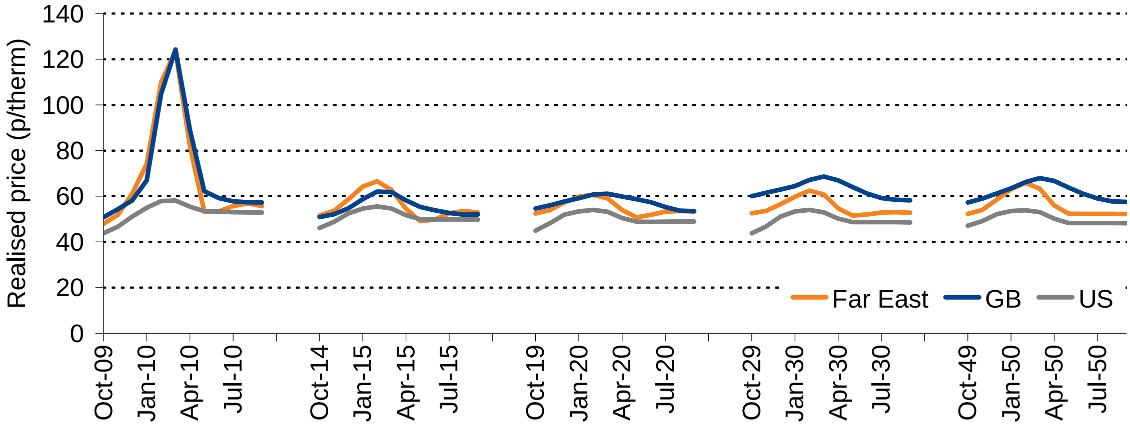
- GB prices also increase under this stress test though less so than in the Qatari outage case. This price rises reflect GB's need to access more expensive non-LNG supplies, and its need to increase the use of storage.
- There is minimal impact from this stress test on Far East and US prices, reflecting the local nature of the Milford Haven outage.

Figure 42 – NG high demand stress test – gas prices (2009 money)

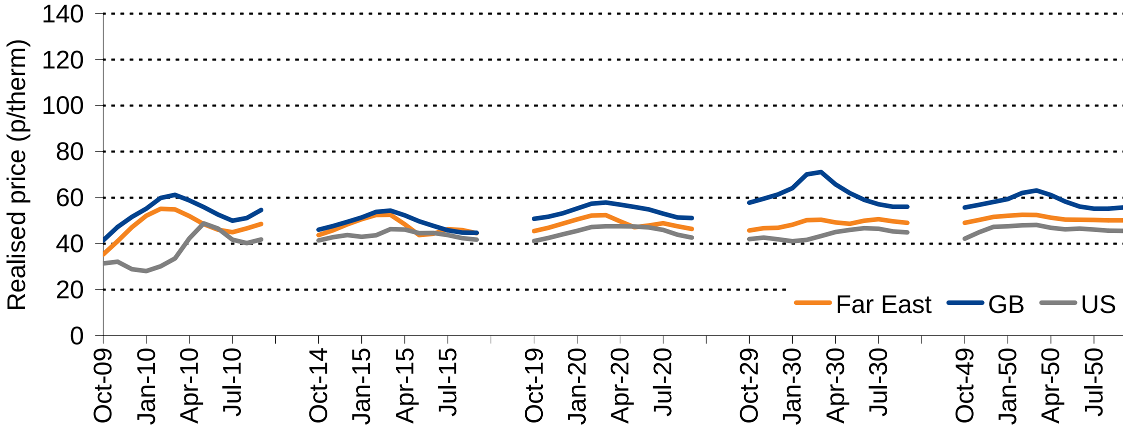
No outage and 2000 typical weather



Qatar outage and 1985 severe weather



Milford Haven outage and 1985 severe weather



5.6 US unconventional gas sensitivity

In this section we examine the effect of changes to the quantity of projected US unconventional gas production, as follows:

- In the increased production scenario we assume a 7% increase on Business-as-usual US unconventional gas production.
- In the decreased production scenario we assume a 7% decrease on Business-as-usual US unconventional gas production.
- The increase (and, conversely, decrease) in unconventional gas production amounts to 20bcm (of around 300bcm total US unconventional gas production) in 2009/10 through to 23bcm (of 340bcm total) in 2049/50.

The following results compare the Business-as-usual scenario under 1985 weather severity and the same scenario with both an increase and a decrease to the assumed projections for US unconventional gas supplies.

5.6.1 Monthly gas flows to GB

This section compares the monthly gas flows to GB between the Business-as-usual (1985 severe weather) case and the same scenario with increased and decreased projections for US unconventional gas production. This is shown in Figure 43.

In the Business-as-usual case, the key points arising are:

- The increased level of demand due to the severe winter causes a high level of storage use in GB in all modelled years, and in some cases choosing to supply the continent during these periods via the GB-Europe interconnector.
- In 2049/50, GB exports heavily due to its low demand compared to Europe.

In the High US unconventional gas scenario:

- The reduced requirement for LNG in the US means that more is available to GB, hence LNG flows increase in some years.

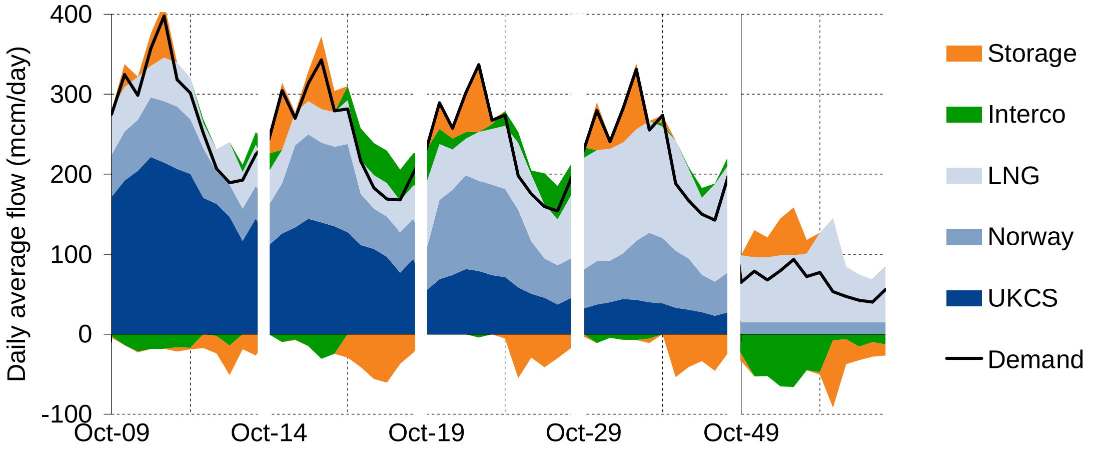
In the Low US unconventional gas sensitivity:

- Due to its reduced indigenous production, the US has a higher demand for LNG, making it less available to GB. This has the most noticeable effect during the summer months in 2029/30 where LNG is replaced by Norwegian gas flows.

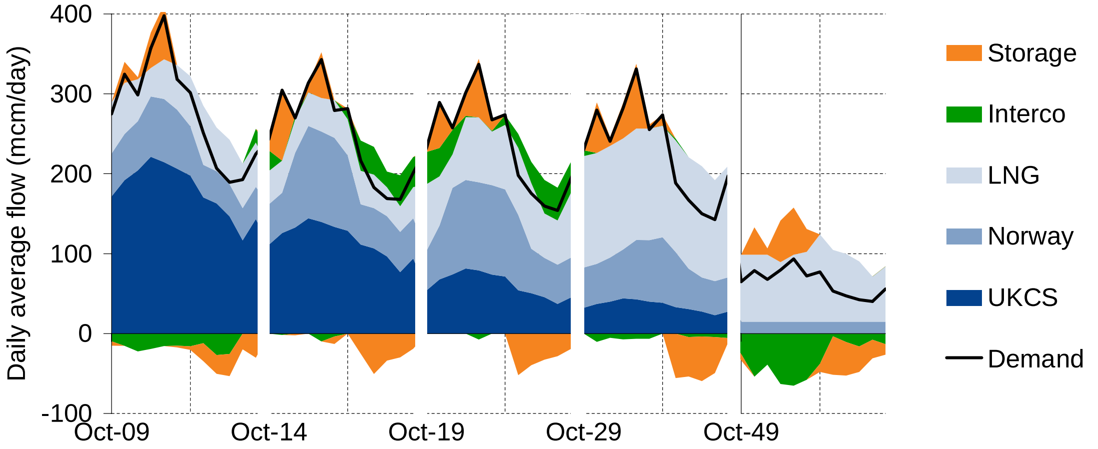
In terms of the use of storage, there is minimal variation between the Business-as-usual, the high US unconventional gas production case and the low US unconventional gas production case. Storage is used extensively across all years given the winter severity, but is never fully depleted.

Figure 43 – US unconventional gas sensitivity – monthly gas flows to GB

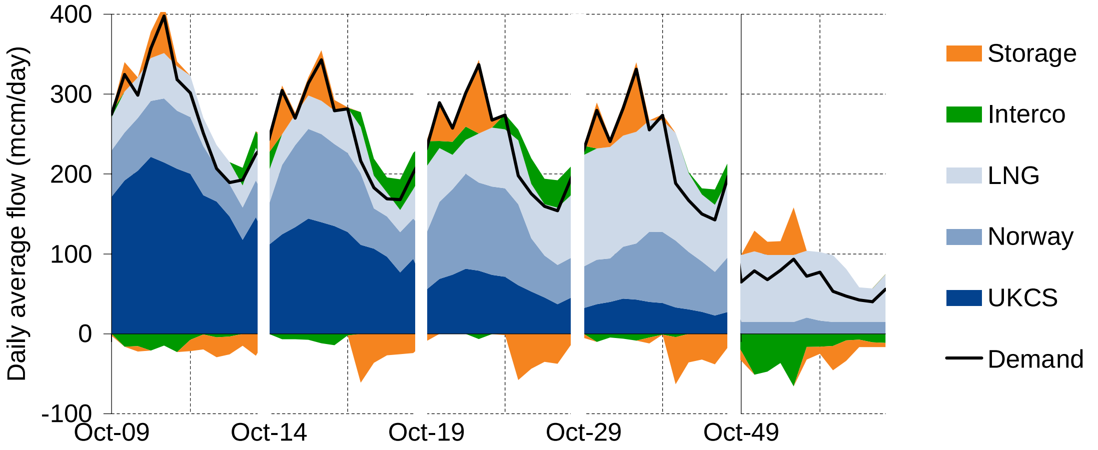
Business-as-usual



High US unconventional gas



Low US unconventional gas



5.6.2 LNG flows to GB

This section compares the LNG flows to GB between the Business-as-usual (1985 severe weather) case and the low and high projections scenarios for US unconventional gas production. This is shown in Figure 44.

In the Business-as-usual case, the key points arising are:

- LNG imports increase over the period, peaking in 2029/30 due to GB's high reliance on LNG by this year.
- In 2029/30, the terminal utilisation is at 100% during the winter due to the severe weather induced demand.

In the High US unconventional gas scenario:

- LNG flows to GB increase significantly from those in the Business-as-usual scenario. In 2009/10, extra LNG is imported during the summer months, whereas in 2019/20 more is made available to GB over the winter.

In the Low US unconventional gas sensitivity:

- LNG flows to GB are decreased from those in the Business-as-usual scenario, mainly in the summer months, as additional LNG quantities are required by the US during the summer to balance its increased use of storage during the winter.

5.6.3 Prices

This section compares gas prices in GB, the US and the Far East between the Business-as-usual (1985 severe weather) case and the high and low projections scenarios for US unconventional gas production. This is shown in Figure 45 on page 92.

In the Business-as-usual case, the key points arising are:

- GB prices are generally at a higher level than those for the US and Far East over the modelled period, and are higher than the Business-as-usual scenario prices under typical weather (see Figure 29 on page 61).

In the High US unconventional gas scenario:

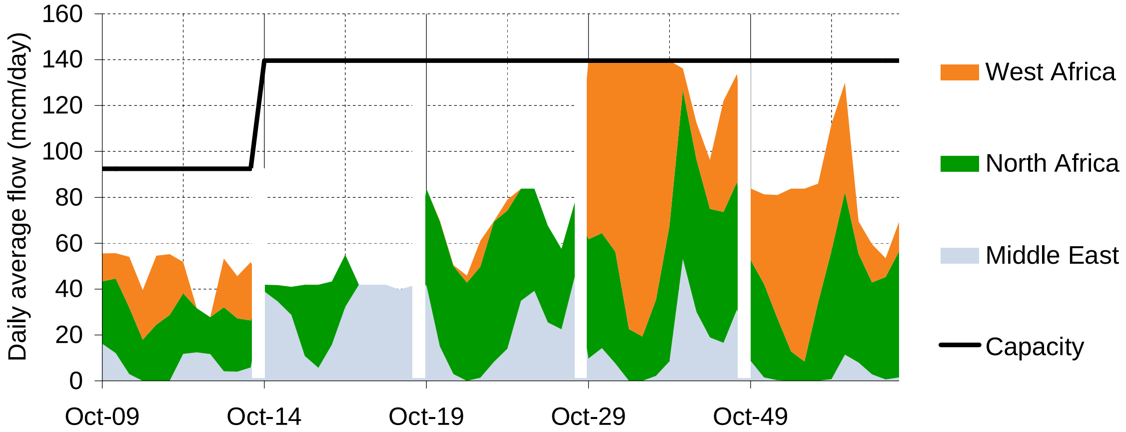
- Winter prices during the first three modelled years are slightly lower than in the Business-as-usual scenario, reflecting the surplus of LNG turned down by the US during winter as a result of its higher unconventional gas production.
- Summer prices are less affected as the US demand for LNG is higher during the summer, as it refills storage volumes used during the winter.

In the Low US unconventional gas sensitivity:

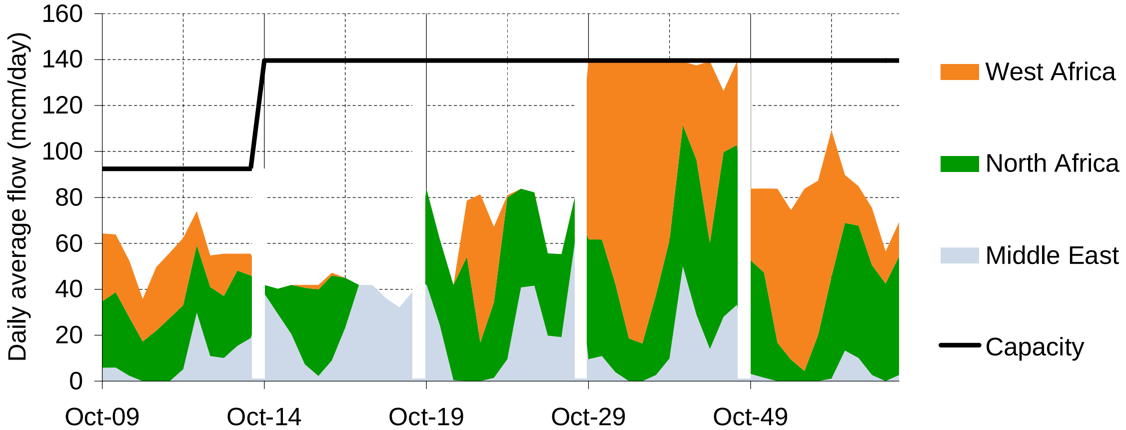
- Gas prices are higher than they are in the Business-as-usual scenario, over the modelled period and particularly in 2009/10, as the reduced US unconventional gas production causes a tightening in the global capacity margin. The resulting higher demand for LNG in the US makes LNG less available to GB and other zones.

Figure 44 – US unconventional gas sensitivity – LNG flows to GB

Business-as-usual



High US unconventional gas



Low US unconventional gas

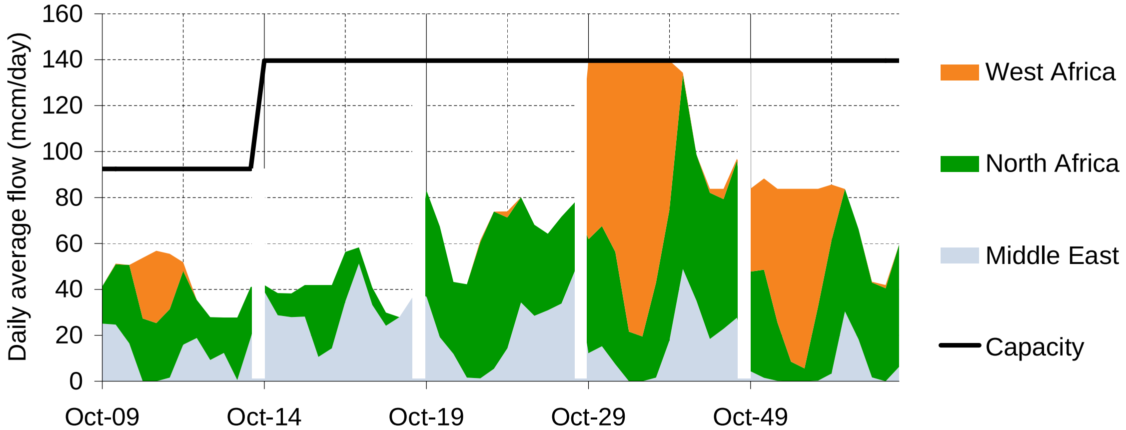
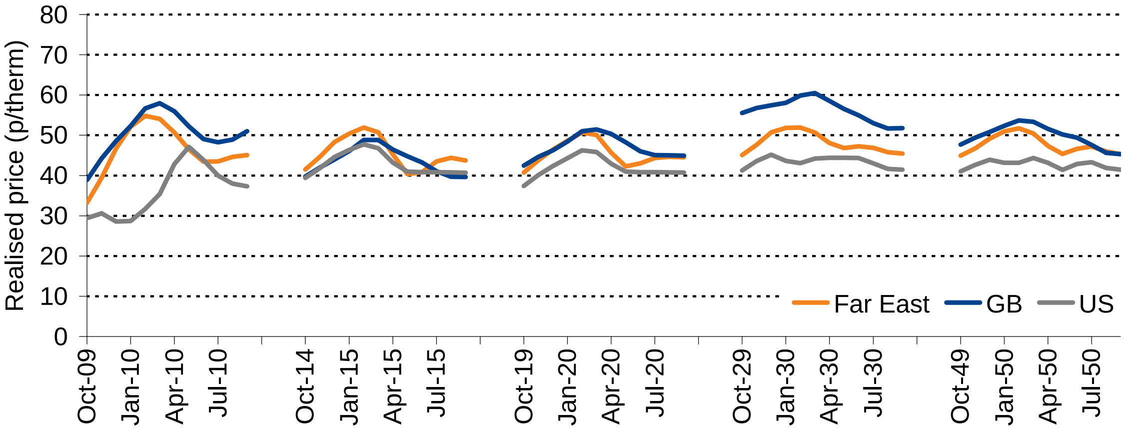
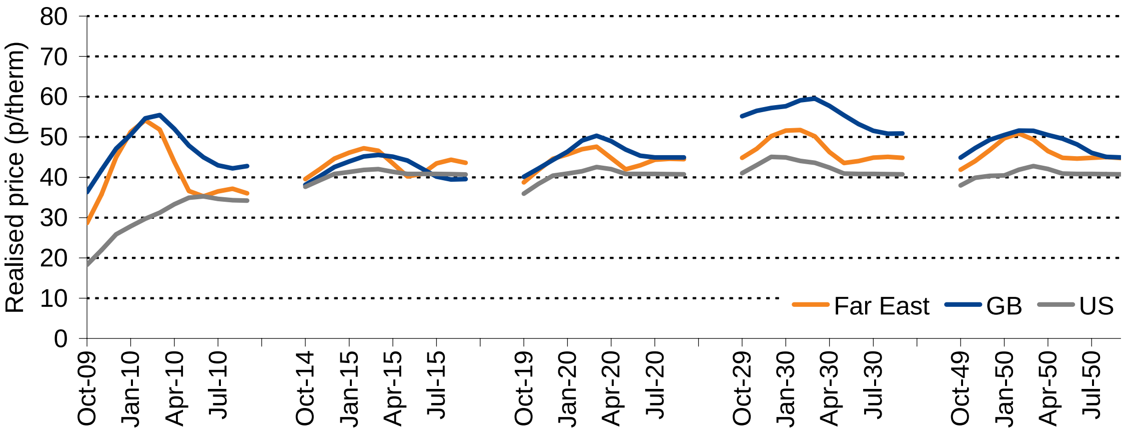


Figure 45 – US unconventional gas sensitivity – gas prices (2009 money)

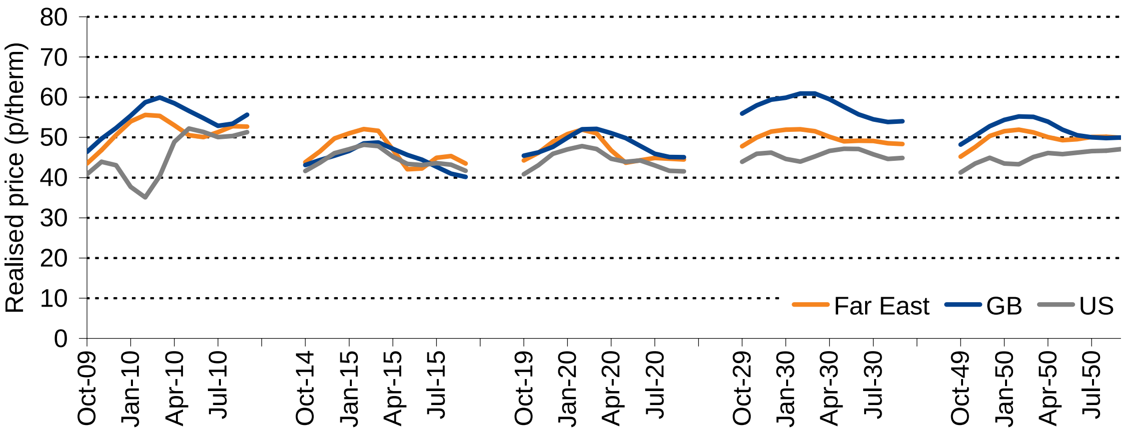
Business-as-usual



High US unconventional gas



Low US Unconventional gas



5.7 US storage flexibility sensitivity

In this section we examine the effect of changes in the behaviour of US storage utilisation by increasing US storage costs to the same level as European storage costs. The following results compare the Business-as-usual scenario under 1985 weather severity with an increase in US storage costs so that they match those in Northwest Europe.

5.7.1 Monthly gas flows to GB

This section compares the monthly gas flows to GB between the Business-as-usual (1985 severe weather) case and the same scenario with higher US storage costs. This is shown in Figure 46.

In the higher cost US storage sensitivity:

- Reduced LNG volumes are available to GB over winter due to higher demand from the US (which is using it in preference to gas from storage). This is more noticeable in 2029/30 and 2049/50 where the reduced LNG flows are replaced by increased storage use, increased flows from Norway, and, in 2049/50, reduced exports during winter.

5.7.2 LNG flows to GB

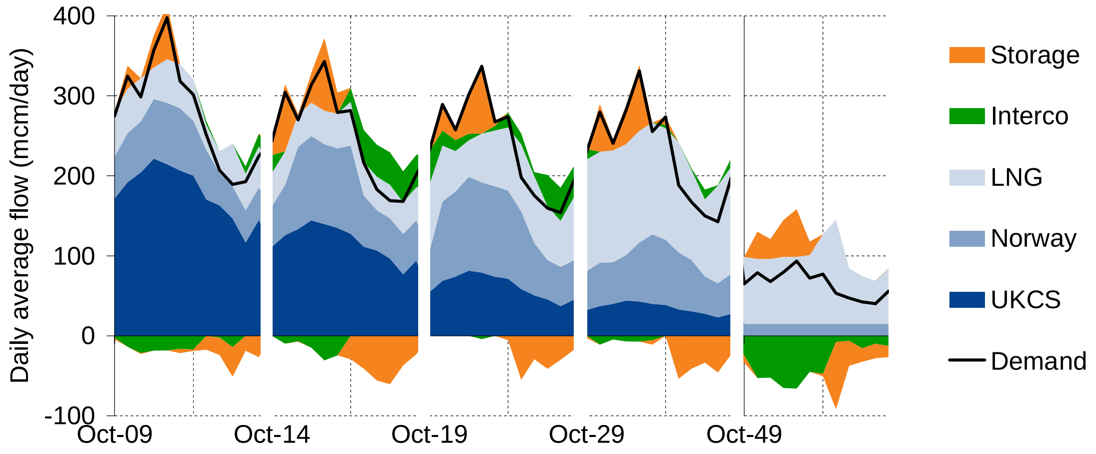
This section compares the LNG flows to GB between the Business-as-usual (1985 severe weather) case and the same scenario with higher US storage costs. This is shown in Figure 47.

In the higher cost US storage sensitivity:

- LNG flows to GB decrease from those in the Business-as-usual scenario, mainly over the winter months, as additional quantities are required by the US due to its increased cost of storage use.
- In 2029/30 and 2049/50, much of the West African LNG supplies to GB have been replaced, largely by North African LNG as more West African LNG is attracted the US market over the winter period (on a least cost basis).

Figure 46 – US storage flexibility sensitivity – monthly gas flows to GB

Business-as-usual



Higher cost US storage

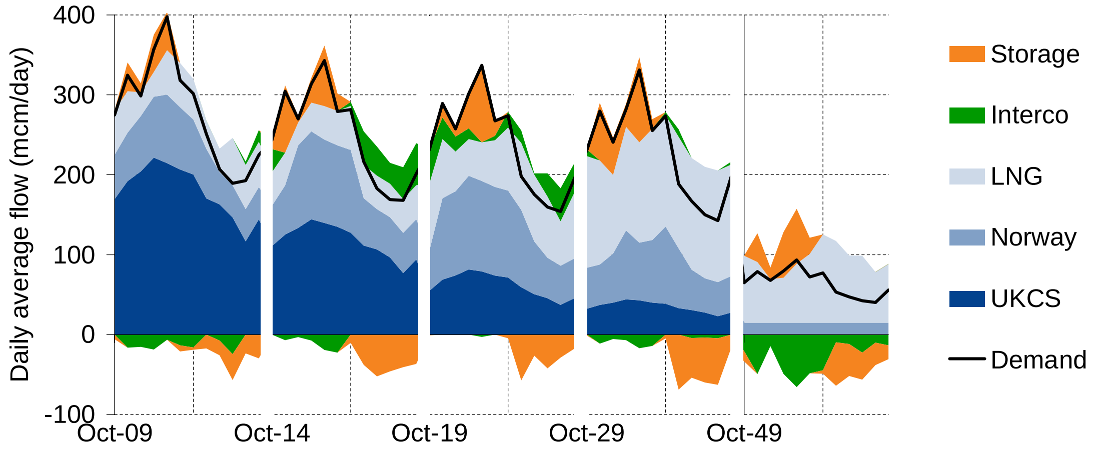
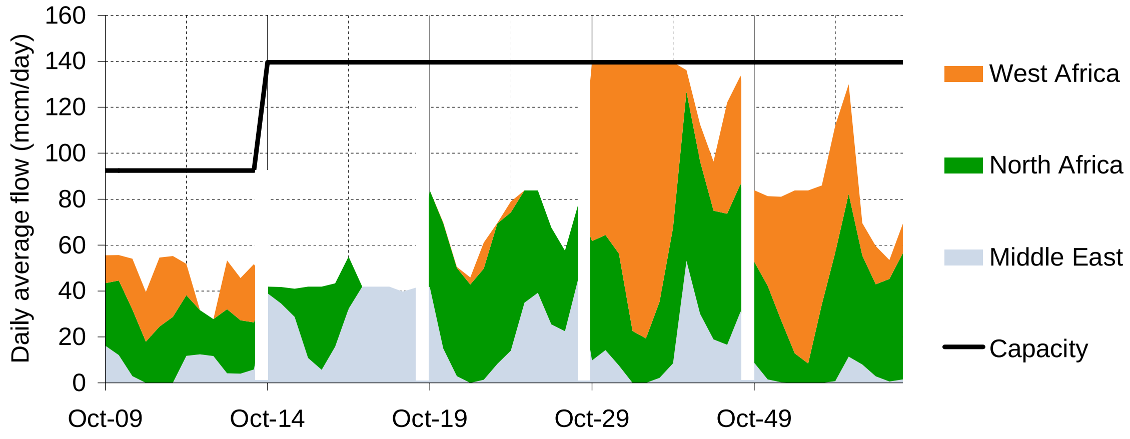
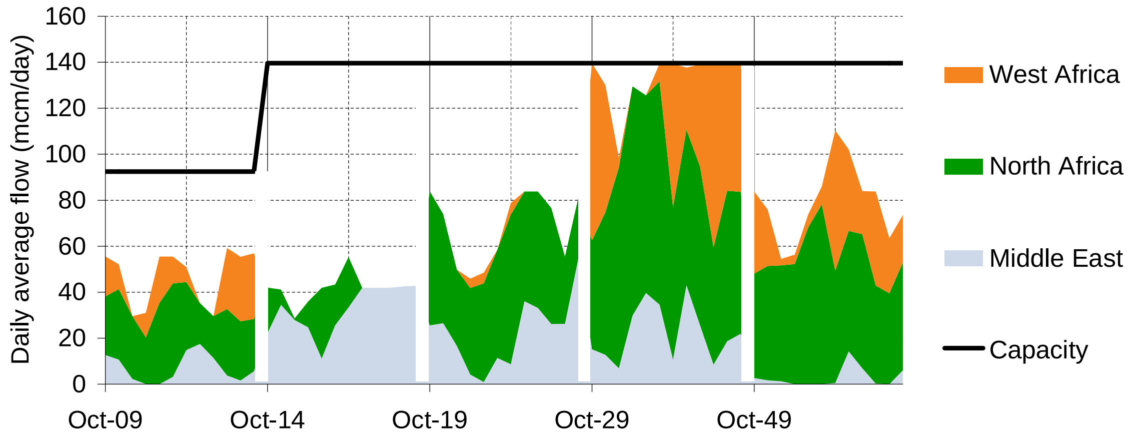


Figure 47 – US storage flexibility sensitivity – LNG flows to GB

Business-as-usual



Higher cost US storage



5.7.3 Prices

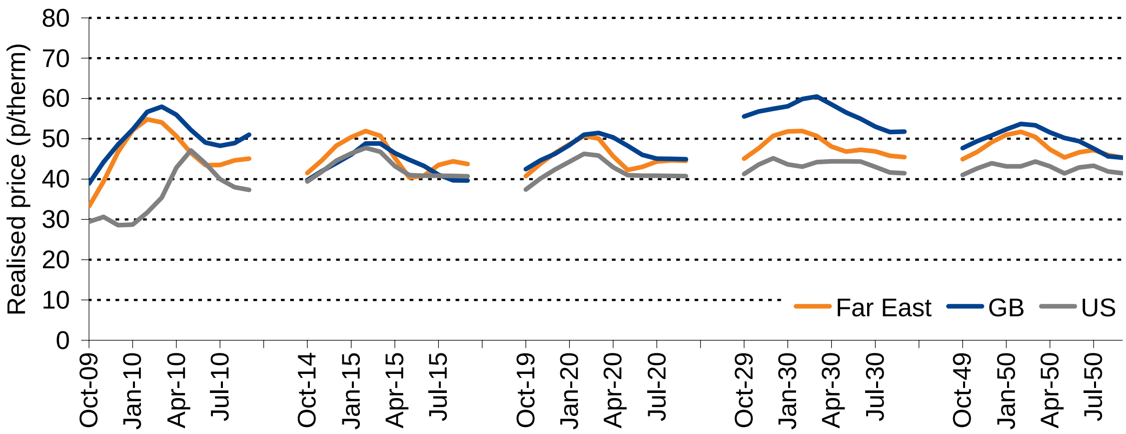
This section compares gas prices in GB, the US and the Far East between the Business-as-usual (1985 severe weather) case and the same scenario with higher US gas storage costs. This is shown in Figure 48.

In the higher cost US storage sensitivity:

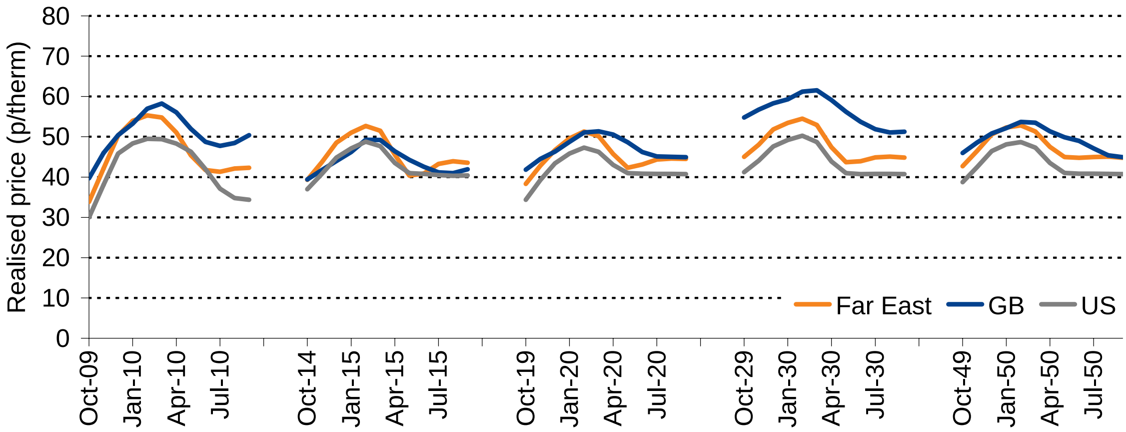
- Gas prices in GB are generally unchanged from those in the Business-as-usual scenario.
- The US and Far East show increased seasonality, however, when compared with the Business-as-usual scenario, reflecting the increased tightness in the LNG market as a result of the increased flows to the US during winter (in preference to their storage use).

Figure 48 – US Storage flexibility sensitivity – gas prices (2009 money)

Business-as-usual



Higher cost US storage



5.8 Dedicated GB LNG supply contract sensitivity

In this sensitivity we have modelled the effect of a dedicated LNG supply contract to GB in order to examine the impact this would have on gas flows and to see whether it has the unintended consequence of displacing other market related gas sources, and hence the overall potential effect on GB security of supply.

We would expect such a long-term dedicated LNG contract to be priced in accordance with the discussion in Section 2.6, namely either tied to an actively traded hub e.g. the NBP, or under a long-term take-or-pay contract with oil indexation. In particular, we would expect such a contract to include an element of price premium, over and above a purely market-related price, which would be required by the LNG supplier to guarantee deliveries to GB, as opposed to being able to freely sell the LNG to the highest priced global market. In terms of modelling we have assumed that the gas is a dedicated supply even though such destination clauses are not permitted under EU regulations.

5.8.1 Monthly gas flows to GB

This section compares the monthly gas flows to GB between the Business-as-usual (1985 severe weather) case and the dedicated GB LNG contract sensitivity with the same weather severity. This is shown in Figure 49 on page 98.

In the dedicated GB LNG supply contract sensitivity:

- LNG flows to GB are significantly greater than in the Business-as-usual scenario, particularly in the years 2009/10, 2014/15 and 2019/20, when LNG flows increase by 45%, 69% and 38% respectively in these years compared to the Business-as-usual scenario. In these early years, the additional LNG flows are predominantly displacing gas supplies from Norway and flows to GB through the European interconnectors (indeed interconnector exports are seen to increase in the dedicated LNG contract case). In years 2029/30 and 2049/50, the increase in LNG flows is less as there is limited extra available LNG regasification capacity in GB, and (in 2049/50) due to very low GB demand.
- Therefore, in terms of the overall potential impact on GB security of supply resulting from this sensitivity, there is a somewhat mixed picture. The displacement of Norwegian supplies could be regarded as having a negative impact, since such supplies are in relatively close proximity to GB and from a politically stable source. On the other hand, the displacement of imports through the European interconnectors, where the gas source is likely to be predominantly from Russia and neighbouring regions, could be viewed as having a positive impact, given the political uncertainties associated with such supplies. Equally, the increased exports to Europe experienced under this sensitivity could also be viewed as a positive contribution to GB gas security of supply as it behaves as the beginning of the pipe rather than being at the end of a long European pipe.
- Storage is used quite heavily in both the Business-as-usual (1985 severe weather) case and the dedicated LNG contract sensitivity. Storage is fully depleted in the Business-as-usual case for 2009/10, but GB demand can continue to be met via the use of LNG.

5.8.2 LNG flows to GB

This section compares the LNG flows to GB between the Business-as-usual (1985 severe weather) case and the dedicated GB LNG supply contract sensitivity with the same weather severity. This is shown in Figure 50 on page 99.

In the dedicated GB LNG supply contract sensitivity:

- As noted in Section 5.8.1 above, LNG flows to GB are significantly greater than in the Business-as-usual scenario, particularly in the years 2009/10, 2014/15 and 2019/20. In years 2029/30 and 2049/50, the increase in LNG flows is limited by the amount of available LNG regasification capacity in GB, and (in 2049/50) the reducing GB demand.
- The balance of LNG sources supplying GB remains unchanged from the Business-as-usual scenario.

Figure 49 – Dedicated GB LNG supply contract sensitivity – monthly flows to GB

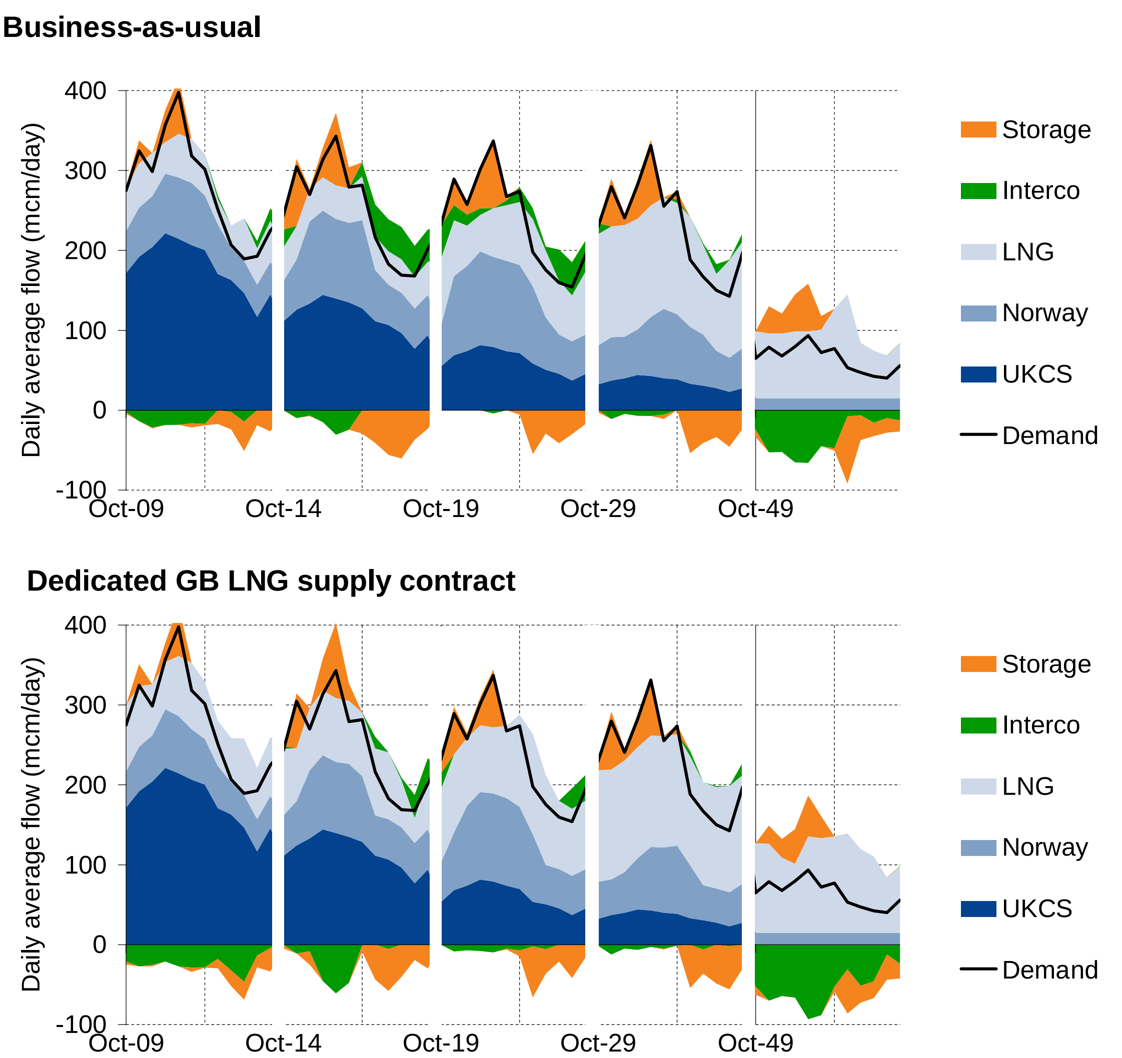
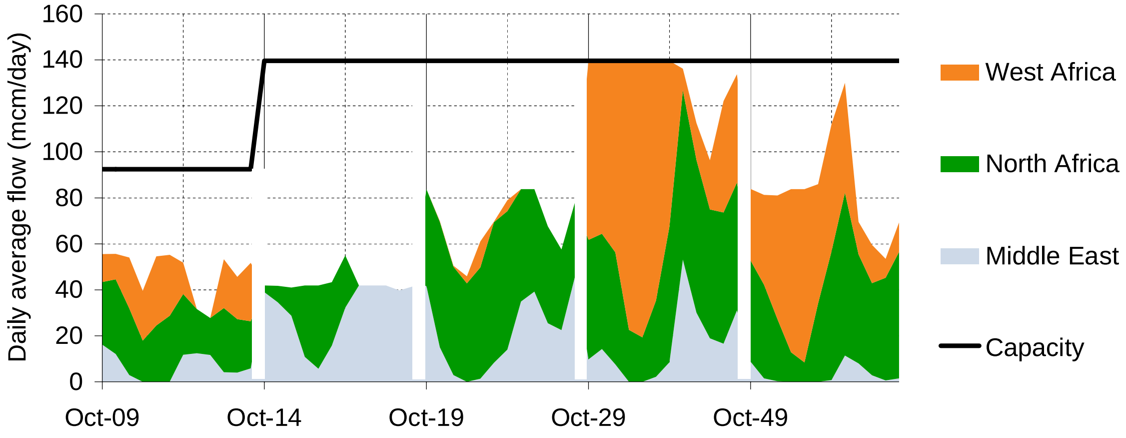
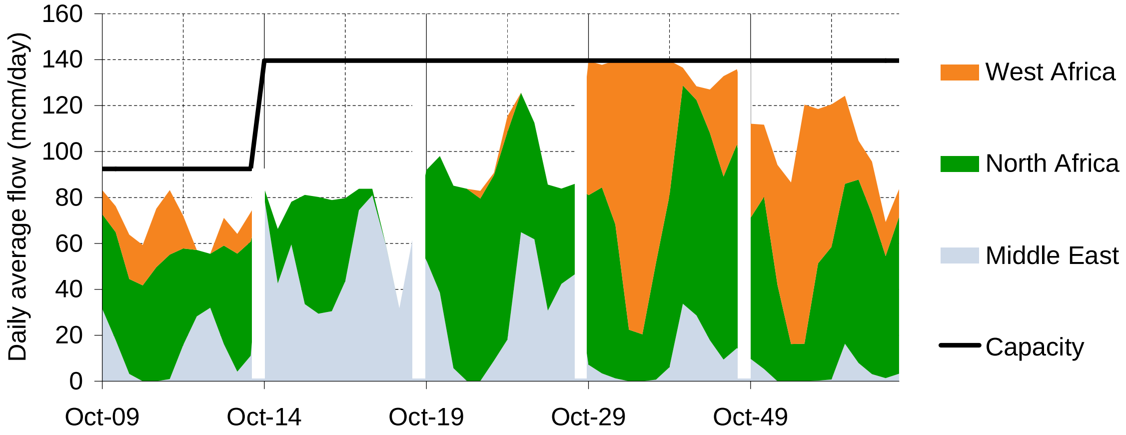


Figure 50 – Dedicated GB LNG supply contract sensitivity – LNG flows to GB

Business-as-usual



Dedicated GB LNG supply contract



5.9 Stress tests and sensitivities – modelling conclusions

The principal modelling conclusions from our sensitivities and stress tests are described below.

5.9.1 Base scenarios – outages

The Qatari LNG outage puts the GB gas system under greater stress than the Milford Haven outage due to the impact that it has on the global gas and LNG markets. However, neither outage results in any demand side response requirement in GB.

Both the Qatari and Milford Haven outages have the effect of reducing LNG flows to GB, in the former case due to the tightening of the global LNG market, and the latter due to the restriction on available GB regasification capacity.

In terms of prices, the Qatari outage has the effect of increasing GB prices quite sharply in the tightest year 2009/10, with lesser price increases in subsequent years. The Milford Haven outage has a much reduced impact on prices.

Storage is very heavily used in the Qatari outage. The Milford Haven outage also shows extensive storage use, generally to a greater extent than in the Qatari outage, reflecting the need for additional flexibility due to the reduced LNG flows to GB.

5.9.2 National Grid high demand

The National Grid high demand increases the stress placed on the GB gas system. As a result, we have increased the GB storage capacity from 2019/20 and the GB regasification capacity from 2029/30. Under these circumstances there is no demand side response required in either the no outage or the Milford Have outage cases. However, in the Qatari outage case, the impact of the outage on the global LNG market results a small amount of demand side response in GB in 2009/10 which can be met by the current levels of CCGT distillate and I&C interruption.

In terms of prices, the Qatari outage has the effect of sharply increasing GB prices. The Milford Haven outage has a reduced impact on prices.

Storage is heavily used in the Qatari outage in all five years. The Milford Haven outage shows slightly less storage use, reflecting the slightly less stressed position of GB and the ability of GB to obtain gas from other sources e.g. Europe.

5.9.3 Other sensitivities

5.9.3.1 US unconventional gas

Increasing the production of US unconventional gas makes more LNG available to GB particularly during the shoulder months, whilst reducing unconventional gas production reduces LNG availability to GB.

In terms of prices, when US unconventional gas production increases, this has the effect of reducing global gas prices slightly, reflecting the increased availability of LNG to the global market. In the low unconventional gas production scenario, prices rise, particularly in 2009/10, as the availability of LNG outside of the US reduces.

In the high US unconventional gas scenario, storage use is largely unchanged from the Business-as-usual scenario, whilst in the reduction scenario storage is used slightly less in GB.

5.9.3.2 US storage flexibility

In this sensitivity reduced LNG volumes are available to GB over the winter due to the higher demand for LNG from the US (which is using it in preference to gas from storage as a result of the inflated US storage tariffs). This is more noticeable in 2029/30 and 2049/50 where the reduced LNG flows are replaced by increased storage use, increased flows from Norway, and, in 2049/50, reduced exports during winter.

LNG flows to GB decrease from those in the Business-as-usual scenario, mainly over the winter months, as additional quantities are required by the US due to its increased cost of gas from storage.

Storage use is very similar to the Business-as-usual scenario until 2019/20, and then increases slightly in 2029/30 and 2049/50 when GB is affected to a greater extent by the increased use of LNG in the US over the winter period.

Gas prices in GB are generally unchanged from those in the Business-as-usual scenario. The US and Far East show increased seasonality, however, when compared with the Business-as-usual scenario, reflecting the increased tightness in the LNG market as a result of the increased flows to the US during winter (in preference to their storage use).

5.9.3.3 Dedicated GB LNG contract

In this sensitivity we have modelled the effect of a dedicated LNG supply contract to GB by increasing the LNG volumes flowing to GB, and examining whether this has any unintended consequence of displacing other market priced gas sources, and hence the overall potential effect on GB security of supply.

In the sensitivity, LNG flows to GB are significantly greater than in the Business-as-usual scenario, particularly in the years 2009/10, 2014/15 and 2019/20. In these years, LNG generally displaces flows from Norway and imported gas from the continent, and exports via the interconnector are generally increased compared with those in the Business-as-usual scenario. The overall impact on GB security of supply is therefore somewhat mixed, with the negative impact of displacing close proximity, politically stable Norwegian supplies, whilst at the same time having the positive impacts of displacing gas predominantly from Russia and neighbouring regions (which could be regarded as being less politically stable) sourced through the European interconnectors, and, at other times, increasing exports to Europe.

The balance of LNG sources supplying GB remains unchanged from the Business-as-usual scenario, with flows coming predominantly from West and North Africa on a least cost basis, as we have not modelled a dedicated contract with a specific source/supplier.

5.9.4 Peak prices and demand side response in GB

A summary of the peak prices and demand side response experienced in GB for each of the scenarios and stress tests is provided in Table 11 below.

Table 11 – Summary of peak prices and demand side response

	Weather severity	Event		Business-as-usual	Carbon-constrained	High GB demand
	'Typical'	None	2009/10	46	46	48
			2014/15	44	41	46
			2019/20	45	44	53
			2029/30	57	54	58
			2049/50	51	40	58
STRESS TESTS	'Severe'	Qatar LNG outage(Dec-Mar)	2009/10	82	82	124 Max DSR/day – 27mcm Total DSR – 54mcm
			2014/15	56	54	62
			2019/20	57	54	61
			2029/30	65	60	69
			2049/50	56	53	68
	'Severe'	Milford Haven outage (Dec-Feb)	2009/10	59	59	61
			2014/15	49	47	54
			2019/20	52	48	58
			2029/30	63	58	71
			2049/50	54	44	63
SENSITIVITIES	'Severe'	None	2009/10	58		
			2014/15	49		
			2019/20	51		
			2029/30	61		
			2049/50	54		
	'Severe'	Unconventional gas increase	2009/10	55		
			2014/15	45		
			2019/20	50		
			2029/30	60		
			2049/50	52		
	'Severe'	Unconventional gas decrease	2009/10	60		
			2014/15	49		
			2019/20	52		
			2029/30	61		
			2049/50	55		
	'Severe'	Use of flexibility (US storage)	2009/10	58		
			2014/15	49		
			2019/20	51		
			2029/30	62		
			2049/50	54		

Scenario not modelled

Scenario modelled and prices below 80p/therm

Scenario modelled and peak prices between 80 and 100p/therm

Scenario modelled and there are penal prices and demand side response in GB

Scenario modelled and there are penal prices and unserved energy in GB

6. POLICY OPTIONS

What the preceding analysis highlights is that, if the GB and global gas markets develop in line with the underlying modelling assumptions, then the GB gas market is relatively resilient to adverse LNG supply shocks, even under severe weather conditions.

The risk of more extreme impacts (in terms of potential physical outages or market price spikes) appears to be confined to the near-term, where liquefaction capacity is effectively fixed and hence a major LNG production outage exacerbates tightness in the global market. In these circumstances, peak GB market prices could be expected to rise by at least a third and potentially require some voluntary demand-side response if demand conditions are high.

By contrast, in the longer-term, a regasification terminal outage at Milford Haven, reducing our ability to import LNG, is expected to have a limited effect on peak market prices (increasing by around 5% under business-as-usual conditions). The implication of this is that, to the extent possible, policies should be directed at supporting or delivering the market conditions that are underpinning the analysis, namely:

- timely investment in global liquefaction capacity;
- development and growth of the global LNG trading;
- open, competitive access to European gas markets; and
- appropriate investment in domestic infrastructure to provide flexibility and import diversification.

Alongside this, it is important to recognise that strategic relationships with major suppliers will supplement and reinforce the reliability of GB LNG supplies in the transition to fully functioning and open global LNG markets. While the liberalisation of continental European gas markets and efficient operation of the domestic market are equally important drivers of supply security, these aspects are outside the scope of this study and are dealt with in other studies for DECC – the focus here is on minimising risks associated with GB's growing reliance on LNG. Against this background we have identified a series of policy options that address the following broad issues:

- Increase reliability of UK LNG supplies.
  - Developing and maintaining relationships with key LNG suppliers.
  - Establishing long-term LNG supply contracts to GB.
- Ensure efficient use and development of LNG regasification capacity.
  - Ensuring the effectiveness of Third Party Access arrangements for LNG.
  - Facilitating the development of more GB regasification capacity;
- Encourage expansion of LNG supply options.
  - Supporting LNG liquefaction developments around the world.
- Reduce exposure to LNG shocks.
  - Facilitating the development of more GB gas supply/demand flexibility tools (e.g. gas storage capacity, demand side response).
  - Holding of strategic LNG stocks (offshore).
  - Holding of strategic LNG stocks (onshore).

- Support for/participation in unconventional gas developments (CBM, shale gas) in the UK, Europe or further afield e.g. China.

6.1 Policy option assessment

We recognise that, because the focus of this assessment is on policies that have a direct impact outside of national boundaries, the impact is less certain than for domestic policies. It should also be noted that, given the limited security risks identified, the value of specific policies may be relatively small.

Each option is described in more detail below alongside a high-level consideration of the costs and benefits. To make the options more comparable, we have also ranked each option according to a set of criteria. These criteria are similar to those used in the Pöyry 2010 Security of Gas Supply study, and cover:

- impact on GB security of supply – the extent to which the policy can be expected to improve GB supply security by minimising outages and price spikes;
- cost of implementation – the direct cost associated with delivering and maintaining the policy;
- ease of implementation – the period before the policy can be enacted and have influence in the market;
- complexity – the simplicity and transparency of the policy for market participants to understand;
- legality – whether the policy is compliant with national and EU legal constraints;
- industry support; and
- unintended consequences – whether the policy will introduce other distortions or inefficiencies to the market.

Dependent on the nature of the option under consideration, the above criteria will have greater or lesser relevance to the assessment.

6.1.1 Developing and maintaining relationships with key LNG suppliers

The development and maintenance of relationships with key LNG suppliers is clearly important, so that UK companies are well received and treated as preferred bidders if they:

- wish to participate in production and LNG liquefaction projects, so that they have their own LNG resources to bring into GB;
- wish to enter into long-term contracts to purchase LNG; or
- need to bring in spot supplies from uncontracted supplies.

We consider that a key element of this policy option is that the relationship between the UK and the target country should be established and maintained at the highest level i.e. Prime Minister or Secretary of State, thereby signifying the level of importance attributed to the issue of energy security.

The key LNG suppliers for the Atlantic basin, which would be of greatest strategic significance for the UK, would include Qatar, Egypt, Algeria, Angola, Nigeria and Trinidad & Tobago.

It is recognised that the nature and dynamics of the individual country relationships will vary, as follows:

- The Middle-Eastern and North African governments and their NOCs place a high value on reputation and relationships, so strong links with these countries are essential to trade.
- Maintaining good relationships is likely to be easier in cases where UK (or western) companies have already formed partnerships with local companies e.g. Qatar (ExxonMobil, Total), Eqypt (BG, GDFSuez) and Trinidad & Tobago (BG, BP, GDFSuez, Centrica)

Whilst the prime reasons for establishing and maintaining good relationships might be viewed from the UK Government's strategic interest in maintaining secure LNG supplies, it should also be recognised that the GB gas market provides an attractive option for LNG suppliers and traders, in the form of a destination market which is the second largest in Europe, has a liquid trading market and secure legal and regulatory frameworks. Such relationship development should therefore be viewed as mutually beneficial for both counterparties.

This option is clearly one that would be implemented over a number of years and would not result in a specific defined event or outcome. Pursuing this option would establish a range of country relationships which allowed, and encouraged, commercial relationships to be developed between relevant gas and LNG market players.

In pursuing this option, the UK Government would need to be mindful of the complexity, and potential interdependence, of the relevant political relationships to ensure that the possibility of jeopardising any individual, and potentially fruitful, relationship (in terms of LNG supply) at the expense of any other, was minimised.

It is also recognised that the development of such relationships primarily for reasons of security of energy supply, would need to be undertaken in the context of the wider political desirability of such relationships, and may therefore not always be of the highest priority.

It should be noted that the Wicks Review (August 2009) also identified the need to foster good relationships with key gas suppliers (the Review specifically highlighted Qatar and Norway) as an important component of the strategy for maintaining GB's security of gas supply.

6.1.2 Establishing long-term LNG supply contracts to GB

This option would involve encouraging the development of long term contracts between GB gas players and LNG suppliers, and including (potentially regulated) mechanisms to ensure delivery of a proportion of the LNG volumes to GB.

It is recognised that destination-specific contracts are prohibited under EU law, and so this option would need to stop short of such measures. Long term contracts will therefore always need to allow any destination clauses to be overridden for economic reasons, but having a long term contract where GB suppliers have first call on the cargoes may be a desirable solution.

It is acknowledged that the majority of LNG supply continues to be sold on long-term contracts (around 83% in 2008 via contracts of 2 years or more duration as described in Section 3.4.1), and that most of these volumes will have already been signed up on such a long-term basis. However, there are a number of players in the market who operate on a portfolio basis e.g. BG, BP, Shell, whereby LNG volumes are targeted on a shorter term basis to those markets offering the best returns. In the current climate in which the LNG market is experiencing a significant supply surplus, there may be increased potential for such market players to consider entering into longer term sales contracts, providing longer term, guaranteed prices, into specific markets e.g. GB. As discussed previously, in the global, liquid LNG market, there is clearly a limit to the influence that can be wielded by the UK Government in achieving such an objective.

Perhaps the best example of an arrangement or outcome in the current LNG market which matches most closely to this objective is that relating to Qatari LNG and its delivery to ExxonMobil Gas Marketing Europe at the South Hook terminal. It may be possible to develop a similar arrangement (on the basis of the approaches described in 6.1.1), whereby GB in effect has 'first call' on LNG supplies, with other potential LNG suppliers, for example, Egypt/BG or Trinidad/BG/BP, if not for existing LNG volumes, then for future ones. Clearly, the major caveat in this type of proposition is that, for the LNG supplying party, the potential motivation would be essentially a trade-off of goodwill or political kudos against its own commercial interests. LNG suppliers will clearly not wish to enter into long-term LNG contracts if they perceive that such arrangements will not provide the same level of return as shorter-term, more flexible arrangements, and therefore may require an additional price premium to ensure delivery to GB. It may be that some additional political leverage could be applied by the local government to the LNG supplier, if the local government valued the improved (or higher profile) political relationship with the UK Government.

It should also be noted that the establishment of such long-term LNG supply contract(s) to GB, where there is some form of mandated (or incentivised) requirement (e.g. via a price premium to a market-related price) to deliver LNG to GB, may have unintended consequences affecting security of supply. This is illustrated in the modelling sensitivity described in Section 5.8 which shows that such dedicated LNG supplies is likely to displace other gas supplies to GB. This sensitivity shows that such supply displacement could have both potentially positive effects on security of supply (e.g. displacing geopolitically uncertain Russian gas supplies through the European interconnectors) and negative effects (e.g. displacing close proximity, politically stable supplies from Norway). The balance in overall impact on security of supply provided by such an option therefore needs to be carefully considered.

Any such option is likely to take some time (perhaps a number of years from an initial contact/relationship) to fully develop, since the establishment of such long-term contracts will involve establishing the necessary government/LNG supplier relationships, and nurturing these over time. However, as noted above, a number of such relationships have already been established between LNG suppliers and the relevant local governments, and it would probably make sense to focus on these initially, should this option be considered worthy of further development.

There are a number of potential sub-options under this general heading of establishing long term LNG supply contracts to GB in which the UK Government might look to take a more interventionist role.

Sub-option 1 – Regulated minimum LNG delivery requirement

One such sub-option could involve the UK Government setting some form of regulatory requirement for LNG suppliers to land a defined minimum proportion of their LNG volumes in GB. The principal difficulty with this option would be establishing a viable regulatory mechanism. Perhaps the most obvious route would be via the existing GB gas supplier licences. However, many (if not most) LNG suppliers to GB are not GB gas suppliers – therefore this route would not be possible in these cases. Where the upstream LNG supplier does have a downstream GB shipper/supplier affiliate, it may be possible to create some form of linked requirement through to the upstream party – however, because of this regulatory complexity we would not recommend this option.

Sub-option 2 – Call option for LNG supplies

A further, perhaps more radical sub-option under this heading could involve the UK Government (or its nominated third party e.g. in the form of an independent 'gas security of supply agency' or National Grid) entering into 'LNG call options' with specified LNG suppliers, whereby it would have the ability to call on specific LNG supplies, under defined times of system stress, and at specified prices. Such LNG call option contracts could be secured via an open tender process. We would envisage that this type of option would require quite a lengthy period (say up to two years, unless it was accorded a high level of urgency) for implementation, taking account of industry consultation processes, appointment of a third party into the LNG purchasing role and the establishment of the necessary contracts. In terms of the financial implications of this option:

- Treatment of the associated costs of operation would require careful consideration – the most likely arrangement would be for them to be recharged across the market as a whole, perhaps based on participants' throughput.
- This type of arrangement would also have the effect of distorting (i.e. inflating) market prices, and may serve to dilute the incentives on GB shippers to balance their own portfolios.

Given the regulatory interventionist nature and the potential market impact of this option, we would not expect it to be favoured by GB gas market participants. Given this, and our overall view that current LNG market is operating satisfactorily in terms of supporting GB security of gas supply and therefore does not require such an interventionist measure, we would not recommend this option.

Both the more interventionist sub-options described above would add costs to the LNG supply chain, which would ultimately be borne by GB gas customers.

We consider that such an arrangement with mandated call options would have to be run by a government-appointed party, rather than existing market participants, since it is not clear how an existing market player could be required to perform the role and/or the market player would not be willing to enter into such contracts above the current market price (without some form of contract price discount provided by government).

6.1.3 Ensuring the effectiveness of Third Party Access arrangements for LNG

One of the reasons why much of the uncontracted and divertible LNG is able to land in GB is because of the TPA regime. Even though some of the terminals themselves have TPA exemption and long-term contracts, they also have use-it-or-lose it provisions as required by the regulator. There are at least 9 capacity holders and a liquid market to sell the gas once it is landed. In many other countries these arrangements are more restrictive and it is more difficult to bring in spot cargoes, which combined with a dominant LNG capacity holder and little or no liquidity in the local markets means that GB and the US have become the destinations of choice for spot cargoes.

Despite moves to further liberalise the EU internal market, if other destinations continue to have more difficult TPA conditions, dominant market players and do not develop liquid traded markets, then GB will have an advantage over these other locations. However, other European LNG importers, as Spain and Portugal already have working TPA arrangements and a number of players, Italy requires at least 20% of new terminals to provide TPA and the new terminals in France, Netherlands and possibly Ireland will be part of the NW European market and actually assist the GB security of supply through providing more supply for possible flows through the interconnections.

Whilst the GB TPA arrangements for LNG are more well-developed than most other markets, with the exception of the US, we still consider that there is a continuing requirement for the UK Government (or Ofgem, as is currently the case) to monitor the effectiveness of the arrangements, to ensure no undue barriers exist to the landing of LNG in GB. This would focus, in particular, on the marketing of spare terminal capacity (via Use-It-Or-Lose-It arrangements, or via bilateral trades) by long-term, TPA-exempted capacity holders at regasification terminals.

In line with the requirement for on-going monitoring and in order to ensure the continued efficient and effective working of the GB LNG capacity access arrangements, the UK government could (through Ofgem, if appropriate) undertake reviews of the following:

- Existing TPA arrangements at current LNG regasification terminals (South Hook, Isle of Grain and Dragon), focusing on the implementation of the capacity anti-hoarding mechanisms (typically via a Use-It-Or-Lose-It auction process) which are required to be implemented by the holder of the TPA exemption for the terminal granted by Ofgem. Such a review could cover the design of the anti-hoarding mechanism e.g. auction timescales, reserve price setting, participation qualification requirements, process for determining available capacity, etc, and the operation of the mechanism in practice e.g. number of auctions held, number of capacity allocations made, customer feedback on the process, etc.
- Other existing arrangements for the marketing and sale of capacity by the long-term capacity holders at existing GB terminals. This would cover the arrangements for bilateral contracting of terminal capacity and could cover elements such as the transparency and non-discriminatory nature of the contracting process, options for unbundling capacity between berthing slots, tank storage and regasification (send-out) capacity, capacity pricing, secondary trading of capacity rights, etc.

Such reviews could be undertaken at any time, and could either be undertaken on a periodic (say every two years) basis or only when a particular aspect of the arrangements has been identified by several parties (or the market as a whole) as being deficient or of not meeting the wider markets requirements.

In general, such reviews should attract a relatively high level of industry support, since it will be in the interests of the market as a whole to have an open, transparent and non-discriminatory process for accessing capacity.

It should be noted that any potential measures suggested as part of this option are designed to ensure the continued smooth working of the LNG supply arrangements to GB, which we consider are currently working without any significant, or at least obviously apparent, shortcomings. They should therefore be considered as part of an on-going framework designed to preclude the emergence of any barriers to market entry, for example relating to discriminatory or non-transparent behaviour.

We consider that it is important to frame this option in these terms so as not to create the impression that the market is considered to be flawed in any fundamental respect. If this impression was inadvertently created, it could have the effect of alienating existing market players e.g. terminal capacity holders, and potential new entrants, and thus having the opposite effect to that intended.

6.1.4 Facilitating the development of more GB regasification capacity

Whilst there is currently a significant surplus of global regasification capacity over liquefaction capacity (as discussed in Section 2), our analysis shows that, in the event of an outage to (a significant proportion of) existing GB regasification capacity for a prolonged period in severe weather and under a very high GB demand profile, this could become a constraining factor for GB gas supply, particularly from 2029/30 onwards as GB becomes more heavily dependent on LNG imports. The addition of further regasification capacity in different locations will serve to improve the robustness of GB's LNG infrastructure, and hence LNG supply reliability, although it will not guarantee that LNG supplies will flow to GB.

There are already a number of potential further GB regasification projects, as discussed in Section 2.5 (Isle of Grain Phase 3, South Hook Phase 2, Isle of Grain Phase 4, Port Meridien, Dragon Phase 2, Amlwch).

It would be in the interests of GB's LNG import security to ensure that, as far as is practicable, there are no undue barriers to parties wishing to construct new LNG terminals, and to establish the associated gas infrastructure e.g. connecting pipelines, Above Ground Installations (AGIs), etc. Therefore it would be prudent to ensure that any relevant permitting and access processes are streamlined and provided with the necessary supporting means, e.g. administrative processes and human resources, to allow efficient and effective operation. This principle could apply in a range of areas, such as:

- granting access to the necessary gas infrastructure e.g. licensing, HSE clearance; and
- minimising the regulations around import of LNG e.g. tax considerations.

In practical terms, this option could take the form of a thorough review of the existing processes and procedures for acquiring the necessary licences, permits and authorisations that are required for a party to establish a regasification terminal in GB, with a view to identifying potential improvements. This could be a relatively short process, requiring around six months to complete and should attract a good deal of industry support, since it would be targeted at making the process easier for LNG regasification project developers in GB.

Whilst a policy initiative along these lines would seek to ensure that the regulatory and legal framework is in place to allow the development of additional GB regasification capacity, it is recognised that, under this option, the establishment of such additional capacity would be a commercial decision left to market participants. We would contend that such commercially-based decision making has already served GB well by delivering the current levels of regasification capacity. On the basis that we do not consider GB regasification capacity to be a constraining factor for GB gas supply security, either currently or for the foreseeable future, in anything other than the most extreme (and low probability) circumstances, we do not envisage, or recommend, that any direct regulatory intervention is required in this area.

6.1.5 Support for LNG liquefaction developments

This option covers a number of indirect support mechanisms for the development of liquefaction projects outside of GB, with the objective of increasing the overall global supply of LNG, and hence increasing potential total LNG volumes theoretically able to flow to GB.

Such support could include a number of potential streams of activity (many of which are already in operation) for example:

- providing support for companies wanting to sell various services e.g. equipment, design services, consultancy, etc. to overseas liquefaction projects; and
- encouraging the Export Credit Guarantee Department (ECGD) to participate in financing new projects.

The objective of this option would be to generate goodwill and to support the development of relationships with major LNG producing countries. The intention would then be to translate such positive goodwill between the UK and the LNG producing country into material benefits for the supply of LNG to GB e.g. those described under 6.1.1 above, such as securing LNG equity resources for GB by participating in liquefaction project development or entering into long-term contracts to purchase LNG.

As noted above, the activities described under this option will only have an indirect impact in terms of helping to improve the reliability of LNG supplies to GB. The activities would be designed to foster an environment in which some of the other suggested policy options would have an improved chance of succeeding.

6.1.6 Facilitating the development of more GB gas supply/demand flexibility tools

As GB's indigenous, flexible gas supply sources in the UKCS are depleted, together with the anticipated increase in intermittent power generation and its consequential impact on the daily gas demand for gas-fired generation, we consider that GB will have an increasing requirement for short-term flexibility to manage the overall gas supply/demand position. Our modelling analysis for this study, which takes account of both the causal factors described above, shows that, particularly under a very high GB demand scenario, there is a need for such increased daily supply/demand flexibility from 2019/20 onwards.

Such daily supply/demand flexibility could be provided by a number of potential mechanisms, with the most likely sources being:

- Gas storage – typically the more flexible, and shorter-cycle, salt cavern storage facilities. Such storage facilities are able to switch between injection and withdrawal modes within short timeframes thereby responding to within-day changes in gas demands which will become increasingly common as the proportion of intermittent generation in GB increases.
- Demand Side Response – this would include the use of CCGT distillate as back-up supplies for power generation, Industrial & Commercial customer interruption or provision of new technologies (such as electricity smart grids). Such forms of demand side flexibility allow additional gas supplies to be provided to the system at relatively short notice to assist in supply/demand balancing.

Whilst we would expect the development of such additional flexibility to be primarily driven by market economics and incentives, the UK Government could take a number of steps to encourage the development of such mechanisms, described in more detail below.

Storage planning and permitting process review

A review could be undertaken of the processes and procedures for acquiring the necessary licences, permits and authorisations that are required for a party to establish a gas storage facility in GB, with a view to identifying potential improvements. Such a review would need to take account of the planned modus operandi and activities of the recently established Infrastructure Planning Commission. For offshore storage facilities, the review would also cover the requirements e.g. storage leases and the associated lease costs, established by the Crown Estate. The review could be a relatively short process, requiring around six months to complete and should attract a good deal of industry support, since it would be aimed at improving the process for storage project developers in GB.

Market incentives review

The objectives of such a review would be to assess whether the existing gas market arrangements, in particular the daily balancing incentives, are sufficient to encourage the appropriate development of flexibility/balancing tools e.g. storage, contract interruption, etc, and, if not, to develop additional proposals to sharpen the incentives. This could be a relatively short process, requiring around six months to complete.

However, it may not attract widespread industry support, since the potential outcome of such a review would be to increase the penalties paid by GB shippers as part of the daily balancing regime. Such changes to the balancing regime may also have the unintended consequence of increasing the overall level of penalty charges that needed to be recovered from all GB shippers via the revenue neutrality mechanism.

For the avoidance of doubt such a review would be designed to consider only the incentives and not about a move to within day balancing.

We consider that the GB gas market has in the past reacted to supply/demand fundamentals by building new import infrastructure and securing additional gas supplies e.g. LNG. However, we also consider that, as described above, the potential impact on the gas system of the planned increase in intermittent generation will create requirements for the provision of additional balancing flexibility. We would therefore recommend that this issue be kept under review, particularly in the light of developing GB gas demand forecasts and profiles, with a view to pursuing the steps suggested above should it prove necessary.

6.1.7 Holding of strategic LNG stocks (offshore)

This option was also considered in the Pöyry 2010 Security of Gas Supply study.

The option would involve a regulatory requirement to hold LNG stocks in tankers offshore of GB. Effectively a temporary strategic storage, the UK Government could procure (or oblige a central body such as National Grid to procure) one or more tankers of LNG at the start of each winter and keep it/them offshore ready for immediate supply delivery, or for sale into the market after the worst of the winter had subsided.

This type of option was used by Spain in 2003/4 and 2005/6.

Such an option depends on spare berthing and onshore tank capacity being available. The process for releasing it into the market would probably be by auction to market participants, who could then feed it into the gas On-the-day Commodity Market (OCM). The costs of tanker rental would be borne by the Treasury and the revenues from the sale would offset this. As it would be a temporary arrangement, it would have a relatively low capital cost, but higher variable cost, so would be cheaper in the short-term, but would be less cost-effective as a long-term measure. Chartering a tanker would be a few £m per winter (based on current rates) plus the difference in value of the cargo from when it is purchased to when it is sold.

Provision of an LNG tanker kept offshore has the advantage of such a decision only being made on a year by year basis and so avoids having to commit significant sums into long-term strategic gas provision. This facility would be under UK Government control, either under a set of defined guidelines or at the UK Government's discretion. This option would, however, have the limitation of providing relatively small volumes of additional gas supply.

One of the main unintended consequences of this option is that, if it was adopted by a number of national governments and resulted in the tying up a number of tankers for a number of months in the winter, this could tighten the capacity for LNG transportation and unduly influence the price of LNG. Further, an auction process would mean that gas shippers to other countries could potentially purchase the cargo and lead to the LNG not being delivered to GB.

In terms of industry support for such an option, we would expect there to be some concern that this option would add an unnecessary cost burden on market participants and that it might unduly affect LNG market prices, particularly if it was proposed that the option be adopted when there was a low perceived risk of supply security failure.

The option would, however, have the advantage of guaranteeing the availability of small quantities of LNG when required, unlike those options focusing on (unguaranteed) contractual solutions or the provision of additional regasification capacity (without any guarantee that the LNG or gas would actually arrive). However, to provide any significant contribution to GB security of supply would require a significant number of vessels in order to the meet the volume requirements.

6.1.8 Holding of strategic LNG stocks (onshore)

This option would involve a regulatory requirement to hold strategic LNG stocks in onshore LNG tanks. Although strategic storage is normally considered as underground storage that gives both a deliverability and volume dimension, LNG storage can also be considered for strategic reasons to provide a short duration supply to support a system that has run into difficulties.

This could be achieved either by constructing new LNG tanks for this purpose or by requiring existing LNG regasification terminals to maintain a minimum LNG inventory level. These two sub-options are considered below.

Construction of new LNG tanks for strategic LNG stocks

This option was considered in the Pöyry 2010 Security of Gas Supply study.

Under this option, additional LNG storage tanks would be built at one or more of the LNG import terminals – it may be appropriate, and cost-efficient, to add such additional capacity in conjunction with a planned expansion programme at one of the existing LNG terminals.

LNG would be regasified and released into the market upon instruction from Government, under a defined set of circumstances and rules.

The cost of the LNG tanks and the LNG in store could either be borne by the Treasury or recovered through transportation charges. Revenues of the LNG released could accrue to the Treasury or be used to offset the additional transportation charges. The investment cost would be in the region of £10m's.

Due to the additional tank construction required under this option, it would have a relatively long lead time of at least two years (and if it involved the construction of an entirely new regasification terminal then a lead time in excess of three years).

In terms of industry support for such an option, as for the option involving the holding of offshore strategic stocks, we would expect there to be concern in the industry that this option would be adding an unnecessary cost burden on market participants, any such investment might displace commercially proposed infrastructure and that it might unduly affect LNG market prices, particularly if it was proposed that the option be adopted when there was a low perceived risk of supply security failure.

As for the option described in 6.1.7 above this option would have the advantage of guaranteeing the availability of the LNG (and gas) when it was required.

Utilisation of existing LNG tanks for strategic LNG stocks

This option would involve the introduction of a regulatory requirement for existing LNG terminals to maintain a minimum LNG stock in the tanks for security of supply purposes.

Under the option, a regulatory obligation would be placed on the LNG terminal operator to monitor stock levels and to ensure that a minimum stock level was maintained (i.e. replenished) within a defined period of time e.g. seven days. It may be necessary for the terminal operator to procure additional LNG to maintain the minimum stock level.

The costs of these arrangements would then need to be recovered, potentially from shippers using the LNG terminal.

This option would have the overall negative market effect of reducing the (total) flexibility of the use of the regasification terminals. It is also likely to be objected to by existing terminal operators and LNG traders on the grounds of a retrospective application of regulatory rules to existing regasification capacity.

Given that the option utilises existing regasification capacity, once the regulatory, operational and charging arrangements have been agreed, it would be relatively quick to implement, say between 6 and 12 months.

As for the preceding options involving strategic LNG stocks (the option described in 6.1.7 and the preceding sub-option in 6.1.8), we would expect there to be concern in the industry that this option would be adding an unnecessary cost burden on market participants and that it might unduly affect LNG market prices and future commercial development, particularly if it was proposed that the option be adopted when there was a low perceived risk of supply security failure.

6.1.9 Support for/participation in unconventional gas developments

Given the potential impact of unconventional gas (as has been seen in the US and as described in 3.1.1.1), it would be prudent for the UK Government to take an active role in promoting its development. Supporting the development of unconventional gas production would be an indirect way of reducing the global demand for LNG, thereby making additional LNG volumes available to flow to GB. Of course, we would expect that, over time, and depending on the trends in the relative economics of production, LNG production would be adjusted to reflect anticipated unconventional gas production. Indeed, there has already been an example of this in Gazprom's recent announcement[9] that the Shtokman LNG project may be delayed or cancelled, given the recent increases in unconventional gas production in the US, which was originally the prime target market for Shtokman LNG.

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[9] Platts European Gas Daily – 8 February 2010

Perhaps the most obvious, and direct, way for the UK Government to support unconventional gas development would be to focus on developments in the UK. In the event that commercial unconventional gas production in the UK were to expand significantly (as opposed to expansion elsewhere in the world), this would have the most direct impact on GB's gas import requirements, including LNG.

It is recognised that, to date, unconventional gas production in the UK has been restricted to small scale coalbed methane developments, and that the jury is still out on the potential in the UK for other forms of unconventional gas production, for example shale gas. However, the level of interest and related exploration activity has undoubtedly increased significantly in recent months, and a number of market players have formed alliances to further pursue potential developments (Marathon Petroleum/Greenpark Energy, BG/Composite Energy, Nexen Exploration/Island Gas) whilst others have recently established their own dedicated teams focusing on unconventional gas opportunities (Centrica).

One area on which the UK Government could focus to encourage unconventional gas developments in UK, would be to ensure that the permitting and licensing process for such developments receive the appropriate priority e.g. via any accelerated or streamlined process managed by the Infrastructure Planning Commission, and that there are no undue barriers to these developments.

In addition to pursuing developments in the UK, the UK Government could also directly promote the participation of GB gas players in exploration activities overseas, such as coalbed methane and shale gas in Europe, or further afield, e.g. China.

6.2 Policy recommendations

The assessment of the policy options against each of the criteria is summarised in Table 12 below, using a traffic light system to show each option's contribution.

Table 12 – Summary assessment of policy options

	Impact on GB security of supply	Cost of implementation	Ease of implementation	Complexity	Legality	Industry support	Unintended consequences
LNG supplier relationships	Green	Green	Amber	Amber	Green	Green	Green
Long term GB LNG contracts	Green	Amber	Red	Red	Amber	Amber	Red
LNG TPA arrangements effectiveness	Amber	Green	Amber	Amber	Green	Green	Green
GB regasification capacity facilitation	Amber	Amber	Amber	Amber	Green	Amber	Green
Global LNG liquefaction development support	Amber	Green	Red	Amber	Green	Green	Green
GB supply/demand flexibility	Amber	Amber	Amber	Amber	Green	Amber	Amber
Offshore strategic LNG stocks	Amber	Red	Amber	Amber	Green	Red	Red
Onshore strategic LNG stocks	Amber	Amber	Amber	Amber	Amber	Red	Red
Unconventional gas development support	Amber	Green	Red	Amber	Green	Green	Green

Red signifies a negative assessment, amber signifies an ambiguous or potentially negative assessment, green signifies a positive assessment.

As noted above, we consider that the global LNG market can be regarded as a well functioning market and that GB has established successful access to this market by the development of regasification terminals, the booking of regasification capacity by a range of gas market participants and the establishment of the necessary upstream LNG supply arrangements. The global LNG market has reacted to recent perceived demand increases by the development of significant additional liquefaction capability, which will provide a surplus of LNG supply over demand for at least the next five years, and probably for longer. Our view is that, given the appropriate pricing signals, further LNG liquefaction capacity will be developed to meet demand, and LNG will continue to flow to GB. Closer to home, the 'GB LNG market' is further assured by the regulatory oversight of the use of regasification capacity e.g. through Use-It-Or-Lose-It arrangements, ensuring that utilisation of GB's regasification capacity is available to those who wish to use it.

Another important element in the overall global gas supply/demand picture is the potential for increased production of unconventional gas. It is likely that the recently experienced surge in US unconventional gas production will be, at least to some extent, replicated elsewhere in the world. The timing and extent of this growth remains unclear, but any increase in unconventional gas production should serve to further ease the overall global supply/demand balance.

Our analysis shows that the risks to GB security of gas supply as a result of developments in the global gas and LNG markets are minimal, and that the GB gas system may only be under stress in extreme circumstances, for example in the event of a coincidence of severe weather (1-in-20 winter severity), an unusually high GB demand level and a major and prolonged outage of LNG supply or GB regasification infrastructure.

Therefore, on the basis that we do not foresee anything more than a low likelihood of disruption to GB gas supply, and that potential policy options involving a high degree of regulatory intervention are not required, would have the effect of distorting market operation and prices, and would be unpopular with the market participants, we would recommend the following policy options be considered for possible implementation:

- **developing and maintaining relationships with key LNG suppliers** – we consider that, whilst this option may not have easily defined or quantifiable timescales or outputs, given the nature of the LNG market, it is key to securing long-term reliable LNG supplies to GB; and
- **ensuring the effectiveness of Third Party Access arrangements for LNG** – as described in our analysis, whilst we consider that the GB gas market currently provides relatively easy access for LNG suppliers, periodic reviews of the access arrangements are prudent and will serve to reassure market participants that the arrangements are being actively managed to identify potential improvements.

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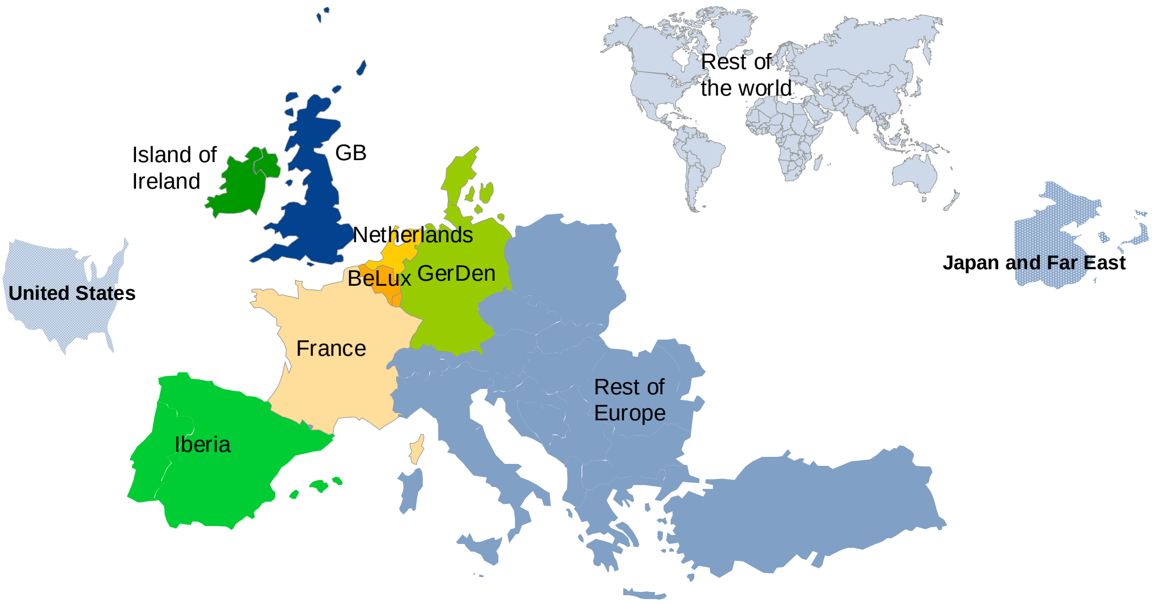
ANNEX A – PERSEUS

Perseus models gas dispatch at a daily resolution in order to minimise the cost of supply. The Linear Programming algorithm also ensures that a set of basic constraints are met, including meeting demand every day in each country, respecting capacity constraints and Take or Pay obligations. The model examines the interaction of supply and demand worldwide on a daily basis, pipeline imports and interconnections between the different zones, as summarised in Figure 18 below.

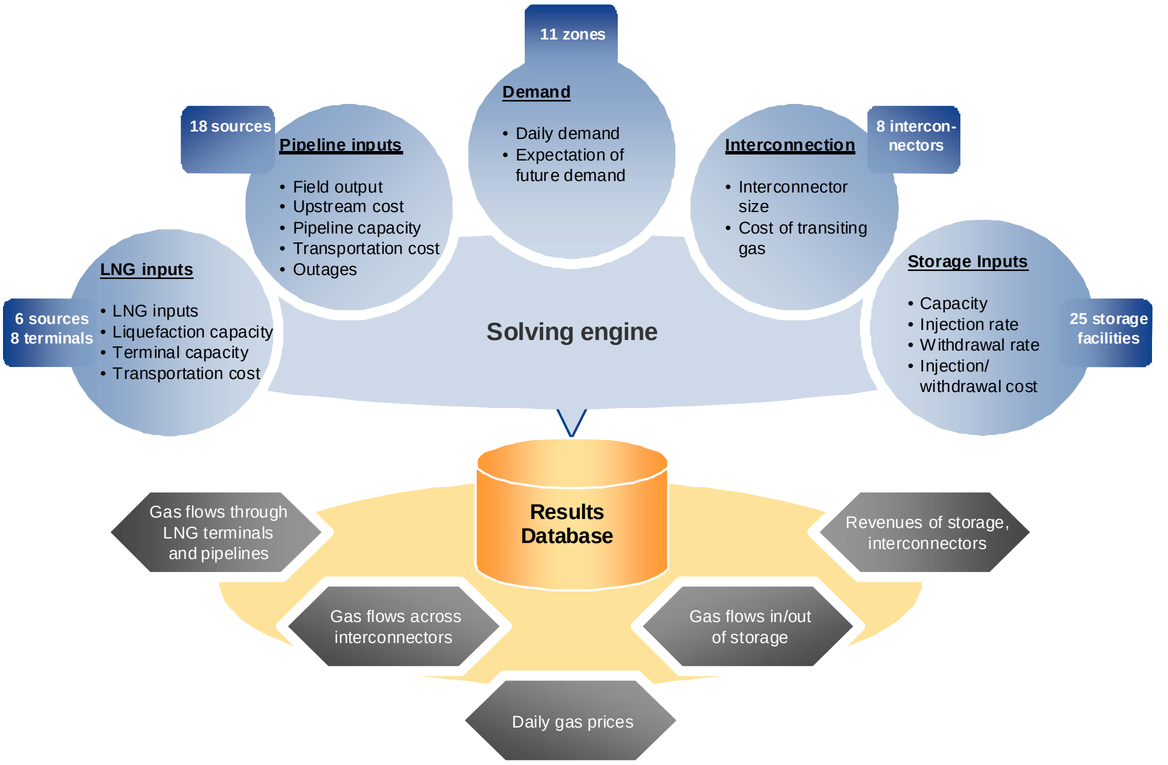
Figure 51 – Geographical coverage of Perseus



Great Britain, the Island of Ireland zone and the Continental NW European zones are modelled in detail, alongside all existing and proposed LNG terminals and their interaction with the global LNG market.

The range of assumptions that go into Perseus and the types of outputs it produces are shown in Figure 52.

Figure 52 – Structure of Perseus



Perseus innovates in many areas by adopting the following modelling principles:

- Rolling Optimisation, which removes perfect foresight;
- tree-based expected futures, which represents the risk aversion of market players; and
- special treatment of LNG, which includes a delay between decision and delivery.

A.1.1 Rolling optimisation

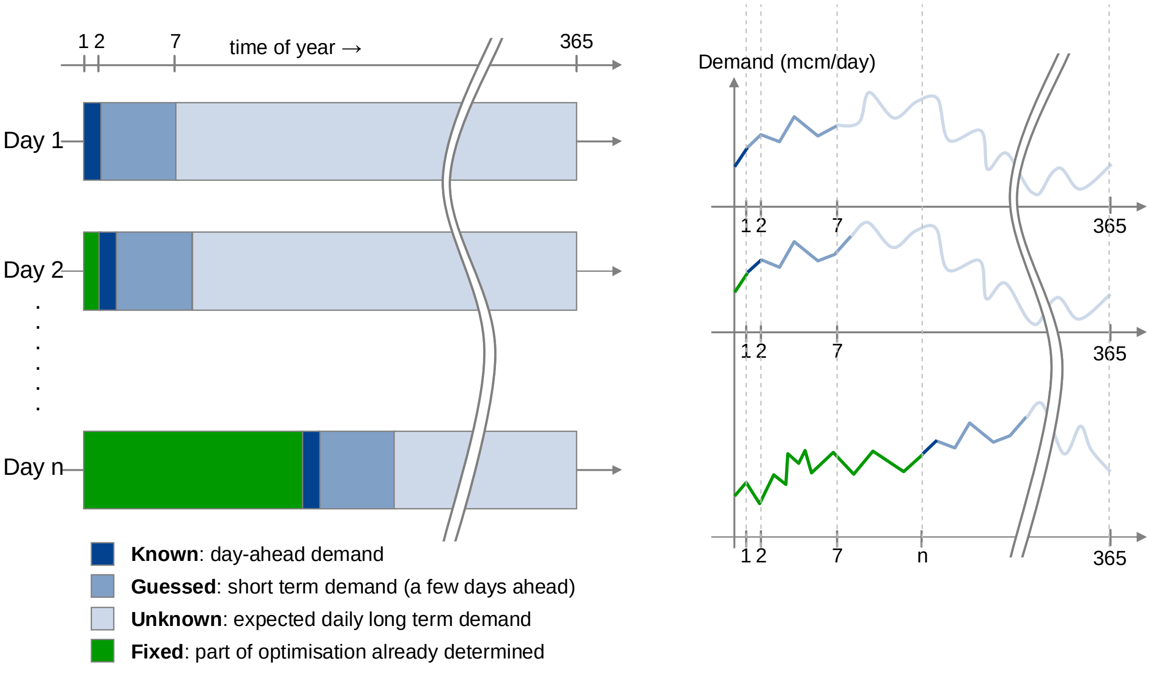
Perfect foresight is the main weakness of Linear Programming models where demand is volatile. Whilst perfect foresight is generally adequate to determine the dispatch in an average world, modelling variability of gas demand due to wind intermittency requires the removal of this perfect foresight.

Rolling optimisation is a set of optimisations where information is divided in three time horizons:

- 1 day ahead: perfect information of demand;
- 2-7 days ahead: limited information of demand (weather forecast); and
- more than 8 days ahead: very limited information of demand (Seasonal Normal Demand, last year's demand, general weather and market knowledge).

For every time step, future demand consists of these different time horizons, which are then rolled on for the next optimisation, as shown in Figure 53.

Figure 53 – Demand in the rolling optimisation methodology



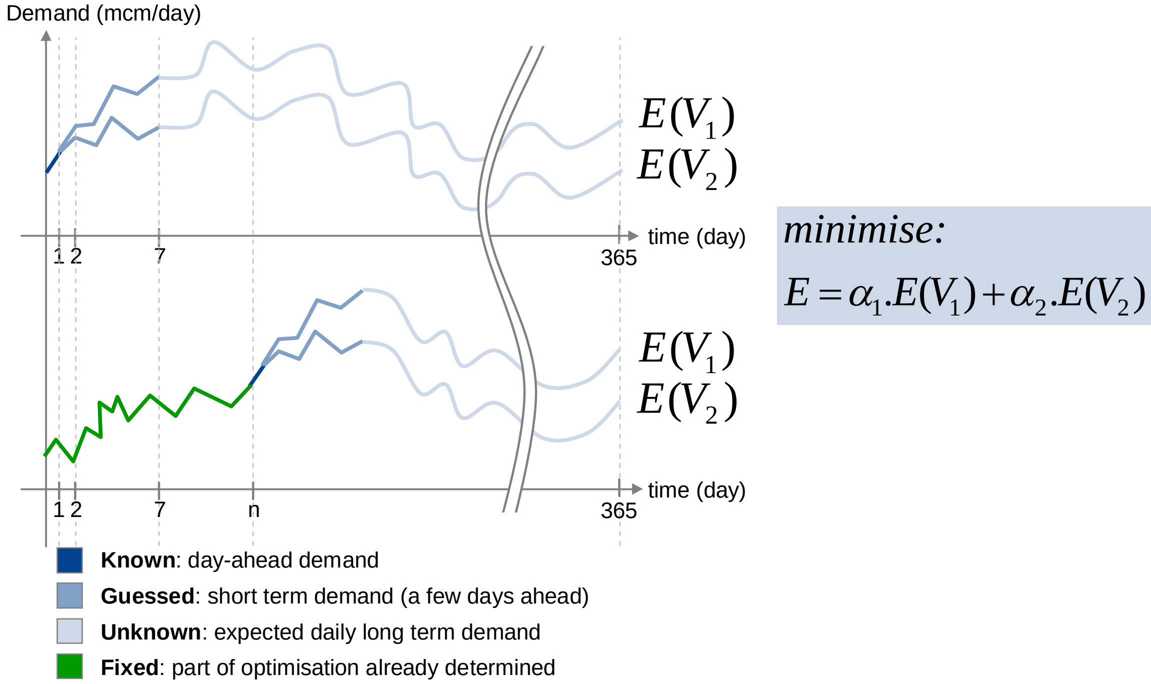
A.1.2 *Tree based approach*

A tree based approach is derived from Stochastic Programming, which is a common technique for optimisation under uncertainty. In this case, market players want to optimise their behaviour in a world of uncertain future demand.

In the Rolling Optimisation methodology, the unknown expected future can be set arbitrarily to the Seasonal Normal Demand for example. However, different players will have different behaviours depending on their portfolio and their risk aversion. A tree approach represents different expected futures at the same time, which encompass a combination of different supply outages and daily demand scenarios. This represents the market determining the dispatch in order to minimise the cost of supplying the probabilistic future.

Figure 54 shows an example where we consider two possible future demand paths, weighted by the probability α_1 and α_2. In this instance, the model will minimise the cost of supplying the two branches, weighted by the same factors. In the study, we intend to use a higher number of branches – we initially think about eight branches – which will allow us to cover both supply and demand future expectations.

Figure 54 – Tree-based approach



A.1.3 Treatment of LNG

Perseus models the limited foresight of future demand in dispatching LNG cargoes and flow from LNG tanks. We assume that the market has to take an LNG dispatch decision a few days in advance (a week for example), but that there is an element of flexibility with the LNG tank that can be dispatched day-ahead. The LNG tank in this context works like a very short range storage supplied by the cargo and withdrawing in the market. The LNG cargo dispatch decision is made with only a vague idea of the future, and in that way LNG cannot fully respond to a short cold spell.

The worldwide LNG market is very complex, and we make a number of simplifying assumptions in Perseus in order to be able to run the optimisation of supply and demand in an acceptable timescale. We capture the interaction between the continental gas markets and the US, the Far East and the Rest of the World by defining these as three separate zones which acts as competing demand zones for LNG.

Perseus currently assumes that all cargoes can go from any liquefaction plant to any regasification terminal, and that cargoes are fully 'market determined'.

ANNEX B – MODELLING ASSUMPTIONS

This annex contains more detail regarding the demand, infrastructure, supply, contractual, economic and commodity assumptions made for the two main scenarios. For each scenario we have split the assumptions into four tables:

- the first relates to the demand, indigenous production, import capacity and long-term contracts for each of the demand zones in Perseus;
- the second relates to the interconnection between the different Perseus demand zones, which are mostly taken from the ENTSO-g European Ten Year Network Development Plan 2010-2019;
- the third relates to the supply assumptions from the main supply sources outside the Perseus demand zones; and
- the last, contains the oil and coal prices assumed in the model along with the exchange rates.

In the first three tables we have presented the current (2009/10) volumes/capacities and where there is a change into the future we have presented the peak/trough/plateau levels and the year in which it is achieved. In some cases, such as where there is continuous decline in production, we have specified some milestone values.

B.1 Business-as-usual scenario

Table 13 – Demand zone assumptions – Business-as-usual scenario

Demand zones:	GB	Ireland	France	BeLux	Neth.	GerDen	Iberia	RoE*	US	Asia (LNG)	RoW (LNG)
Domestic demand	DECC EMO data	Decrease until 2018, by 2.5%/Y then increase by 1.5%/Y	Stable until 2018, then increase, by 1.6%/Y on average	Increase from 2010 to 2030, by 1.05%/Y on average	Slight decrease until 2018, then increase by 2.0%/Y	Decrease by 0.7%/Y until 2019, then increase by 0.6%/Y	Decrease by 1.1%/Y until 2019, then increase by 2.4%/Y	Steady growth until 2026 of 1.9%/Y	Stable until 2020, then steady increase until 2025, declining from 2026 onwards	Steady increase from 2010 onwards at an average of 1.6%/Y	Steady increase until 2012, then stable from 2013 onwards
Powergen demand		Rising from 5.1GW to 5.9GW in 2025	Rising from 6.2GW to 21.2GW in 2030	Rising from 8.4GW to 11.2GW in 2029	Rising from 16GW to 22GW in 2030	Rising from 26GW to 29GW in 2030	Rising from 30GW to 41GW in 2030	Rising from 73GW to 159GW in 2030			
Demand profiles	Historic + modelled Power Gen	Historic + modelled Power Gen	Historic + modelled PGen	Historic + modelled PGen	Historic + modelled PGen	Historic + modelled PGen	Historic	Seasonal normal profile	Seasonal normal profile	Seasonal normal profile	Seasonal normal profile
Storage capacities	4.7bcm in 2010; 10.8bcm in 2020	0.2bcm throughout	11.9bcm in 2010; 13.9bcm from 2015	0.7bcm in 2010; 1.1bcm from 2015	2.5bcm in 2010; 6.4bcm from 2015	18.6bcm in 2010; 26.8bcm from 2015	9bcm in 2010; 10.1bcm from 2015	42bcm in 2010; 50bcm from 2015	N/A	N/A	N/A
LNG terminals	34 to 51bcm by 2011/12	None	17 to 34bcm by 2013/14	9bcm, no further expansion	0 to 25bcm by 2015/16	None	65bcm, no further expansion	28 to 61 bcm by 2015/16	150 to 187bcm by 2012	314 to 343bcm by 2018	53 to 109bcm by 2018/19
Import pipelines	Norway 42 - 46bcm by 2012/13	None	Norway 18.4bcm	Norway 15.3bcm	Norway 18.7bcm	Norway 38.3bcm Russia 0-55bcm by 2015/16	Algeria 11.5 - 19.5bcm by 2010/11	Russia 238-258bcm by 2020 N. Africa 34-54bcm by 2014 Caspian 19-35bcm by 2016	Imports from Canada 78bcm declining to 24bcm by 2030	N/A	N/A
Indigenous production	In decline No new finds	Corrib in 2011 then decline	Small and in decline No new finds	Negligible No new finds	Sm. fields in decline Gro'n declines post 2015	Small and in decline No new finds	Negligible No new finds	In decline No new finds	EIA f'cast 577–558 by 2015 to 633 by 2030	N/A	N/A
Take-or-Pay contracts	None	None	Renewal of existing contracts	Renewal of existing contracts	Renewal of existing contracts	Renewal of existing contracts	Renewal of existing contracts	Renewal of existing contracts	None	Continue	Continue

Table 14 – Interconnector assumptions – Business-as-usual scenario

To / From	GB	Ireland	France	BeLux	Neth.	GerDen	Iberia	RoE
Great Britain		11.3 bcm Nothing new	-	IUK 20bcm Nothing new	BBL 17bcm reverse flow from 2016/17	-	-	-
Island of Ireland	Virtual only No physical		-	-	-	-	-	-
France	-	-		2.3 bcm Nothing new	-	Virtual only No physical flow	From 2.4bcm to 3.6bcm by 2010/11	7.2bcm link with CH Nothing new
Belgium & Luxembourg	IUK 23.6bcm Nothing new	-	27.4bcm Nothing new		10.2bcm Nothing new	From 9.2bcm to 12.1bcm by 2012/13	-	-
Netherlands	BBL 14.2bcm to 17bcm from 2011/12	-	-	From 46bcm to 58.8bcm by 2015/16		65.2bcm No significant change	-	-
Germany, Denmark, Sweden	-	-	20bcm No further expansion	15.6bcm to 17.4bcm by 2012/13	From 9.5bcm to 14.6bcm by 2012/13		-	PL 1.1-1.8bcm CZ 6.6bcm AT 2.5-9.8bcm CH 17bcm
Iberia	-	-	From 0.1bcm to 3.4bcm by 2013/14	-	-	-		-
Rest of Europe	-	-	1.5bcm link with CH Nothing new	-	-	PL 26.3bcm CZ 59.1bcm AT 9.1bcm CH virtual only	-	

Table 15 – Supply source assumptions – Business-as-usual scenario

Supply sources:	Norway	Russia	Caspian	N. Africa Alg, Lib, Egy	Atlantic Tri, Ven, Nig, Ang, E.Guinea	Mid. East Qat, Yem, Abu, Oma, Iran	Pacific Aus, Ind, Malaysia, Peru, US
Reserves	No new major finds	Plentiful	Plentiful	Plentiful	Plentiful	Plentiful	Plentiful
Maximum export gas available (supply – demand)	Peaks in 2011 at 114bcm, declines more quickly post 2020	Peaks at 236bcm in 2016, declines to 226bcm by 2024	18.8 to 36bcm by 2025, steady thereafter	Peaks in 2016 at 152bcm , declining thereafter	54 to 136bcm by 2018, declining thereafter	101 to 158bcm by 2010/11, declining after 2016	84 to 106bcm by 2020, declining thereafter
Minimum production rates	90% except Ormen Lange 40% and LNG 85%	80% except LNG 85%	40-50%	40% for pipeline; 85% for LNG	85%	85%	85%
Export pipe capacities	132 to 136bcm by 2012	238 to 317bcm by2020 incl. NordStream 2012-15 SouthStream 2016-20	18.8 to 36bcm by 2025 incl. Azeri gas 2016 Iraq/Iran from 2025	46 to 79 bcm incl. Galsi by 2013 Arab Gas Pipe 2011-13	N/A	N/A	N/A
Liquefaction capacity	5.4bcm/yr	12 to 35bcm by 2019	N/A	27 to 55bcm by 2013	54 to 136bcm by 2018	101 to 158bcm by 2010/11	110 to 192bcm by 2025
Production costs / oil indexed price	Oil indexed except Ormen Lange	Oil indexed	Oil indexed	Oil indexed	Some oil indexed and some at LRMC	Some oil indexed and some at LRMC	Oil indexed

Table 16 – Economic assumptions for the Business-as-usual scenario

Commodity (in 2008 real money)	2009/10	2014/15	2019/20	2029/30	2049/50
Oil ($/bbl)	80.00	80.00	80.00	80.00	80.00
Coal ($/tonne)	75.00	75.00	75.00	75.00	75.00
Carbon (€ /tonneCO2)	15.00	35.00	35.00	35.00	35.00
Exchange rate ($/£)	1.65	1.80	1.80	1.80	1.80
Exchange rate (€/£)	1.11	1.25	1.25	1.25	1.25

B.2 Carbon-constrained scenario

Table 17 – Demand zone assumptions – Carbon-constrained scenario

scaled using IEA 450 scenario demand
(giving demand scaling reduction of up to 50% by 2050 in comparison to BAU)

unchanged from BAU scenario

Demand zones:	GB	Ireland	France	BeLux	Neth.	GerDen	Iberia	RoE*	US	Asia (LNG)	RoW (LNG)
Domestic demand	DECC EMO data	Decrease until 2018, by 2.5%/Y then increase by 1.5%/Y	Stable until 2018, then increase, by 1.6%/Y on average	Increase from 2010 to 2030, by 1.05%/Y	Slight decrease until 2018, then [illegible]	Decrease by 0.7%/Y until 2019, then [illegible]	Decrease by [illegible]	[illegible]	[illegible]	[illegible] 2010 [illegible] at an average of 1.6%/Y	Steady increase until 2012, then stable from 2013 onwards
Powergen demand		Rising from 5.1GW to 5.9GW in 2025	[illegible]	[illegible]	[illegible]	[illegible] 29GW in 2030	[illegible] to 41GW in 2030	[illegible] 73GW to 159GW in 2030	[illegible] declining from 2026 onwards		
Demand profiles	Historic + modelled Power Gen	Historic + modelled Power Gen	Historic + modelled PGen	Historic + modelled PGen	Historic + modelled PGen	Historic + modelled PGen	Historic	Seasonal normal profile	Seasonal normal profile	Seasonal normal [illegible]	Seasonal normal profile
Storage capacities	5.8bcm in 2010; 19bcm in 2030	0.2bcm throughout	11.9bcm in 2010; 13.9bcm from 2015	0.8bcm in 2010; 1.1bcm from 2015	2.5bcm in 2010; 6.4bcm from [illegible]	18.6bcm in [illegible]	9bcm [illegible]	[illegible]	[illegible]	[illegible]	N/A
LNG terminals	34 to 51[illegible] by 2011	[illegible]	[illegible]	[illegible] expansion	[illegible] by 2015/16	None	64 to 75 bcm by 2013/14	28 to 61 bcm by 2015/16	150 to 187bcm by 2012	314 to 395bcm by 2018	53 to 57bcm by 2010/11
Import pipelines	Norway 42 - 46bcm by 2012/13	None	Norway 18.4bcm	Norway 15.3bcm	Norway 18.7bcm	Norway <u>38.3bcm</u> Russia 0-55bcm by 2015/16 declining to 0-38bcm by 2029 and 19bcm by 2049	Algeria 11.5 -19.5bcm by 2010/11	Russia 238-258bcm by 2020, 131 <u>by 2050</u> N. Africa 34-54bcm by 2014, 29-49 <u>by 2050</u> Caspian 19-35bcm by 2016, 4-20 by 2050	Imports from Canada 78bcm declining to 26bcm by 2030	N/A	N/A
Indigenous production	In decline No new finds	Corrib in 2011 then decline	Small and in decline No new finds	Negligible No new finds	Sm. fields in decline Gro'n declines post 2015	Small and in decline No new finds	Negligible No new finds	In decline No new finds	577–558 by 2015, capped at 570 post 2015, declining to 540 by 2050	N/A	N/A
Take-or-Pay contracts	None	None	Renewal of existing contracts	Renewal of existing contracts	Renewal of existing contracts	Renewal of existing contracts	Renewal of existing contracts	Renewal of existing contracts	None	Continue	Continue

Table 18 – Interconnector assumptions – Carbon constrained scenario

To / From	GB	Ireland	France	BeLux	Neth.	GerDen	Iberia	RoE
Great Britain		11.3 bcm Nothing new	-	IUK 20bcm Nothing new	BBL 17bcm reverse flow from 2016/17	-	-	-
Island of Ireland	Virtual only No physical		-	-	-	-	-	-
France	-	-		2.3 bcm Nothing new	-	Virtual only No physical flow	From 2.4bcm to 3.6bcm by 2010/11	7.2bcm link with CH Nothing new
Belgium & Luxembourg	IUK 23.6bcm Nothing new	-	27.4bcm Nothing new		10.2bcm Nothing new	From 9.2bcm to 12.1bcm by 2012/13	-	-
Netherlands	BBL 14.2bcm to 17bcm from 2011/12	-	-	From 46bcm to 58.8bcm by 2015/16		65.2bcm No significant change	-	-
Germany, Denmark, Sweden	-	-	18.25bcm No further expansion	15.6bcm to 17.4bcm by 2012/13	From 9.5bcm to 14.6bcm by 2012/13		-	PL 1.1-1.8bcm CZ 6.6bcm AT 2.5-9.8bcm CH 17bcm
Iberia	-	-	From 0.1bcm to 3.4bcm by 2013/14	-	-	-		-
Rest of Europe	-	-	1.5bcm link with CH Nothing new	-	-	PL 26.3bcm CZ 59.1bcm AT 9.1bcm CH virtual only	-	

These are the same as the Business-as-Usual scenario

Table 19 – Supply source assumptions – Carbon-constrained scenario

Supply sources:	Norway	Russia	Caspian	N. Africa Alg, Lib, Egy	Atlantic Tri, Ven, Nig, Ang, E.Guinea	Mid. East Qat, Yem, Abu, Oma,	Pacific Aus, Ind, Malaysia, Peru, US
Reserves	No new major finds	Plentiful	Plentiful	Plentiful	Plentiful	Plentiful	Plentiful
Maximum export gas available (supply – demand)	Peaks in 2011 at 114bcm, declines more quickly post 2020	Peaks at 236bcm in 2016, declines to 226bcm by 2024	18.8 to 36bcm by 2025, steady thereafter	Peaks in 2016 at 152bcm , declining thereafter	54 to 70bcm by 2018, declining thereafter	101 to 132bcm by 2010/11, declining after 2016	110 to 175bcm by 2018, declining thereafter
Minimum production rates	90% except Ormen Lange 40% and LNG 85%	80% except LNG 85%	40-50%	40% for pipeline; 85% for LNG	85%	85%	85%
Export pipe capacities	132 to 136bcm by 2012	238 to 164bcm by2020 incl. NordStream 2012-15 SouthStream 2016-20 falling to 69.5bcm by 2049	18.8 to 36bcm by 2025 incl. Azeri gas 2016 Iraq/Iran from 2025	46 to 79 bcm incl. Galsi by 2013 Arab Gas Pipe 2011-13	N/A	N/A	N/A
Liquefaction capacity	5.4bcm/yr	12 to 31bcm by 2019	N/A	27 to 55bcm by 2013	54 to 87bcm by 2018, falling to 55 by 2049	101 to 143bcm by 2010/11, falling to 124 by 2049	110 to 146bcm by 2018, falling to 122bcm by 2049
Production costs / oil indexed price	Oil indexed except Ormen Lange	Oil indexed	Oil indexed	Oil indexed	Some oil indexed and some at LRMC	Some oil indexed and some at LRMC	Oil indexed

Table 20 – Economic assumptions for the Carbon-constrained scenario

Commodity (in 2008 real money)	2009/10	2014/15	2019/20	2029/30	2049/50
Oil ($/bbl)	80.00	80.00	80.00	57.60	57.60
Coal ($/tonne)	75.00	75.00	75.00	75.00	75.00
Carbon (€ /tonneCO2)	15.00	35.00	35.00	35.00	35.00
Exchange rate ($/£)	1.65	1.80	1.80	1.80	1.80
Exchange rate (€/£)	1.11	1.25	1.25	1.25	1.25

The only difference from the Business-as-usual scenario is a reduction in the oil price from 2029/30 onwards by the same proportion as the reduction in the IEA's 450 scenario over the IEA's reference scenario (as requested by DECC).

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