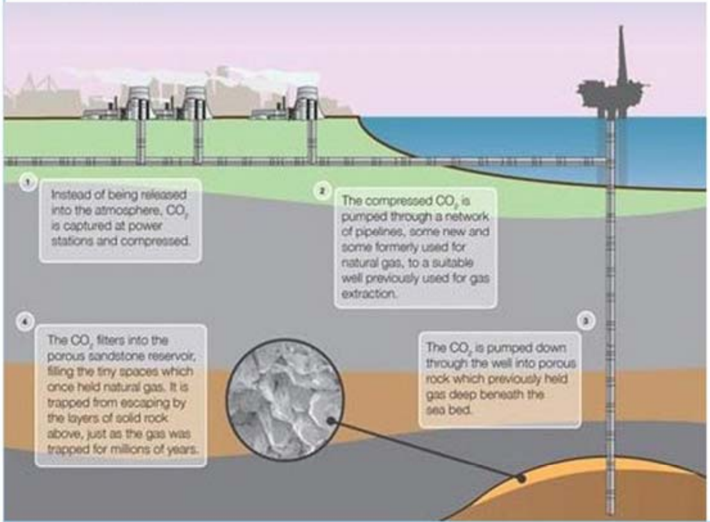

Gas Transportation
Ten Year Statement 2009

nationalgrid

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Disclaimer

This Statement is produced for the purpose of and in accordance with National Grid Gas plc's obligations in Special Condition C2 of its Gas Transporters' Licence relating to the national transmission system and Section O4.1 of the Transportation Principal Document of the Uniform Network Code in reliance on information supplied pursuant to Section O of the Transportation Principal Document of the Uniform Network Code. Section O1.3 of the Transportation Principal Document of the Uniform Network Code applies to any estimate, forecast or other information contained in this Statement. This Statement is not intended to have any legal force or to imply any legal obligations as regards capacity planning, future investment and the resulting capacity.

Cover Pictures (Clockwise from top left)

- Treaddow PRI (Pressure Reduction Installation), Herefordshire
- The "Beast" is a trench excavator being used on the Easington to Ganstead project
- Wormington Compressor Station, Gloucester
- Looking east across the River Towy crossing on the Milford Haven to Aberdulais section of the Milford Haven gas pipelines project, after construction. (During and after construction photos below.)
- CCS Carbon Capture and Storage (CCS) overview diagram.

During Construction

After Construction

Foreword

The 2009 edition of the Ten Year Statement is published in line with Special Condition C2 of our Gas Transporters' Licence and Section O of the Uniform Network Code. Special Condition C2 requires that the Ten Year Statement, published annually, shall provide a ten-year forecast of transportation system usage and likely system developments that can be used by companies, who are contemplating connecting to our system or entering into transport arrangements, to identify and evaluate opportunities.

The Statement explains our latest volume forecasts, system reinforcement projects and investment plans. It has been published at the end of the 2009 planning process following a re-appraisal of our analysis of the market and expands on the work published in our "Transporting Britain's Energy2009: Development of Energy Scenarios" document in July 2009. The Statement forms the basis of our industry wide consultation process, Transporting Britain's Energy, due to restart in the New Year, and is the first element of our 2010 planning process.

Layout

The Statement contains essential information on actual volumes, the process for planning the development of the system, including demand and supply forecasts, system reinforcement projects and associated investment. The main body of the document provides an overview of the key issues, with all the detail contained in the appendices.

I hope you find the 2009 Ten Year Statement both interesting and informative. However, with our goal of continually developing the document, we would welcome any comments on the style and content of the document.

I look forward to receiving your views on the Statement, including suggestions as to how it might be further improved.

Nick Winser, Executive Director, Transmission

National Grid

December 2009

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Chapter One

Executive Summary

The purpose of this document is to set out our assessment of the future demand and supply position for natural gas in the United Kingdom, and the consequences for investment in the gas transmission network.

This document details National Grid's latest 'Business As Usual' forecasts, but also makes reference to our Gone Green (2009) scenario throughout. The 'Business As Usual' forecast is National Grid's current view of supply and demand, with this approach making no assumptions with regard to major changes to current known policy, regulatory framework or potential incentives and/or subsidies. The Gone Green (2009) scenario details a potential energy mix, focussed on energy saving and electricity decarbonisation, that meets the EU 2020 targets. This approach targets not just the electricity sector, but also the heat and transport sectors. By comparing the two different approaches it is possible to identify potential areas that need to be targeted in order to progress towards the 2020 targets.

Our current Business As Usual forecast suggests the UK will get around halfway towards the 2020 renewable targets.

Demand & Supply Outlook

The effects of the recession and high energy prices since September 2008 have caused considerable changes in gas demand. Total gas demand[1] has been falling since September 2008, with DN gas demand reducing by 8% in gas year 2008/9 when compared with the previous year. This trend has continued throughout 2009. From 2008 to 2018, gas demand is projected to fall at a rate of around 0.3% per annum, with DN demand falling at 0.7% per annum and NTS demand forecast to grow at an average of 0.4% per annum. This is a reduction on previous forecasts, driven by higher fuel price forecasts, higher domestic energy efficiency and slower economic growth in the short-term. Annual gas demand is not forecast to return to 2008 levels during the forecast period.

The reduced forecast in annual demand has resulted in a lower forecast of peak gas demand, a key driver for investment in transportation infrastructure. Peak demand is forecast to rise at 0.3% per annum over the forecast period, with the majority of this increase driven by growth in the power generation sector due to new gas-fired plant connecting to the NTS.

In the Gone Green (2009) scenario it is likely that higher fuel prices and an increase in the cost of carbon will be a consequence of the push towards renewable energy. This results in even lower DN gas demands with energy efficiency improvements combining with gas' market share decreasing caused by the introduction of heat pumps, locally connected electric heating and solar thermal heating. Power generation demand is also lower in this scenario with lower transmission electricity demand, less new capacity due to existing nuclear plant remaining open for longer and lower station load factors all contributing to this view. Peak gas demand is also lower in 2018/19 in the Gone Green (2009) scenario than in the Business as

[1] All gas demand references in this document are weather corrected unless otherwise specified.

Usual case due to lower DN demand and a lower amount of total gas-fired power generation capacity.

Our supply forecasts continue to be built around analysis of declining UK Continental Shelf (UKCS) supplies, supplemented with increasing volumes of imports. With new import projects now on stream, there is a surplus of import capacity to the UK. Global demand reductions and development of unconventional sources of gas have meant surplus LNG has consistently arrived at UK LNG terminals, this year. How this may change when global recession abates is a key uncertainty to the forecast which, combined with the increased connectivity of the UK gas markets to Continental Europe through the Interconnector and BBL pipelines, adds to the uncertainty on how supply will be used to match demand. Longer term, the proposed development of more storage in the UK also provides considerable uncertainty in terms of what will be built and when. Though potentially lower in terms of annual volumes, in a Gone Green (2009) scenario, there is a need for more responsive or flexible gas supplies to provide gas for power generation for the effects of wind intermittency.

Our Development of Energy Scenarios document, released in July, highlighted our latest Base Case supply forecasts. Our latest forecasts are similar to our 2008 view though our latest assessment of import dependency and therefore import flows has been marginally reduced through forecasts of lower demand.

Investment Implications

The potential incremental entry flows at the Hole House Farm storage facility are likely to require a new 3-4 km pipeline between Warmingham and Elworth. When comparing auction signals at the remaining entry points to our supply sensitivities, there are some points of interest. In particular (and in common with previous auctions) signals at Bacton, St Fergus, Teesside and Theddlethorpe have been limited compared with the potential levels of supply at these entry points. Without clear auction signals, entry capacity at such terminals will be only available up to the baseline level of capacity and so may be constrained below the level of maximum supply potential.

All Flat Capacity requests from DNOs have been allocated in full, with all flex requests in the transitional period also being accepted. Requested increases in Flex Capacity in constrained areas of the system were rejected in the enduring period following the receipt of firm Flat Capacity bookings from former interruptible sites in these areas.

Looking forward, the ‘base case’ projection is for a reducing level of load related investment as demand moderates. This trend is expected to be offset to some extent by a growing investment profile associated with refurbishment and replacement of ageing equipment.

Although the investment is centred around the base case scenarios, the implications of Gone Green (2009) have been assessed. Under this scenario there is a need for more responsive or flexible gas supplies, to provide gas for power generation for the effects of wind intermittency. This in turn is expected to result in the need for increased flexibility in terms of gas supply, notably new storage, and investments in networks.

In this year's Ten Year Statement an investment sensitivity has been reported to reflect the growing number of customer enquiries that we have received for new connections. Much of this is associated with the potential for both a growing reliance on storage in the UK and a potential increase in gas fired power generation which could be required to replace ageing or environmentally sub-standard plant. Much of this investment would be highly sensitive to the location of new connections and will be monitored on an ongoing basis.

Next Steps

The production of the Ten Year Statement is the final milestone in our 2009 long-term planning cycle. The forecasts contained within the document will be used as a starting point for our 2010 consultation. In addition, targeted questionnaires will be circulated to a range of industry players, requesting demand and supply forecast data, shortly after the publication of this document.

Chapter Two
Document Scope

2.1 Overview of “Transporting Britain’s Energy” Process

The production of the Ten Year Statement (TYS) is essentially the conclusion to the planning process for the current planning cycle. As in previous years, there are areas of remaining uncertainty. These will be addressed through the impending “Transporting Britain’s Energy” (TBE) consultation, which will initiate the planning process for 2010. We propose to use the forecasts contained in this 2009 TYS as the starting point for this consultation. Shortly after the publication of this document, targeted questionnaires will be circulated to a range of industry players (producers, importers, shippers, storage operators, terminal operators, transporters and consumers) requesting demand and supply forecast data and inviting views on our underlying assumptions.

The proposed programme for next year’s plan is as follows:

- Publish 2009 Ten Year Statement – December 2009
- Circulate 2009 Consultation questionnaires – January 2010
- Receive responses to questionnaires – February 2010
- Hold consultation meetings – February/March 2010
- Provide feedback via the internet on responses received – June 2010
- Produce outline investment proposals based on updated demand and supply forecasts and publish at an industry seminar – 8th July 2010
- Publish 2009 Ten Year Statement (including an assessment of the 2009 LTSEC auctions) – December 2010

2.2 Structure of Document

The Statement has been structured such that the main body of the document, Chapters 3 to 7, sets out the key drivers and uncertainties affecting demand, supply and the provision of capacity on our system. Chapters 3 and 4, respectively, provide an overview of our latest demand and supply forecasts. Chapter 5 outlines our plans for investment in the NTS based on the supply forecasts discussed in Chapter 4, and presents the currently approved NTS projects and those under consideration for construction. Chapter 6 then covers the latest commercial developments affecting our transmission system. Chapter 7 covers some of the work we have been doing to assess the impact of long-term energy and environmental targets, and introduces some areas of work that National Grid (outside the Transmission business) is working on to help reduce carbon emissions into the atmosphere.

The appendices provide details of the methodologies used to produce the demand and supply forecasts, the latest demand and supply scenarios themselves, actual gas flow data, system maps and connection specifications (including gas quality). The final sections of the document contain a section on industry terminology and a conversion matrix.

As with the 2008 TYS, we have incorporated all the demand and supply data shown in this year’s document within an Excel spreadsheet file on our website.

2.2.1 Distribution Network Long Term Development Statements

This Ten Year Statement concentrates solely on the transmission network. Information relating to the Distribution Networks can be found in the Long Term Development Statements / Plans which can be accessed via the links below.

National Grid UK Distribution Long Term Development Plan

Northern Gas Networks Long Term Development Statement

Scotia Gas Networks Long Term Development Statement

Wales & the West Utilities Long Term Development Statement

Chapter Three

Demand

3.1 Overview

This section provides an overview of our latest gas demand forecasts, which cover the period through to 2018/19. As well as our central planning case – Business as Usual – this section also includes details of our Gone Green (2009) scenario. This scenario has been developed in order to assess the potential energy mix required in order to meet the EU 2020 targets for renewable energy. In addition to describing the drivers behind the 2009 forecasts, this section also endeavours to explain the key differences between the Business as Usual forecast and the Gone Green (2009) scenario and some of the potential consequences of increased amounts of renewable generation.

In the Business as Usual case, the most significant aspects of this year's forecast are the sharp reduction in demand in 2009 and the lower overall growth rates across the ten-year period. Demand in the DNs (Distribution Networks) is forecast to decrease over the ten-year period with demand growth driven by an improving economic outlook and new housing completions more than offset by the impact of rising end user gas prices and energy efficiency initiatives. Demand from the NTS is forecast to increase with 13.6 GW of new CCGT plant included in the forecast. 7.5 GW of CCGT plant is already under construction, with some of this currently commissioning. Exports to Europe are also forecast to increase due to lower GB demands and an improved global (LNG) supply position. From 2008 to 2018, gas demand is projected to fall at a rate of around 0.3% per annum, with DN demand falling at 0.7% per annum and NTS demand forecast to grow at an average of 0.4% per annum.

In the Gone Green (2009) scenario it is likely that higher fuel prices and an increase in the cost of carbon will be a consequence of the push towards renewable energy. This results in lower DN gas demands with energy efficiency improvements combining with gas' market share decreasing and being replaced by heat pumps, locally connected electric heating and solar thermal heating. Power generation demand is also lower in this scenario with lower electricity demand, less new capacity due to existing nuclear plants remaining open for longer and lower station load factors all contributing to this view. Annual gas demand in the Gone Green scenario is approximately 10% lower in 2020 than in the Business as Usual case.

This reduced annual gas demand forecast also results in a lower peak gas demand, a key driver for investment in transportation infrastructure. Peak demand is forecast to rise at 0.3% per annum over the forecast period, with NTS demand growing at 2.1% per annum and DN demand falling at 0.4% per annum.

Peak gas demand is about 7% lower by 2020 in the Gone Green (2009) scenario than in the Business as Usual case due to lower DN demand and a lower amount of total gas-fired power generation capacity.

Appendix 2 details our current gas demand forecasts and Appendix 3 contains actual demand figures. References to historical demand in this document mean weather-corrected demand unless otherwise stated, in order to discount the effect of the weather when assessing actual demand against forecasts.

3.2 Energy Prices

In order to produce our gas demand forecasts it is necessary to develop a set of fuel price assumptions, particularly the prices paid by end users. One of the key considerations in the development of these assumptions is price trends, as high energy prices have been seen to reduce energy demand. Understanding why historic price movements have occurred can give a better insight into how energy prices are likely to change in the future and hence their influence on energy demand can be better forecast. This section covers wholesale energy prices, concentrating on recent price trends in key energy markets. The impact of these prices on gas demand is covered in section 3.3, with our fuel price forecast presented in more detail in section 3.5.3.1.

Key trends in 2009 include the ongoing recovery of oil and coal prices after starting the year at their lowest levels for years. A steady and continuous increase has been seen in both commodities, with oil rising particularly fast. Oil has almost doubled in price since the start of the year, mainly due to positive views of economic recovery. Coal has seen a lesser increase, ending October 2009 30% higher than its lowest point in March. The reductions in electricity demand from recession and seasonal changes along with fewer unplanned generation outages, have meant that plant margins have brought electricity prices down since winter. Electricity prices have remained fairly stable all year generally around £35 / MWh since mid February. Gas prices have also reduced since the start of 2009. This, as with electricity, is due to seasonal demand reductions since the start of the year alongside recession led demand reductions. In addition, the increase in deliveries of LNG to the UK market via the existing terminals and the new terminals in Wales has put downward pressure on wholesale gas price.

The linkage between oil prices and UK gas prices has weakened substantially this year, due to the increasing amount of gas imports to the UK coming from LNG, which is mainly a non European or Russian source and hence not oil linked. This has not only decreased the oil linkage but has created a high degree of arbitrage between the UK and the US Henry Hub prices, as this LNG can relatively easily go to either market.

The increase in LNG is because the global down turn means global demand has dropped so LNG is plentiful and available to the UK. When economic recovery occurs, global gas demand may return, removing excess LNG from the world market. As the UK has no long term LNG contracts, this is likely to reduce the levels of LNG arriving in the UK.

Oil price is having less of an effect on gas price between 6 and 12 months from the gasday. Beyond this, oil price is still the major influence on gas price. The degree of oil linkage that the UK gas price experiences depends on many factors including the availability of gas from a non European origin (currently just LNG), but also on how new gas contracts are written. There are signs that whether oil linkage should be excluded or have less influence on gas price in new European gas contracts is at least being discussed, so maybe in the future it will be less influential (but any developments here appear still a long way from fruition).

Once the global economic recession finishes, LNG deliveries to the UK may reduce. However a degree of natural arbitrage between UK and US hubs has been established and may continue. Less LNG would mean more influence of European gas, and a return to a greater oil linkage, as long as oil linkage remains a fundamental part of new contracts. All these factors may lead to a gradual reduction in the influence of oil price over UK gas price over time.

National Grid's gas price forecasts are currently based on an oil linkage continuing, with UK gas prices possibly indexed more closely to US LNG prices being forecast as a sensitivity.

3.2.1 Oil Prices

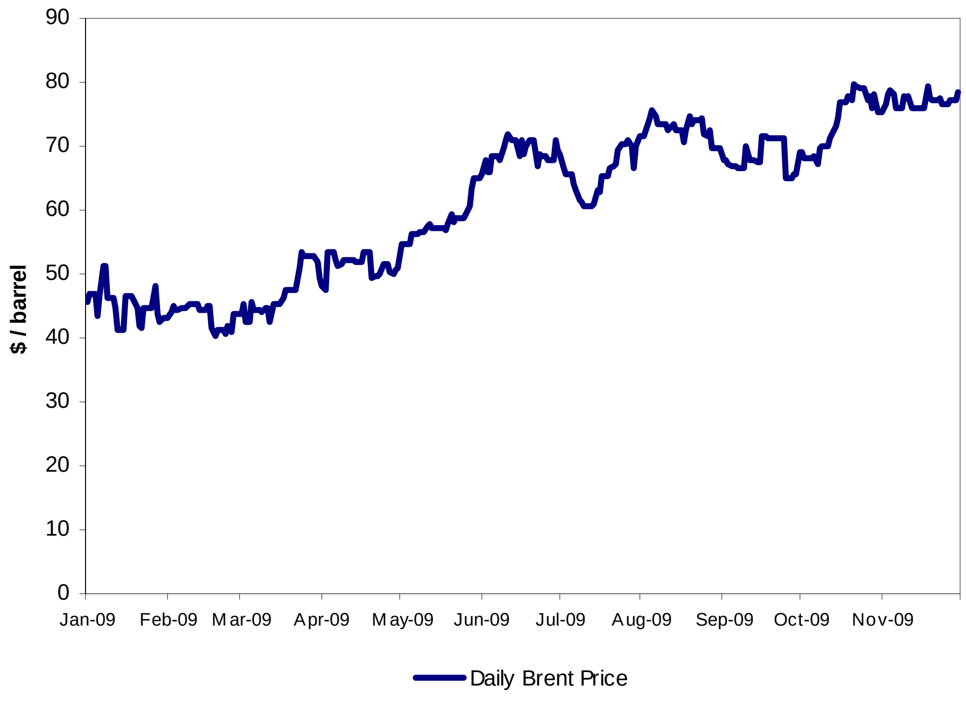
Oil prices started 2009 at levels last seen in 2005. After the peak of $147 / barrel in July 2008, the oil price started 2009 at $45 / barrel. Some market commentators suggest that just as the highest oil price seemed to have been artificially elevated by trading activity, the lowest oil price could have been artificially lowered by the trading activity particularly as call options came into effect, as prices dropped and money moved out of oil markets into something more stable thus making oil fall further. The end result of this could have been an over correction downwards in oil price, meaning that oil price started 2009 particularly low, therefore as other markets settled down, there was always likely to be a natural recovery in the oil price.

Oil price has recovered steadily since winter 2008/09. In fact it has steadily increased since March to a highest level of $80 in October, twice the March price. Throughout November 2009 the oil prices has remained just under $80 / barrel.

Figure 3.2A shows the Brent crude oil price in 2009.

FIGURE 3.2A – Oil Prices

Source – www.theice.com



World demand has remained relatively low, in 2009 and has continuously been more than matched by world supply capability, throughout 2009. The reductions in world demand are such that the supply / demand position is no longer tight, and therefore small changes in the supply or demand side have had less influence over oil price movements than seen in 2008. This is one reason why OPEC production cuts in the early part of the year had little impact on the oil price.

A result of supply / demand fundamentals having less influence is that other factors have been the main driver of oil prices. In 2009 oil prices have been influenced by views of world economic health more than any other factor. The theory is that once the world recovers from economic down turn, demand will return. Prices have risen throughout the year as a result of signs of economic recovery. The prices for oil in 2010 are higher than the current prices, in line with views of a more healthy economy in the future. Stock market increases have also resulted in money coming back into commodities. A weakening dollar has also helped oil price increases throughout the year.

Since the start of June the oil price has been generally in a range of $65 - $75 /barrel (bbl) since the start of June. Market commentators say there is no surprise it is in this range as $70 /bbl is the price level quoted by many non OPEC oil producing countries as the required level to make a profit.

In late October the price rose to its highest level for a year, breaking the $75 /bbl mark to sit at the current level of $ 79 /bbl. This was due to encouraging US bank results and official figures showing the US economy had moved out of recession. Also there has been stronger than expected growth in Asia and a weak dollar.

There is a view that if prices reach $80 /bbl a large number of options will be triggered meaning the sellers of these call options will be forced to buy oil futures thus raising the price further. The improving economic situation, leading to increasing oil price, has also resulted in the market looking bullishly at some physical factors such as the US stock inventory data, which since September is having the influence of increasing the oil price when it indicates a demand increase, but does not appear to reduce the oil price if it indicates lower than expected demand levels. This is against a background of oil demand that is still historically relatively low, though.

The views of future economic growth, trading floor options and short term corrections must be considered alongside the reality of physical oil stocks.

But there are doubts on whether oil prices can be sustained given the fragile state of the global economy, despite some signs of a recovery. Stock levels of oil and oil distillates such as diesel and heating oil are at their highest in Europe for decades. There is a lot of oil being stored offshore in tankers around the world. This has risen in Europe by 25% in September. In Asia diesel stocks are rising fast with inventories in the Singapore hub trebling since August to record levels. US drivers are consuming 5% more fuel than last year, but a diesel glut has forced refineries to scale back or shut. Refineries are running with more spare capacity than they have had for years. In October, the largest independent US refinery Valero Energy said its refineries were running at 80% capacity possibly moving to 70% in November 2009.

This EIA[2] quote made in August appears to still summarise the oil price this year very concisely. - ‘The oil market continues to be defined by the tension between optimism over the perceived recovery of the global economy on the one hand and persistently weak global consumption of crude oil and other liquid fuels on the other.’

[2] Energy Information Administration – Official Energy statistics from the US Government.

3.2.2 Gas Prices

In 2009 gas prices started at around 60p/th for January and the first half of February. Once the cold winter weather started to dissipate in mid February, demand dropped, and prices reduced dramatically, to just over 30p/th. Prices then continued to reduce slowly and consistently throughout the year until late September, when the beginning of the winter period caused prices to start to increase. Prices remained below 30 p /th throughout November 2009.

Figure 3.2B shows the day-ahead wholesale gas price during 2009.

FIGURE 3.2B – Gas Price

Source – Heren Day Ahead NBP Price

2008 witnessed the sixth successive year of wholesale gas price increases in the UK (except for 2007), with increases in 2008 higher than seen previously. In 2009 everything changed. The average day ahead price for 2008 was 57p/th. In 2009 (up to the end of October) the average day ahead price was 31p/th. Gas prices have reduced throughout the year since the period of cold weather and Russia / Ukraine dispute, on reduced demand from recession, new supplies from extra LNG, and oil linkage effects on a lower oil price (lagged by six months).

There is a historical linkage between oil and gas price, which has an approximate 6 month lag. The peak oil price of $147 occurred in mid July 2008, followed by a rapid, sustained drop for the next 5 months. The established relationship would infer gas prices may have dropped from mid January 2009, for 5 months.

At the start of January there was a spell of cold weather in the UK. This coincided with the 2 week Russia / Ukraine crisis. The Russia / Ukraine crisis resulted in most of the Russian gas supplies to Europe being cut off for a two week period. Due to a combination of high domestic demand and Interconnector exports, the NTS experienced many days of relatively continuous high demand. During this period there was plentiful supply from UKCS, Norway, LNG from Isle of Grain and storage. In spite of significant depletion of some storage stocks, UK gas prices remained relatively low, below the Continental contract price thus enabling the Interconnector to continue to export, based on price differentials. In mid February winter demands subsided. This combined with healthy supplies and the oil linkage influence, resulted in the gas prices dropping sharply from 60p/th to 35p/th in a few days, as the market realised the winter was finishing, and the system had coped very well, especially with the new supplies of LNG being seen from Isle of Grain stage 2.

For the rest of the year there has been a continuous theme. Extra Supplies of LNG have arrived consistently at the two new terminals in Milford Haven as they have commissioned and begun commercial operation. This has helped bring UK gas prices down throughout the year as LNG ships have frequented these new facilities bringing a steady and significant extra supply of gas to the UK from LNG.

The day ahead price has started to increase since mid September, due to the usual seasonal demand increase and a few concerns over Norwegian Supplies, (which have appeared once the demand required them). However the day ahead price is rising to levels lower than the forward prices for winter would have suggested, and the forward prices are generally reducing. This indicates a market that has so far been well supplied and is considered to have no major supply issues for the coming winter season.

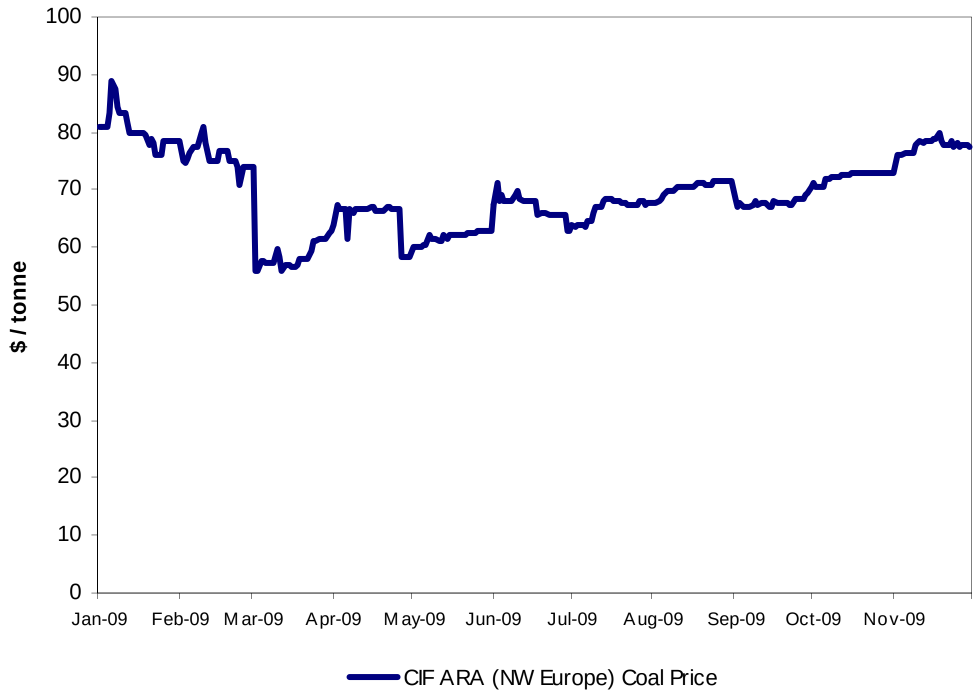
3.2.3 Coal Prices

As indicated in Figure 3.2C, global coal prices have shown quite a degree of movement throughout the year. They have been roughly tracking oil prices down to their lows in March, and increasing since then. However the rises since March have been much less pronounced than oil, and the coal price has ended November 2009 at $77 / tonne; actually lower than the $80 / tonne at which it started the year.

Figure 3.2C shows the daily coal price during 2009.

FIGURE 3.2C – ARA Coal Prices

Source – Heren Daily European Electricity Report



The oil price has to some extent been mirrored by movements in the price of coal, as they have many of the same drivers. The most notable driver for forward prices of both oil and coal is views of the global economic recovery.

Coal, however, has its own supply chain and demand requirements and particular price drivers relating to these, particularly demand from India and China. These have fluctuated in the last few months due to levels of Chinese stock piles and the return of Chinese coal mines to production after long closures for safety concerns; and in India due to the effects of the typhoon season and the continuing underlying increases in domestic coal demand.

The price peaked in July 2008 at over $224 / tonne, driven by strong global demand, particularly in China and India, coupled with a shortage of available capacity and freight. Since then, the economic downturn has restricted demand particularly from China and India, two of the main importers of coal, and the main global manufacturers of goods. Large worldwide reductions in demand from the industrial sector and increased supplies, as producers diverted more low-grade coking coal material to the power generation market as demand from steel mills caused the price to drop, leading to the lowest price since 2007 in the March 2009 at $56/tonne. A sign of how low demand for coal had reached was the fact that Australia's Newcastle coal port, the world's largest coal export terminal, was being under-utilised for the first time in years. Since then the economy has started to recover, and demand has increased accordingly. The forward prices, as with oil, reflect the views of slow steady economic recovery.

Coal Prices have risen slower than oil. This could be due to queues in Australian coal ports abating in recent months and high stock piles offsetting some of the increases in Chinese and Indian demand. This demand is anticipated to continue. This with expectations of demand growth in the rest of Asia, South Africa and the Atlantic Basin, next year has lead to slight price rises for this period, as the demand increase is anticipated to more than counter the increase in supply.

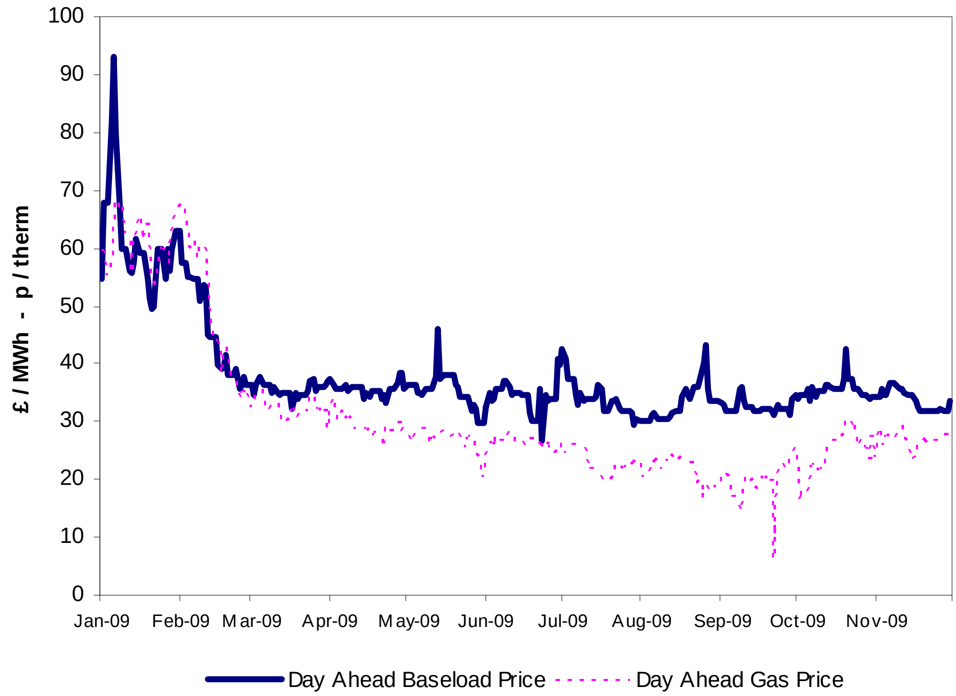
3.2.4 Power Prices

UK baseload power prices started the year tracking the UK gas price. The price was generally around £60 /MWh until mid February when the baseload electricity price tracked the gas price downwards due to the warming weather. However, the electricity price has remained fairly constant all year due to consistently good margins, whereas the gas price has reduced on greater supplies. Whilst reasonably consistent, the baseload price has exhibited a trend of a very slight decline since mid February. It has averaged £35 / MWh, over this period.

Figure 3.2D shows the day-ahead wholesale electricity gas price during 2009 with the day-ahead wholesale gas price for reference.

FIGURE 3.2D – Electricity Day Ahead Baseload

Source – Heren European Daily Electricity Markets



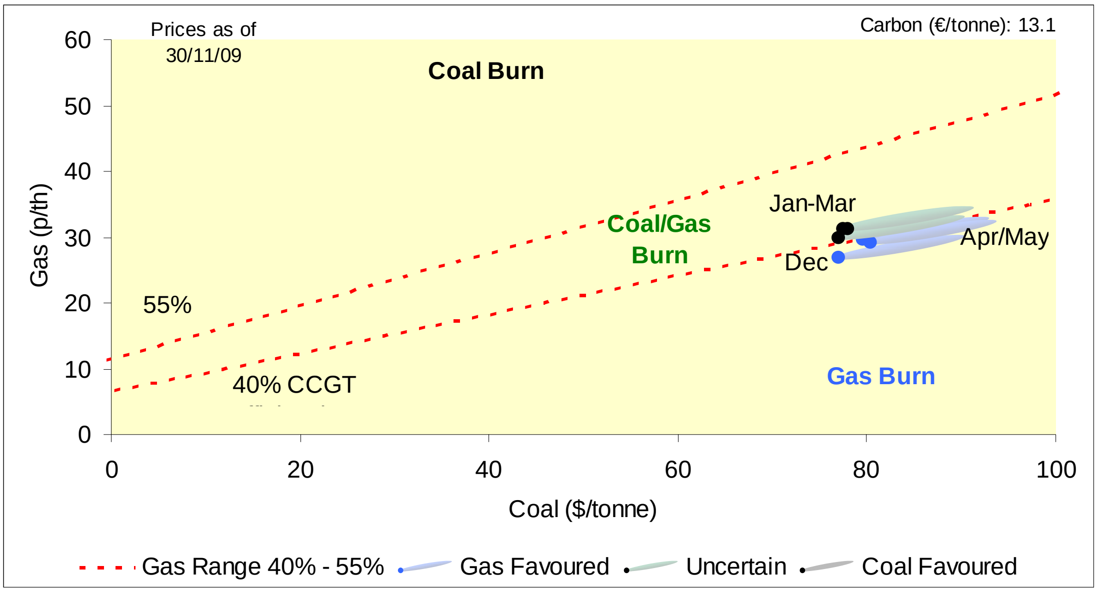
Demand reductions and gas price reductions in mid February caused electricity prices to follow, also reducing dramatically over a few days in the middle of February. Prices fell from around £55/ MWh in early February to under £40/MWh in a few days. From this point through the rest of spring, the day ahead baseload electricity generally remained in the £35 - £40/MWh range for the rest of the year, displaying a very slight downward trend. From summer onwards it continued to reduce slightly, to average just under £34 MWh for the period. The influence of the reduction in gas prices was largely offset by the coal prices gradually increasing throughout the year, particularly as coal has been the marginal fuel through summer 2009 and a little beyond. The impact of ROCs could also be adding to the electricity price. Margins have been healthy throughout the year. In the last few months margins have been particularly healthy as a number of power stations have returned from scheduled summer maintenance, helping prices remain at the same price as summer for the early part of the winter period.

From the start of the year until mid February, the high gas price meant that coal was favoured over gas for electricity generation. From mid February the gas price dropped to such an extent, and remained low all year, that it was easily favoured over coal for electricity generation for the rest of the year.

Figure 3.2E compares the cost of coal-fired generation with the cost of gas-fired generation, including the cost of CO_2. The graph shows prices on certain forward markets on a specific day. Each point represents the price of coal compared to the price of gas at a certain time, for a particular forward market (e.g. the second quarter of 2010). The smearing represents National Grid's view on the effect of transportation costs for the fuels. The chart shows where gas is more favoured for electricity generation than coal, where coal is more favoured and also the large range where it depends on other factors. This range is due to many factors including the different efficiencies of different power stations, with older stations tending to be less efficient. Depending on which stations you compare, there can be a different fuel favoured for generation. As can be seen from the graph, as of 30th November 2009, January to March 2010 have an uncertainty in which fuel is favoured to generate electricity, whereas during December 2009 and April and May 2010, gas is expected to be the favoured fuel for electricity generation.

FIGURE 3.2E – Relative Fuel Prices

Source – Heren Daily European Electricity Report, Platts International Coal Report, Heren Day Ahead NBP Price



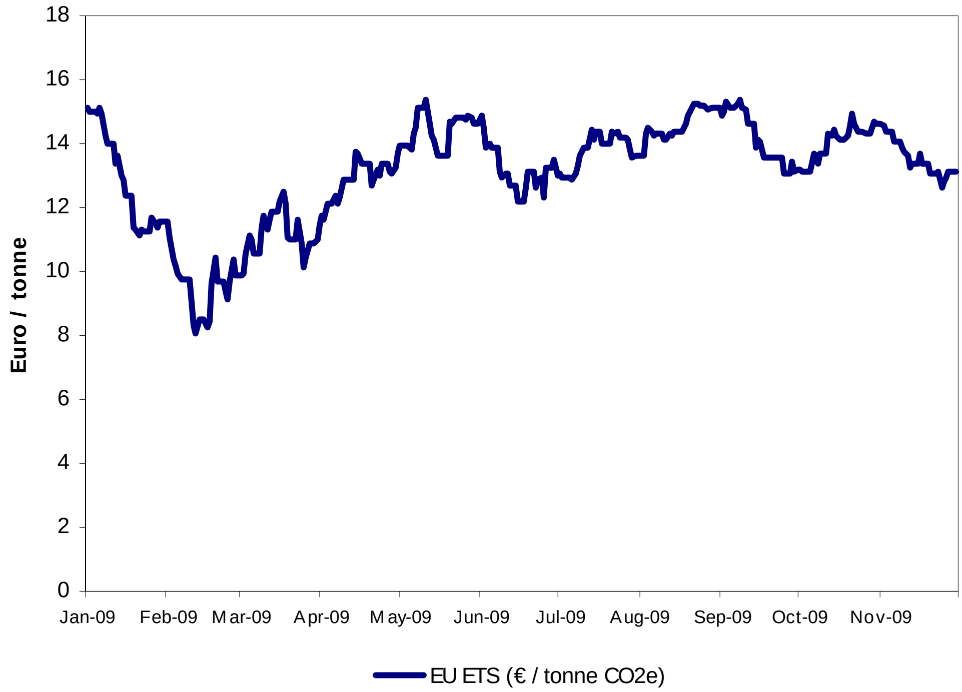
3.2.5 Carbon Prices and Emissions Trading

Phase 2 of the EU ETS covers the period from 2008 to 2012. The carbon price in 2009 has shown a strong correlation with general energy prices and economic data. The average price for 2009 is around €10 less than for 2008. Prices Figure 3.2F shows the spot carbon price traded in 2008.

Figure 3.2F shows the daily European carbon price (EU ETS)

FIGURE 3.2F – Carbon Price

Source – Heren European Daily Electricity Markets



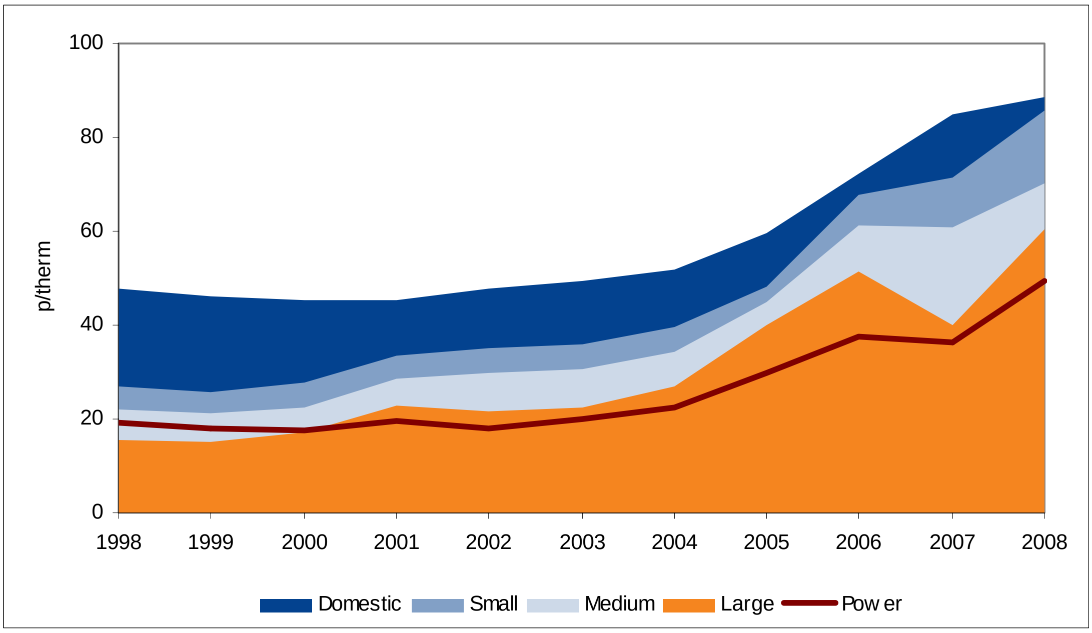
The prices in 2009 are lower than in 2008 due to general energy demand reducing in the economic downturn, particularly lower industrial demands resulting in more carbon credits being available to the market.

The low prices in February were attributed to speculative trading activity, upon expectations of price drops when Germans issued their permits. It also coincided with UK Gas and electricity prices dropping.

3.3 Historical Gas Demand / Recent Trends

The past eighteen months have seen unprecedented levels of volatility in both the energy markets and the world financial markets. As discussed in the early part of this chapter this has seen end-user gas prices in the UK reach record levels (see Figure 3.3A) and a rapid decline in the UK economy, resulting in a recession. The effect of the economic downturn on energy demand has been significant with a rapid decline in both electricity demand and gas demand, with the latter particularly concentrated in the traditional Distribution Network (DN) market sectors. Although this document focuses on gas, the level of electricity demand has an obvious impact on gas-fired power generation demand.

FIGURE 3.3A – Annual end user gas prices
Source: DECC



For gas supply year 2008/9, weather-corrected electricity demand from National Grid's Transmission system fell by almost 6% when compared with the previous year as shown in Figure 3.3B. Weather corrected gas demand in the DN markets fell by 8% over the same period as shown in Figure 3.3C.

Figure 3.3B - Monthly Transmission power demand
Source: National Grid

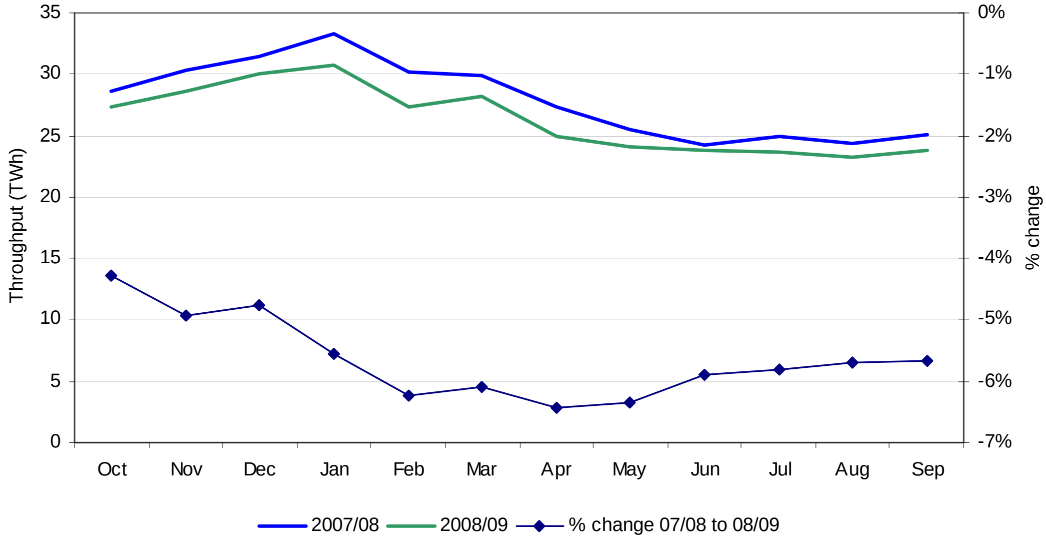
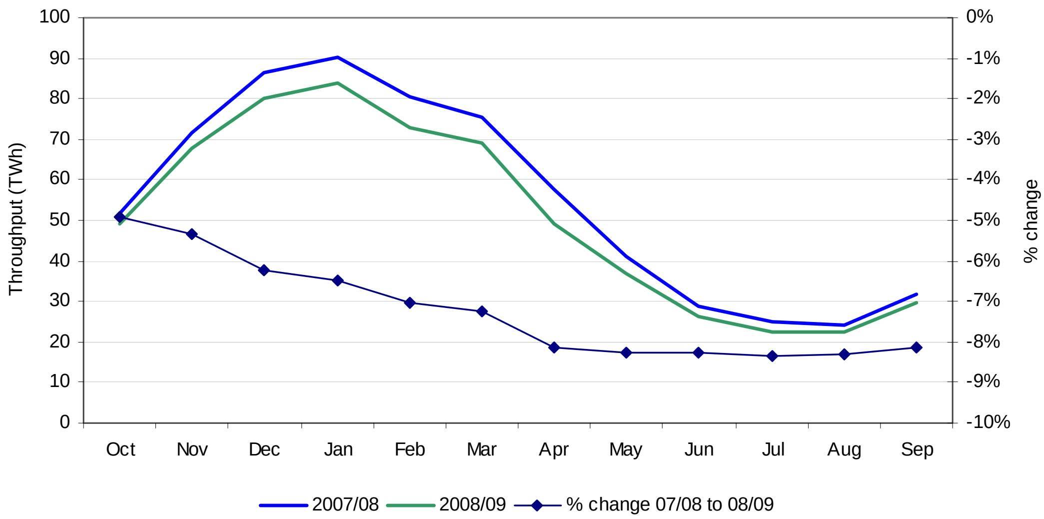
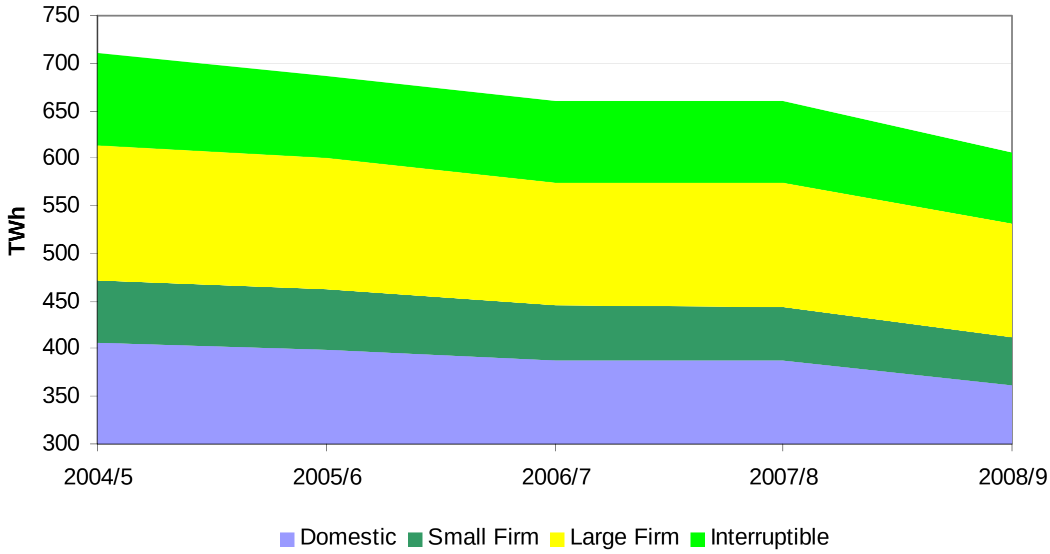


FIGURE 3.3C - Monthly DN Gas Demand
Source: National Grid



This fall in DN demand is a continuation of recent trends. Gas demand in the DNs fell by over 10% between 2004 and 2008, a reduction that coincided with the rise in end-user gas prices highlighted in Figure 3.3A. It is also noticeable that this fall in DN demand has been prevalent across all market sectors from domestic consumers to large industrial users. Figure 3.3D shows the fall in distribution network gas demand over the past five years with demand in gas year 2004/5 over 700TWh. This fell to just over 600TWh in gas year 2008/9.

FIGURE 3.3D – Distribution Network gas demand
Source: National Grid

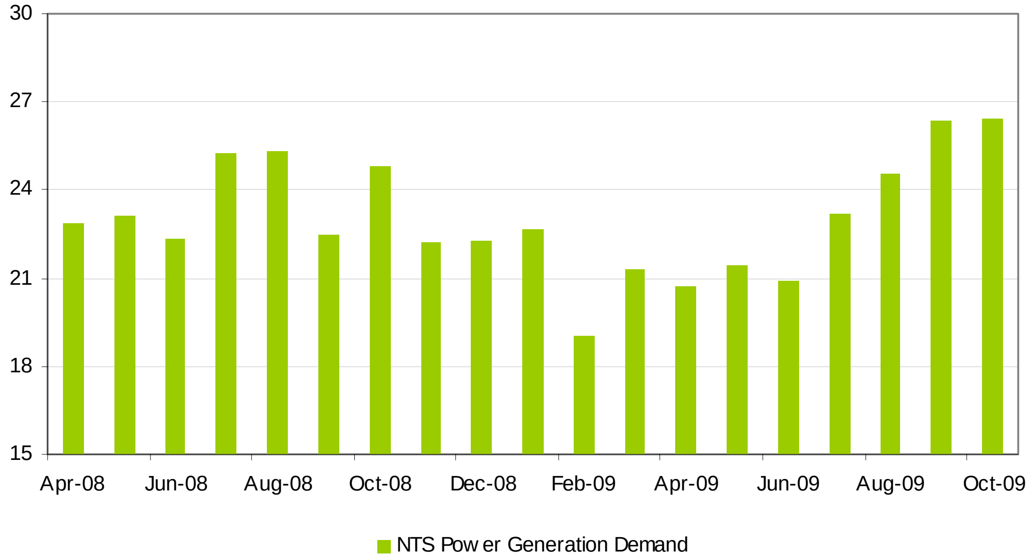


The steady increase in end-user prices over the past five years, coupled with government policies around energy efficiency and carbon emissions reductions, is thought to have changed consumer behaviour and stimulated energy efficiency improvements. Our analysis of the demand reduction in the domestic (0-73.2 MWh p.a.) gas sector suggests that a significant proportion of this fall is due to increased energy efficiency, with scope for further reductions into the future. Rising public awareness of their carbon footprint and the impact on global warming may also be affecting consumption. The key element driving this demand reduction is the underlying cost of energy, which is driving both changes in consumer behaviour as well as the implementation of energy efficiency measures such as cavity wall and loft insulation. The installation of more efficient boilers is also helping to drive domestic gas demand down. Section 3.5.3.2 covers our energy efficiency analysis in more detail.

The non-domestic sectors in the gas Distribution Networks have also seen demand fall rapidly during the recession. This has again been influenced by fuel prices, but also a combination of demand destruction (with gas consumers going out of business) and temporary reductions in production, examples being sections of manufacturing having longer Christmas breaks than usual and the high profile instances of the large car manufacturers shutting down for periods of up to a few months. Energy efficiency improvements also drive down demand in the non-domestic sector, although this has been evident for a longer period of time, particularly in the energy intensive industries where fuel bills make up a large proportion of overall costs.

Conversely, gas demand in the power generation sector increased by over 6% in 2008. The very high coal prices in the summer of 2008 saw gas become a more competitive fuel for generation despite the corresponding high gas prices. The delay in fitting FGD equipment to some of the opt-in LCPD coal plants and the continued problems with nuclear plant availability also contributed to gas' share of the generation mix rising. Power generation gas demand fell in the early part of 2009 as coal and carbon prices fell dramatically and electricity demand also fell due to the impact of the recession. This trend was reversed in the later part of 2009 with falling gas prices seeing an upturn in demand in this sector, as highlighted in Figure 3.3E.

FIGURE 3.3E – NTS gas-fired power generation
Source: National Grid



Exports to continental Europe have been above 4 bcm for the past two calendar years. These volumes have been driven by a combination of new UK import infrastructure and differences between the UK gas price and Continental contracted gas. Due to the global recession, there now appears to be increased availability of 'international' supplies for the UK; notably LNG and to a lesser extent Norway as Continental buyers take less gas or change their timing for receipt of gas due to pricing arrangements that are indexed to oil albeit lagged. For 2009 there is also a driver for higher exports to the Continent on account of increased depletion of Continental storage, partly as a result of the Russia / Ukraine dispute. In 2009 continental exports (excluding December) have increased by over a third, compared to the previous year.

Irish exports have fallen in 2009 with the impact of the recession reducing demand in the traditional market sectors and outweighing any increase in the power generation sector due to additional capacity being connected.

Demand has progressed very much in line with our forecasts during 2009 with weather-corrected DN demand around 0.5% lower than our forecast. Overall demand on the NTS (excluding continental exports) is around 1% over forecast for the same period, with this largely due to the increase in power generation demand in recent months.

3.4 Interaction with Gas Distribution Networks & Offtake Arrangements

Our forecast of the demand for gas from consumers connected to distribution networks is supported by a dialogue with each of the Distribution Network Operators (DNOs) responsible for major pipeline systems connected to the transmission network. The process of information exchange that we adhere to in this relationship is documented by Section H of the Offtake Arrangements Documents, which outlines key points in the timing of the process and the obligations placed upon each party to provide data to support the other's system planning and development activities.

Our dialogue with the DNOs involves the sharing and discussion of forecast assumptions, including key influences upon market development such as price and the commissioning of major new loads, and detailed forecasts of demand over a ten year period. Both parties are required to provide the other with their forecast of gas demand, although there is no obligation on either party to use the projections so provided. The information exchange runs in parallel to our TBE consultation process and allows us, where appropriate, to share the output from that work with DNOs. The extent of the information that we provide to a DNO is unaffected by the ownership of the business in question.

Parties to the information exchange are at liberty to employ any appropriate methodology for the production of their gas demand forecasts in line with license definitions. For information and guidance we publish the methodology that we have adopted for such work on the National Grid website (see section A1.1 of this document). Each of the gas Distribution Networks also publish their own Long Term Development Statements / Plans – see Chapter 2 of this document for links to these.

3.5 Gas Demand Forecasts

3.5.1 Forecast process

Gas demand is influenced by a number of factors, each having a varying degree of influence. A key sensitivity is the gas price, but also the level of exports, which means assessing the European and Irish markets, the level of energy efficiency improvements, CCGT developments and the strength of the economy are all key factors considered when producing the forecast. This gives a flavour of some of the key forecast drivers, but is by no means an exhaustive list.

The process that is employed to develop the annual gas demands is based upon a combination of different techniques, including econometric modelling, assessment of increased energy efficiency, monitoring of information from the enquiries for new loads, analysis of the consumption of existing large demands and market analysis. Detailed analysis of certain market sectors – domestic, small commercial end users, large commercial end users, industrial consumers and power generation – is carried out. Each forecast is developed from a set of planning assumptions, which are discussed in more detail below.

The data used to support these assumptions and the subsequent forecasts is obtained from independent consultants and organisations as well as our Transporting Britain's Energy (TBE) consultation and a process of information exchange between the Distribution Network businesses and ourselves. This consultation process incorporates data-gathering questionnaires aimed at specific sectors of the industry (including consumers) and meetings with major industry demand-side stakeholders, such as power generators and gas shippers. The TBE consultation both informs, and helps us to validate, our forecast and planning assumptions. These planning assumptions are subject to routine review and update in the period between each forecast.

The process that is employed to develop the gas demand forecast in the Gone Green (2009) scenario is based on the same approach as outlined above. However, as the driver in this scenario is to reduce carbon emissions and increase the renewable share of energy, there is a greater emphasis on energy efficiency, low carbon forms of power generation and renewable technologies such as heat-pumps. The Gone Green (2009) scenario has been developed in order to assess one way of apportioning the relative contribution to the EU 2020 target across three sectors – electricity, heat and transport. Different aspects of the scenario, e.g. the level of energy efficiency improvements required, therefore have to be adjusted until the target is met. This approach results in aspects of the forecast being treated differently. For example, a detailed fuel price forecast or economic background is not used in order to develop the Gone Green (2009) scenario. A certain level of demand is required to meet the target and any fuel prices would be more of an output from this process rather than an input to it.

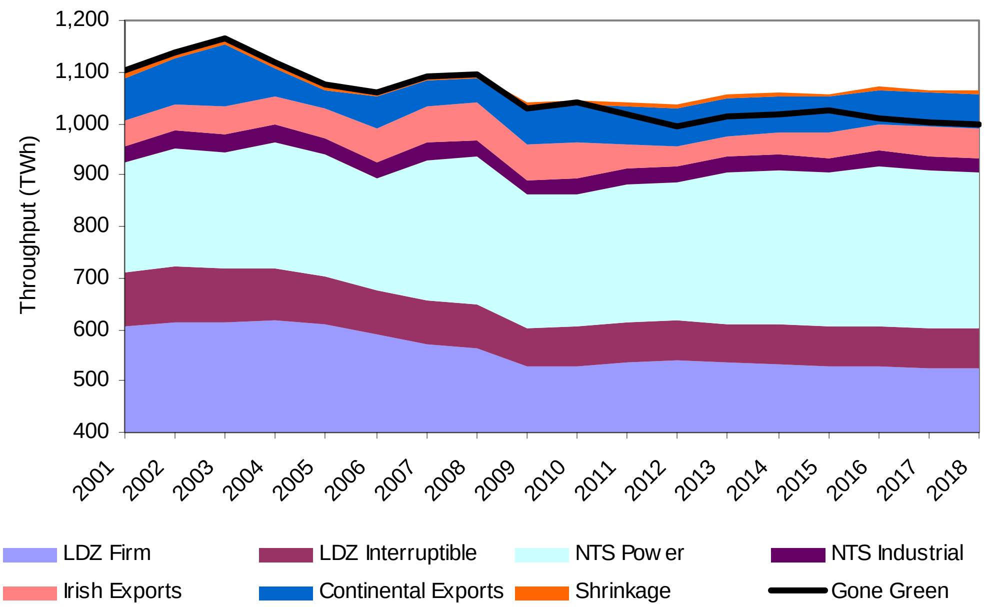
The commentary in this section refers to our Business as Usual case unless specified. Where possible a comparison with our latest Gone Green (2009) scenario has been included.

3.5.2 Gas Demand Forecasts

3.5.2.1 Annual Gas Demand Forecasts

Figure 3.5A shows both historical annual gas demands and our 2009 forecast. All demands shown are weather corrected. The history shows the continued fall in DN demand from 2004 and the increase in NTS demand over the past two years, driven largely by increased gas-fired power generation demand. The gas demand in the Gone Green (2009) scenario is also shown on this chart. Annual gas demand in the Business as Usual case is forecast to be broadly similar by the end of the forecast period as in 2008/9. Annual demand in the Gone Green (2009) scenario is around 10% lower than the Business as Usual case by 2020.

FIGURE 3.5A – Historical and Forecast Annual Gas Demand
Source – National Grid



In the Business as Usual case, the most significant aspects of this year's forecast are the sharp reduction in demand in 2009 and the lower overall growth rates across the ten-year period. The impact of the recession in 2009 is evident. DN demand is forecast to fall by around 6.4% in 2009 predominantly due to the contracting UK economy. NTS demand is also predicted to fall, by around 2.3%, with lower power generation, industrial and Irish export demand being offset to some degree by greater exports to Continental Europe. Overall demand is therefore forecast to fall by just under 5% in 2009.

Our forecast for the economy is that we will begin to see a return to growth in mid 2010, with GDP levels returning to 2% growth from 2012 onwards. Coinciding with a reduction in end user fuel prices, this results in a small amount of growth in the DNs, although this is also driven by new power generation demand within the networks. Over the long term, however, the demand growth driven by the improving economic outlook and new housing completions is more than offset by the impact of rising end user gas prices and energy efficiency initiatives. These, coupled with increasing carbon prices and government policy, are forecast to result in increased levels of energy efficiency and renewable energy, thus reducing gas demand. The long term DN forecast is therefore that demand will fall over the ten-year forecast period.

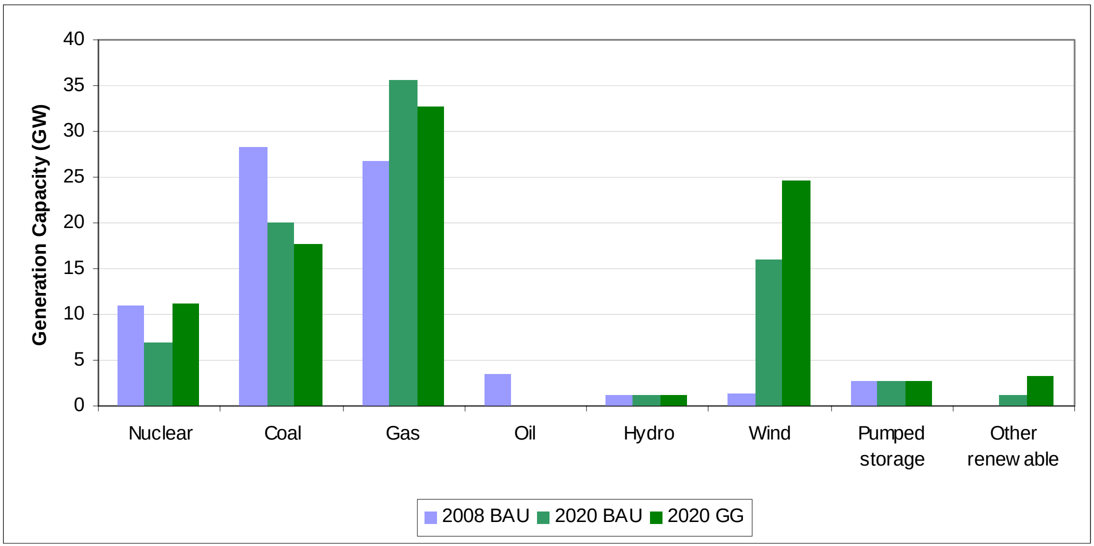
The impact of the recession is evident in the Gone Green (2009) scenario as well. In this scenario it is likely that higher fuel prices and an increase in the cost of carbon will be a consequence of the push towards renewable energy. This results in lower DN gas demands with energy efficiency improvements combining with gas' market share decreasing and being replaced by heat pumps, locally connected electric heating and solar thermal heating.

In the Business as Usual case, after falling in 2009 gas demand in the power generation sector is forecast to increase in subsequent years as new CCGT plant connects to the NTS, replacing LCPD opt-out coal-fired generation and ageing nuclear plant. 13.6 GW of new CCGT plant is forecast to connect to the NTS by 2018/19, although at a slower build up rate than in previous forecasts due to our lower forecast of electricity demands increasing the forecast plant margin. 7.5 GW of CCGT plant is currently under construction, some of which is commissioning, which may result in very high plant margins in the short-term. These high plant margins may result in some gas-fired plant being mothballed in the short-medium term thus reducing demand. The load factors, and therefore annual output, of existing gas-fired stations is forecast to decrease over the period due to age and station efficiency. Some of the existing stations are also forecast to close for these reasons.

In the Gone Green (2009) scenario the amount of gas-fired power generation capacity is lower than in our Business as Usual case. Existing nuclear plant is assumed to receive ten-year life extensions, helping to reduce carbon emissions and maintaining the level of nuclear capacity until the construction of new nuclear plant which is included from 2019/20 in this scenario. Combined with lower electricity demands this results in less of a requirement for new CCGT build, with 10.7GW included by 2018/19. Existing stations also begin to close earlier, with the load factors of those stations that remain open lower than in the Business as Usual case.

Figure 3.5B compares the level of power generation capacity in the Business as Usual and Gone Green (2009) scenarios.

FIGURE 3.5B – Power generation capacity mix.
Source – National Grid



Exports to Europe are forecast to increase in the early part of the forecast period due to lower GB demands and an improved global (LNG) supply position arising through lower demands. Though subject to considerable uncertainty, we forecast these exports to be maintained over the forecast period.

Exports to Ireland are forecast to fall in the short to medium term due to a combination of lower Irish demand due to the recession and the onset of new indigenous supplies. Exports are then predicted to increase as these indigenous volumes decline, thus increasing the level of exports, although not back to the level seen in 2008 due to a lower forecast of overall Irish demand.

3.5.2.2 Peak Gas Demand Forecasts

The reduced forecast in annual demand has resulted in a lower forecast of peak gas demand, a key driver for investment in transportation infrastructure. Peak demand is forecast to rise at 0.3% per annum over the forecast period, with NTS demand growing at 2.1% per annum and DN demand falling at 0.4% per annum. The ‘spiky’ nature of the growth rates is indicative of new CCGT loads connecting to the NTS.

Peak gas demand is about 7% lower by 2020 in the Gone Green (2009) scenario than in the Business as Usual case due to lower DN demand and a lower amount of total gas-fired power generation capacity.

The peak forecast is derived using our established weather / demand modelling methodology which has detected no significant change in the weather sensitivity of demand despite lower annual throughputs. Peak demand forecasts in the weather sensitive DN sectors therefore have a very similar profile to the annual forecasts.

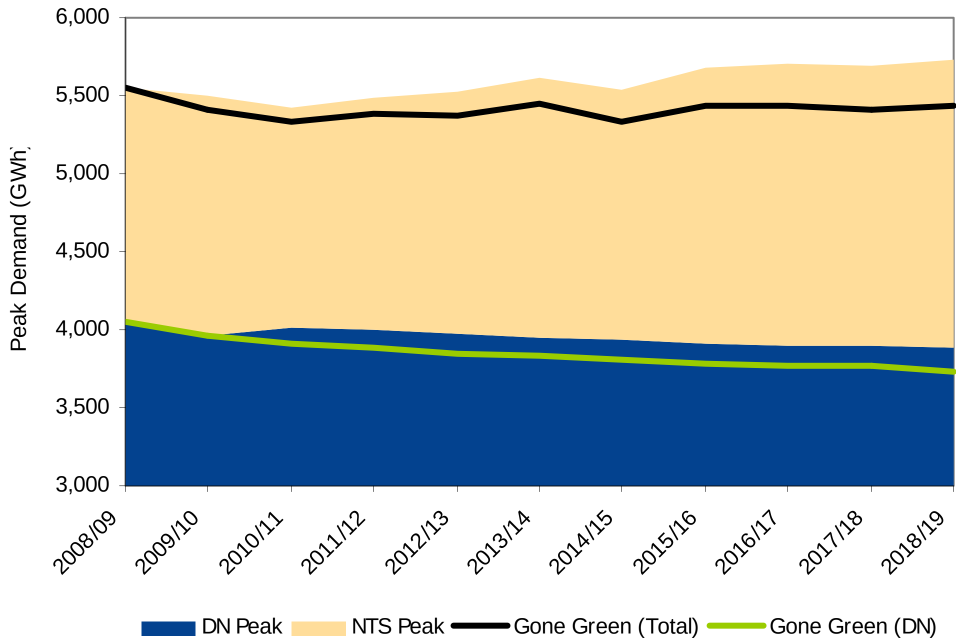
Figure 3.5C shows our latest NTS and DN peak demand forecast and an indicative level of peak demand in the Gone Green (2009) scenario. The DN forecasts should be seen as complementary to the DN exit requirements provided through the Offtake Capacity Statement (OCS). This chart does not take into account the move to ‘universal firm’ demand post 2011. We are currently in the process of assessing the potential impact of demand that is currently interruptible becoming firm and how that would alter our peak demand forecasts.

In the Gone Green (2009) scenario the level of peak demand from gas-fired power generation will depend greatly on the amount of wind generation at the time of peak gas demand. Gas-fired power stations, particularly the older, less efficient plants, may well exist as back-up plant for wind generation.

There is a potential for significant swings in the amount of gas-fired power generation required at times of cold weather, depending on whether the wind is blowing and to what degree. There are also implications on the type of plant that is best suited to act as back-up for wind generation, as well as the gas supplies that would be required. This aspect is covered in Chapter 4 of this document.

Any analysis of peak gas demand in a Gone Green (2009) scenario needs to account for the fact that there is little to no wind generation and all gas-fired power stations are operating at their peak capacity.

FIGURE 3.5C – Forecast Peak Gas Demand
Source – National Grid



3.5.3 Key Forecast Drivers and Assumptions

This section outlines the key drivers affecting this year's forecast.

3.5.3.1 Fuel Prices

Wholesale price changes filter into all market sectors, from power generators through to domestic end-users. Although the wholesale price makes up a larger proportion of an industrial consumer's bill than a domestic consumer, domestic end-users have still seen significant energy price increases during the past six years.

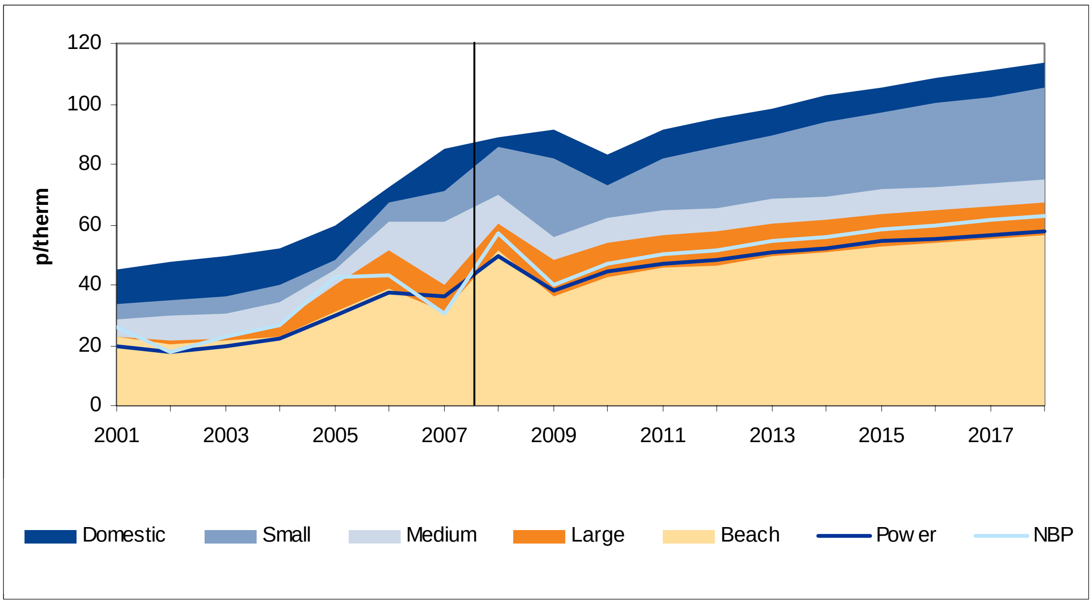
After price reductions in the domestic sector in the early part of 2007, a round of price increases by the major suppliers in early 2008 was followed by further significant price increases in late summer 2008 after a long period of rising wholesale prices. The timing of these price increases combined with the beginning of the economic downturn has resulted in demand falling in this sector. Although there were a series of smaller-scale price reductions in early 2009 as wholesale prices fell, this did nothing to slow the falling demand. No further decreases in domestic end-user prices have been forthcoming despite pressure from consumer groups and the media.

The common theme with the end-user price rises in the past few years has been the unprecedented media coverage, which has seemingly heightened domestic users awareness of energy consumption. The period of increasing prices has coincided, not unsurprisingly, with falling DN demand. Reductions in domestic weather-corrected gas demand, by far the largest sector of DN demand, were seen for the first time in 2005 and have been followed by three further years of reductions.

DN consumption has decreased by 10% during the past four calendar years with further falls in 2009. Our analysis suggests that the vast majority of the fall in consumption in the domestic sector over this period is due to increased levels of energy efficiency. In the larger demand sectors the drive to reduce consumption in the face of higher fuel bills is also evident, with the recession also resulting in demand destruction, particularly in the energy intensive large firm and interruptible sectors.

Increasing fuel prices result in consumers taking action in order to reduce consumption. Our historical analysis and subsequent forecast assumes that the majority of this action is increased energy efficiency, with greater public awareness and government schemes accelerating this process.

FIGURE 3.5D – End User Gas Price Forecast
Source – National Grid



Our fuel price forecasts for the 2009 gas demand forecasts are based on outturn wholesale prices and end-user prices for 2008. Our approach to forecasting fuel prices is based on historical price movements, the relationship between end user prices and wholesale markets, the relationship between different fuel prices (e.g. gas and oil), consultation feedback, forward markets and the forecasts of specialist consultancies.

Historically there has been a strong relationship between the oil price and the UK wholesale gas price. Although this link has not been as evident in recent months our forecast assumes that this link remains over the longer-term. Our fuel price forecast projects a relatively strong oil price over the period following a period of relatively lower prices in the short-term. Although a number of commentators have suggested that with increasing levels of LNG, the link could be broken, with NBP prices being possibly indexed more closely to US LNG prices (e.g. Henry Hub), we are currently viewing this as a sensitivity to our central case forecast.

Our forecast reflects the view that with a return to growth in the global economy, energy will return to being relatively costly when compared with the earlier part of this decade. The pressures of climate change, the likely premium placed on fossil fuels, probably in the shape of carbon prices or taxes, and political pressure to reduce energy demand and increase efficiency are likely to result in higher energy prices. Certainly the push towards the 2020 renewable and carbon targets is likely to result in an increase in end user prices.

The wholesale gas price rises result not only in an increase in end-user gas prices, but also in strong power prices. Figure 3.5D presents our forecast of end user gas prices, with a fall in end user prices in the short-term before a return to rising prices in the medium-term. The wholesale price is reflected in the larger end-user categories prices falling more promptly than in the domestic market, hence the lag in gas prices falling in the smaller sectors in 2010 as opposed to 2009.

The forecast for the coal price, which has a significant impact on our power generation models due to it generally being the competing fuel with gas, is that it will generally track the oil price. Over the longer term a reduction in the coal price is projected as coal demand falls in Europe. This is due to a forecast increase in the carbon price in Phase III of the EU ETS, as carbon credits begin to be fully auctioned rather than allocated, initially in the power generation sector, and the end of the period of operation for coal plants opting out of the LCPD. Operation of coal plants in the early part of the opt-out period under LCPD suggest that a number of these plants may use up their allocated hours of operation before the designated end date of December 2015, with the avoidance of higher carbon prices in Phase III of the EU ETS one of the possible reasons for this.

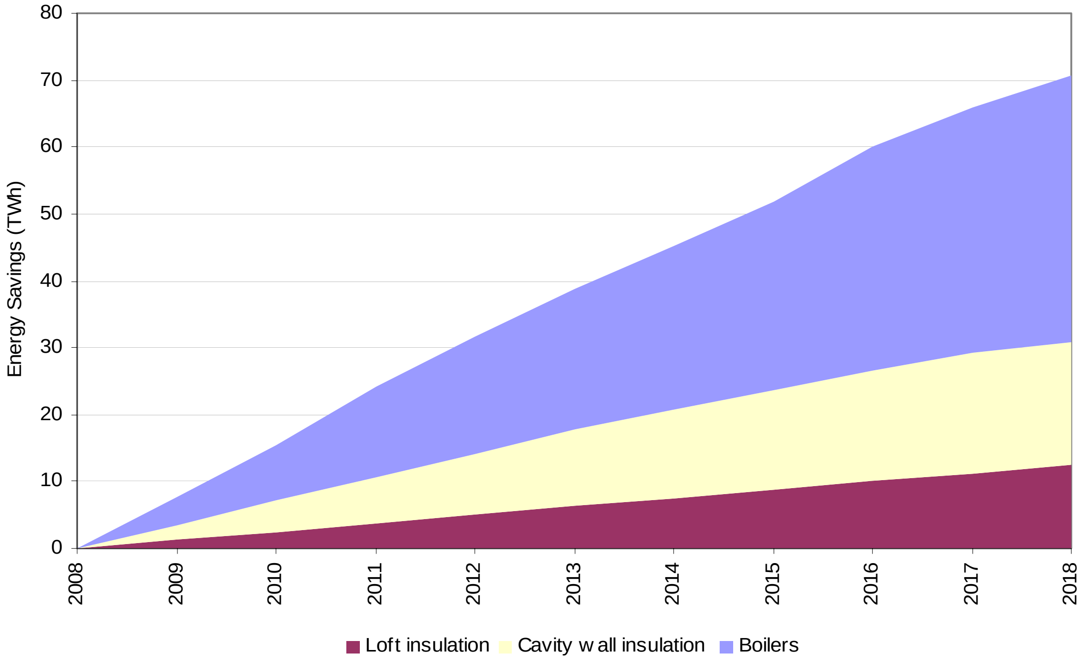
Our central case assumes that there will be a degree of seasonality to the NBP price resulting in gas-fired generation operating more as the base load plant in the summer when gas prices are lower, with coal operating more as the base load plant in the winter period.

As stated earlier in this chapter the Gone Green (2009) scenario doesn’t include a specific fuel price forecast. It is highly likely that in this scenario energy prices will rise and certainly the level of demand in the Gone Green (2009) forecast is in the lower range of our sensitivity analysis – see section 3.6.

3.5.3.2 Energy Efficiency

Increased thermal efficiency is forecast to have a significant impact on DN demand over the course of the forecast period. Our forecast assumes that most of the impact of higher end-user prices is an increase in thermal efficiency. Our analysis of historical levels of energy efficiency, by looking at rates of boiler replacement, cavity wall installation and loft insulation for example, suggest that much of the fall in domestic demand has been driven by such measures being implemented. There is also scope for further improvements in the future, both with the further implementation of existing measures and newer technologies, such as smart meters.

FIGURE 3.5E – Domestic Energy Efficiency Savings



The Gone Green (2009) scenario assumes a similar level of energy efficiency for boiler replacement, cavity wall insulation and loft insulation combined with a move towards renewable heat through the development of heat pumps, locally connected electric heating and solar thermal heating.

Our forecast also takes into account the government drive towards zero-carbon homes by 2016. Our assumption is that new homes will use less energy over the forecast period as appliances and heating systems become more efficient. Certainly, new homes currently being built will almost always use less gas for water and heating than existing properties that may have been built up to one hundred years ago.

3.5.3.3 Economic Factors

Our econometric models take into account a number of other factors when forecasting gas demand. Although fuel prices in each sector do have a significant impact, factors such as household disposable income, the number of new households forecast and commercial / manufacturing output are also modelled. Our models combine data from specialist independent consultancies with our own forecasts e.g. the fuel price forecasts described earlier.

The impact of the economic downturn is covered at the beginning of Section 3.3, with demand falling rapidly due to the recession. Although some demand will return as the economy returns to growth, it is forecast that this will be at a much slower rate than the demand fell in the economic downturn. It is likely to be more energy efficient sources of demand that replace the demand that has been lost, possibly due to environmental pressures.

The forecast for economic growth over the next ten years is lower than in previous forecasts, with average economic growth reduced due to the current economic downturn. As stated earlier, our forecast is that we will begin to see a return to growth in mid 2010, with GDP levels returning to 2% from 2012 onwards.

The short-term economic outlook is probably the biggest uncertainty in our forecasts and as stated earlier we are looking at sensitivities around our base case to assess two ‘recession cases’ – one with a deep and long lasting recession and the other with a rapid economic recovery.

As stated earlier in this chapter the Gone Green (2009) scenario doesn’t use a specific economic background.

3.5.3.4 Power Generation

Our power generation forecasts are supported by information received from TBE consultation feedback, customer enquiries, journals, press releases and other sources. A power generation background is developed based on known and potential station closures, and the connection of new generation capacity to replace this plant. The timing of these openings and closures is important when assessing how the power generation market will look over the next ten years and beyond, with the plant margin, the fuel mix, suppliers generation portfolios, government and environmental legislation all taken into account when developing the forecast. This section describes the business as usual generation background forecast and the Gone Green (2009) scenario background, with a comparison between the key aspects of the forecast. The commentary refers to the Business as Usual case unless stated otherwise.

Each generation background is then used as a basis for the forecast of gas demand from power generation.

3.5.3.4.1 Generation Background Scenarios

The business as usual approach assumes no major changes to current known policy, regulatory framework or incentives.

The impact of the recession has been keenly felt with electricity demand falling rapidly during the course of winter 2008/09 and future power generation projects being delayed due to the current economic climate and the lower demands.

The combination of lower forecast electricity demands and 7.5 GW of CCGT plant currently under construction is likely to result in very high plant margins in the next few years, certainly up until the closure of the LCPD opt-out plant. There is therefore the possibility of mothballed capacity, particularly between 2010 and 2014. This could be marginal oil and gas plant or even opt-out coal plant conserving some of their 20,000 hours for closer to 2015, although this would seem less likely.

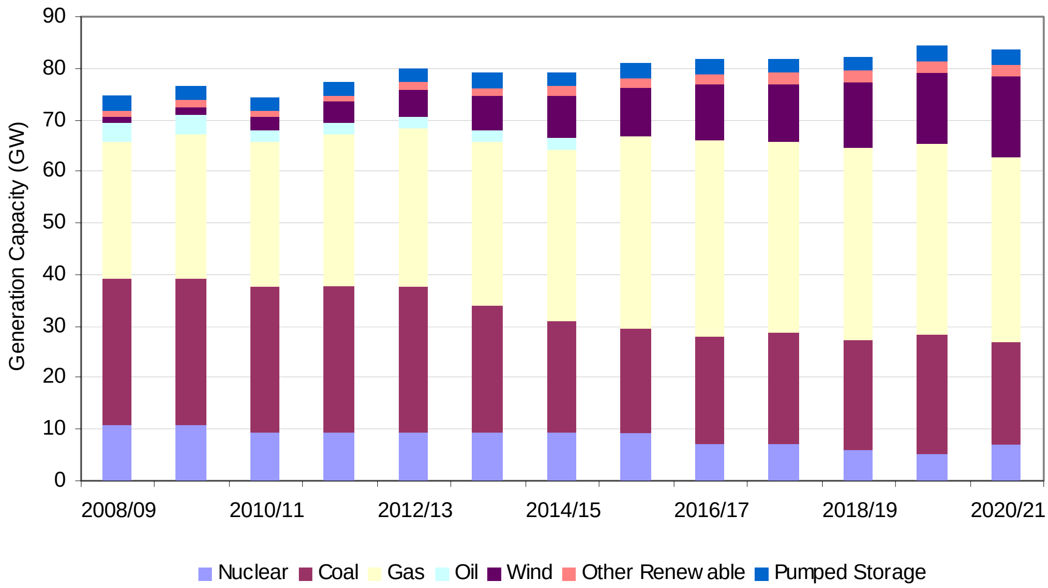
The lower electricity demand forecast gives rise to much greater uncertainty from a plant-mix perspective, although it is less likely that there will be a 'generation crunch' around 2016 due to the loss of around 12 GW of oil and coal plant due to LCPD.

As alluded to earlier in this section, the cost of emissions under the EU ETS is likely to benefit gas over coal in the longer term, with carbon prices forecast to increase in Phase III of the scheme. The forecast broadly assumes that gas will be the base load fuel in the summer months, with coal operating more as base load during the winter months. The spark and dark spreads, which indicate the profit that can be made by burning either gas or coal for power generation, are forecast to be relatively close together, as has been borne out by recent history.

Among the key factors affecting the development of our generation background and thus the amount of new gas-fired generation forecast to be connected are the LCPD and further environmental legislation such as the Industrial Emissions Directive (IED), the EU ETS, the rate of development of renewable energy sources, and the future of nuclear generation in the UK. The following sections detail our forecasts for the major plant types in the generation background.

Figure 3.5F shows the build up of capacity by fuel type in the business as usual scenario. The total capacity increases over the forecast period to account for the intermittency of wind generation.

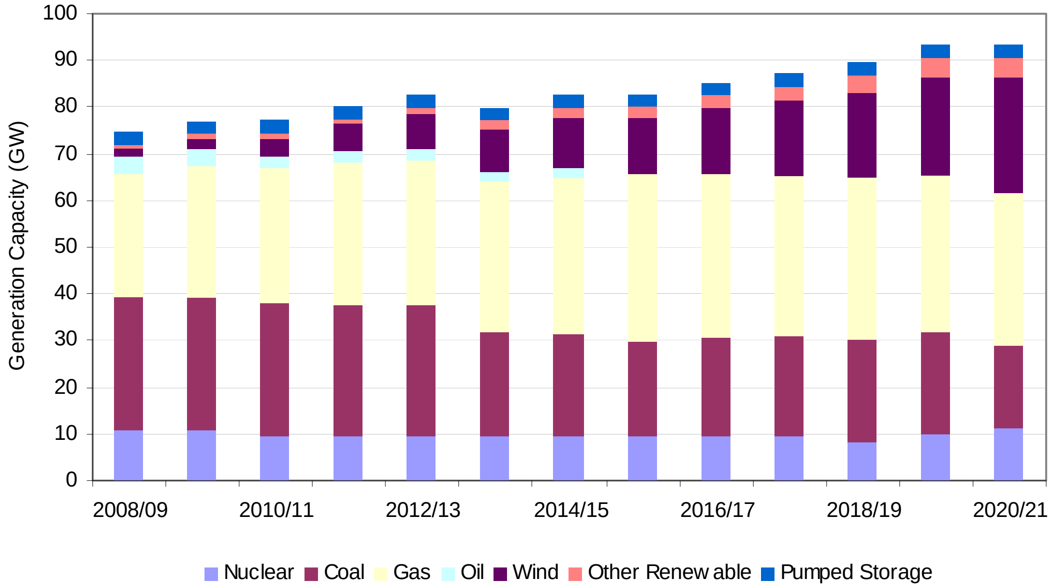
FIGURE 3.5F Power generation mix in Business as Usual case
Source: National Grid



The Gone Green (2009) background is based broadly on the Business as Usual background, with some key differences to enable the 2020 targets for both renewable energy and carbon emissions reductions to be met. The major difference is the increased amount of renewable capacity included in the scenario, with longer life extensions for nuclear plant and lower electricity demand resulting in less of a requirement for new thermal plant.

Figure 3.5G shows the build up of capacity by fuel type in the Gone Green (2009) scenario. The greater amount of renewable capacity is evident, resulting in a greater overall level of capacity to account for the intermittency of wind generation.

FIGURE 3.5F Power generation mix in Gone Green (2009) scenario
Source: National Grid



3.5.3.4.2 Environmental Legislation

The revised LCPD, which became effective from 1st January 2008 introduced stricter limits on emissions of nitrous oxides, sulphur and particulates (e.g. dust) from existing coal and oil plants. All coal and oil plants connected to the GB Transmission System were required to either ‘opt-in’ or ‘opt out’ of the LCPD. Those ‘opting-in’ are subjected to the new emissions limits, with those opting-out restricted to 20,000 hours of operation between 1st January 2008 and 31st December 2015. These opt-out plants must close by the end of 2015 or when they have used all their 20,000 hours, whichever comes first.

Opting-in to the LCPD resulted in plants fitting Flue-Gas Desulphurisation (FGD) equipment, if they had not already done so, which was a significant investment.

Our forecast assumes that the 12 GW of opt-out plant will begin to close from 2012 onwards. This forecast is principally based on the operation of the plant in the first eighteen months of the LCPD.

LCPD opt-in coal plant is forecast to begin to close towards the end of the next decade as the stations reach ages of 50+ years and further emissions restrictions impact on operation.

The proposed next phase of environmental constraints may have a significant effect on the future generation outlook. The proposed Industrial Emissions Directive (IED) will follow the LCPD in 2016. IED proposes to consolidate a number of environmental directives, one of which is the LCPD into a single directive. The final EU legislation is due to be finalised in December 2010 following the consultation process, but has seen many changes and developments.

For coal stations built prior to 1987 nitrous oxide emissions limits will reduce under the IED. This would apply to all existing coal stations in Great Britain. Under IED nitrous oxide limits would be reduced to limits that currently apply to stations built later than 1987. Coal stations that have 'opted in' to the LCPD are thought to have the following options under IED:

- Meet the new limits - by fitting further emissions reduction apparatus such as Selective Catalytic Reduction (SCR) equipment if required - and have no limit on their operation.
- Meet a gradual declining limit set by the UK government until the IED limit is enforced by 2020.
- Opt out of the new proposals and operate for a maximum of 20,000 hours until 2023. (This would be similar to the current opt-out option under LCPD)

In both scenarios it is assumed that the majority of existing coal stations will close under the IED due to the age of these stations. Those that remain open will probably be required to retro-fit carbon capture and storage (CCS) which will further reduce the efficiency of the station. There is also the option of re-planting at certain sites, although there will be geographical limitations as a carbon capture network may be required in order to remove the carbon. This could result in a cluster of stations being developed in one area fitting CCS and benefiting from reduced costs by using a network to remove carbon. Chapter 7 discusses the potential role for National Grid in future CCS projects.

Nuclear capacity is expected to reduce by around 4.9 GW by the end of the forecast period. This is despite the forecast assuming that all the AGR nuclear stations are granted five year extensions beyond their existing planned closure dates, except where a longer extension has already been granted. A sensitivity to this forecast may be that the existing AGR plant continues to operate until they are re-planted. Our forecasts do not include any new nuclear plant in the ten-year period. Our forecast is that the first new nuclear plant connects in 2019/20.

In the Gone Green (2009) scenario, the existing AGR plants are forecast to receive ten-year life extensions. This will maintain the level of nuclear capacity at around the 9GW level until the first new nuclear plant connects in 2019/20 in this scenario. The increased nuclear capacity assists in meeting the carbon targets for 2020.

Over the course of the next ten years, 13.6 GW of new CCGT plant capacity is predicted to make up the bulk of the shortfall caused by coal, nuclear and oil plant closures, with 7.5 GW of this capacity already under construction. Some of the existing gas stations are forecast to close over the forecast period, with this becoming more prevalent in the ten to fifteen year horizon due to the age of the stations and the impact of IED.

The Gone Green (2009) scenario includes less new CCGT capacity – 10.7GW by 2020 - due to a combination of lower electricity demand and increased nuclear capacity. In the short-term the forecast for new CCGT build matches that in the Business as Usual scenario. Post 2020, any new gas plant being built is assumed to have to fit CCS. In the longer-term (2030 and beyond) all fossil fuel plant will have to capture any carbon emissions in order for the 2050 carbon targets to be achieved.

The government recently announced that between two and four coal plants will receive government funding to assist in the development of carbon capture and storage (CCS). At the point when CCS becomes a ‘proven’ technology then all coal plants – and possibly gas – will have to have CCS technology. Our understanding is that this would apply to existing and new plants.

Our forecast assumes 3.2 GW of new ‘clean coal’ capacity during the next ten years, with the possibility of existing plant also receiving funding to retrofit CCS. The forecast assumes that existing opt-in coal plant begins to close from around 2020 due to age, further environmental constraints and the potential cost of retrofitting CCS.

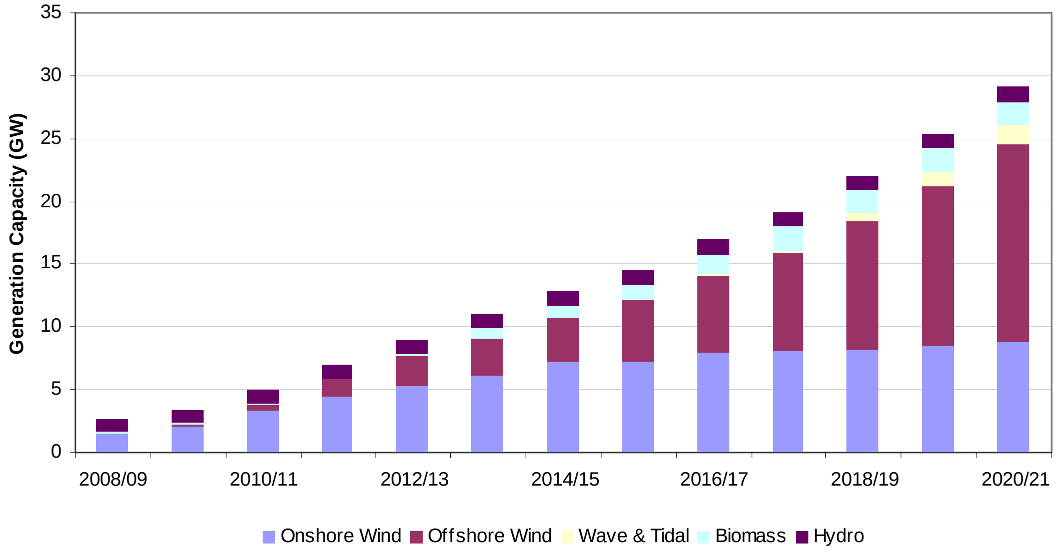
The Gone Green (2009) scenario includes a similar level of 'clean coal' capacity during the next ten years, although the first plant to fit CCS is forecast slightly earlier with higher carbon prices likely. Post 2020 the amount of clean coal capacity increases as CCS becomes a 'proven' technology.

The first transmission connected offshore wind farm is forecast to begin commercial generation in early 2010. A number of recent announcements have been made about the 're-evaluation' of large renewable projects, with lower oil prices, lower electricity demand and the difficulty in obtaining credit all resulting in project delays. This has resulted in a lower level of renewable generation forecast to connect to the transmission system in the earlier part of the ten-year period, although our 'business as usual' view in 2020 is similar to last year.

14.5 GW of new renewable plant is forecast to be built by 2018/19 with most of this connected to the transmission system. The vast majority of this renewable capacity is forecast to be onshore and offshore wind generation, with some biomass plant also forecast to connect in the ten-year forecast period. This will result in around 16% of electricity supplied coming from renewable sources by 2018/19. This is a higher number than previously forecast, principally due to lower electricity demand forecasts resulting in the renewable generation output being a larger share of consumption. This would result in the UK getting to about halfway towards the EU 2020 target of 15% of UK energy being from renewable sources.

There is significantly more renewable plant included in the Gone Green (2009) scenario, as would be expected. In order to meet the 2020 renewable energy targets, around 35% of annual electricity generation will need to be generated from renewable sources in this scenario. There is almost 25GW of wind capacity included in this view, with additional wave, tidal and biomass capacity pushing the total renewable capacity figure up to almost 30GW. Figure 3.5H shows the build up of renewable capacity by type in the Gone Green (2009) scenario. In order to meet the EU renewable energy targets over 2GW per year of new renewable capacity will need to connect to the Transmission System up to 2020. In our Gone Green (2009) scenario offshore wind capacity is over half the total renewable capacity connected by 2020, with a particularly rapid build up in the final part of the next decade.

FIGURE 3.5H Transmission connected renewable capacity in the Gone Green (2009) scenario.
Source: National Grid



3.5.3.5 Exports

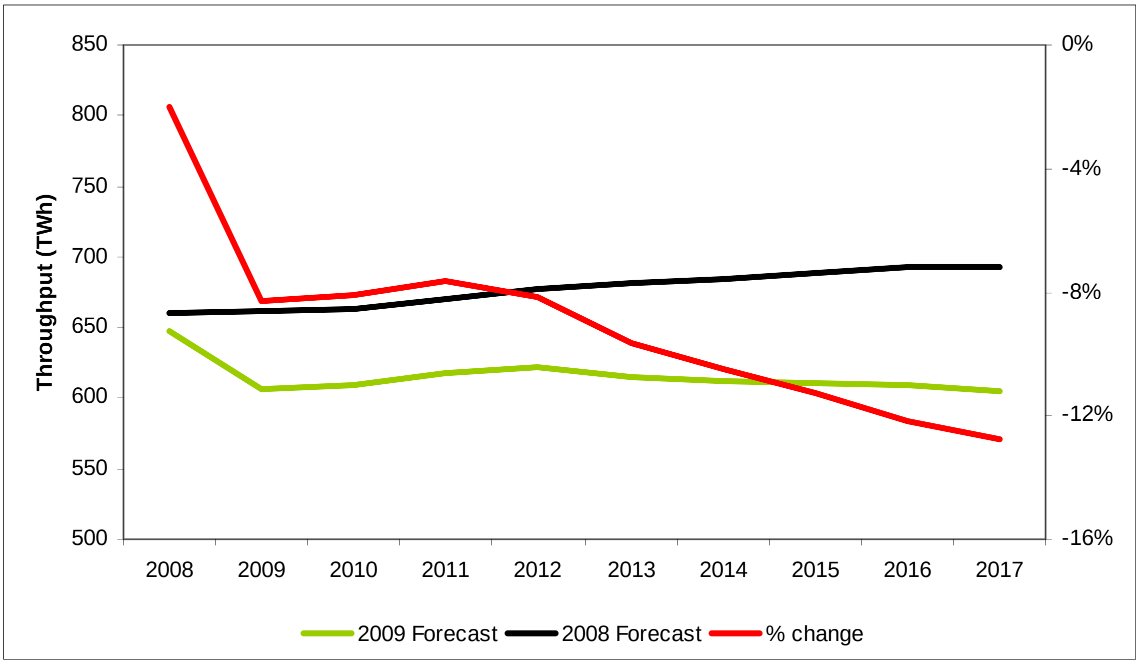
Exports to Europe are forecast to increase in the early part of the forecast period due to an increase in imported gas to the UK from other sources. They are then projected to fall over the entire forecast period as greater levels of imports are required due to the continuing decline of supplies from the UKCS. Chapter 4 covers the forecast operation of continental interconnectors and the role they may play in the UK supply / demand balance.

Exports to Ireland are also forecast to fall in the short to medium term as new indigenous supplies from Corrib begin to be delivered, with the possibility of LNG imports via the Shannon LNG project further reducing the requirement for gas from the UK. Irish gas demand is forecast to grow in all sectors over the ten-year period, although the economic downturn is likely to see a slowing of this growth. Planned new gas-fired power generation projects will also increase demand resulting in an increase in exports from the UK, particularly with indigenous supplies from Corrib forecast to reduce in the latter part of the forecast period.

3.6 Forecast Comparisons

The following charts provide a comparison of the current business as usual forecasts with those appearing in the 2008 Ten Year Statement and serve to highlight how the assumptions detailed have impacted upon our demand forecasts.

FIGURE 3.6A – Comparison of Total DN Annual Throughput Forecasts
Source: National Grid



As Figure 3.6A shows the 2009 forecast of DN demand is significantly lower than in 2008. The vast majority of this difference is due to the impact of the recession, with the forecast for calendar year 2009 significantly lower than this time last year. The greater levels of energy efficiency improvements included in the forecast, coupled with an overall weaker economy over the ten-year period results in the forecast being around 13% lower than last year in 2017.

FIGURE 3.6B – Comparison of Total System Annual Throughput Forecasts
Source: National Grid

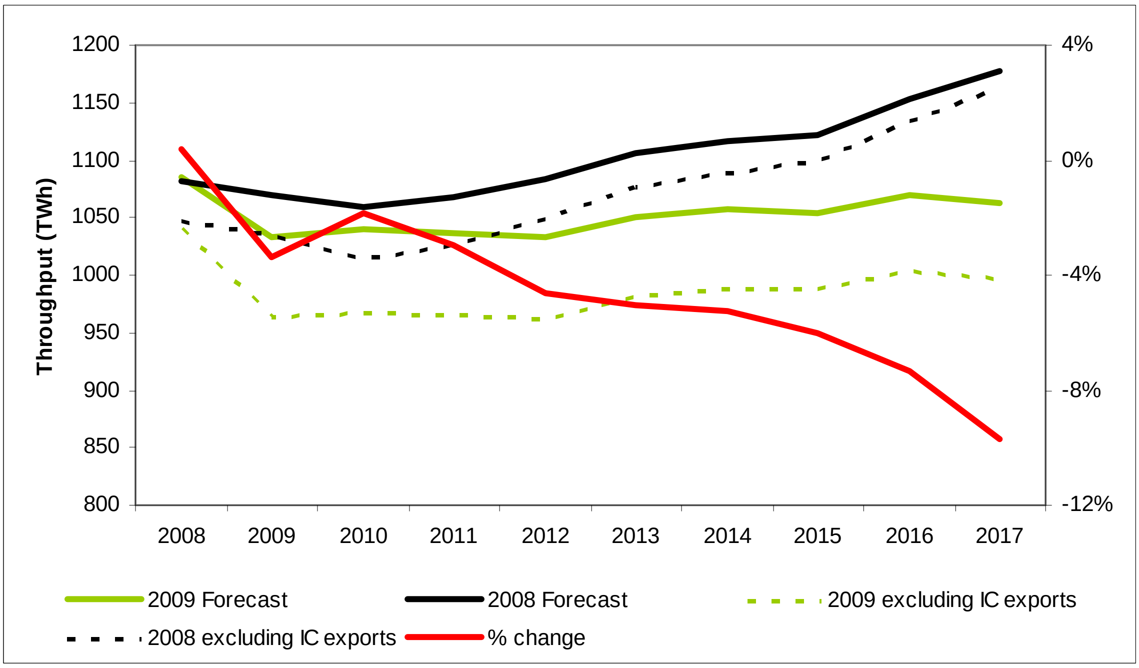


Figure 3.6B compares the 2009 forecast of total system demand with the 2008 forecast. The difference between the two forecasts is less marked in the short-term here due to the higher forecast for exports to the Continent counteracting the impact of the recession and reduced gas-fired power generation demand to some extent. The higher level of Continental exports does reduce the percentage difference between the two forecasts at a system level when compared to a DN level. Both forecasts are shown without these exports to highlight the effect this part of the forecast has.

Overall, the forecast demand through the NTS is almost 10% lower in 2017 than forecast in 2008 through a combination of lower demands in all sectors apart from Continental exports. The recession; slower economic growth rates over the period; greater energy efficiency improvements; lower electricity demand reducing power generation requirements; and lower exports to Ireland due to lower indigenous energy demand in Ireland all combine to give this significantly lower forecast.

3.7 Forecast Sensitivities

Alongside our base case of demand a number of sensitivities have been developed to enable us to look at a range of potential demands in the future. Given the volatility seen in energy markets over the past eighteen months and the uncertainty over the length and severity of the current economic downturn, this work is especially relevant this year.

This work has been developed for the Energy Markets Outlook document which will be published by DECC and Ofgem later in the year. To give a flavour of the sensitivities assessed, cases were analysed for economic variables, fuel prices, energy conservation, power generation capacity and output, CHP capacity, warm weather and exports to both Ireland and the Continent. In this year's sensitivities we have also developed two 'recession cases' – one with a deep and long lasting recession and the other with a rapid economic recovery.

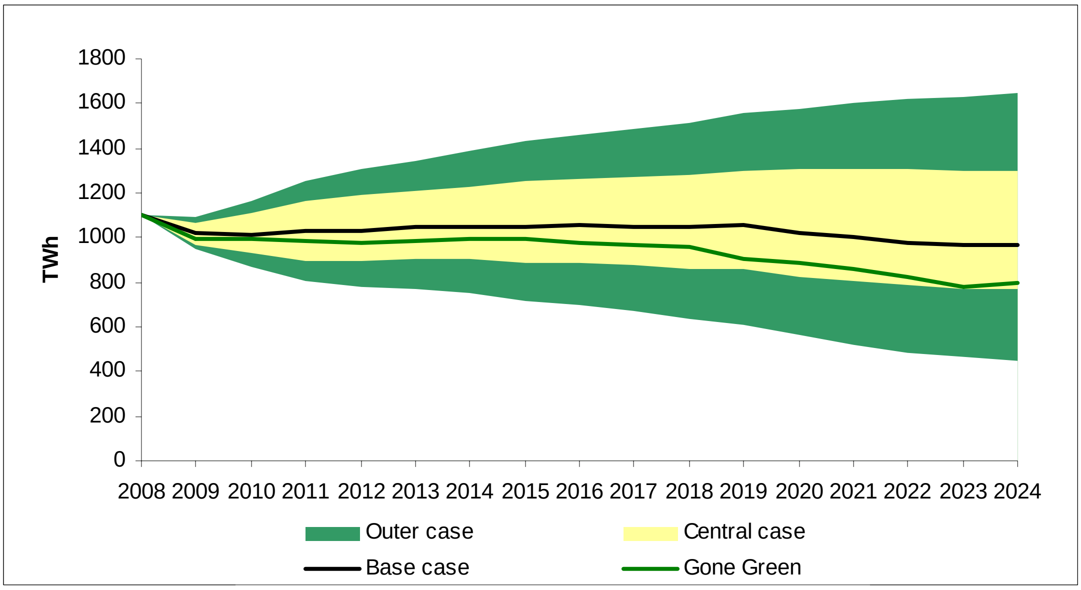
Figure 3.7A shows a possible range of gas demands around our base case forecast. The outer case assumes that all factors are acting independently and pushing gas demand in one direction, hence the extremely wide range. In practice these variables are not mutually exclusive and it is unlikely they would push gas in one direction. For example, it is possible that weaker fuel prices and weaker economic growth could coincide thus cancelling each other out to a certain degree, as far as the impact on demand is concerned. The central case takes this into account and gives a more probable band of demand levels.

This central band is noticeably wider in the short-term than last year. The volatile nature of energy markets in the recent past suggests this is a more prudent approach. This range also reflects the uncertainty still surrounding the length and depth of the recession and when a return to economic growth will be seen. Over the longer-term there is a little more scope for an upturn in demand in the sensitivities we have analysed, which reflects the level of this year's forecasts and the underlying assumptions behind them.

The demand in our Gone Green (2009) scenario falls inside the lower central range of our sensitivity analysis. According to our analysis this suggests that this level of demand is plausible with higher fuel prices than in our business as usual case a likely outcome. In the short to medium term the Gone Green (2009) demand is closer to our Business as Usual case, with demand falling towards the lower part of the range in the latter part of the decade as more renewable sources of energy enter the market and replace gas for both heating and power generation.

FIGURE 3.7A – Sensitivities around Base Case Demand Forecast

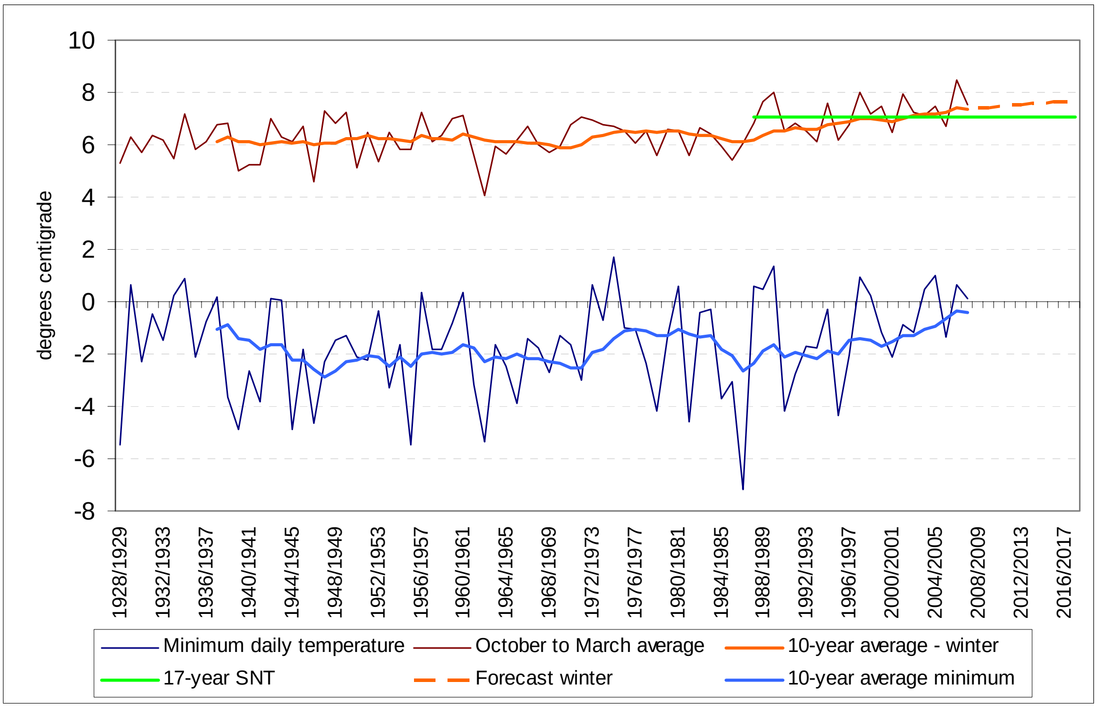
Source: National Grid



3.8 Impact of Climate Change on Peak Gas Demand

The UK Energy Industry commissioned the Met Office to examine the impacts of climate change on their strategy, operations and planning. EP2; The Impact of climate change on the UK Energy Industry, was a year long research project involving the majority of the UK energy industry and facilitated by the Met Office. National Grid was one of the project partners along with C.E. Electric, Centrica, EDF Energy, EON, Northern Ireland Electricity, npower, Scottish Power, Scottish and Southern Energy, United Utilities and Western Power Distribution. Figure 3.8A shows minimum daily and winter average temperatures[3].

FIGURE 3.8A - Winter average and minimum daily temperatures
Source – National Grid



The 10 year average winter temperature fluctuated just above 6 degrees until the late 1980s when a warming trend started. The dotted line is a moving 30-year climate average obtained from the EP2 project. This is above the 17 year average from October 1987 to September 2004 and therefore a new seasonal normal basis will be required for the next 5 year period starting October 2010[4].

There is much more volatility in minimum temperatures and therefore, more caution is required before peak day demands are adjusted for climate change. Any change to our methodology would require licence changes. The gas transporters licence currently requires at least 50 years of historical weather to be used in calculating peak day demand. The coldest day out of the last 80 years, in Scotland, was only 13 years ago (December 29th 1995) and the coldest day in the rest of the country was 22 years ago (January 13th 1987).

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[3] The temperatures are a weighted average of the weather stations used for gas demand modelling. The weights are based on seasonal normal gas demand.

[4] Seasonal normal weather has to be reviewed every 5 years.

Chapter Four

Supply

4.1 Overview

The main purpose of our forecasts is to derive a supply-demand position that can be used to identify and assess potential NTS investments and other business needs. Whilst our forecasts detailed in this section primarily deal with our Base Case or Business as Usual (BAU) environment, where Government 2020 targets for renewables are not fully met, we also make frequent reference to the supply implications for a Gone Green (2009) scenario where renewable targets are met. Under this scenario we have lower annual gas demand (about 10% lower in 2020) and increased electricity generation through wind with gas fired generation as the primary back-up for wind intermittency. Hence whilst annual demand for gas and therefore supplies are lower, a Gone Green (2009) scenario results in additional needs for gas supply, notably to accommodate gas demand for power generation arising through wind intermittency. Hence supplies in a Gone Green (2009) scenario will need to be more flexible / responsive than they are today. This flexibility is anticipated to be delivered from those supplies that are best placed to respond, namely gas storage, possibly LNG imports (from gas held in LNG storage tanks) and through new or enhanced gas interconnectors from the Continent. A further consequence of more flexible / responsive supplies is the need for a gas network able to accommodate such flow variations. This is further detailed in Section 5.

Our supply forecasts continue to be built around analysis of declining UK Continental Shelf (UKCS) supplies and higher imports. With new import projects now on stream and further completion of projects expected later this gas supply year, there is a considerable surplus of import capacity to the UK. However as we have frequently observed capacity may not relate to delivery. This, combined with the increased connectivity of the UK gas markets to Continental Europe through interconnectors and globally through a growing LNG market, adds to the uncertainty on how supply will be used to match demand.

Our 2009 forecast is similar to our 2008 view, though our latest assessment of import dependency and therefore import flows has been marginally reduced through forecasts of lower demand. Import dependency is forecast to reach 69% in 2018/19 with a requirement for significant levels of LNG by this time.

Since publication of the 2008 TYS, the seventh LTSEC auctions (Long Term System Entry Capacity) have taken place (in September 2009). Through this mechanism, we have received an investment signal for the release of further capacity at Holehouse Farm. Elsewhere we witnessed further bidding at Bacton though this was below the current release obligation. Chapter 5 and Appendix 2 provide further details on the auction results and their implications regarding network investment. As in previous years, in relation to the majority of existing entry points, the auctions are still to provide us with clear signals that would justify investment above the baselines (release obligations) adopted for our present price control period. Consequently, our supply forecasts continue to be built primarily from information received through a combination of our TBE consultation process and commercial sources. As in previous years, there have been deferrals and delays to some projects (notably proposed storage developments) and this combined with the utilisation of import capacity provides significant uncertainty as to the future pattern of gas supplies. As we have reported previously, investments in the NTS will only be made where there is firm evidence that they are required. This will be determined primarily through auction signals.

This year we have again had an excellent response to our TBE consultation process in relation to UKCS supplies and to a lesser extent import projects. Information from upstream producers again accounts for approximately 90% of the total used to compile our UKCS supply forecasts.

This chapter covers the potential make-up of future supplies to the UK, commencing with a review of the changing nature of gas supplies since 2000. This is followed by an examination of the rate of decline of the UKCS and the resulting import dependency. This leads to sections on European supply and demand (including Norway), and Liquefied Natural Gas (LNG) importation, to put the issue of future supplies into the UK into the context of the broader European and global LNG markets. Proposed UK import and storage projects are described and we outline how we have developed our Base Case supply forecast. We then briefly detail the implications of the latest auctions and then focus on supply source uncertainty. From a security of supply perspective we assess the longer term supply position in terms of an assessment of future storage developments. Finally, Appendix 2 presents the supply forecasts in greater detail, including the uncertainty in developing the forecasts, while Appendix 3 presents actual supply information from the 2008/9 gas supply year.

4.2 UK supplies since 2000

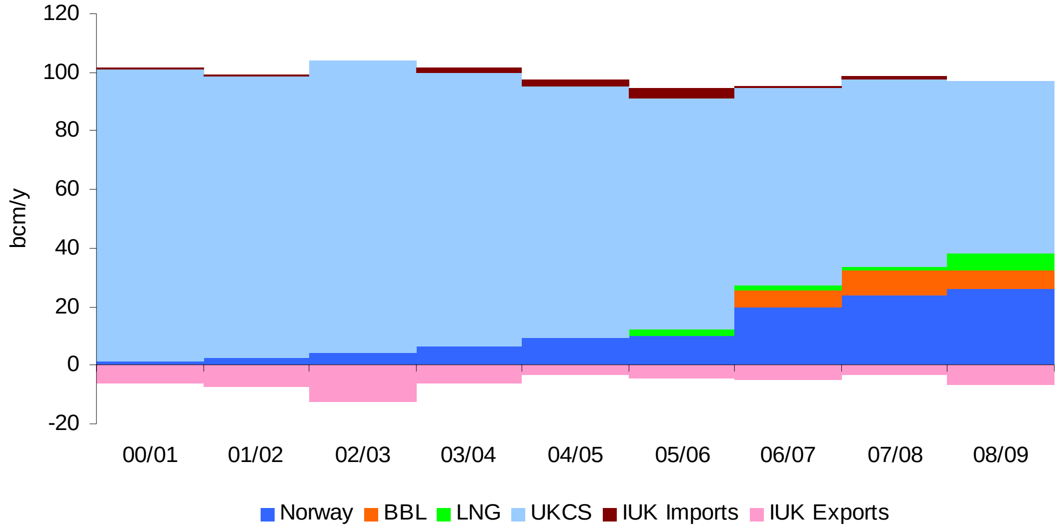
The changing nature of gas supplies to the UK since 2000 provides a good insight of how future supply patterns may develop. Until 2003/4 the UK was a net exporter of gas, since then the level of imports has progressively increased as UKCS supplies have declined. Besides the need for increased imports, recent history has provided a further understanding of the potential behaviour of imports and the interaction of international markets and global events; for example:

- The global influence of LNG supplies, notably through increased production and recent lower global demand for gas in many markets
- The development of unconventional gas sources in the US
- The interaction of Norwegian gas supplies between the Continent and the UK
- The behaviour of the Interconnector (IUK) as a marginal supply source for the UK and Continental markets. Though not as obvious, the flow patterns through the BBL pipeline from the Netherlands have also been changing
- The impact of international events such as the Russia-Ukraine dispute (European supplies), the Kashiwazaki-Kariwa nuclear power plant outage in Japan (global LNG), and US hurricanes (pricing behaviour and Atlantic LNG)

Figure 4.2A below shows the changing mix of annual gas supplies to the UK[5] since 2000, the chart also shows exports through IUK.

[5] Gas supplied to the NTS

FIGURE 4.2A – Historic annual UK gas supplies & IUK exports
Source: National Grid

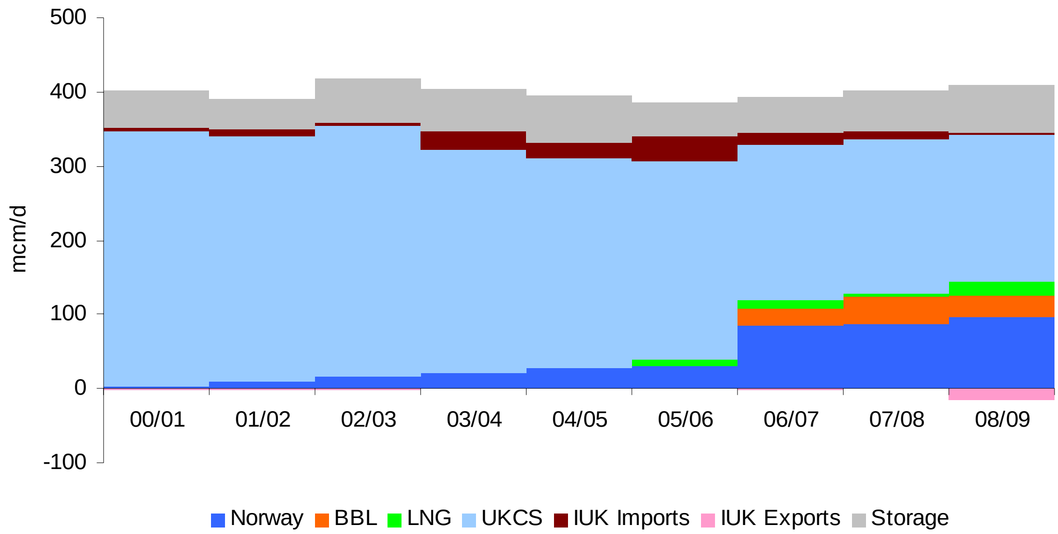


The chart highlights:

- UK self sufficiency followed by the decline of UKCS production
- The increase in Norwegian gas supplies, notably post 2006/7 (Langeled)
- Imports through BBL from 2006/7
- Continued exports through IUK despite increasing import dependency
- Variation in LNG imports since 2005/6, with high global LNG demand in 2007/8 pulling LNG away from the UK but returning in 2008/9 due to lower global demand and increased production
- Though not shown, the first two months of 2009/10 has continued the trend of increasing imports, notably from LNG

The peak winter position since 2000 shown in Figure 4.2B shows similar trends to Figure 4.2A, but emphasises the contribution of storage, and the fall in IUK import volumes as other imports have increased.

FIGURE 4.2B – Historic peak gas supplies & IUK exports
Source: National Grid



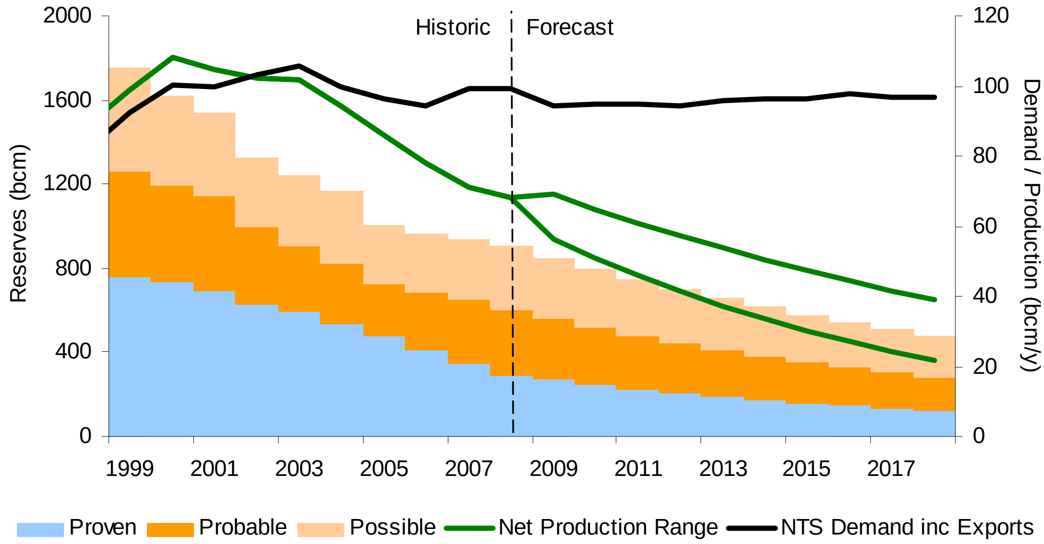
4.3 UKCS Supplies

4.3.1 UKCS Gas Reserves

Data for 2008 published by DECC (Department for Energy & Climate Change) shows that remaining UKCS gas reserves continue to decline. Reserves decline started in 1997 as a result of production levels that were greater than discovery rates and revisions to reported reserves. Since 1999, remaining reserves have been declining by ~7% per annum. Figure 4.3A shows remaining reserves split into the categories of proven, probable and possible. It also shows historic NTS demand and net UKCS production.

FIGURE 4.3A – UKCS remaining gas reserves

Source: Office for National Statistics (ONS), DECC, National Grid



The historic part of Figure 4.3A uses data published by the Office for National Statistics (ONS) and DECC. Reserves are split into 3 main categories:

- “Proven” reserves are defined as those currently in production
- “Probable” reserves have a >50% chance of being developed
- “Possible” reserves have a <50% chance of being developed

“Net” production published by the ONS & DECC is a measure of the gas available for consumption after taking into account flaring and gas consumed in production operations. National Grid data for forecast annual demand is shown for comparative purposes. Demand levels include Irish and Continental exports but exclude non-NTS gas to power stations. DECC data indicates that at the end of 2008, proven reserves were 292 bcm, probable reserves were 309 bcm and possible reserves were 306 bcm. In 2008, 68 bcm of gas was produced, giving a Reserves / Production ratio of approximately 13 years (907 bcm reserves / 68 bcm production). In practice, production is expected to continue well beyond 13 years as production rates fall. New discoveries or transfer of reserves from more speculative reporting categories may also extend the lifespan.

In the forecast area of the chart we have used trend analysis to indicate what reserves and production may look like out to 2019. This also enables us to compare with our 2009 Base Case UKCS forecast, though a direct comparison is not exact due to reporting differences including some gas that flows direct to power stations rather than entering the NTS

Table 4.3A shows a comparison of UKCS production as reported by DECC and UKCS flows entering the NTS as estimated[6] by National Grid.

TABLE 4.3A - UKCS Production (bcm/y) as reported by ONS/DECC and National Grid
Source: ONS, DECC, National Grid

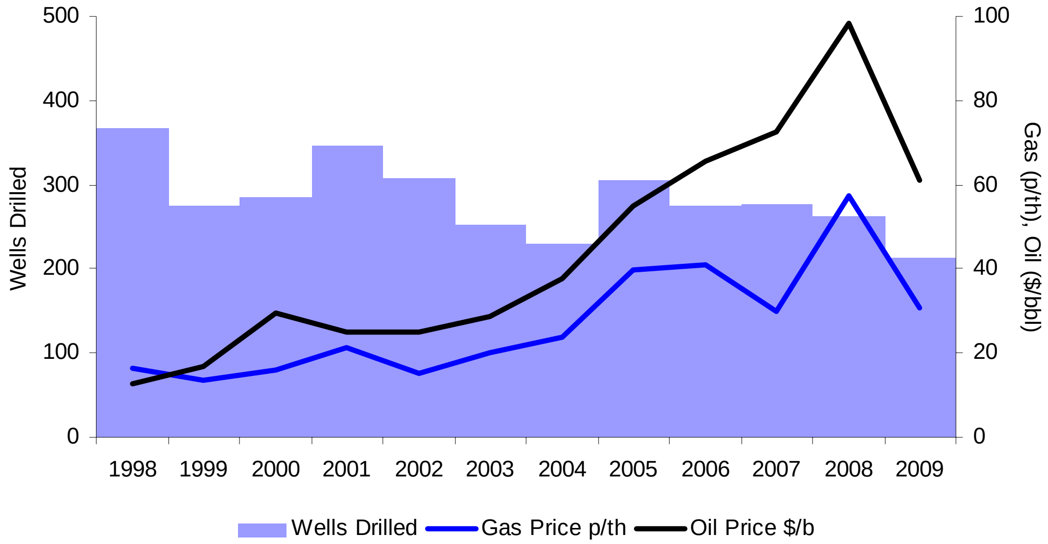
bcm/y	2000	2001	2002	2003	2004	2005	2006	2007	2008
ONS & DECC net production	108	104	102	102	95	86	78	71	68
National Grid NTS	99	99	97	98	91	84	75	67	63
ONS & DECC % change	-	-3%	-2%	-0%	-7%	-9%	-9%	-9%	-4%
National Grid % change	-	+1%	-2%	+1%	-7%	-8%	-10%	-11%	-5%

Average annual decline rates for the DECC data since the fall in production post 2004 have been ~8%. If net production as reported by DECC continues to decline at 8% and remaining reserves of 907 bcm are not changed, by 2018 UKCS production would be ~30 bcm/y and remaining reserves would be ~478 bcm. This is around the centre of our reported trend analysis for production (22 – 39 bcm). Based on our UK demand forecast of approximately 97 bcm in 2018, this would indicate import dependency of between 60% and 77%.

4.3.2 UKCS Drilling & Commodity prices

Figure 4.3B shows offshore drilling activity on the UKCS since 1998, and includes data for exploration, appraisal and development drilling. The chart also shows average gas and oil prices from various sources.

FIGURE 4.3B - Historic offshore UKCS drilling and realised North Sea oil & gas prices
Source: Mix of DECC, NBP & Brent data[7]



[6] Data is estimated by National Grid as Norwegian imports through Vesterled and Tampen Link are combined with UKCS supplies on entry to the NTS

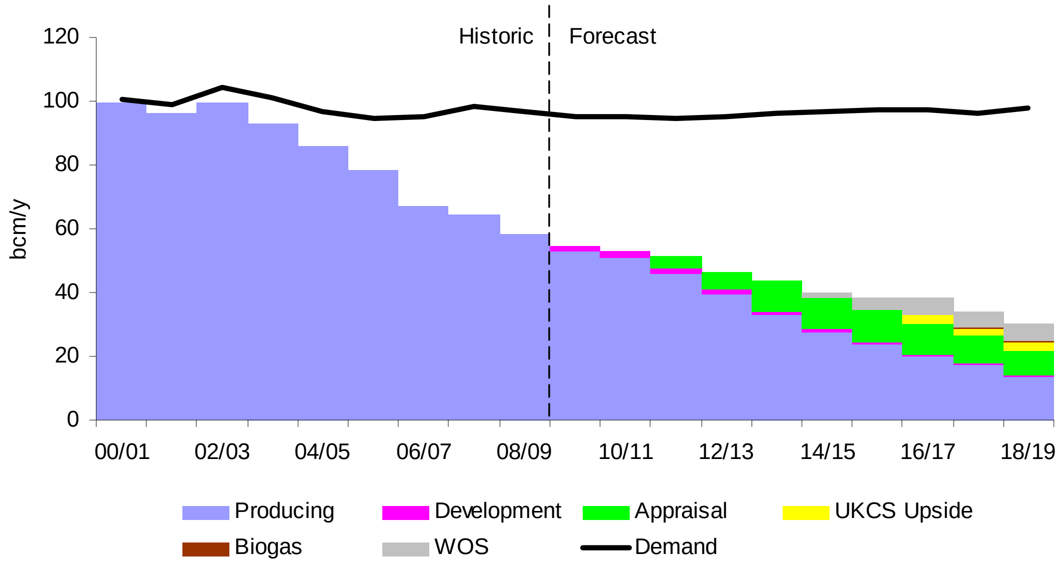
[7] 2009 Data is indicative and derived from first 11months of 2009

The chart shows that drilling rates have fallen in 2009, possibly as a result of the current economic down-turn and falls in both oil and gas prices. The chart also shows that despite record prices in 2008, the historic trend of drilling activity shows a gradual decline. As UKCS production rates have been declining since 2004, this would indicate that overall production decline will continue unless a number of significant discoveries are made.

4.3.3 Ten Year UKCS Forecast

Our 2009 UKCS gas forecast is shown in Figure 4.3C. As in previous years, data collection and analysis was facilitated by the UK's offshore producer association, Oil & Gas UK. Around 90% of our data was sourced through this process and it continues to provide an excellent basis for our forecast.

FIGURE 4.3C - Historic & forecast UKCS annual production
Source: National Grid



The difference between the demand and UKCS supplies indicates our import dependency over the forecast period. Our current UKCS forecast indicates that the UK will be ~46% import dependent by 2010/11, and ~69% import dependent by the end of the 2018/19, this is slightly lower than reported in 2008 (51% for 2010/11 & 72% for 2017/18), primarily due to lower demands and to a lesser extent a slight increase in our UKCS forecast.

This year we are showing the UKCS forecast in greater detail due to uncertainties over the timing of new field developments. The fields within the forecast are split into a number of categories:

- Producing: fields currently in production
- Development: fields where production is anticipated to begin over the next 2 years
- Appraisal: fields which may be in the early stages of development or those that we believe may enter production within the forecast period
- UKCS Upside: A factor for future gas production from fields which are currently unknown to us
- Biogas: Future production which could come from biogas
- WOS: West of Shetlands

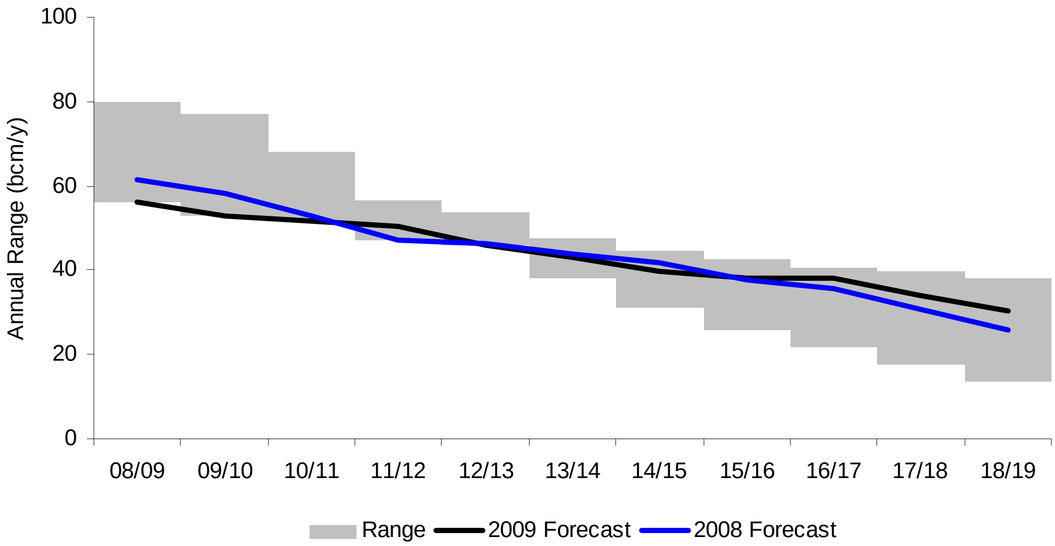
Many of the fields in the "Development" and "Appraisal" were present in previous forecasts but recent economic conditions may contribute to a delay in the first gas production from these fields. Our aggregated UKCS upside assessment for 2009 is just 7bcm, lower than our 2008 assessment of 13 bcm. The fall has been caused largely by the inclusion of additional fields in the "appraisal" and "West of Shetlands" category.

Progress continues to be made on the West of Shetlands project and reports indicate that an investment decision may be made in 2010.

Figure 4.3C also includes a contribution from biogas, based on a growth profile of meeting 1% of UK gas supplies by 2020. National Grid and United Utilities have recently won funding from the UK government for a demonstration project near Manchester which could be operational by 2011. This technology has been utilised in Europe and North America and could, as considered in a Gone Green (2009) environment, contribute a much more significant contribution to the supply mix by 2020. Alternatively or in addition, the UK could also be producing coal-bed methane for grid injection before the end of our forecast period.

Figure 4.3D shows our 2008 and 2009 annual UKCS forecasts, and a shaded area that indicates a range of other UKCS forecasts.

FIGURE 4.3D - Comparison of forecasts for UKCS annual production
Source: National Grid, various



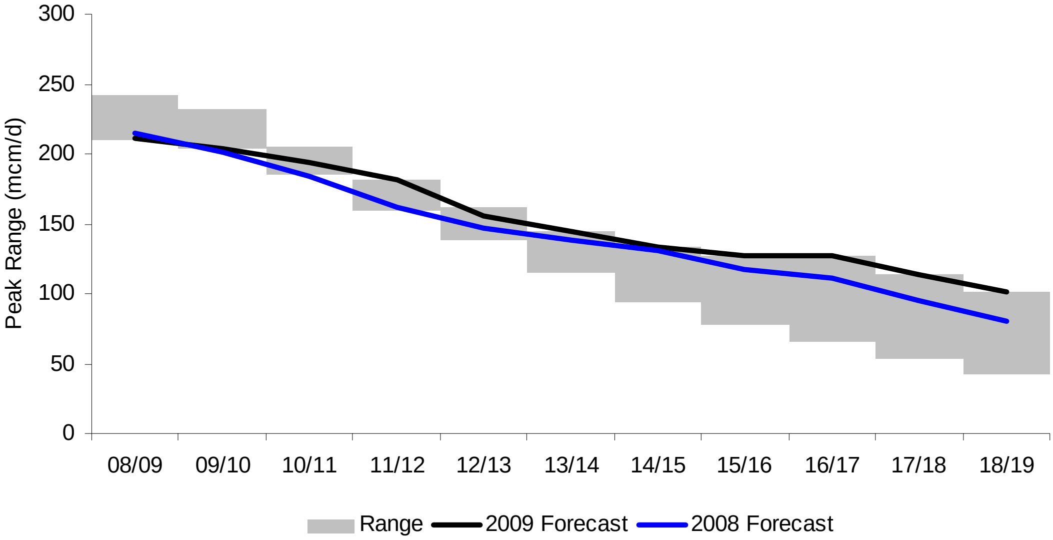
Our 2009 forecast is a little lower than the 2008 forecast in the first few years due to assumptions related to field decline and the potential suppression of production by low demands / low prices / higher imported gas availability (caused by the current global recession). For the central part of the forecast they are similar, for the latter part the 2009 forecast is higher, in part due to West of Shetlands developments. Across the period the forecasts for production volumes are essentially the same at 482 bcm in 2008 and 480 bcm in 2009.

The shaded area shows the range of other UKCS annual forecasts. Our forecasts move from the lower end of the range in the short term towards the upper end in the long term due to our assumptions for UKCS upside and West of Shetlands production. Variations in forecasts can be attributed to a number of factors including; variations in the definition of the gas supply year, gas processing and offshore consumption, CV conversion rates and our UKCS upside assumptions.

UKCS forecast data from Ofgem's "Project Discovery" document was higher than our forecast but within the range of data available to us.

Figure 4.3F shows our 2008 and 2009 peak UKCS forecasts, and a shaded area that indicates a range of other UKCS forecasts.

FIGURE 4.3F Comparison of forecasts for peak UKCS production
Source: National Grid



Our 2009 forecast for peak UKCS production is a little higher than in the 2008 forecast due to updated information on new field developments. For security planning purposes, we assume that flows will be up to 90% of our peak forecast during periods of high demand. The shaded area shows the range of other UKCS peak forecasts, on comparison with our forecasts these follow a similar trend for similar reasons to the annual forecasts.

In a Gone Green (2009) scenario there may be government incentives to promote UKCS development hence whilst overall demand requirements may be lower the contribution of UKCS in absolute terms is expected to be similar if not higher than for our BAU forecast.

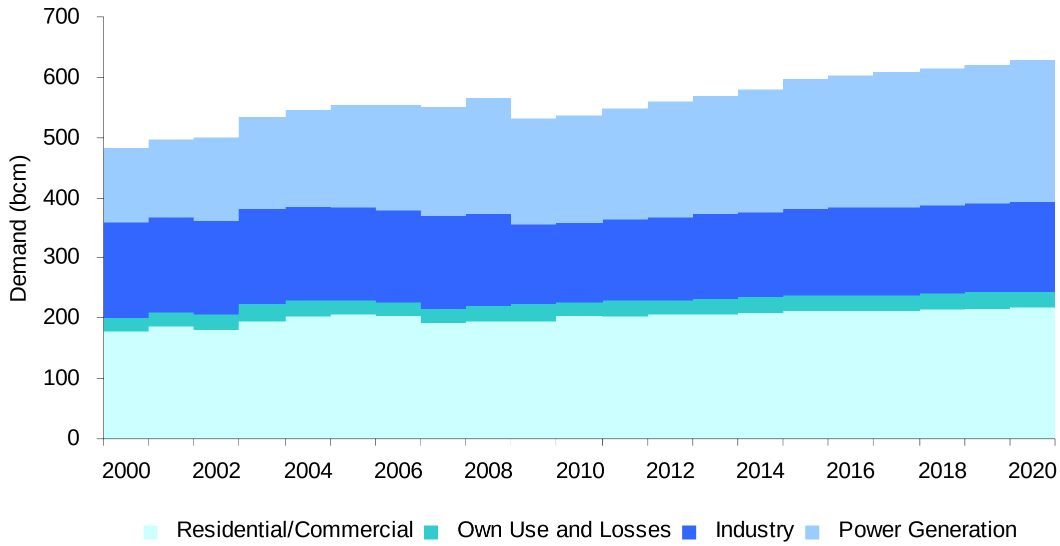
4.4 European Supply & Demand

4.4.1 European Demand

For both supply and demand Europe excludes the CIS and Georgia. The forecast up to 2015 is provided by IHS Global Insight with the period from 2015 to 2020 extrapolated by National Grid.

Figure 4.4A shows historic European demand since 2000 and forecast European demand through to 2020 broken down by market sector.

FIGURE 4.4A - European gas demand
Source : IHS Global Insight & National Grid

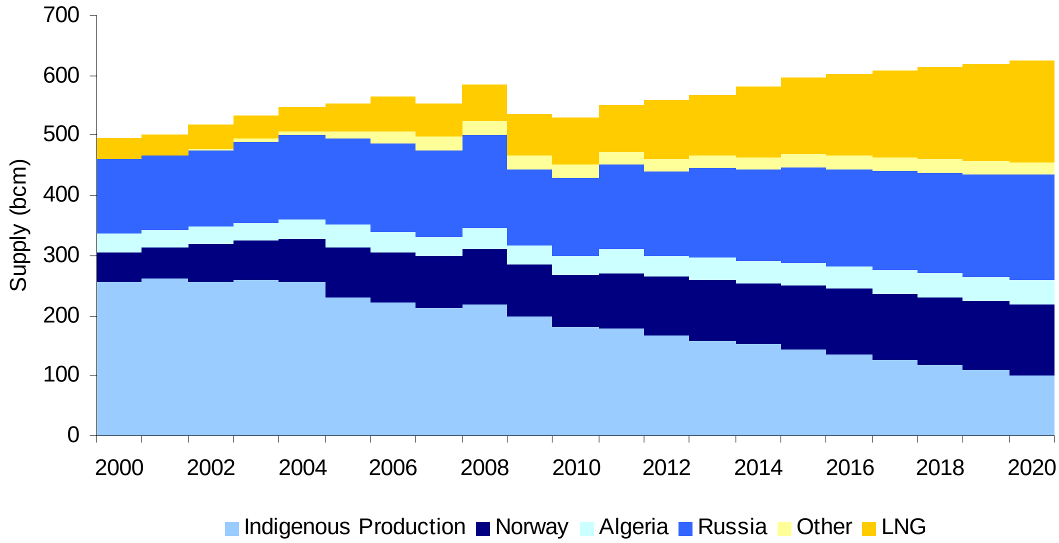


The chart highlights that European demand has increased slowly since 2000, primarily through growth in power generation. The chart also shows the impact of the recession on demand. European demand is forecast to grow at just below 2% per year until 2015 and then at a lower growth rate of 1% up until 2020, reflecting the impact of greater energy efficiency measures. While all sectors see some growth throughout the period the dominant factor is power generation growing over 20% from 2008 to 2020.

4.4.2 European Supply

Figure 4.4B shows historic European supply since 2000 and forecast European supply through to 2020 broken down by supply source.

FIGURE 4.4B European supplies
Source : IHS Global Insight & National Grid

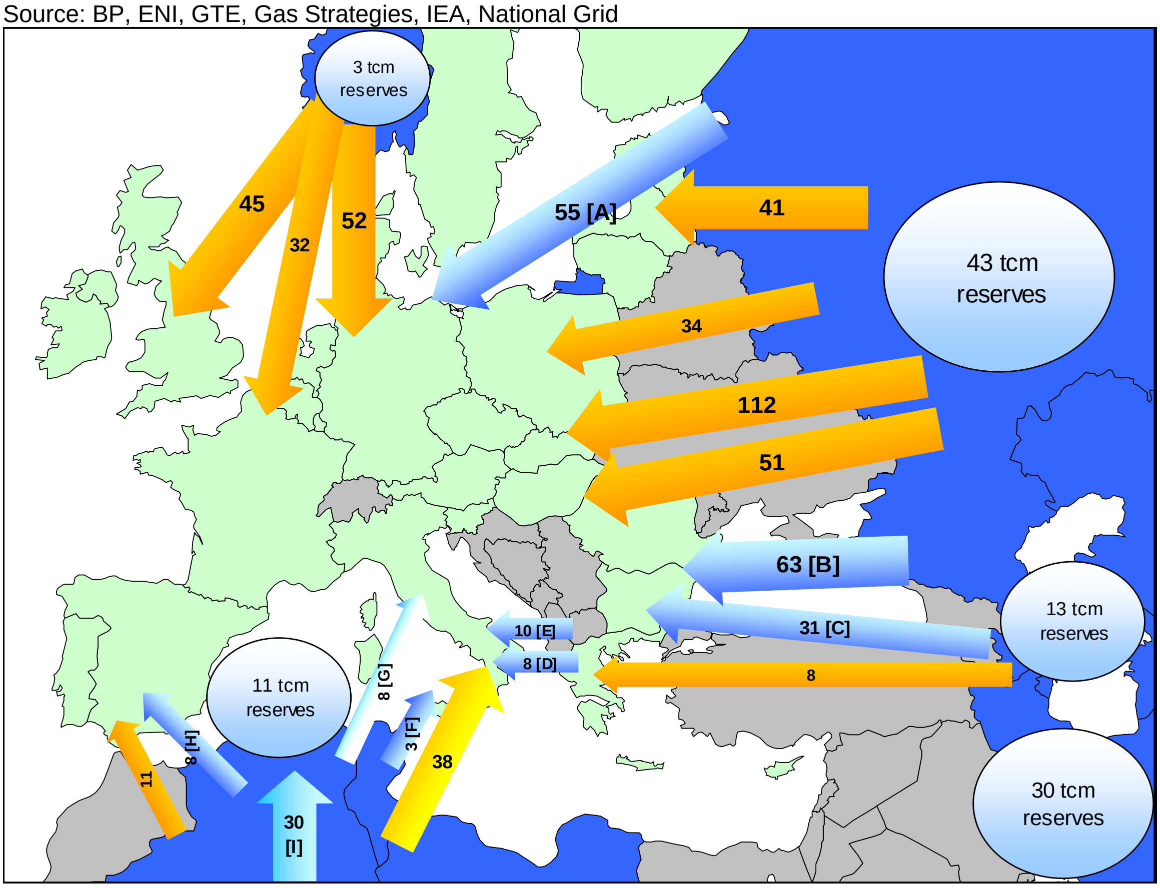


The chart shows a steady decline in indigenous production throughout the 20 years. The combination of a forecast for higher demand and lower indigenous production creates a requirement for an additional 160 bcm of imports per year by 2020 compared to 2008 levels. This represents a 44% rise and an increase in import dependency from 63% in 2008 to 84% in 2020. Norwegian and Russian supplies are forecast to grow slightly over the period, but the largest growth rates are seen in LNG increasing its share to 27% or 169 bcm by 2020.

4.4.3 European Infrastructure

Excluding indigenous supplies and LNG imports, the European Union has 3 major sources of supply; Russian/Central Asian supplies from the East, North African from the South and Norwegain from the North West. Figure 4.3D highlights existing and proposed pipeline capacities from these sources.

FIGURE 4.3D - Existing import routes and planned new pipelines
Source: BP, ENI, GTE, Gas Strategies, IEA, National Grid



Capacity	Existing Routes	New Pipelines
0-19 bcm/y	0	0
19-40 bcm/y	0	0
>40 bcm/y	0	0

Norwegian export capacity is discussed in more detail in the next section, but currently Norway can export approximately 130 bcm through 5 pipelines to Continental Europe (estimated capacity 84 bcm) and 3 pipelines to the UK providing an additional 46 bcm. Since the cancellation / postponement of the Skanled project there are no new export pipelines reported to be constructed in the near future from Norway for export markets.

There are numerous existing pipeline routes for Russian and Central Asian gas to Europe via the Ukraine and Belarus into Poland, Slovakia, Hungary and Romania. In the Baltic region, Finland, Estonia, Latvia and Lithuania are supplied via Belarus or directly from Russia. Existing capacity for all of these routes is estimated at 238 bcm with approximately 163 bcm through Ukraine, 45 bcm through Belarus and 30 bcm directly to the Baltic States. There are major plans for additional capacity from Russia with the emphasis on achieving diversified supply options and reducing the reliance on transit countries. The planned import routes from Russia and Central Asia as detailed on the map include:

- [A] Nord Stream two 27.5 bcm pipelines from Russia under the Baltic Sea to Germany, first pipeline due 2011 second due 2012.
- [B] South Stream from Russia under the Black Sea to Bulgaria and then on to Southern and Central Europe, capacity of 63 bcm due to be commissioned by end of 2015.
- [C] Nabucco connecting the Caspian Sea to Baumgarten in Austria via Turkey, planned capacity of 31 bcm due to commence in 2014 with full capacity available 2018.
- [D] ITGI – Turkey – Greece – Italy an extension of the Turkey-Greece interconnector opened in 2007 planned to take 8 bcm of Azeri gas to Italy, due late 2012.
- [E] TAP – Trans Adriatic Pipeline 405 km pipeline from Thessaloniki in Greece to Albania, before 115 km underwater section to Brindisi, planned capacity of 10 bcm due to open in 2011

Gas from North Africa is currently exported through 3 pipeline routes to Italy and Spain. Existing pipeline capacity is approximately 49 bcm. There are several projects in development to increase existing capacities and establish new routes:

- [F] Transmed a further expansion of 3.5 bcm, due for completion Q4 2009
- [G] Galsi an 8 bcm pipeline connecting Algeria to Italy through Sardinia due 2013
- [H] Medgaz an 8 bcm 210 km undersea link between Algeria and Spain due 2010.
- [I] Trans-Saharan pipeline (NIGAL) although not connecting directly to Europe this potential ~4000 km link from Nigeria to Algeria could provide access to increased reserves to the existing and planned pipelines.

Many of these projects require significant investment in order to be completed and the global recession could lead to delays in obtaining this investment, partly due to the difficulties in the banking sector but also because of increased uncertainty over demand in the target markets. In addition to this many projects also need to secure sources of supply to ensure the pipelines are utilised once complete. Hence these factors could lead to delays, cancellation or changes to the capacities from the values stated above. If all the projects were to be completed they would currently add nearly 200 bcm extra import capacity to the EU.

In addition to the importation projects there are several interconnection projects at various stages of development that aim to increase the flexibility of the European gas network. One of the key aims is to increase the ability to reverse flows, notably from North West Europe to the East and the South. These projects were given a boost earlier in the year when the European Commission made available €2.4bn for gas and electricity infrastructure projects through the European Energy Programme for Recovery (EEPR).

4.4.4 UK Continental imports

No new import routes from the Continent to the UK are currently planned though BBL is expected to expand capacity in 2010 through additional compression. Due to relatively high capacity in existing Continental import routes (40+ bcm/y) there is considerable uncertainty as to how this import infrastructure will be utilised in the future. At a high level we assume that over time the operation of BBL will become increasingly commercial (thus responding more to market signals) with IUK continuing to respond to supply demand balances / price differentials between the UK and Continent. Hence imports from the Continent and exports to the Continent will tend to follow market dynamics between the UK and the Continent. Drivers for more imports and exports include:

More imports

- High UK prices or low contracted Continental prices
- Receipt of surplus contracted gas
- Low UK imports of LNG or from Norway

More exports

- Low UK prices or high contracted Continental prices
- Exploitation of gas contracts i.e. take minimum and source extra gas from a lower priced UK market
- High UK imports of LNG or from Norway

In a Gone Green (2009) scenario with lower UK demands, Continental imports may be lower than those in our BAU forecast with the possibility of higher exports to the Continent. The expected greater variation of UK gas demand brought about through CCGT backup for wind intermittency provides a need for more flexible supplies. Therefore, opportunities may exist for Continental imports to provide more balancing type services to the UK and also from the UK to the Continent. Further European liberalisation and improved access to Continental storage could provide further stimulus to these expected roles.

4.5 Norway

4.5.1 Norwegian reserves and production

The current export capacity from Norway (including Tampen) is about 130 bcm with the UK accounting for about 45 bcm of this. Reported flows over the last 4 years show annual load factors of 80%-85% to Continental Europe, with a winter / summer ratio of approximately 55% / 45%. With seasonal differentials expected to continue we would not expect annual load factors to significantly exceed this level over our 10 year forecasting period.

We anticipate that the utilisation of Tampen / FLAGS will continue to increase as Gjøa, Vega and Vega Sør fields come on line. These fields, like Statfjord, contain associated gas so we would anticipate them to operate with a high load factor.

There is a great deal of uncertainty over the ultimate level of recoverable reserves in the Norwegian sector. This year has seen the “undiscovered” reserves in the Barents Sea downgraded by 9% to approximately 500 bcm. There is also uncertainty over the overall level of reserves present at Ormen Lange, although further evaluation is expected before any revision of reserves.

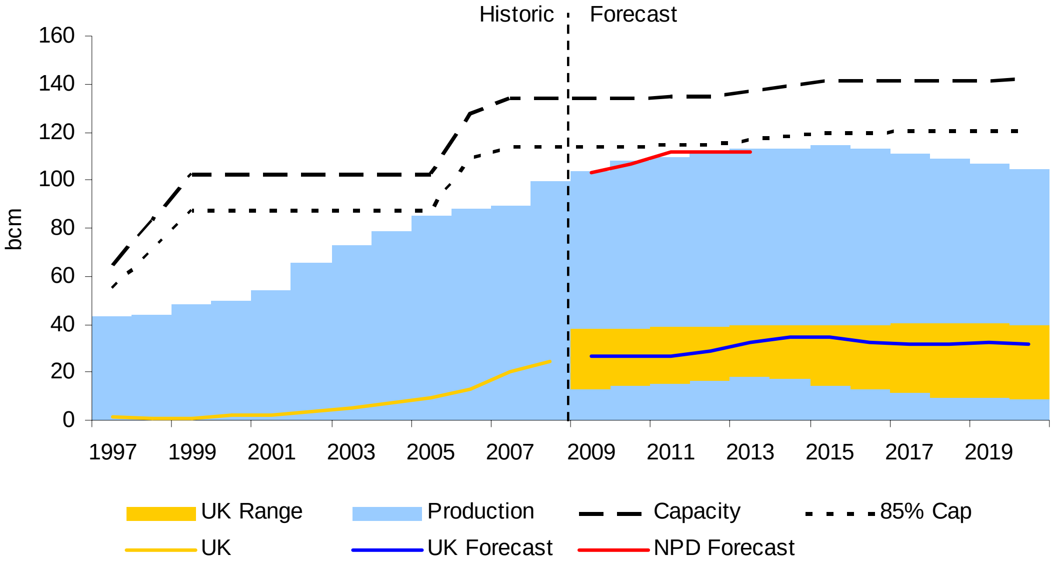
There are currently no reported plans for major new Norwegian export projects for the near future though some upgrades to the existing network are expected to maintain flexibility. These could result in some minor increases to capacity in existing routes over the next few years. The available capacity along with our view on production growth leads us to forecast a plateau of Norwegian production at ~114 bcm in 2015. In the absence of any major new Norwegian developments, this level of production is forecast to marginally decline post 2015.

4.5.2 UK Norwegian imports

Figure 4.5A shows our forecast of future Norwegian production and the proportion of flows to the UK. This is shown as a range to reflect high and low Continental load factors with the resulting UK supply determined by difference. Our central forecast for Norwegian flows to the UK plateaus in 2014 at about 35 bcm, equivalent to an annual load factor of approximately 74%.

FIGURE 4.5A Norwegian production8

Source: NPD, National Grid



In a Gone Green (2009) scenario with lower UK demand and the possibility of comparable or even higher UKCS production, it may be challenging for flows from Norway to be as high as in our BAU forecast. Any additional import flows from LNG may also put pressure on Norwegian imports to the UK. However Norwegian flows may be comparable to our BAU forecast if UK exports to the Continent are sustained or potentially even increase due to price differentials between spot markets and Continental contracted prices. Due to relatively close proximity to the UK, there may also be opportunities for Norway to further develop its role to provide greater swing (seasonal or even daily flexibility) to the UK to support the expected greater variation of UK gas demand brought about through CCGT backup for wind intermittency.

4.6 LNG

4.6.1 LNG Trends

Global LNG trade remained flat in 2008 compared to 2007, despite the addition of Argentina which increased the number of importing countries to 18. Total LNG imports remained at 226 bcm with the three biggest Asian importers, Japan, South Korea, Taiwan and the biggest European importer Spain increasing their proportion of imports to 75% compared to 70% in the previous year.

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[8] Includes Snøhvit

Figure 4.6A shows imports by region over the last 8 years. The chart shows a trend of increased imports to both Europe and Asia with far more variation in imports to the Americas.

FIGURE 4.6A – LNG imports 2000 - 2008
Source: BP Statistical Review 2001-2009

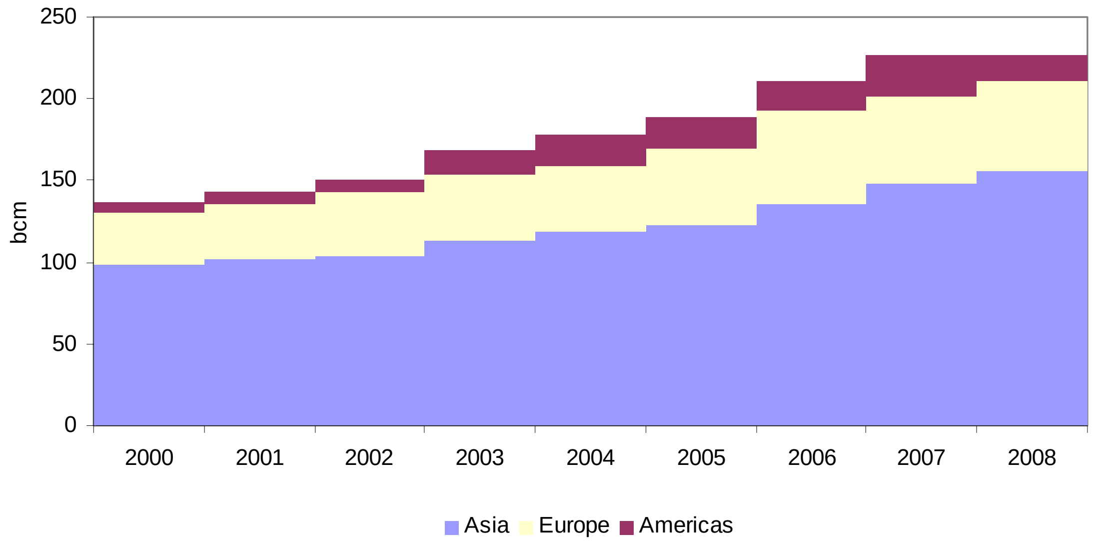
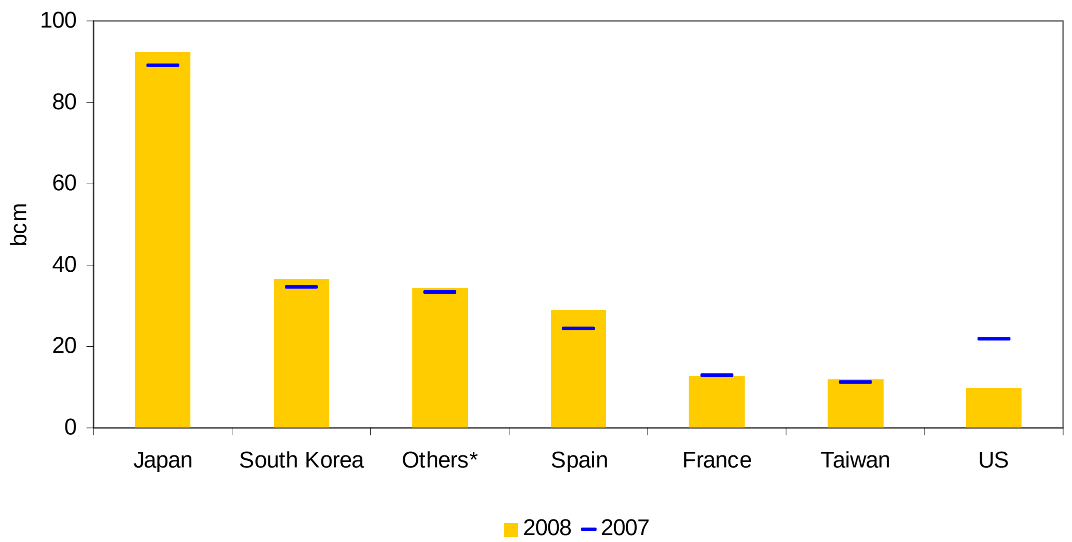


Figure 4.6B shows global LNG imports in 2008 by destination with the red line representing 2007 imports. The chart highlights that most of the major importers increased imports in 2008 apart from the US which saw a substantial reduction, driven by lower gas prices though the growth of unconventional sources of gas.

FIGURE 4.6B – Volumes of LNG imports in 2008
Source: BP Statistical Review 2008-2009



* Others include: Belgium, Greece, Italy, Portugal, Turkey, UK, Dominican Rep, Mexico, Puerto Rico, China, India and Argentina

4.6.2 UK LNG Imports

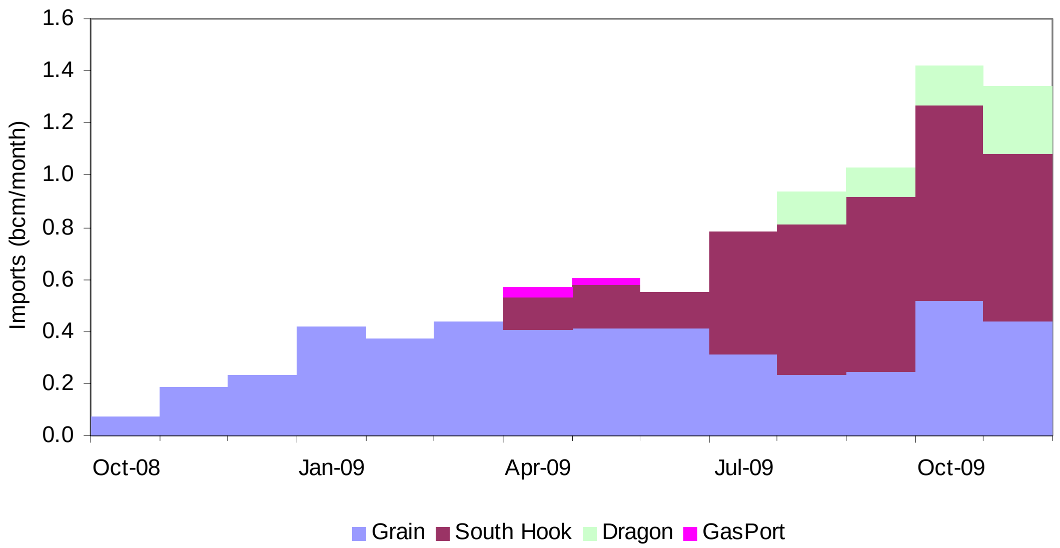
In 2008 the UK imported under 1 bcm through the Isle of Grain, mostly during the winter months of late 2008. Grain saw the completion of its Phase 2 in late December 2008 taking total capacity to 13.3 bcm/y (9.8 million tonnes a year). The UK's import capacity increased further in summer 2009 with the commissioning of South Hook Phase 1 (10.5 bcm/y) and Dragon (6 bcm/y). South Hook Phase 2 is expected to double capacity in late 2009 or 2010.

Total capacity at Grain following the Phase 3 expansion (due in 2010) will stand at ~20 bcm/y, in addition Grain announced in August 2009, the commencement of an open season for a possible Phase 4 expansion, dependent on potential customer demand.

Besides the three land based UK LNG terminals, LNG importation facilities also exist through ship to shore transfers at Teesside's GasPort. So far two ships have delivered LNG through this facility, the last ship was in April / May 2009.

A combination of increased UK capacity and increased availability of LNG, in part brought about by low US gas prices, has resulted in far greater LNG flows to the UK in 2009. To date[9] over 8 bcm has been imported through the Milford Haven and Grain terminals in 2009. Figure 4.6C shows monthly flows (average) from the three terminals during 2009. During October 2009, the highest monthly flow to date, the contribution of LNG made up almost 18% of total UK supplies. On a daily basis the maximum LNG flow to date has been 72 mcm on the 11th November, equivalent to over 22% of total UK supply for that day.

FIGURE 4.6C – UK LNG imports October 2008 to November 2009
Source: National Grid



Besides the significant increase in LNG imports, the flow of LNG into the NTS has resulted in far greater day to day variations than experienced with other import sources, thus highlighting the need for network flexibility. With increasing levels of LNG capacity and imports forecast, the need for network flexibility is anticipated to grow further.

In a Gone Green (2009) scenario with lower UK demands, LNG imports may be lower than those in our BAU forecast. However as we have experienced this summer, a global surplus of

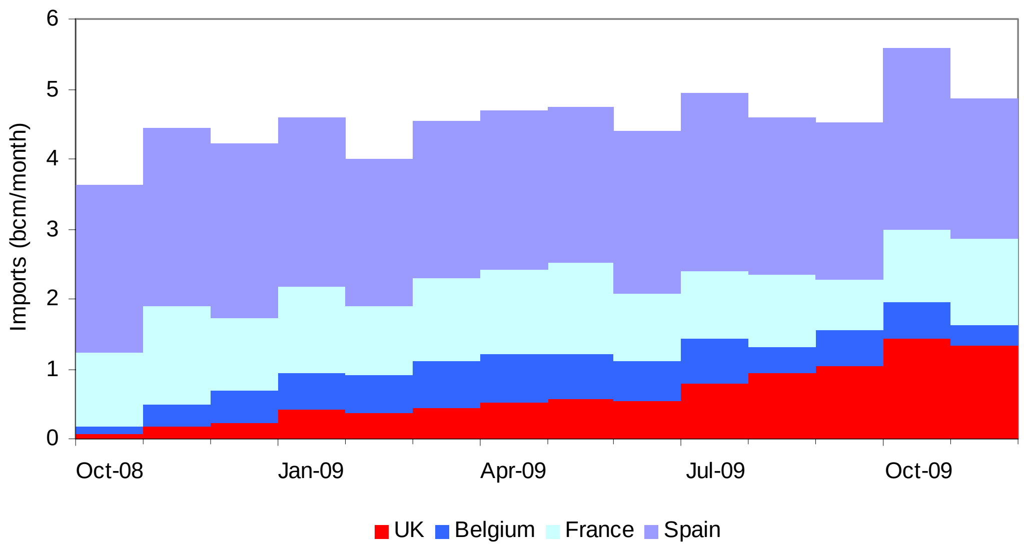
[9] End of November 2009

LNG production relative to demand could well continue to find its way to the UK as a result of lower demands in other markets. LNG imports may also find a new role in term of providing flexible supplies from stored LNG to the UK to support the expected greater variation of UK gas demand brought about through CCGT backup for wind intermittency. LNG imported to the UK may also be indirectly exported to Continental markets.

4.6.3 European LNG Imports

Figure 4.6D shows European monthly LNG imports from October 2008 to November 2009 for four European countries where data is readily available. During this period the UK's LNG as a proportion of European LNG increased steadily from relatively from low levels to exceed 25% at the end of the period. Total European LNG imports, for the countries shown, exceeded 5 bcm/month for the first time in October 2009.

FIGURE 4.6D – European LNG imports October 2008 to October 2009
Source: National Grid, Fluxys, Enagas & GRTGaz Data



The IEA states that European LNG annual re-gas capacity will reach almost 200 bcm/y once the European LNG projects under construction are completed. On a monthly basis this is equivalent to about 16 bcm/month, this is considerably more than the highest level of imports received to date. In 2009 the South Hook and Dragon LNG terminals in the UK became operational, also expected in late 2009 is the Adriatic LNG terminal in Italian waters, which is the worlds first offshore gravity based structure. Spain the biggest importer in Europe has under construction a 7th terminal. The Netherlands will join the list of European LNG importers once the Gate LNG terminal is complete around 2011 with Sweden also having a small LNG terminal under construction. A number of other countries including Germany and Poland have plans for LNG terminals but these, as yet, have not reached the construction stage.

4.6.4 LNG Liquefaction Capacity / Production

September 2008 saw the 6 bcm 5th train at Australia's North West Shelf plant commission taking total worldwide nameplate LNG production capacity to ~280 bcm. 2008 production was

~226 bcm equivalent to an annual utilisation rate of 81%. In 2008 a final investment decision (FID) was made for Algeria's Gassi Touil 6.5 bcm project.

2009 has seen a significant increase in nameplate LNG production capacity with first production from Indonesia's Tangguh plant (5.2 bcm plant in July 2009), as well as Russia's Sakhalin II (Train 1, ~6.5 bcm plant in March 2009) and Qatar's Rasgas 6, and Qatargas II (10.5 bcm and 21 bcm respectively) with first LNG production from Yemen's Train 1 announced in October 2009 (9.2 bcm). These facilities when fully operational will add over 50 bcm to nameplate capacity, a global increase of almost 20%.

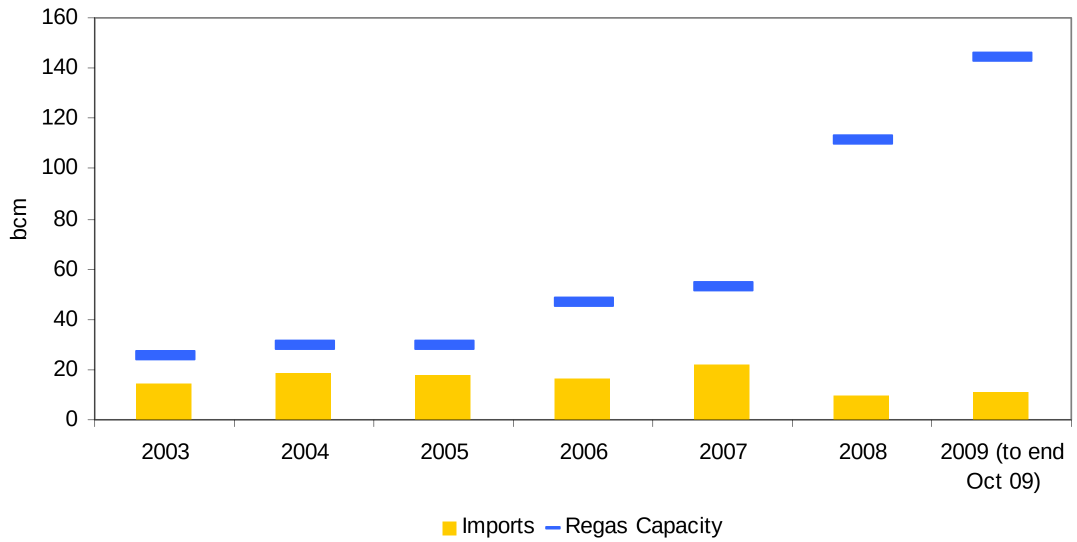
The IEA forecasts that LNG production capacity, from plants already under construction, will exceed 400 bcm by 2014. At similar levels of utilisation as seen in 2008 (~80%), this results in more than an additional 100 bcm of LNG supply over 2008 levels.

4.6.5 LNG Re-gasification Capacity

Worldwide LNG re-gasification capacity has continued to increase as new plants are completed. The US now has direct re-gas capacity in excess of 100 bcm, second only to Japan. Despite the recent growth in US import capacity imports peaked at just over 20 bcm in 2007, with 2008 imports less than 10 bcm.

The chart below shows US imports since 2003 together with the build up in capacity.

FIGURE 4.6E – US LNG imports and terminal capacity
Source: National Grid, Pan EurAsian Enterprises

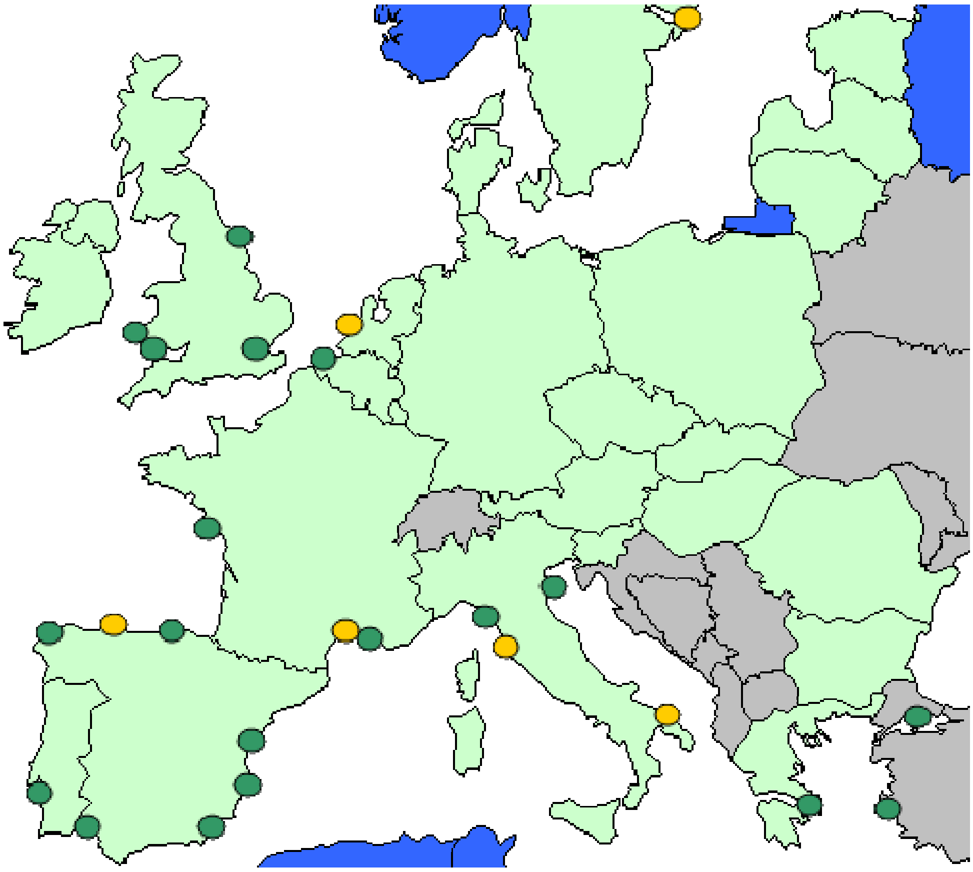


In 2009 the pace of LNG imports to the US have slightly increased to around 11 bcm as of the end of October 2009, this still represents very low utilisation rates compared to available capacity.

Re-gas capacity worldwide at the end of 2008 was approximately 600 bcm, an average utilisation rate of just 35%. The IEA forecast re-gas capacity to increase to over 800 bcm by the end of 2010. The UK's total import capacity by 2010 will be over 50 bcm some 25% of the total European capacity, unlike the US the utilisation of UK LNG import infrastructure has been high in 2009 as shown in Chart 4.6C with utilisation running at 57% in October and slightly less at 54% in November.

Figure 4.6F shows a map of completed and under construction LNG terminals in Europe.

FIGURE 4.6F – European LNG Terminals
Source: National Grid, GNL, various



Under Construction

Operational

4.6.6 LNG Tankers

The LNG tanker fleet consisted of almost 300 vessels by the end of 2008, with 48 ships delivered in 2008. Half the vessels are less than 5 years old reflecting the significant increase in shipping capacity in recent years. The 14 Q-Max and 22 Q-Flex ships ordered by Qatar Gas Transport Company (QCTC) as part of the LNG train investments have now all been delivered, South Hook has seen some Q-Max deliveries with the slightly smaller Q-Flex being the largest vessels to Grain.

The total number of voyages made by the LNG tanker fleet in 2008 increased by less than 1% compared to 2007, despite the increasing number of vessels.

4.7 UK Import & Storage Projects

4.7.1 Importation Projects

2009 saw the completion and operation of the next phase of UK import infrastructure namely Grain Phase 2 and the South Hook and Dragon terminals at Milford Haven. Since 2005 the UK has developed a diverse set of import routes from Norway, Holland, Belgium and from other international sources through LNG.

TABLE 4.7A – Existing UK Import Infrastructure, completed
Source – National Grid

Import Project	Operator / Developer	Type	Location	Capacity (bcm/y)
Interconnector	IUK	Pipe	Bacton	25.5
BBL Pipeline	BBL	Pipe	Bacton	~15
South Hook 1	QP / ExxonMobil	LNG	Milford Haven	10.5
Dragon	BG/Petronas	LNG	Milford Haven	6
Isle of Grain Phase I & II	National Grid	LNG	Isle of Grain	13.5
Langeled	Gassco	Pipe	Easington	25
Tampen[10]	Gassco	Pipe	St Fergus	10
Vesterled	Gassco	Pipe	St Fergus	13
GasPort	Excelerate	LNG	Teesside	~4
			Total	**~123**

TABLE 4.7B – Under Construction and Proposed projects
Source – National Grid

Import Project	Developer	Type	Location	Date	Capacity (bcm/y)	Status
BBL Expansion	BBL	Pipe	Bacton	2010+	~3	FID[11] taken
South Hook 2	QP / ExxonMobil	LNG	Milford Haven	2009/10	10.5	Under construction
Dragon 2	BG Group / Petronas	LNG	Milford Haven	2013+	6	Planning received (1 Tank)
Isle of Grain 3	Isle of Grain LNG	LNG	Isle of Grain	2010	7	Under construction
Isle of Grain 4	Isle of Grain LNG	LNG	Isle of Grain			Open season underway
ConocoPhillips	Partners	LNG	Teesside	2014+	7+	Most planning granted, no FID

10 Limited by available capacity in FLAGS

11 FID - Final Investment Decision

Canvey LNG	Partners	LNG	Canvey Island	2014+	5.4+	Planning rejected, potential resubmission
Port Meridian	Hoegh LNG	LNG	Offshore barrow	2013	4	Most planning granted, no FID
Other LNG	Various	LNG	n/a	2013+		Conceptual
	Total under construction (inc. proposed)				**17.5 (43+)**	

4.7.2 Storage

The Aldbrough storage facility started commercial operation in July 2009 with an initial space of 60 mcm of the final 370 mcm available. Additional capacity is expected to become available in 2010 with full completion by 2012. When completed, deliverability from the site will be approximately 40 mcm/d, placing Aldbrough second only to Rough in terms of deliverability.

Centrica who purchased Caythorpe from Warwick Energy in September 2008, has also purchased a controlling stake in the offshore Baird storage project, a potential 1.6 bcm project feeding into Bacton. The proposed offshore 5 bcm Hewett storage project is also destined for Bacton. With baseline entry capacity at Bacton at 1783 GWh, in aggregate, the potential entry (200+ mcm/d) and exit (100+ mcm/d) capacity at Bacton could (subject to auction signals) result in the need for new network infrastructure. Besides Baird, Centrica have interest in another offshore project Bains, this obtained planning permission in June 2009.

TABLE 4.7C- Existing UK storage
Source – National Grid

Storage Project	Operator	Location	Space (bcm)	Deliverability (mcm)
Rough[12]	Centrica Storage	Southern North Sea	3.3	43
Hornsea	SSE Hornsea	Yorkshire	0.3	18
Hatfield Moor	Scottish Power	Yorkshire	0.1	2
Holehouse Farm	Energy Merchants Gas Storage	Cheshire	0.05	6
Humbly Grove	Star Energy	Hampshire	0.3	7
Aldbrough[13]	SSE / Statoil	Yorkshire	0.06	~10
LNG Storage[14]	National Grid LNG Storage	Various	0.18	35
		Total	**4.3**	**~121**

[12] Rough typically manages to exceed the storage capacity listed

[13] Initial space available, final space when fully completed 0.37bcm

[14] Avonmouth, Glenmavis and Partington

TABLE 4.7D - Storage under construction
Source – National Grid

Storage Project	Developer	Location	Space (bcm)	Gas Year
Aldbrough[15]	SSE / Statoil	East Yorkshire	0.37	2009/10
Holford	E.ON	Cheshire	0.16	2011/12
Stublach[16]	Storengy UK Ltd	Cheshire	0.14	2013/14
		Total	**~ 0.6**	

A number of storage projects have received planning permission, if these were all to proceed to construction they could contribute in excess of 4 bcm storage capacity. However since last year's Ten Year Statement there has been limited movement in terms of achieving project FIDs. During the last year Centrica gained planning permission for its Bains storage project and EDF Energy purchased 10 salt caverns from British Salt in July 2009 for development adjacent to its existing project.

TABLE 4.7E - Storage with planning permission
Source – Various

Storage Project	Developer	Location	Space (bcm)	Planning Granted	Status
Stublach[17] II	Storengy UK Ltd	Cheshire	0.25	Dec-06	FID approved
Hole House Farm Expansion	EDF Energy	Cheshire	0.1	Mar-09	No FID
British Salt	British Salt	Cheshire	0.2	Jul-08	No FID
Caythorpe	Centrica	East Yorkshire	0.2	Feb-08	No FID
Aldbrough II	SSE / Statoil	Yorkshire	0.4	May-07	No FID
Portland	Portland Gas Ltd	Dorset	~1	July-07	No FID
White Hill Farm[18]	E.ON	Yorkshire	~0.4	Oct-07	No FID
Gateway Storage	Stag Energy	East Irish Sea offshore Barrow	~1.5	Nov-08	No FID
Bains	Centrica	Offshore Barrow	0.5	Jun-09	No FID
		Total	**~ 4.3 bcm**		

[15] Final capacity of project, space includes existing storage (this is excluded in total)

[16] Phase I of project

[17] Phase II of project

[18] Initial planning granted, onshore planning to be updated in 2010, offshore to be applied for in 2010

A number of storage projects have applied for planning permission that has not yet been granted, many of these have resulted in public enquires.

TABLE 4.7F - Storage awaiting planning permission
Source – National Grid

Storage Project	Developer	Location	Space (bcm)	Date Applied	Status
Saltfleetby	Wingas	Lincolnshire	~0.7		Gone to Public Enquiry
Fleetwood	Canatxx	Lancashire	~1	Feb-09	Re-submission of planning following Secretary of States rejection in Oct-07
King Street	NPL	Cheshire	~0.2		Gone to Public Enquiry
		Total	**~ 1.9 bcm**		

The table below includes some of the projects which have yet to apply for planning permission, these include some offshore storage proposals that if built would significantly increase the amount of UK storage space.

TABLE 4.7G - Planning permission not yet applied for
Source - Various

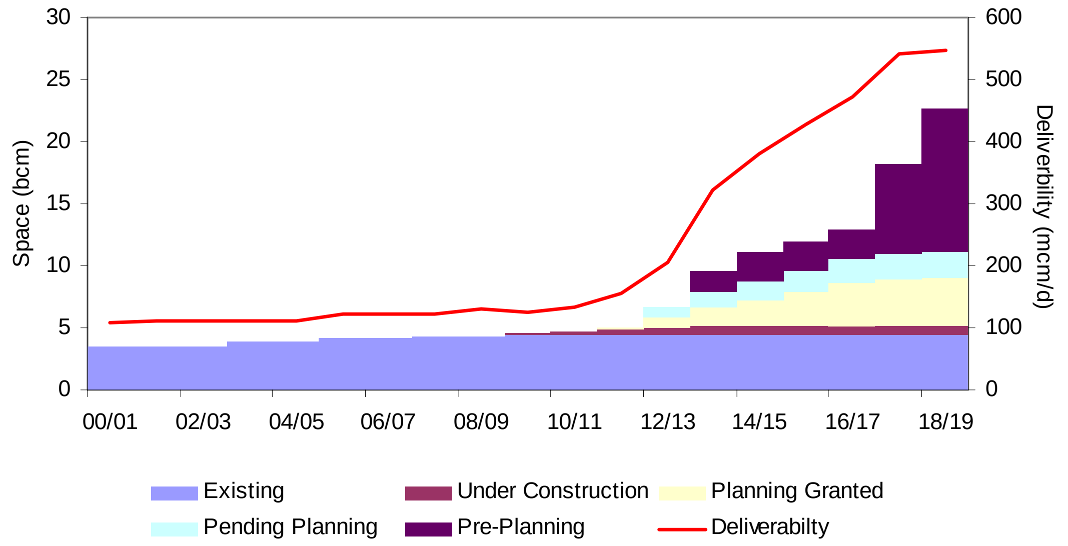
Storage Project	Developer	Location	Space (bcm)
Albury	Star Energy	Surrey	0.2
Albury II	Star Energy	Surrey	0.4
Esmond Gordon	Encore Oil	Offshore	~4
Baird	Centrica / Perenco	Offshore Bacton	1.7
Hewett	Eni	Offshore Bacton	~5
Gateway II	Stag Energy	Offshore Bacton	1.5
Hatfield West	Scottish Power	Yorkshire	0.1
		Total	**~13**

Figure 4.7A shows for each year since 2001 the 'at the time' status of storage projects under the classifications of: existing, under construction, planning granted and pre-planning. The chart highlights considerable activity in terms of storage proposals and to a lesser extent planning granted but relatively limited new storage projects actually completed or under construction.

FIGURE 4.7A – Historic status of UK storage developments
Source – National Grid

Figure 4.7B shows historic storage levels and the current status of potential storage developments in the UK. Despite all the proposals for new storage developments, actual storage capacity has only increased by around 1 bcm since 2000, with the majority of the increase coming from the enhancements to the Rough facility. Storage deliverability has stayed broadly the same since 2000 with the increases from Humbly Grove, Holehouse Farm, Aldbrough and expansions at existing facilities being offset by reductions due to the conversion of Grain to an LNG import facility and the closure of Dynevor Arms LNG storage facility in 2009. The volume of projects shown in the chart below includes almost 13 bcm of offshore developments, none of these have yet received a FID.

FIGURE 4.7B – Potential UK storage developments
Source – National Grid

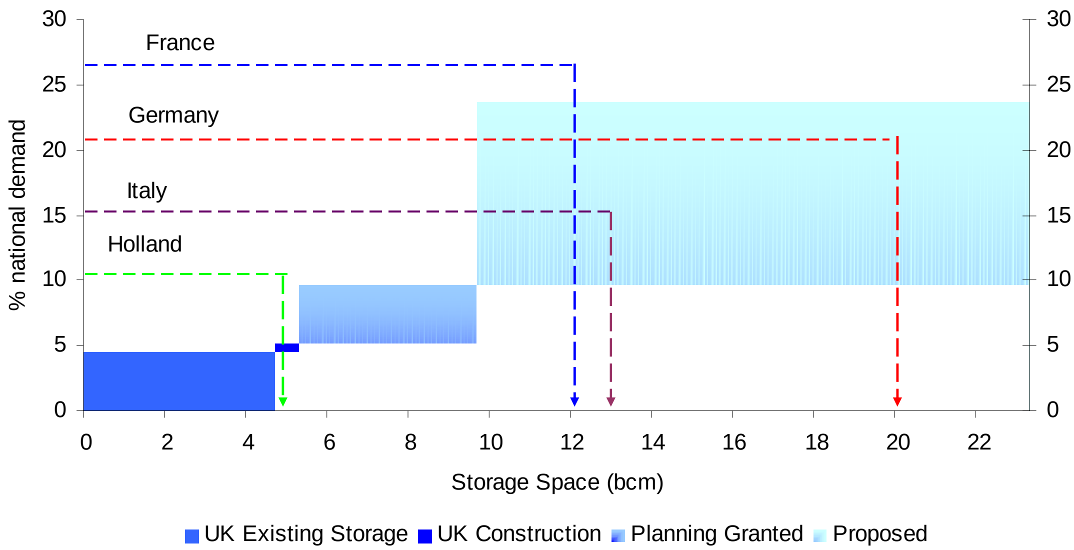


In a Gone Green (2009) scenario with lower UK demands, there are arguments to support more or even less UK storage. The expected greater variation of UK gas demand brought about through CCGT backup for wind intermittency provides a need for more flexible supplies. Therefore, opportunities will exist for UK storage to provide new services. Other new services for storage could also be created if there were increased obligations on suppliers or a need to provide cover for any loss of supply source. Section 4.9 details the role of storage from a security of supply perspective.

Primarily due to historical availability of indigenous supplies, the UK has had much lower storage capacity than comparable European markets. With import levels now at approximately 40% and rising, a comparison with European storage levels is now more meaningful. Figure 4.7C shows the UK storage position compared to other largest European gas consuming countries.

FIGURE 4.7C – Comparison of European storage vs national demand

Source – IEA Data & National Grid



The chart shows UK and European storage as a percentage of national demand. With the exception of Holland which has significant indigenous supplies the UK has currently relatively low levels of storage compared to the other major European gas markets. The chart shows that the UK position could radically change if UK storage was to be developed as proposed. However this possibility needs to be tempered with the relatively small amount of storage currently under construction and the general slow pace of storage projects in obtaining FIDs.

4.8 2009 Base Case Supply Forecast & Auctions Update

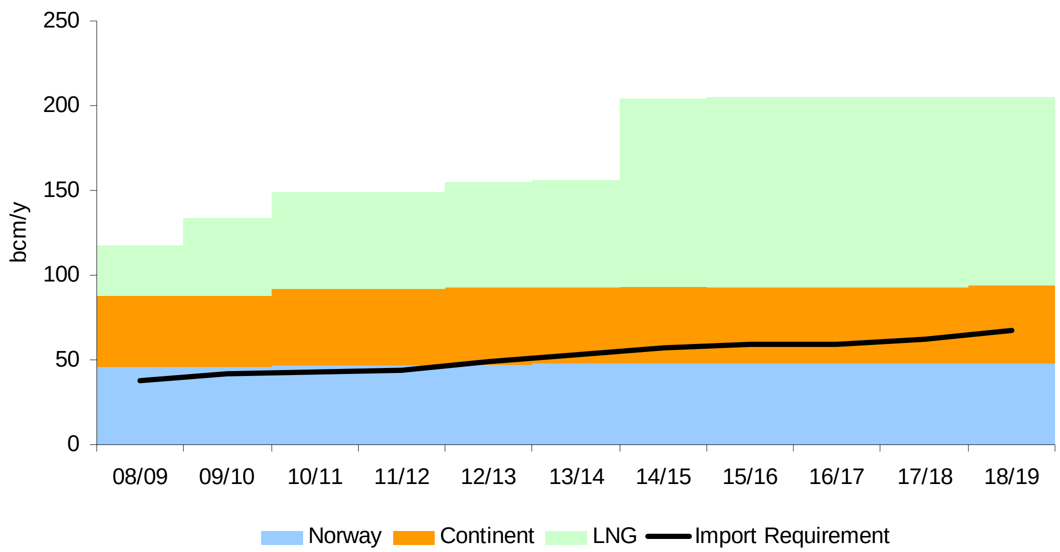
4.8.1 Base Case Development: Annual Supplies

As in previous years, we have created a “Base Case” which is intended as a starting point for further analysis and scenario creation. In creating our Base Case, a number of drivers were considered but key considerations were demands, and import capacity.

Our 2009 annual demand forecast is 5% lower than our 2008 forecast over the 10 year period. With a surplus of import capacity this has created even more scope for supply variations from our Base Case.

Figure 4.8A shows total import capacity of all reported import projects (see Tables 4.7A and 4.7B) by supply type. Current UK import capacity exceeds import requirements by about 3 fold and even exceeds total UK demand. If further import projects (all LNG) are constructed as proposed, import capacity could exceed 200 bcm/y by 2014/15[19]. In order to create realistic supply scenarios for network design and other business plans, not all supplies can flow at capacity at the same time, so consideration needs to be given to what could realistically flow, rather that what in the extreme could flow.

FIGURE 4.8A Import capacity and UK import requirement
Source: National Grid, all data available



For our Base Case forecast, we examined the following for all UK supply sources:

- General supply availability
- Alternative supply options for example diversion of Norwegian supplies to the Continent or LNG to other destinations
- Market behaviour, notably when gas prices are low
- Observations of recent performance

[19] The total of 200 bcm exceeds the reported projects in Tables 4.7A and 4.8B as the chart includes estimated capacities for Grain Phase 4 and ‘other’ LNG projects

With lower forecast demands and higher capacity from completed or near completed import projects there is considerable uncertainty as to how supplies will meet demands. To capture this ongoing supply uncertainty, we have enhanced the approach previously used that prioritised or used a merit order of gas supplies. For each supply source we have developed a “core” / “non-core” concept where “core” represents what gas is likely to flow and “non-core” represents what gas may flow. For each supply component this has allowed us to determine a range of possibilities that are not at extreme limits, but at realistic levels.

It should be noted that as import capacity far exceeds import requirements, even this approach only partly captures possible supply patterns.

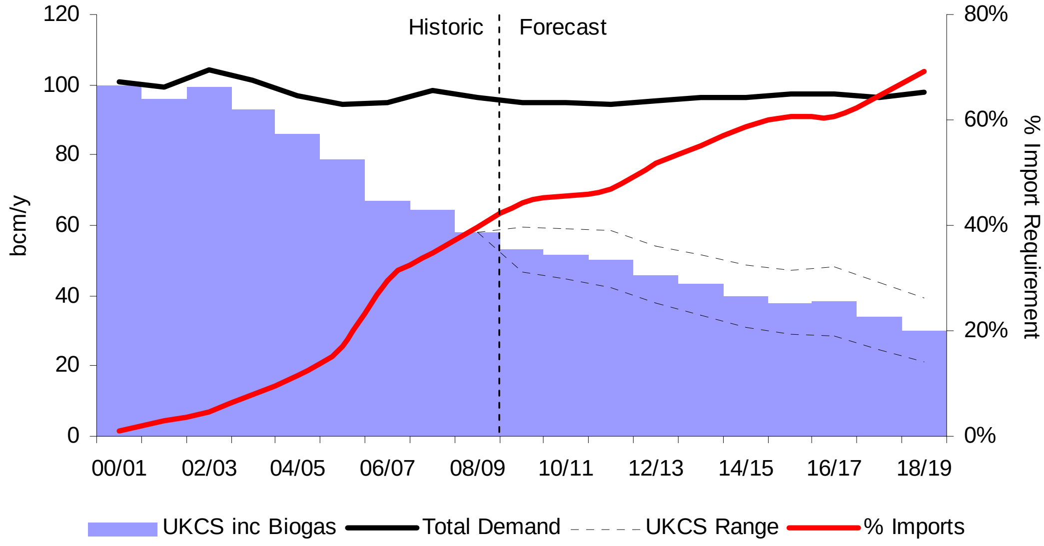
In the following sections that detail each of the supply sources, we have identified the basis for “core” gas and “non-core” gas. We have only been partially explicit as to how each of the “non-core” components have been allocated as this was achieved in part through an iterative basis. At a high level, the allocation process is as follows:

1. Determination of annual demand
2. Determination of “core” and “non-core” components for each supply source
3. Allocation of “core” gas to annual demand
4. By difference identify the annual shortfall to be made up from “non-core” gas
5. Due to an excessive surplus of “non-core” capacity, further review “non-core” capacity from each supply source. Hence “de-rate” capacity with lower load factors based on anticipated behaviour
6. Finally allocate the remaining supply shortfall to “non-core” supply sources based on revised “de-rated” availability

4.8.2 Base Case UKCS Supplies

Figure 4.8B shows our 2009 UKCS forecast in aggregate and as discussed earlier, indicates that the UK may be ~69% import dependent by the end of our forecast period. This is lower than last years figure of 72% due to lower demands and to a lesser extent, marginally increased UKCS production. Around the forecast is a range commencing at +/- 10% of our 2008/09 forecast and thereafter increasing by +/- 2% per year. Also shown on the chart is actual UKCS supplies and annual demands since 2000/01 (the demand line has not been weather corrected). Forecast demands include exports to the Continent and Ireland.

FIGURE 4.8B UKCS annual supplies & demands
Source: National Grid

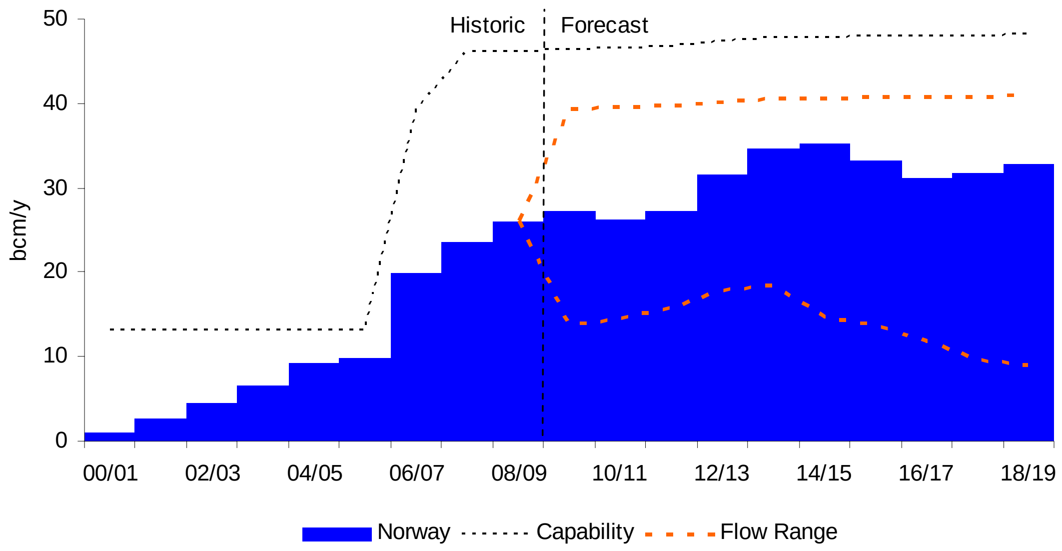


The rapid increase in import dependency between 2006/07 and 2007/08 was due to a combination of events in 2006/07, namely low demands, (not weather corrected), and high Norwegian imports as Continental shippers took less gas. This in turn suppressed some UKCS production from high-swing fields, and provides a good example of where "non-core" supplies have been reduced.

4.8.3 Base Case Norwegian Supplies

Figure 4.8C shows Norwegian imports to the UK since 2000/01, and post 2008/09 our Base Case forecast for Norwegian flows to the UK, as well as the capacity of their pipelines to the UK. The forecasts include both "core" and "non-core" gas, with "core" gas representing ~50% of imports at the start of the forecast period, and ~30% at the end. Around the forecast we have also shown a possible range for imports. The upper range is based on 85% of existing capacity. The lower range is based on our "core" gas assessment, which is driven by our Norwegian production forecast and represents volumes which would be expected to flow to the UK under normal circumstances.

FIGURE 4.8C Base Case Norwegian flow forecast to the UK
Source: National Grid



Our forecast shows further growth in Norwegian imports to about 27 bcm/y before levelling off in 2009/10. Our forecast increases thereafter due to higher Norwegian production with no commensurate increase in Continental export capacity. Thereafter a slight decline is forecast post 2015 due to higher export capacity to the Continent (this is assumed through new compression rather than a new pipeline).

4.8.4 Base Case Continental Imports

It must be stressed that there is considerable uncertainty over future flows through both BBL & IUK due to:

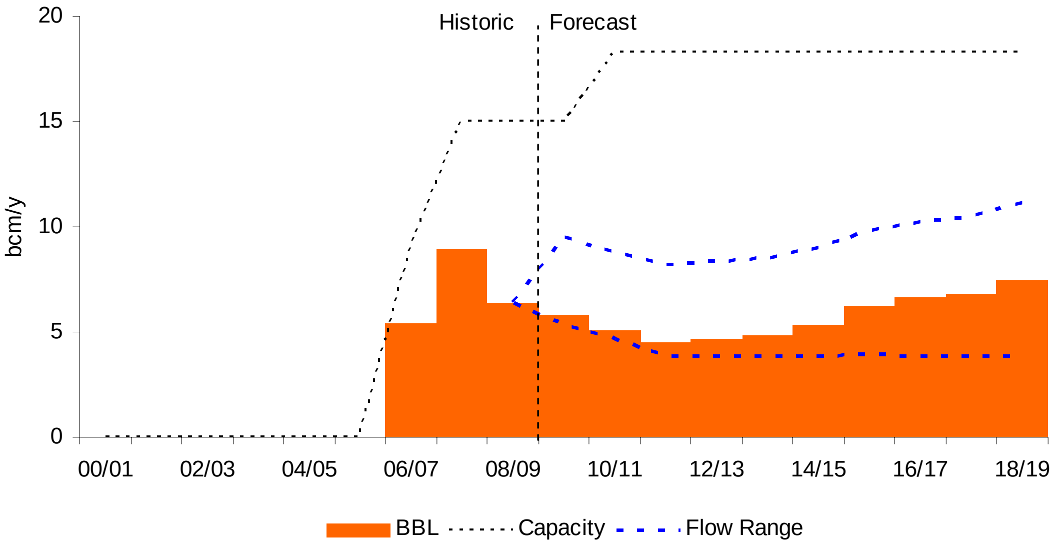
- Options to flow gas to alternative markets
- The pace of EU market liberalisation and access to transmission pipelines & storage
- Development of new commercial arrangements (namely BBL's commercial reverse flow service)
- Possible gas quality issues

In our Base Case forecast we assume that the current basis for imports via BBL will continue broadly unchanged. Namely, BBL volumes will be guided by reported contractual flow rates, but in the short term flows will become more responsive to market differentials between the UK and the Continent due to trading behaviour and the commencement of non-physical reverse flows. It has been observed that daily BBL volumes have become more volatile since flows began in 2006/07. Over the long term, as the UK becomes more import dependent and there is a need for new or expanded import infrastructure, there is the possibility that BBL's capacity may be further expanded. Alternatively there could be a new pipeline to the Continent to effectively link up with an increase in gas transport capacity to Europe from Russia through Nord Stream, and to a lesser extent South Stream and other routes (such as Nabucco).

Figure 4.8D show imports via BBL since 2006/07, and post 2008/09 our Base Case for imports via BBL as well as BBL's capacity. This is assumed to increase by 3 bcm in 2010/11 though an approved compression project. The forecasts include both "core" and "non-core" gas, with "core" representing ~90% of imports at the start of the forecast period and ~50% at the end. Around the forecast we have shown a possible range, with the upper range based on an upside for the forecasts of 3.65 bcm/y, equivalent to 10 mcm/d, with the lower range based on "core" gas assumptions. Our "core" forecast is gradually reduced due to increased commercial arrangements including non-physical reverse flows, to approximately half of the original 8 bcm/y import contract between Centrica and Gasunie.

Flows may begin to increase in the latter half of the period as UK becomes more import dependent, and if Europe's supply diversity improves through additional infrastructure and market liberalisation.

FIGURE 4.8D Base Case BBL flow forecast to the UK
Source: National Grid



For IUK we continue to assume that this pipeline will continue to respond to market conditions, tending to operate seasonally between a UK market with summer / winter price differentials alongside a Continental market that is predominantly supplied through long term oil-indexed contracts.

For our Base Case forecast we have considered that a reduced UK demand environment and increasing importation capacity combined with relatively open market access should act as a driver for overall export behaviour.

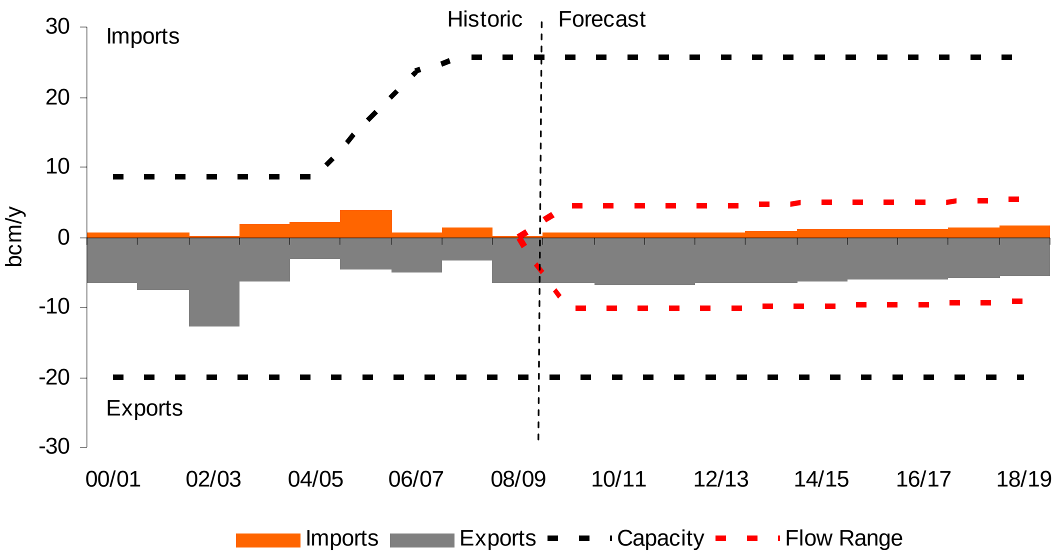
As the UK's import dependence increases over time we assume IUK gradually imports more / exports less, although it continues to be a net exporter and retains some measure of seasonality.

Figure 4.8E shows imports and exports through IUK since 2000/01 and post 2008/09 our Base Case forecast for the UK (as well as import & export capacity). Due to its commercial type behaviour and flow history, we assume no "core" gas. The contribution provided by the "non-core" component is based on the following drivers:

- Average observed flows (aggregated for both imports/exports) for the last 5 years have averaged ~20 mcm/d
- The import/export split for our 2009 forecast is based on recent experience (predominantly export behaviour)
- In the short term, we assume the UK will remain well supplied and therefore drive export behaviour
- In the long term we assume the UK will tend to import more from the Continent and this will slowly reduce export flows
- Modest changes in IUK import / export behaviour to limit forecast (supply and demand) volatility

Around the forecast we have shown a possible range for IUK flows: both the upper and lower ranges are based on a tolerance of +/- 3.65 bcm/y, equivalent to +/- 10 mcm/d.

FIGURE 4.8E Base Case IUK flow forecast
Source: National Grid



4.8.6 Base Case LNG Supplies

Of all the supply components, LNG imports provide the greatest level of UK supply uncertainty due to numerous factors:

- Limited operational experience to date
- Global options to deliver gas to alternative (contracted or higher priced) markets
- An excess of global LNG re-gasification capacity over LNG production which provides destination options
- A view that most LNG imports to the UK may not be limited by “destination clauses” which are common in LNG contracts and therefore is not specifically destined for this country
- The prospect of greater LNG availability for traded markets due to the global recession which has reduced LNG demand

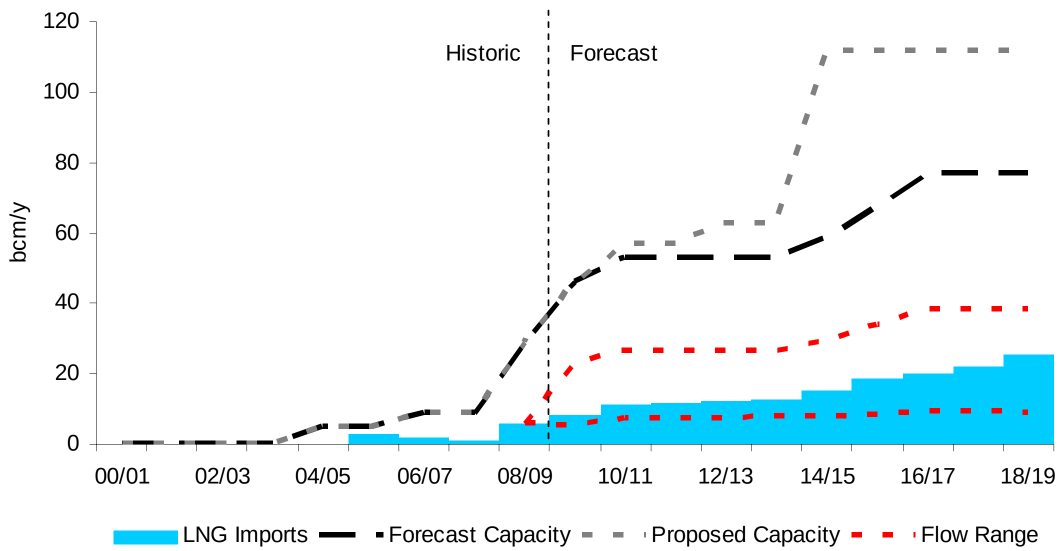
- Uncertainties regarding the commissioning dates of new import facilities (particularly in Europe & the US) and how such facilities will operate
- Finite daily UK demand and competition from other gas sources (mainly Norway & UKCS production), which may inhibit the relatively high delivery capacity of LNG import facilities

As with other supply components we have applied a "core" / "non-core" approach in determining our LNG import forecasts which have not been based on a global LNG model, but on operational experience to date and other metrics.

For "core" LNG imports we have included an assessment for LNG boil-off and combined this with a load factor (12% of capacity) which represents the lowest annual load factor observed to date in the UK. For future plants not yet constructed, or which may operate as merchant facilities, we have applied an even lower load factor. For "non-core" gas we have made the assumption that LNG import facilities can operate at a load factor up to 50% of installed capacity. This may appear low but needs to be considered in the context of global utilisations rates for LNG terminals (usually well below 50%) and the very high capacity of future and existing LNG facilities relative to UK import requirements.

Figure 4.8F shows LNG imports since 2005/06 and post 2008/09 our Base Case forecast for LNG imports, as well as our forecast capacity for LNG. The forecasts include both "core" and "non-core" gas, with the upper range based on 50% of forecast capacity and the lower range based on the "core" gas assumptions detailed above.

FIGURE 4.8F Base Case IUK flow forecast
Source: National Grid



The chart shows a rapid expansion of LNG capacity from 2008/09 as Milford Haven and the Grain expansion come on-stream. We assume further LNG import capacity is commissioned through our ten year planning period as UK import dependency increases. Our Base Case shows a gradual build-up of LNG imports which approach 10 bcm in 2009/10 and exceed 20 bcm in 2016/17. Although these forecasts are well below installed capacity they represent a significant proportion of UK imports. For example, a flow of 10 bcm/y relates to about 10 LNG cargoes per month (based on 135,000 m^3 vessels). The uncertainty for future LNG imports is highlighted by the considerable ranges shown in the chart. Whilst high rates of delivery may not necessarily be achieved on an annual basis, high delivery rates may occur for relatively short periods.

4.8.7 Base Case Annual Match

Figure 4.8G brings together the supply components discussed previously. The chart shows:

- Little or no growth in annual demand
- A decline in UKCS production
- Relatively high levels of Norwegian imports with only modest growth from current import levels
- A short term reduction in Continental imports before growth is resumed due to increasing UK import dependency
- A phased but significant build-up of LNG imports

FIGURE 4.8G Base Case annual supply
Source: National Grid

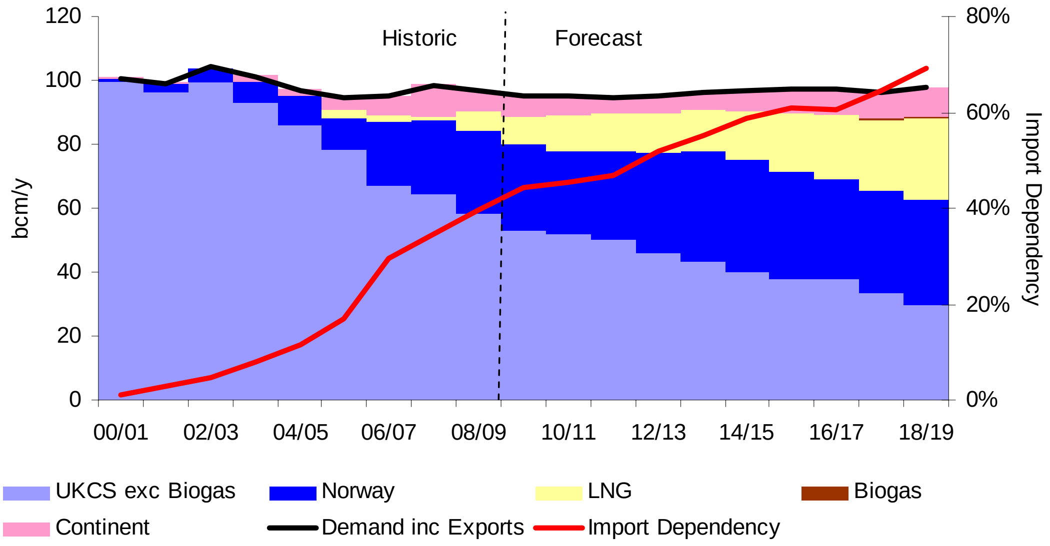


Table 4.8A shows the relative potential contributions of the different supply types to the UK supply mix in 2008/09, 2011/12 when the UK may be just under 50% import dependent, and the end of our forecast period in 2018/19. As with Figure 4.8G, points to note are:

- Although in decline, UKCS production is still significant by 2018/19 and could be contributing up to 30% of the supply mix by the end of the period
- The growth of all imports, particularly LNG.

TABLE 4.8A – Potential Forecast Supply Contributions
Source: National Grid

	2008/09	2011/12	2018/19
UKCS	60%	53%	30%
Norway	27%	29%	33%
LNG	6%	13%	26%
Continent	7%	5%	9%
Biogas	-	-	1%

4.8.8 Base Case Storage Supplies

For the peak position, we also need to include storage. As shown in Figure 4.7B and discussed in Section 4.7 there are numerous proposals for new storage in the UK. By 2018/19 in aggregate the peak deliverability of all existing and proposed storage facilities could be ~550 mcm/d when combined with the current deliverability of ~120 mcm/d.

Inclusion of all storage proposals in our Base Case is neither practical nor realistic for the following reasons:

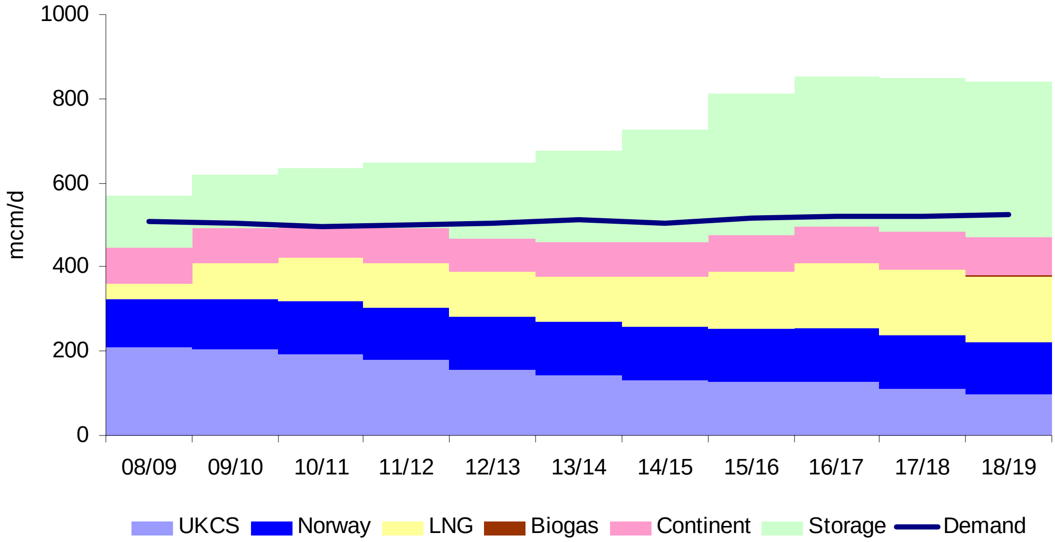
- The history of many storage developments has been one of slippage and deferral with relatively few new storage projects being completed over the last decade. Recent economic conditions have ensured that this trend has continued
- The absence of capacity signals from the entry capacity auctions for most of the proposed projects
- Difficulties in obtaining planning, permits and funding
- The sheer magnitude of potential delivery from all storage facilities (~550 mcm/d) in the context of 1:20 peak day demands of ~500 mcm/d

In our Base Case we have included all storage facilities that are currently under construction and those which we believe are well advanced in terms of securing planning, financial backing and commitment from major shippers. Even for some of these we assume some slippage. Whilst the approach does tend to pick "winners", the sites not included in our subsequent analyses are interchangeable with those that are included.

4.8.9 Base Case Peak Match

Figure 4.8H shows our forecast peak position for our Base Case.

FIGURE 4.8H - Base Case peak supply
Source: National Grid



The chart shows our resultant Base Case peak supply-demand position. The demand line is our 1:20 peak day demand. UKCS is shown at 90% deliverability, and all imports are based on our best view of peak supplies rather than capacity. Storage deliverability is consistent with our Base Case forecast.

In terms of peak demand, the forecast shows a near static position. It also shows non storage supplies (NSS) of over 400 mcm/d throughout the period which is relevant for capacity planning and network design. However, for operational planning (e.g. the Winter Outlook process) we tend to use more rigorous assumptions based on recent experience and available information.

Over time, the peak position becomes increasingly well covered but only through our assumptions for new storage developments. Storage is expected to play an increasingly important role in maintaining security as import dependency increases. Section 4.9 details an assessment of longer term security.

4.8.10 2009 LTSEC Auctions

Appendix 2 details our Base Case peak flow forecasts and flow ranges for all major entry terminals. The charts also show the capacity we are obligated to release and capacity booked through the long term system entry (LTSEC) and annual monthly (AMSEC) auctions. These were last held in September 2009 (LTSEC) and March 2009 (AMSEC). For ease of conversion from energy to volume, all of these charts assume a calorific value (CV) of 39.6 MJ/m^3 rather than using terminal specific CV forecasts.

In the 2009 LTSEC auctions there was some bidding activity at most ASEPS. Of note was the additional entry capacity requested at Hole House Farm and increased bidding activity at Bacton, these are shown in Figures A2.4I and A 2.4A respectively in Appendix 2.

The next LTSEC auctions are expected to be held in March 2010 when the entry capacity substitution and retainer regime will also commence.

4.9 Security of Supply

Due to doubts over how surplus import capacity will be used and development of new supplies, notably storage, there is considerable uncertainty regarding supply levels that make up our Base Case supply forecast. Indeed, the potential variation within certain supply types, such as LNG or via IUK is so high that any attempt at an analysis that quantifies the range of individual supply types is often of limited value.

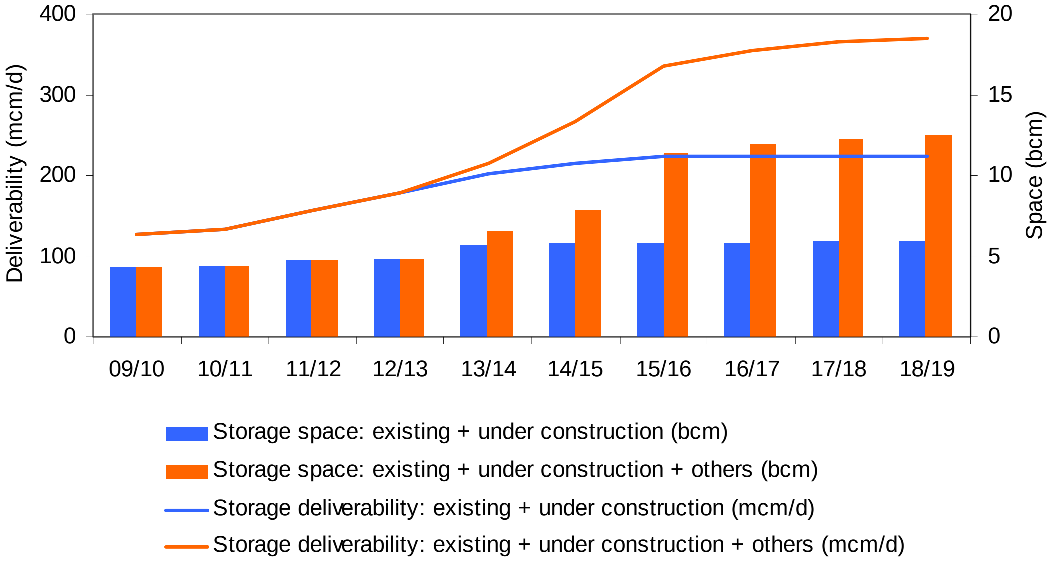
With such uncertainty regarding non-storage supplies the role of storage is likely to become increasingly important in ensuring security of supply. This year we have developed a new approach to address longer term security of supply whereby a top down approach is used with regard to storage, i.e. all storage that is available is assumed to be used rather than considering what storage is needed. Hence the key variables that are determined from the analysis is what level of non storage supply is required to ensure security of supply and from an alternative perspective what (new) additional storage is required for no increase in existing levels of non storage supply.

The approach used is as follows:

- The analysis uses a load duration curve based supply demand match, for average and severe (1 in 50) demands, for each year of the ten year forecast period
- The analysis considers only the top 60 days of each load duration curve, representing the two coldest months of the winter
- To identify future storage needs, only existing storage or storage that is under construction as detailed in Tables 4.7C and 4.7D are included in the analysis. For consistency on the supply side, supplies are also limited to our forecasts for UKCS, existing import infrastructure and import projects under construction
- All available storage (up to 60 days duration) is assumed to be used during the assessment, with the assumption that the net effect of any storage cycling over the 60 day period is zero
- For supply to equal demand, a resultant level of non storage supply (NSS) is determined for each year and the demand condition analysed. Alternatively any additional storage required to maintain existing levels of NSS is also calculated
- The resultant level of NSS can then be compared as a % against our forecast use of NSS. An increasing level of NSS indicates either:
    - a need for NSS to flow at higher levels for sustained periods
    - the need for more storage
    - or the need for a demand response

Figure 4.9A shows aggregated space and deliverability for existing storage sites and those under construction. Also shown is our Base Case view of storage developments.

FIGURE 4.9A - Storage space and deliverability



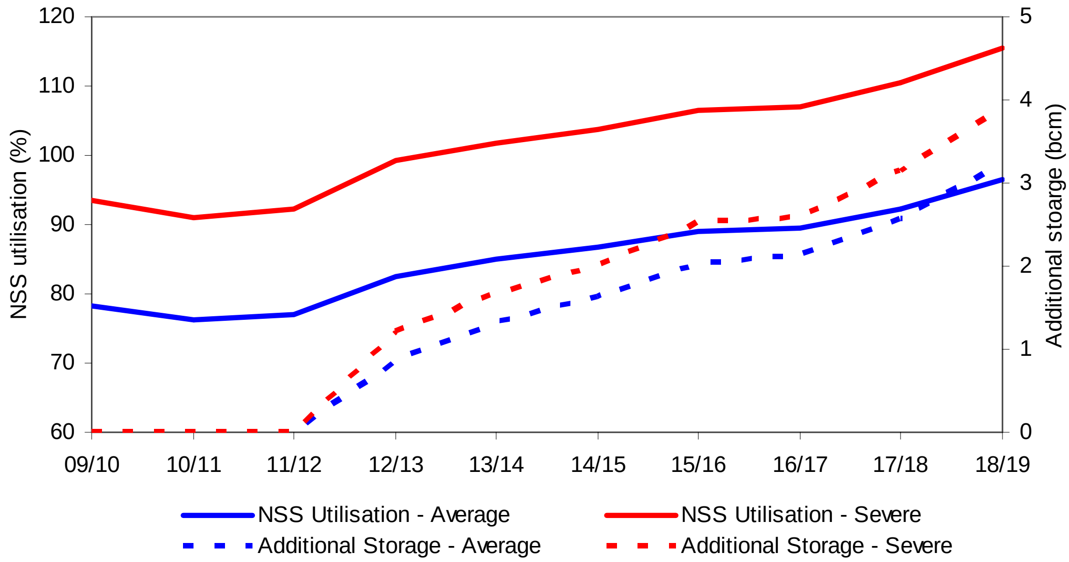
The chart shows two very different views of potential storage within the UK over the next ten years. The space and deliverability by 2018/19 for existing storage and those storage projects that are currently under construction are 4.9 bcm and 189 mcm/d respectively. This compares with our Base Case view in 2018/19 of 12.5 bcm space and deliverability of 370 mcm/d. It should be noted that the Base Case view only represents about half of all the potential storage projects that are currently being proposed.

The following conditions were considered:

- Demand: average and severe (1 in 50) winters
- Storage: existing and under construction
- Import infrastructure: existing and under construction
- Supply utilisation rates: 90% UKCS, 85% Norway, 60% BBL, 0% IUK and 50% LNG

Whilst the modelled LNG utilisation rate is low, it is reflective of international levels where regasification capacity is at least twice that of LNG production capacity. The outcome of the analysis is shown in Figure 4.9B, with the chart showing the resultant level of NSS utilisation relative to the assumed levels detailed above or alternatively a measure of additional storage needed to maintain existing levels of NSS.

FIGURE 4.9B - Non storage supply (NSS) utilisation or additional storage



For average conditions, the chart shows NSS utilisation rates (relative to assumed levels detailed above) rising steadily through the forecast period from an overall level of about 80% in 2009/10, towards 100% in 2018/19. For severe conditions the increase in NSS is from about 90% in 2009/10, to above 110% in 2018/19.

The alternative metric for maintaining existing levels of NSS results in an additional storage requirement of about 3 bcm for average conditions and 4 bcm for severe conditions by 2018/19.

Obviously, the assumptions used in this analysis are critical to the results, for example the increased requirement of NSS could alternatively be met by import infrastructure operating at higher utilisation rates, the construction of further import capacity or even a demand side response. To meet the 2018/19 increase in NSS one or a combination of the following could apply:

- As detailed above an increase in storage of 3 – 4 bcm
- An increase in the assumed level of LNG utilisation from 50% to about 95%
- An increase in the assumed level of IUK utilisation from 0% to about 80%
- If LNG utilisation remained at 50% then the level of LNG import capacity would need to increase from approximately 50 to 90 bcm/y
- A demand side response of about 50 mcm/d across the winter

Whilst the above analysis could be interpreted to show considerably less storage required in the future than the 20 bcm or so of proposed UK storage, the analysis does not take into account any decrease in non storage supply utilisation rates or alternatively increased demand brought about by further reliance on CCGTs or increased exports to the Continent. For example, a supply shock of a 50 mcm/d loss for 60 days would result in an additional requirement of 3 bcm from the remaining NSS sources or additional storage. This 50 mcm/d supply loss could represent the outage of a major pipeline or sub-terminal, reduced LNG imports or could be interpreted as an additional 50 mcm/d of demand if sustained exports were seen via IUK, as experienced during last winter during the Russia Ukraine dispute. Not surprisingly, such a supply shock when incorporated into the scenario using current storage plus storage under development would result in much higher NSS utilisation rates, increased storage needs or a higher demand side response. Combined with a cold winter these needs escalate considerably.

In a Gone Green (2009) scenario, with significant amounts of wind generation on the electricity network, wind intermittency will lead to greater variations in gas demand, as CCGTs act as backup. This will result at certain times in a further increase in the need for higher utilisation of NSS or alternatively more storage. Indeed, at a high level, our analysis into future CCGT back-up for wind suggests that wind intermittency could have a comparable effect to changes in demand as temperature variations have today. Hence the combination of cold weather and a drop in the wind will have even greater consequences in terms of change than the variations in gas demand experienced today even if in a Gone Green (2009) scenario overall demands are lower.

Chapter Five

NTS Capacity Provision and Investment

5.1 Overview

This section provides information on the future investment proposals on the National Transmission system necessary to comply with legislation and other requirements.

The 2009 investment planning process has been undertaken on a similar basis to those conducted in previous years, with the TBE consultation process providing the primary source of information, supplemented by auction signals. As explained in Chapter 4, we have considered a number of sensitivities around the Base Case, in order to look at the potential investment requirements.

This chapter presents the currently sanctioned NTS reinforcement projects, those that are presently under consideration for construction from 2010 to 2011, and investment options for later years, consistent with the supply Base Case detailed in Chapter 4 and signals received in the recent entry capacity auctions. Maps showing the current NTS and approved future investments are presented in Appendix 4.

Although the investment is centred around the base case scenarios, the implications of Gone Green (2009) have been assessed. Though potentially lower in terms of annual volumes, in a Gone Green (2009) scenario, there is a need for more responsive or flexible gas supplies to provide gas for power generation for the effects of wind intermittency. This in turn is expected to result in the need for increased flexibility in terms of gas supply (notably new storage) and investments in networks to deliver such.

The Gone Green (2009) scenario also results in a different power generation fuel mix going forward. Not only the number of new gas-fired stations is likely to be different in this scenario, but also the timing and location of the stations. The development of technology such as carbon capture and storage is one of the issues likely to effect future patterns of gas-fired power generation, as well as the requirement for increased flexibility.

In addition, we have looked at sensitivities around the base case, which are detailed later in this chapter.

5.1.1 Transmission Planning Code

The assessment of future transmission capacity requirements distinguishes between system entry and system exit. National Grid has introduced a Transmission Planning Code that describes how the NTS is planned and developed over the long term and how the planning process interacts with the processes for entry and exit capacity release. A copy of the Transmission Planning Code may be obtained from our website at:

www.nationalgrid.com/uk/Gas/TYS.

National Grid undertakes scenario analysis around the Base Case supply patterns to understand the capability to accommodate different patterns of flows on the system. The analysis is started in advance of long term entry capacity auctions to identify potential projects required to support entry capacity provision. Further entry analysis is conducted after the long term auctions to confirm the need for new entry projects, and review the requirement for projects identified through previous auction signals.

In respect of system exit, analysis is undertaken throughout the year to identify investment requirements for new loads that wish to connect directly to the NTS and to support the provision of capacity to Distribution Network Operators (DNOs).

Our analysis includes consideration of commercial options available to National Grid to avoid or defer investment and to determine the most economic and efficient outcome. Commercial arrangements can include (but are not limited to) booking of constrained services at LNG storage sites, buyback contracts and interruption contracts.

Following the implementation of Modification Proposal 195AV on April 1st 2009, a number of changes to how requests for Exit Capacity are received and allocated have been implemented. Firm Exit Capacity requests are now made over a 6 year period, rather than 4 years with an indicative 5th year as in the previous Offtake Capacity Statement (OCS) process.

Exit Flat Capacity, Exit Flexibility Capacity and Increased Pressure requests from DNOs for gas years up to and including 2011/12 (the Transitional Period) are received and allocated using the same process as in previous OCS allocations. Requests are allocated based upon network capability, forecast directly connected loads and identified system reinforcements.

For gas years from 2012/13 up to and including 2014/15 (the Enduring period) all users are required to procure firm Exit Flat Capacity should they wish to take gas from the NTS. This means that sites which National Grid has previously contracted as long term interruptible sites have the potential to be firm. This significantly increases National Grid Exit Flat Capacity obligations, especially in constrained areas of the system.

Applications for firm Exit Flat Capacity in the Enduring Period are allocated based on user commitment. If users provide required levels of user commitment then requested levels of Exit Flat Capacity will automatically be released.

As in the Transitional Period, requests for increased levels of Exit Flexibility Capacity and Pressure in the Enduring Period are received via the OCS process. Allocations are based upon levels of Flat Capacity procured by all users, current network infrastructure and planned system reinforcements.

Upon receipt of these requests analysis is undertaken to ensure that network capability complies with the Gas Transporters' Licence obligation to provide transportation capacity consistent with meeting 1 in 20 peak day demand.

5.2 Recent Developments

Long term Entry Capacity auction signals received have broadly confirmed the NTS development picture as set out in recent years. However, revisions to demand forecasts and obligations combined with changes to future third party projects suggest greater flexibility regarding timescales of required projects.

5.2.1 Recently Commissioned Pipelines

The projects completed in 2008 include the pipeline reinforcements and regulator required to support entry capacity from Easington area supplies, which supplement the main East-West transmission capability provided by the trans-Pennine pipeline completed in 2007. Further pipeline projects have been commissioned during 2008 in the South East, to provide additional capacity from the Isle of Grain LNG importation terminal, and in the South to support exit growth in the South West.

In addition to the above projects, the Felindre compressor required for Milford Haven entry flows is substantially complete, however cannot be fully commissioned until sufficient entry flows are delivered through the Milford Haven terminals. These delays may impose additional costs in delivering the Felindre project.

5.2.2 Exit User Commitment Summary

In the Transitional Period, demand for exit capacity is significantly less than amounts requested and allocated in previous years The tables below detail the percentage change between the capacity allocated to each LDZ within the DNs in the 2008 OCS process and the capacity allocated in this year's process. A negative number indicates a reduction in allocated capacity agreed between the NTS and DNOs. The tables compare bookings for the same gas year across the 2008 and 2009 planning cycles.

TABLE 5.2B – Percentage change between exit capacity allocated through the 2008 OCS and 2009 Exit Capacity Allocation processes

LDZ	Flat Capacity					
	09/10	10/11	11/12	12/13	13/14	14/15
Scotland	-5.3%	-5.7%	-6.5%	-5.8%	-7.0%	-7.0%
North	-9.4%	-8.1%	-4.2%	6.5%	6.9%	7.2%
North East	-7.0%	-7.6%	-8.8%	1.4%	1.5%	1.6%
North West	-12.4%	-11.2%	-10.7%	-0.2%	-0.2%	-0.2%
East Anglia	-12.7%	-13.2%	-12.6%	-0.4%	-0.4%	-0.4%
East Midlands	-13.5%	-12.5%	-11.9%	-0.3%	-0.3%	-0.3%
West Midlands	-13.1%	-12.2%	-11.9%	-0.3%	-0.3%	-0.3%
North Thames	-12.2%	-12.9%	-12.6%	0.0%	0.0%	0.0%
Wales North	-15.1%	-14.5%	-13.7%	-0.3%	-0.3%	-0.3%
Wales South	-13.7%	-11.4%	-10.9%	-0.5%	-0.5%	-0.5%
South	-8.1%	-9.0%	-8.7%	-9.7%	-9.7%	-9.7%
South East	-3.1%	-4.1%	-3.8%	-4.7%	-4.7%	-4.7%
South West	-15.5%	-15.6%	-16.2%	-3.9%	-3.9%	-3.9%

LDZ	Flex Capacity					
	09/10	10/11	11/12	12/13	13/14	14/15
Scotland	8.5%	10.5%	-0.8%	6.2%	8.8%	9.1%
North	-23.3%	-20.4%	-16.8%	-11.1%	-8.1%	-5.8%
North East	-62.7%	-63.8%	-42.9%	-38.4%	-36.7%	-34.7%
North West	7.2%	-27.4%	-25.4%	-31.4%	-30.4%	-29.9%
East Anglia	-10.0%	-24.0%	-53.6%	-49.7%	-55.7%	-57.7%
East Midlands	-79.1%	-53.8%	-52.5%	-47.2%	-40.2%	-38.0%
West Midlands*	1987.4%	2140.9%	4061.7%	4012.3%	3964.8%	3939.9%
North Thames	61.3%	36.7%	124.2%	100.0%	100.0%	100.0%
Wales North	n/a	n/a	n/a	n/a	n/a	n/a
Wales South	49.5%	30.3%	15.7%	0.0%	0.0%	0.0%
South	-33.5%	-32.2%	-5.5%	-1.3%	-16.0%	-13.3%
South East	-100.0%	-100.0%	-77.9%	-67.7%	-56.8%	-44.6%
South West	-16.8%	-16.9%	-15.6%	-1.0%	-0.9%	-0.9%

*In absolute terms the changes in the Exit Flexibility Capacity in the West Midlands are not as significant as the % calculation indicates.

TABLE 5.2C – Total Exit Capacity allocated to DNs through the 2009 Exit Capacity Allocation Process

Aggregate DN Allocations	Exit Flat Capacity					
	2009 Exit Capacity Allocation Process					
	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Total (GWh/d)	4150	4200	4559	4997	4993	4994
Change from 2008 OCS	-10.4%	-10.2%	-9.8%	-1.9%	-2.0%	-1.9%

Aggregate DN Allocations	Exit Flexibility Capacity					
	2009 Exit Capacity Allocation Process					
	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Total (GWh/d)	-23.8	-20.6	-11.6	18.0	19.2	20.1
Change from 2008 OCS	-9.9%	-18.5%	-17.0%	-14.4%	-13.4%	-11.3%

It can be seen from the above figures that requests for DN Flat Capacity are significantly lower in the Transitional Period than previously seen. In the Enduring Period however, levels procured are similar to those previously signalled.

All Flat Capacity requests from DNOs have been allocated in full, with all flex requests in the transitional period also being accepted. Requested increases in Flex Capacity in constrained areas of the system were rejected in the enduring period following the receipt of firm Flat Capacity bookings from former interruptible sites in these areas. Other requested increases in Flex Capacity were rejected if they could not be accommodated within the capability of the system whilst maintaining existing entry and exit commitments, or if the release would significantly increase operational costs (for example use of shrinkage gas). The total flexibility allocations are within the 238 GWh/d baseline availability (as specified in National Grid's Gas Transporters Licence in respect of the NTS) which equates to approximately 22 mcm/d, however flexibility may be constrained by physical capability within certain areas of the NTS.

5.2.3 Auction Results Summary

In September 2009, a Quarterly System Entry Capacity (QSEC) auction was held for all existing entry points (ASEPs). The bids received for obligated entry capacity were largely consistent with those received in the 2008 QSEC auctions. This year's auction process also saw the release of 165 GWh/d of Incremental Entry capacity at the Hole House Farm storage facility from October 2011.

Total entry capacity obligations into the future are almost double the peak day demand level, making it difficult to assess long term market behaviour, and subsequent supply flows from auction signals alone. Supply flows onto the NTS are naturally constrained by demand. Even under peak load conditions, high supply flows in one part of the system must be balanced by reductions in supply elsewhere. Low demand conditions pose further issues as entry capacity obligations are invariant through the year.

5.2.4 Planning Consents

The Government's decision not to grant planning consent to the proposed development of an underground storage site at Fleetwood in Lancashire has created uncertainties about the need and timing for delivery of a range of new pipelines in the North West and Yorkshire areas. In February 2009, the developer of this storage facility resubmitted their planning application for the project. At this stage National Grid anticipates that the time required to consider the planning decision will put back the expected site completion date for the Fleetwood development by at least 2 years and has therefore placed the projects that facilitate gas entry from the Fleetwood site under review.

The construction of two LNG import facilities at Milford Haven in South Wales has necessitated the construction of new section's of pipeline and Above Ground Installations (AGI) at intervals on the route to accommodate valves and other essential plant and equipment to support operation of the pipeline. AGIs at Treaddow and at Three Cocks, near Brecon, are now complete, but planning permission was refused for a Pressure Reduction Installation (PRI) at Corse, near Tirley. A PRI in the Tirley area is required for the pipeline to operate at full capacity, and National Grid has now submitted a new planning application for a different site in that locality.

Tewkesbury Borough Council officers are minded to ensure that the best possible development is presented to their Planning Committee members and as such have sought changes to the design or the scheme and further information which has had the effect of extending timescales. We still firmly believe that our planning application and the documentation associated with that application were of a very high standard and more than adequate. However, for the reasons noted above and the attention that this application has received in the local community, the Council has requested the further information. NGG is engaged in an ongoing process with the Council to bring forward an application that as far as possible can positively address the local concerns raised throughout the process. We recognise that the Council must consult with a wide range of concerned parties and must weigh up and reconcile any consultation responses. Whilst this is a time consuming process, NGG believes that such an approach presents the greatest chance of success.

There is no certain or fixed timeline within which the Council will deal with the application and the Council can extend the timetable at any time by requesting further information that it may then need in order to advertise the application to the public. We have tried to minimise any additional time that may be required by submitting a very comprehensive planning package including a detailed site investigation report, but nonetheless it is also essential to respond positively to reasonable requests for further improvements to the proposals. As advised previously, it will take a minimum of 60 weeks to build the installation once planning permission has been granted.

5.2.5 Project Lead times

The default lead times for the delivery of incremental entry capacity are 42 months to reflect planning and construction challenges. A lead time permit scheme has also been introduced for new entry projects. A number of permits are available to National Grid and can be used in order to increase the 42 month lead time or additional permits can be gained by reducing it. This system acts as an incentive to complete projects early, where possible, whilst allowing the flexibility for more challenging projects to be completed over a more suitable timescale. A similar arrangement is in place for exit capacity with a nominal lead time of 38 months rather than 42 months.

5.2.6 Investment Implications

The potential incremental entry flows at the Hole House Farm storage facility have triggered the requirement for a new 3-4km 900mm pipeline between Warmingham and Elworth in 2011. When comparing auction signals at the remaining entry points to our supply sensitivities, there are some points of interest. In particular (and in common with previous auctions) signals at Bacton, St Fergus, Teesside and Theddlethorpe have been limited compared with the potential levels of supply at these entry points. Without clear auction signals, entry capacity at such terminals will be only available up to the baseline level of capacity and so may be constrained below the level of maximum supply potential. The introduction of the Transfer and Trade and Substitution obligations will enable the option for this unsold available capacity to be relocated to other terminals. A review of previous auction signals at Bacton led to the deferral of the Kings Lynn to Wisbech pipeline.

Demand statements pertaining to the requirement for capital reinforcement in the south west indicate that the Wormington to Sapperton pipeline will be required for 2010.

5.2.7 Interruptible to Firm Switching

It is still unclear the full extent of investment that will be required to support a wide ranging switch by customers connected to the Gas Distribution Networks from Interruptible to Firm gas contracts. DNOs have recently held auctions for interruptible capacity within their own networks, however take-up of these products have been variable. Currently, Interruptible customers are not supplied during 1-in-20 peak day or high demand conditions, the switch to Firm contracts will increase NTS capacity requirements during these high demand level conditions. Early indications are that an increase in firm load will drive additional investment in Southern and South Western England. In general, the availability of NTS capacity in Scotland and Northern England appears to suggest that further incremental demand from DNOs should not drive substantial investment although there may be exceptions from this scenario, particularly on pipeline spurs away from the main transmission network. However, the timing of such investment will be affected by external influences on demand growth, such as recessionary factors that could moderate demand.

5.3 Investment Plans and Scenarios

5.3.1 Investment Planning Scenarios

The NTS investment planning process uses scenario analysis as a mechanism for managing uncertainty regarding new gas supplies. This technique ensures that a broad spectrum of potential investments are identified, allowing initial feasibility studies to be focused. These initial studies support the delivery of timely and efficient investment of the NTS as requirements are clarified.

The critical aim of the investment planning process is to ensure that the suite of projects proposed within the 2008 TYS has been exhaustively re-appraised to ensure that investment is made in the most efficient manner possible to meet the overlapping drivers of growth, replacement, entry supply flexibility and environmental efficiency.

As Chapter 4 explained we have considered one base scenario in this year's planning process. Section 5.3.7 discusses potential further investment sensitivities that have been considered around this base case.

5.3.2 Investment Planning

Investment planning analysis has been undertaken to ensure that despite the uncertainty regarding the pattern of supplies – in terms of both volume and location – sufficient gas can be transmitted under a variety of supply scenarios in order to meet both the predicted peak demand and lower levels of demand. Undertaking this analysis at demand levels other than at peak is of importance because of the greater potential for unfavourable supply patterns to create localised constraints. For example, an entry point that maintained a high delivery rate for a sustained period might not be able to rely upon high exit demands in the locality of the entry point to absorb the supplies. This results in more gas having to be transported further through the transmission system. This can create an increased capacity requirement at certain demand levels for some specific locations.

The projects listed in Sections 5.3.3 to 5.3.5 are highlighted on the map of the NTS (Figure 5.4A). The same projects also appear by Local Distribution Zones in Appendix 4.

5.3.3 Projects Approved for Construction in 2010

Map ref.	**Project**	**Scope**	**Driver**
E1	Kirriemuir Compressor Station	New Unit	Emissions Reduction
A	Gilwern Offtake	Uprating for higher pressure	Exit South Wales
B	Wormington to Sapperton Pipeline	44km x 900 mm	Exit South West
C	Easington to Paull	26.2 km x 1200 mm	Entry
D	Cambridge multijunction modifications	Modifications for flexible flow configurations	Entry

5.3.4 Projects Approved for 2011 Onwards

Map Ref.	Project	Scope	Driver
E2	St. Fergus Compressor Station	New Units	Emissions Reduction
E3	Hatton Compressor	New Unit	Emissions Reduction
E	Warmingham to Elworth	3-4km x 900mm	Entry
F	Hatton Compressor	Modifications for higher flows	Entry

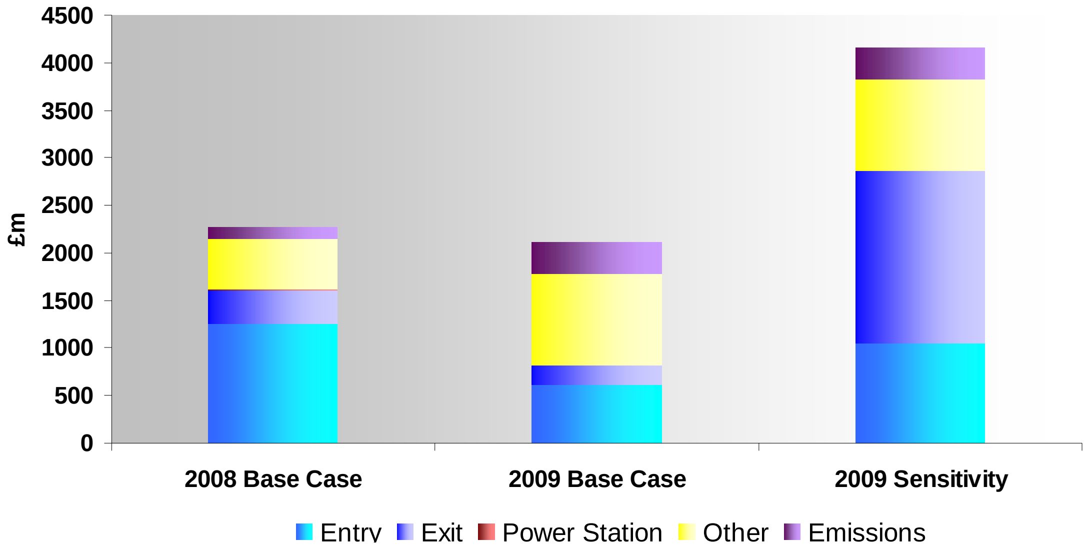
5.3.5 Projects Under Review

Map ref.	**Project**	**Scope**
G	Warburton to Cheshire to Audley	49 km x 1200 mm
H	Wormington to Honeybourne Pipeline	11 km x 900 mm
I	Warrington Compressor	Modifications for higher flows
J	Goxhill to Hatton Pipeline	63 km x 1200 mm
K	Paull to Goxhill Pipeline	6.4km x 1200 mm
L	Kings Lynn to Wisbech	33km x 1200mm
M	Sapperton To Easton Grey	16.7Km x 600mm

5.3.6 Investment in Forecast Period

The chart below shows the investments associated with our Base Case forecast compared with our latest assessment of potential investment over the forecast period.

FIGURE 5.3A – Forecast Spend by Investment Category for the 2009 Base case and entry and exit investment sensitivities over the same period (Real Prices)
Source – National Grid



2009 Base Case

In the 'base case' figures above, 'Entry' relates to approved investment currently being undertaken to meet entry auction signals and the base forecast levels of supply over the period. 'Exit' relates to growth investment consistent with the obligations placed on National Grid under its Gas Transporters' licence to meet capacity requirements of the 1 in 20 peak day criteria. This considers the commitments made under the exit capacity allocation processes, contracted loads and forecast directly connected loads over the period. 'Power Station' investment accounts for the large one-off connections to the NTS. 'Other' investment includes 'non-load' related asset enhancement and the replacement of assets that have reached the end of their economic life. 'Emissions' is the investment forecast to comply with environmental legislation to reduce pollutants.

The general base level of entry and exit investment over this next period is forecast to decrease as the main construction activities associated with Milford Haven and the Trans-Pennine link were completed in 2008. Similarly, the forecast exit investment has reduced due to the completion of the major pipeline works associated with the two large new Power Station connections at Langage and Marchwood. Further reinforcement of the NTS may be required to support large new power stations should signals be received from users under the commercial arrangements for releasing additional NTS exit capacity. Such projects will be included in our Base Case when firm commitments are made to underpin capacity release.

There is an increase in projected non-load related investment ('other') required for asset enhancement and replacement over the plan period associated with the ageing profile of the existing plant base.

Work is in the latter stages to deliver the first emission reduction driver schemes at St Fergus and Kirriemuir and similar additional investment at Hatton is also currently under construction. A further programme of emissions reduction investment is planned at the next priority sites.

2009 Sensitivity

There exists a significant uncertainty relating to exit and entry developments (and associated investment requirements) in the latter half of the 10 year period considered. The '2009 Sensitivity' shown in Figure 5.3A considers the potential impact of this uncertainty on investment requirements.

With LCPD requirements, amongst other factors, National Grid has seen a recent upturn in CCGTs connection enquiries to the NTS. Whilst the 'base case' forecasts include a selection of new CCGT plants to meet future generation requirements, system investment is sensitive to the location of any new plants which materialise. Should any of the potential new connections or loads materialise in the constrained South East, Southern or South West areas of the system then it is likely further system investment will be required.

With the changes to interruption arrangements under the enduring exit regime increased exit capacity obligations also exist. Should this facilitate a change in behaviour of traditionally interruptible sites, currently situated in the constrained areas described above, then further investment may also need to be considered.

This change to the enduring exit regime also affects the exit capacity arrangements for other large traditional interruptible loads such as storage facilities and the UK Interconnector. This coupled with the significant number of enquiries received for new large storage facilities both onshore, in the North West and Southern areas of the system, and offshore, connecting to the Bacton and Barrow terminals, could see a shift in system usage. Investment may then be required to accommodate large scale storage filling requirements at times of concurrent high system demand.

The new storage developments described above, along with new LNG importation projects, may also trigger additional new entry investment requirements.

The above provides a significant potential upside to exit and entry investment compared to the '2009 Base Case' and is shown within the '2009 sensitivity'.

5.3.7 Analysis of Investment Scenarios

Chapter 4 discussed the uncertainties in future supply mix that arise from both potential new developments and from existing or 'under development' supplies that are in aggregate capable of exceeding most peak demand scenarios. These uncertainties are exacerbated to a certain extent by Gas Transporters Licence requirements for National Grid to make obligated capacity available to shippers up to and including the gas flow day. This creates a situation where National Grid is unable to take long term auctions as the definitive signal from shippers about their intentions to flow gas on any particular day.

National Grid continues to develop its processes to better manage the risks that arise from such uncertainties. The approach applied is described further in the Transmission Planning Code and considers range of sensitivities around the Base Case, as well as the obligations placed on National Grid to release capacity to shippers.

Entry points are grouped into zones to develop understanding of entry capability at different ASEPs (Figure 5.3B). The entry points contained within each zone will tend to make use of common sections of infrastructure to transport gas from entry to market, and therefore have a high degree of interaction. However, there remain key interactions between supplies in different zones which mean that interactions between key supplies must also be determined when undertaking entry capability analysis. Examples are the interactions between Teesside and Easington, or Easington and Bacton entry points.

The zonal groupings considered are:

- South East – includes Bacton and Grain, both use common infrastructure away from the Bacton area.
- Easington area – includes Easington, Rough, Aldbrough, Hornsea and Caythorpe, all use common routes out of the Yorkshire area.
- Northern Triangle – includes St Fergus, Teesside and Barrow, all of these northern supplies need to be transported down either the East or West coast of England to get to market.
- West UK – this zone enables sensitivity analysis around potential supplies from Milford Haven.
- North West Corridor – includes storage at Fleetwood and Cheshire.

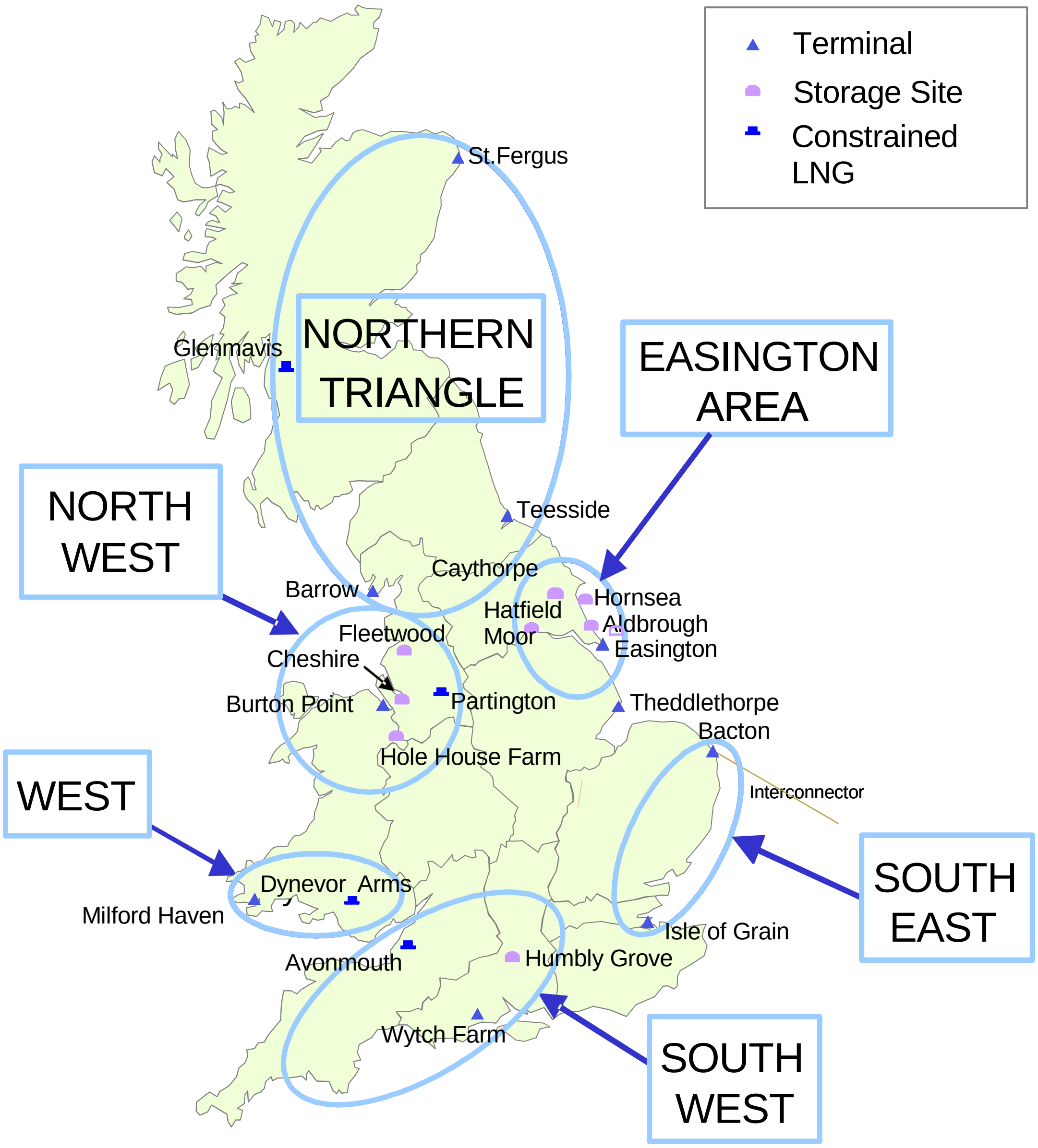
An example of this approach is that the analysis of the Northern Triangle could consider higher flows from the St. Fergus and Teesside entry supplies whilst reducing the other supplies to create a demand balance for the day being considered.

Future flow patterns on the network may necessitate new projects to increase capability where large new entry points connect to the system and manage flow patterns in the central part of the system. These projects are dependent on signals received through the long term entry capacity auctions, and their timing may be affected by the use of substitution to move unsold capacity between entry points. It is unlikely that substitution will remove the need for investment in the system in the long term, but may delay a small number of projects where anticipated flows are capped by obligated capacity levels over a period until incremental entry capacity is re-signalled by shippers. As flow patterns become less predictable and as large new entry and exit points connect to the system, further investment is anticipated in the central parts of the network. Key scenarios examined through the investment planning process include:

- High North-South flow patterns, generated by increased entry flows in the North West and mid-East Coast areas travelling down each side of the system to meet demand in the Midlands and South/South East.
- High South-North flows along the east side of the system, generated by large entry flows around the mid-East Coast being displaced northwards and westwards by increased South East flows
- High cross-system flows created by high East-West and West-East flow patterns, for example due to High North West flows or due to high South East flows.

Further load growth in the southern parts of the NTS will also necessitate investment for exit from the system.

FIGURE 5.3B – Zonal Evaluation of Investment Requirements
Source – National Grid



5.3.8 Longer term projects under consideration.

Longer term NTS projects (i.e. those after 2011) that are being considered to provide capacity beyond the requirements of medium term supply patterns include:

- Reinforcement of the feeder to the South West to facilitate increased exit requirements and to industrial users.
- Further reinforcement in southern England to facilitate Interruptible to Firm switching.
- Reinforcement in the West Midlands area to mitigate changing supply patterns that could result in lower pressures arising from an increasing tendency to push gas northwards from South Wales and the South East into the Midlands.
- Further reinforcement in the Easington area to accommodate changing supply patterns.
- Further reinforcement in the North West area for potential new supplies.
- No new specific reinforcement has been identified for incremental entry capacity that might come on stream after 2011.

The timing of such projects will, in part be dependent on the effect of entry capacity substitution but will be mainly influenced by the ability of shippers to generate auction signals and developers, shippers and DNOs to provide commitment on exit capacity through the entry and exit commercial processes. It is expected that the current economic climate will contribute to delaying the development of new infrastructure connecting to the NTS, adding to the uncertainty of NTS supply and demand patterns into the future.

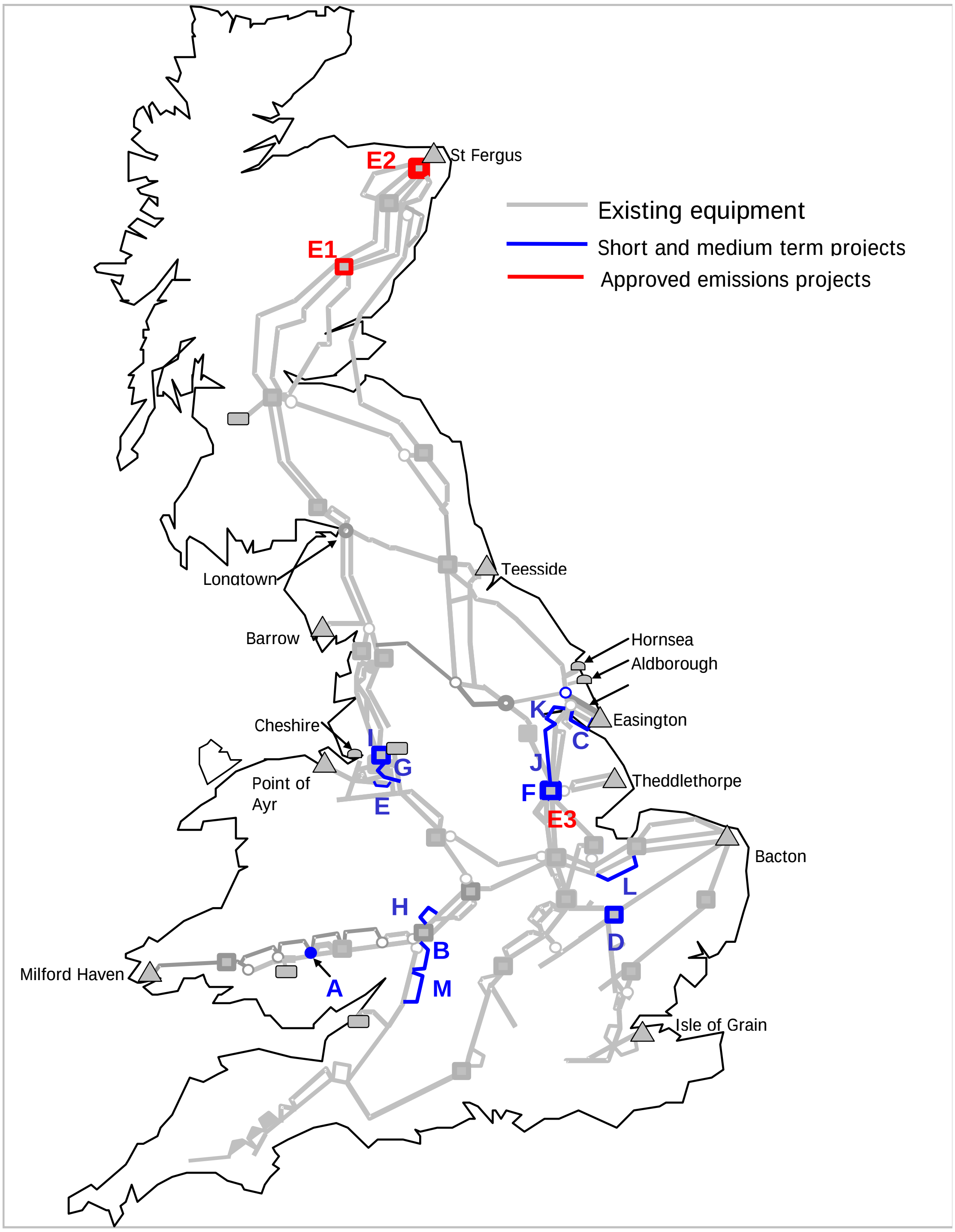
5.3.9 Emissions related investment

Significant ongoing investment on the gas turbine compressor fleet is required to reduce emissions and comply with the Pollution Prevention and Control (PPC) Regulations 2000. Emissions are regulated by the Environment Agency (EA) in England and Wales and the Scottish Environment Protection Agency (SEPA) in Scotland.

Prioritisation of compressor sites at which to invest has been agreed with the environmental regulators and is subject to annual review to ensure those sites with the highest emissions are targeted, taking into account anticipated supply pattern changes into the future and associated compressor utilisation projections. This approach is to ensure the largest reduction in fleet emissions is realised for the available investment expenditure. At present the expectation is that Peterborough would be the next candidate site for emissions investment.

5.4 NTS Projects Map

FIGURE 5.4A – NTS Projects Completed, Approved & Under Consideration
Source – National Grid



5.5 The Planning Act 2008

National Grid strongly supports the changes to the planning system that were introduced by the Planning Act 2008 and believe that the establishment of a single consenting regime will streamline the planning system to provide greater certainty, efficiency and consistency for all whilst ensuring the quality of decision-making, including appropriate community and stakeholder involvement, is improved.

In particular we support the inclusion of statutory requirements for pre-application consultation. In seeking to develop best practice, our experience has demonstrated that pre-application consultation, using a range of methods to help people better understand our proposals and solicit their views (for example, using 3D virtual modelling in some cases to demonstrate what developments would really look like), is fundamental to ensuring effective community engagement, ultimately contributing towards the successful granting of consent for projects. This, coupled with definitive timescales for consultation responses for the formal consultation stages of the planning process, should provide greater certainty for all and more timely delivery of nationally significant energy projects.

Our pipeline planning processes have been modified to take into account the requirements of the Planning Act 2008 and seek to apply best practice during the consultation phase. This new process is being trialled on the recently approved Warmingham to Elworth pipeline. Lessons learnt will then enable our planning processes to be modified and applied to future pipelines.

Chapter Six

Commercial Developments

6.1 Overview

A number of initiatives have been developed during this year and where applicable will be further developed over the coming year. The major areas of commercial developments are:

- NTS Offtake Reform
- Transmission Price Control Review Changes
    - Introduction of the Enduring Transfers and Trades process
    - NTS Entry Capacity Substitution
    - NTS Exit Capacity Substitution
- Transmission Charging
- QSEC and AMSEC Auction Movement
- Force Majeure
- NTS Capacity User Commitment Proposals
- Flow Weighted Average Calorific Value
- European Developments
- System Flexibility

6.2 NTS Offtake Reform

In 2005 Ofgem announced its decision to delay the introduction of enduring exit reform by two years and so a UNC Modification Proposal was raised (0046) which reflected this delay and also introduced transitional arrangements to the Uniform Network Code that formalised the arrangements between Distribution Network Operators and National Grid Gas NTS. This enabled Distribution Network Operators to agree with National Grid Gas NTS their flat and flexibility capacity and pressure requirements for the duration of the transitional exit period.

National Grid Gas NTS raised Modification Proposal 0116 "Reform of the NTS Offtake Arrangements" in September 2006 in order to facilitate NTS Offtake reform, which proposed the release of separate flat and flexibility capacity products during July 2007 for use from 1st October 2010 onwards.

National Grid Gas NTS subsequently varied the original 0116 Modification Proposal in November 2006 to 0116V and a number of industry parties raised alternative proposals to 0116V (0116A, 0116BV, 0116CVV & 0116VD). The Authority directed on the 5th April 2007 that 0116V should be implemented with effect from 1st April 2008[20] i.e. that the transitional arrangements should apply for an additional year. Therefore a further Modification Proposal (0142) was introduced to extend the transitional exit period for an additional year to cover 2010/11.

[20] Notice of implementation of 0116V was subsequently removed following the Competition Commission appeal.

An appeal under the Energy Act 2004 in relation to energy code modifications and the GEMA decision to implement new NTS Offtake arrangements was made by E.ON UK and upheld by the Competition Commission. Ofgem subsequently announced in February 2008 that they would reconsider all five UNC Modification Proposals. Given that this process would not be complete before April 2008 (when the transitional arrangements were due to end), National Grid Gas NTS raised proposal 0198 seeking to extend the transitional arrangements for one further year.

In the meantime a UNC Review Group was initiated (0166) and as a result of the industry meetings held in relation to this Review Group Proposal, two further UNC Modification Proposals, 0195 "Introduction of Enduring NTS Exit Capacity Arrangements" and 0195AV "Introduction of Enduring NTS Exit Capacity Arrangements", were raised. Ofgem stated that they would consider these two new proposals alongside the existing five.

Ofgem announced on 1st December 2008 that the authority (GEMA) had approved the implementation of 0195AV but that subsequently an issue had arisen with the 0195AV legal text in that it did not accurately reflect the proposal. Revised legal text was submitted to an emergency UNC Modification Panel meeting on 4th December 2008 that corrected the issue. The Modification Panel directed that the proposal be re-consulted on in order to ensure that all affected parties were satisfied that the legal text revision was appropriate. The outcome of the consultation was referred back to Ofgem before 24th December 2008 and a decision to implement Modification Proposal 0195AV effective from 1st April 2009 for NTS Exit (Flat) Capacity applicable bookings from 1st October 2012, was made on 19st January 2009.

The initialisation processes and first July applications have been held successfully, with Users being informed of both their initialised quantities and their allocated quantities of Enduring Annual NTS Exit (Flat) Capacity for October 2012 onwards.

6.3 Transmission Price Control Review Changes

6.3.1 NTS Entry Capacity Transfers and Trades

In the 2007-2012 price control review Ofgem placed an obligation on National Grid Gas NTS to facilitate the transfer of unsold obligated entry capacity and the trade of sold firm entry capacity between entry points. In order to facilitate this obligation a number of Modification Proposals were developed, culminating in proposal 0169 and the associated Trade and Transfer Methodology Statement being approved in September 2007. This proposal introduced temporary trade and transfer arrangements, with a Transfer and Trade auction being held in October 2007, allocating capacity for the period November 2007 to March 2008.

National Grid Gas NTS then set about developing permanent arrangements through a series of industry workshops. UNC proposal 0187A was subsequently approved on 23rd April 2008 and implemented from 1st June 2008. The implementation of proposal 0187A incorporated the trade and transfer mechanism into the existing monthly RMSEC auction (now RMTNTSEC); which again allowed Users to surrender any previously acquired capacity that they no longer required prior to the RMTNTSEC auction and then be used to, along with any available unsold NTS Entry Capacity, to satisfy capacity requests within the RMTNTSEC auction process. NTS Entry Capacity requests at an ASEP will be initially satisfied by unsold and surrendered NTS Entry Capacity at that ASEP with any unsatisfied NTS Entry Capacity requests then being satisfied by moving (Transfer and Trade) any remaining unsold NTS Entry Capacity and surrendered NTS Entry Capacity between ASEPs.

Whilst this process has operated successfully since August 2008 it was facilitated by a number of offline processes. A full system solution was implemented in May 2009.

6.3.2 NTS Entry Capacity Substitution

In the 2007-12 Price Control Review Ofgem has introduced an obligation for National Grid Gas NTS to undertake entry capacity substitution. Under this obligation unsold non-incremental obligated entry capacity at entry points can be substituted to other entry points where incremental obligated entry capacity is required to be released. National Grid Gas NTS will seek to substitute entry capacity before releasing funded incremental obligated entry capacity at the entry point.

This obligation has been established to encourage National Grid Gas NTS to make efficient use of the existing network infrastructure prior to undertaking any further investment in the network. National Grid Gas NTS has been working with the industry and Ofgem to identify the most appropriate way to introduce entry capacity substitution.

National Grid Gas NTS has submitted its proposed NTS Entry Capacity Substitution Methodology Statement to the Authority for approval. Along with the methodology statement, UNC modification proposal 0265 has been raised and a change to the Transmission Transportation Charging Methodology proposed.

To address concerns raised by some Shippers not all unsold non-incremental obligated entry capacity will be available for substitution. The methodology allows Shippers to buy a “retainer” in respect of unsold non-incremental obligated entry capacity. This retainer will exclude the retained entry capacity from potential substitution for the next 12 months. This process allows Shippers that have projects in development, but cannot commit to buying entry capacity, to ensure that capacity remains at the original ASEP at a lower cost than to buy the capacity. UNC modification proposal 0265 and the proposed change to the Transmission Transportation Charging Methodology facilitate retainer charges.

The Authority has approved the Gas Entry Capacity Substitution Methodology Statement and it is anticipated that it will publish its decision on the Modification Proposal and the Charging Methodology towards the end of 2009 such that substitution will be effective from the QSEC auction to be held in March 2010.

6.3.3 NTS Exit Capacity Substitution

Ofgem introduced an obligation for National Grid Gas NTS to undertake NTS Exit Capacity Substitution in the 2007-12 Price Control Review. NTS Exit Capacity Substitution would only apply to Exit Capacity from 01 October 2012 onwards i.e. the enduring period. National Grid Gas NTS has a licence obligation to submit an Exit Capacity Substitution Methodology Statement to the Authority by 4th January 2011. Workshops will be held with the Industry to discuss the most appropriate way to introduce this obligation. National Grid Gas NTS published a timetable in December 2009 for future NTS Exit Capacity Substitution workshops.

6.4 Transmission Charging

The Gas Transmission Charging Methodologies Forum ("Gas TCMF") is the industry forum that reviews gas transmission charging arrangements.

One of the key areas for review has been the methodology by which NTS Exit Capacity prices will be determined with changes having been implemented in March 2009 for the setting of NTS Exit (Flat) Capacity charges from 1^{st} October 2012 post exit reform. Changes have also been made from 2009 in regard to the setting of Constrained LNG credits, the source of supply and demand data used for calculating both entry and exit capacity prices, and the minimum reserve prices applied in the long term entry capacity auctions.

Charging changes have also been consulted on in relation to proposed changes in NTS Entry Capacity User Commitment arrangements (see section 6.7) to facilitate drawing down on the credit put in place, and the proposed entry capacity substitution methodology (see section 6.3.2) to introduce the retainer charge.

During 2009, National Grid Gas NTS has launched a fundamental review of entry charging principles. This is in response to growing industry concern about the increasing rate of the TO entry commodity charge. National Grid Gas NTS has started to analyse the existing and potential future entry capacity procurement and anticipates developing charging proposals with the industry in 2010.

The Gas TCMF has continued to review all aspects of the NTS Entry and Exit Charging arrangements with initiatives having been implemented to seek to provide greater transparency with regard to charge setting, including holding a number of industry workshops. Supporting information is available in the Gas Charging area of the National Grid Gas NTS website including a range of reports and presentation material along with details of how to obtain a copy of the Transportation Model used for determining NTS Entry and Exit capacity prices.

6.5 QSEC and AMSEC Auction Movement

In October 2008 National Grid Gas NTS raised Modification Proposal 0230. This Proposal sought to permanently amend the periods in which Quarterly and Monthly NTS Entry Capacity are offered for sale. It was proposed that National Grid Gas NTS held the QSEC auction between 1^{st} March and 31^{st} March (inclusive) instead of 1^{st} September and 30^{th} September (inclusive); and the AMSEC auction would be held between 1^{st} June and 30^{th} June (inclusive) instead of 1^{st} February and 29^{th} February (inclusive). The timetable of auctions within the Modification proposal meant that there would have been an 18 month gap between the QSEC auctions.

National Grid Gas NTS argued that it would be beneficial if the QSEC auction were moved to March, which would result in Incremental NTS Entry Capacity being released from 01 October leading to capacity being released at the start of the winter period. The AMSEC auction movement to June would avoid the two auction processes overlapping and ensure that both auctions are consistent and release capacity from 1^{st} October. The proposed implementation date was 1^{st} April 2009, with the first AMSEC auction to take place June 2009 and the first QSEC auction proposed to take place in March 2010.

Modification Proposal 0230A was raised (and subsequently varied, 0230AV) by E.ON to change the proposed auction processes so that the QSEC auction would be held between 1^{st} March and 31 March (inclusive) instead of 1^{st} September and 30^{th} September (inclusive) to apply from 1st March 2010. This Modification Proposal was raised to ensure there was not an 18 month gap between the QSEC auctions. In addition the AMSEC auction would continue to be held between 1st February and 29th February (inclusive) but offer capacity for an 18 month period rather than 24 months. It was argued that Modification Proposal 0230 restricted User's ability for long-term entry capacity as the 18 month period between QSEC auctions to bid for long-term capacity was too long.

The following long-term entry capacity auction structure from Modification Proposal 0230AV was implemented in May 2009:

- February 2009 AMSEC (as per current UNC arrangements)
- September 2009 QSEC (as per current UNC arrangements)
- February 2010 AMSEC (and annually, thereafter with an 18 month transaction period)
- March 2010 QSEC (and annually, thereafter)

To clarify, National Grid Gas NTS held a QSEC auction in September 2009 and will hold another QSEC auction between 1st March and 31st March 2010 (inclusive) and between 1st March and 31st March each year. The AMSEC auction will continue to be held between 1st February and 29th February (inclusive) but the capacity period offered for release in the AMSEC auction will be for an 18 month period.

6.6 Force Majeure

National Grid Gas NTS raised Modification Proposal 0262 in August 2009. This Proposal seeks to provide clarity with respect to the treatment of NTS Entry and Exit Capacity where a Force Majeure has been called at either an ASEP or an NTS Exit Point. This Modification proposes that Users registered as holding firm capacity (quarterly, monthly capacity at an ASEP and Annual NTS Exit (Flat) Capacity at an NTS Exit Point) will receive a force majeure rebate. The Authority are considering this proposal and a decision was anticipated in December 2009.

6.7 NTS Capacity User Commitment Proposals

UNC Review Group 0221 was established in September 2008 to assess whether or not the current credit arrangements, in place for securing Shipper User holdings of long term NTS Entry Capacity, were sufficiently robust and provide the correct balance of risk between various Shipper Users. Modification Proposal 0246 "Quarterly NTS Entry Capacity User Commitment" was raised by National Grid Gas NTS as a consequence of discussions within Review Group 0221 and is currently with Ofgem for direction. Proposal 0246, if implemented, would remove, what the Review Group agreed was, an inappropriate length of time between Shipper Users being allocated capacity in a QSEC auction and them committing financially to the capacity acquired. The proposal would also enhance the current regime by removing the ability for Users to defer their Quarterly NTS Entry Capacity commitments.

EDF Energy (0246A) and British Gas Trading (0246B) have raised alternative Modification Proposals. All three proposals were submitted to Ofgem in May 2009, Ofgem is conducting an Impact Assessment and a decision is expected later this year. Implementation of any of these proposals would lead to changes to the credit security arrangements related to QSEC Capacity holdings, which would in turn affect the operation of future QSEC auctions.

The aforementioned ability for Shipper Users to currently defer their Entry Capacity commitment also applies at NTS Exit Points. National Grid Gas NTS raised Modification Proposal 0261 “Annual NTS Exit (Flat) Capacity Credit Arrangements” to remove this current ability for the User’s to defer their Annual NTS Exit (Flat) Capacity. This proposal was approved by Ofgem on 9th December 2009 and will be implemented from 1st January 2010.

6.8 Flow Weighted Average Calorific Value (FWACV)

The UK’s move toward greater diversity of supplies and the development of new types of supplies may lead to a greater propensity for CV capping effects through the current application of The Gas (Calculation of Thermal Energy) Regulations 1996 (as amended in 1997), thereby potentially resulting in increased levels of energy that cannot be billed to end consumers. In April 2009 National Grid Gas NTS raised UNC Review Proposal 0251 “Review of the Determination of Daily Calorific Values” in order to:

- review the existing Flow Weighted Average CV and CV shrinkage arrangements;
- consider the issues which impact on the accuracy of the FWACV methodology when comparing actual energy delivered to the system against that which is billed to gas consumers;
- develop potential solutions to resolve any issues identified;
- if necessary, explore the process for amendment to the Regulations; and
- develop relevant amendments to the Regulations and UNC to deliver any proposed changes to the current arrangements.

Management of low CV supplies such as bio methane has been the main topic of discussion within the Review Group and at the time of writing, the group was scheduled to meet again to agree its recommendations.

6.9 European Developments

In September 2009 the European Commission’s “Third Package” of legislative proposals for gas and electricity entered into force, becoming applicable from 1st March 2011. They outline a new energy framework to better enable progress towards liberalised and open European markets. The package implements new rules on EU Transmission companies which include the promotion of ownership unbundling, alongside restrictions on ownership of Transmission companies by non EU entities.

Another key facet is the establishment of a European Network of Transmission System Operators for Gas (ENTSOG). European Transmission companies, certified under the third package, will have a formal obligation to cooperate via ENTSOG. This cooperation will eventually manifest itself in ENTSOG having a formal advisory role with the Commission, the drafting of at least 11 potentially binding European Network codes, production of annual European winter and summer supply outlooks and a bi-annual European Ten Year Network Development Plan. ENTSOG was founded on 1st December 2009 and that National Grid will be amongst the founding members.

GTE+, the organisation formed by Gas Transmission Europe (GTE) to facilitate the transition between the non binding cooperation of GTE and the binding goals of ENTSOG, has committed to producing its first European Ten Year Network Development Plan by the end of

2009. This was the final stage of a three stage approach, which incorporated first capacity, then demand and capacity and finally, demand, supply and capacity to give an overall European Ten Year Network Development Plan as foreseen in the “Third Package”. [For more information see www.entsog.eu.]

6.10 System Flexibility

Changes in gas fired generation behaviour resulting from increased wind powered electricity generation to support renewable targets driven by regime developments and types of connectees may potentially cause greater volatility in gas flows and hence require a more flexible system to accommodate them. Examples of these include:

- increased wind powered electricity generation to support renewable targets;
- flexible offtake profiles;
- increased LNG importation; and
- evolving interconnector, storage and supply behaviour.

The magnitude and materiality of these developments is uncertain, however, National Grid Gas NTS are keen to investigate the potential impact of these changes before they occur. In order to understand the potential impacts, the following need to be considered: what data / information should be analysed; what timescales should be monitored for trends and what trends would be a cause for concern.

Following an initial industry workshop in June 2009, National Grid Gas NTS presented in November 2009 to the industry the proposed data indicators in order to gauge whether system usage patterns are changing sufficiently to warrant future regime change. The proposals generated useful debate and feedback and National Grid Gas NTS will consider the points that have been raised before finalising, and subsequently collating and presenting on, the indicators early in 2010. An Ofgem consultation on the topic is also anticipated.

Chapter Seven

Long Term Energy & Environmental Targets

7.1 Overview of Targets

The UK Government has set two key environmental targets relating to renewable energy and green house gas emissions (GHGs):

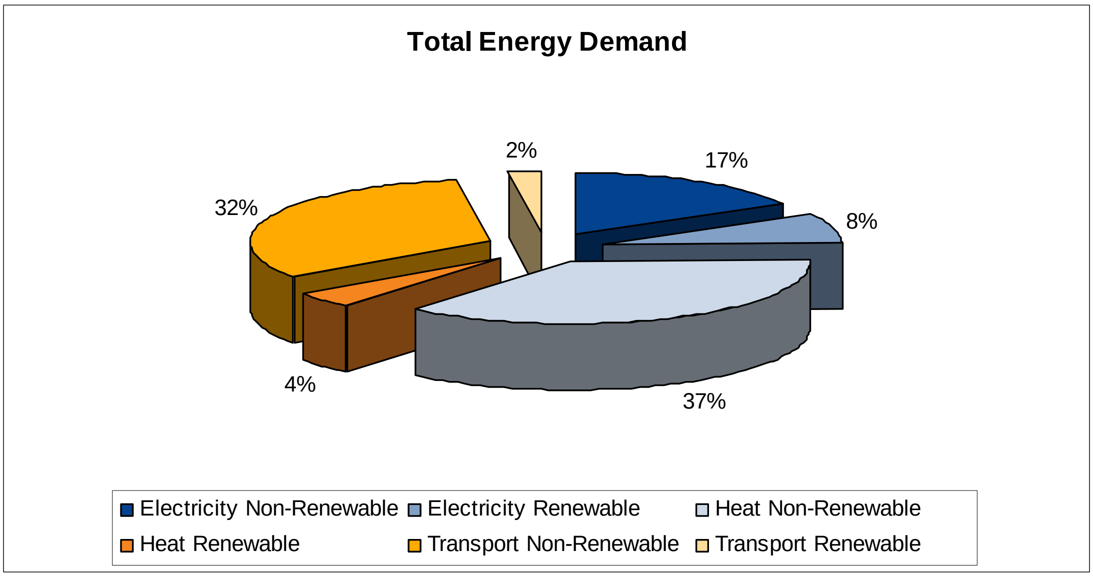
1. The first of these targets is part of the EU's integrated energy/climate change proposal that addresses the issues of energy supply and climate change and in doing so sets a target of 20% of European energy (including electricity, heat & transport) to come from renewable sources by 2020. The UK contribution to this target is 15% which is lower than the European wide average due to the UK's low starting point (2% compared to EU average of 9%); however, the UK has the largest increase of any country due to it's low starting point, economic strength and it's high potential for renewable generation i.e. significant wind, wave and tidal resource.
2. The second target, which follows the principles of the overall EU 20/20/20 vision (20% of energy from renewable sources along with a 20% reduction in GHG emissions and 20% improvement in energy efficiency by 2020) but goes even further, has been incorporated in the recent Climate Change Bill and sets a target of 80% reduction in GHGs from the 1990 levels by 2050.

Clearly the size of this challenge means significant changes in Government and regulatory policies coupled with increased incentives to help facilitate the construction of necessary infrastructure and maximise energy efficiency measures. These changes will need to ensure the access regime delivers the timely connection of new renewable and low carbon sources of generation some of which may well need to be connected ahead of associated network reinforcement.

7.2 2020 Scenarios

Our base case or "business as usual" forecast described in this document only reaches around half of the renewable sources required by 2020. Consequently, we have been developing a range of holistic energy scenarios to inform our understanding of the priorities across all sectors e.g. electricity, heat and transport. There is, of course, more than one way of apportioning the relative contribution to the target across the three sectors. In developing our energy scenario for 2020, we have focussed on the strategic priorities of saving energy and electricity decarbonisation, which represent the most economic and efficient hierarchy of measures as no other sectors offer such huge near term potential combined with a mature and economic technology platform. In both the heat and transport sectors, in which carbon mitigation technologies can be relatively expensive, we have suggested those solutions which seem to us to be appropriate and economic in their own context, for example, advocating the introduction of high efficiency boilers and insulation measures, rather than heat pumps (which are better suited to new properties), in much of the existing housing stock. The result of this analysis is reflected in Figure 7.1A.

FIGURE 7.1A - Total Energy Demand in 2020
Source: National Grid



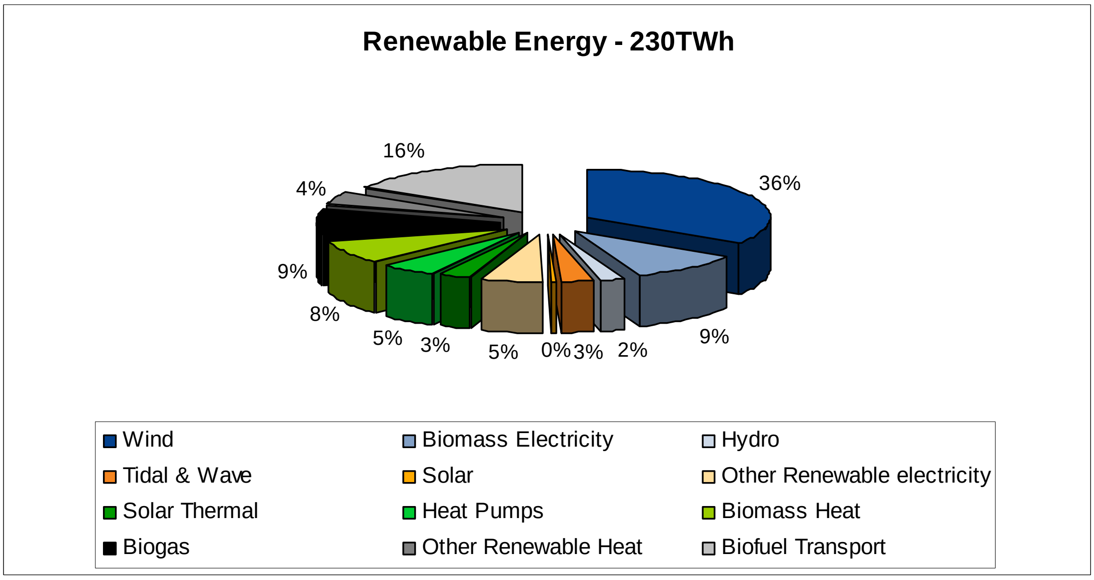
We have also assessed, at high-level, the plausibility of delivering the required volumes of different renewable energy technologies, by reviewing potential installation rates and the experience elsewhere around the world. The scenario is certainly plausible but achieving the required levels of different (and often emerging) technologies represents a significant challenge.

The scenario that we have developed assumes that the whole of our renewable energy target is met domestically. In addition it incorporates changes agreed to the elements of the target since the original Government's "UK Renewable Energy Strategy" (RES) document was published e.g. a limit to aviation demand and electric transport counting towards the biofuel target. Hence our scenario is directly comparable to that incorporated in the Government's updated "UK Renewable Energy Strategy" and "UK Low Carbon Transition Plan" published in July 2009.

A breakdown of the contribution from the different renewable technologies in our scenario is shown in Figure 7.1B.

FIGURE 7.1B – Breakdown of Renewable Energy in 2020

Source: National Grid



Under the EU's 2020 target, renewable electricity's share of overall electricity demand has to be in the range 30%-36%, assuming only some contribution from heat and transport, to achieve the overall renewable share of energy i.e. electricity has the largest burden. Our scenario assumes 32% of electricity will come from renewable sources (mostly wind and biomass) with heat providing 10% (mostly biomass and heat pumps) and transport 7% (biofuel). This compares to the updated RES levels of 30% for electricity, 12% for heat and 10% for transport.

Obviously there will be a number of alternative ways to deliver the target which will involve less renewable generation but these scenarios would require significant behavioural change to increase the renewables share of heat (e.g. heat pumps) and transport (e.g. biofuel and electric cars) along with high levels of energy efficiency. We are continuing to progress work which examines the potential for biogas injection into existing pipelines, and there may be greater potential for this than is reflected in the chart above.

Given the importance of natural gas in heating and clean power generation for many decades to come, we are also developing our view on how our gas network will evolve and considering the development of carbon networks. We will also continue to monitor the wholesale gas markets and facilitate industry understanding of the availability of gas in the coming decades.

During this document we have highlighted the potential impact on gas demand and the energy mix that meeting the dual environmental targets might have when compared to our BAU forecast. Clearly to achieve these targets an alternative set of investments will be required compared to our BAU list and should therefore be considered in that light and will be achievable given the correct market arrangements, policies and investment funding/support.

7.3 Indicative Reinforcements to meet Environmental Targets

In June 2008, the Government published its consultation on a UK Renewable Energy Strategy. Following on from this, the Electricity Networks Strategy Group (ENSG), a cross industry group jointly chaired by the Department of Energy and Climate Change and Ofgem, asked the three electricity GB Transmission Licensees, National Grid, Scottish Hydro Electric Transmission and Scottish Power Transmission with the support of an Industry Working Group to take forward a study to:

1. Develop electricity generation and demand scenarios consistent with the EU target for 15% of the UK's energy to be produced from renewable sources by 2020 (this scenario was developed in the second half of 2008 and has subsequently been updated, as shown above, however, the small changes to the progress of wind, predominately offshore, will have no material affect on the results of the ENSG work).
2. Identify and evaluate a range of potential electricity transmission network solutions that would be required to accommodate these scenarios.

In July 2009, ENSG published a report 'Our Electricity Transmission Network: A Vision For 2020': http://www.ensg.gov.uk/assets/ensg_transmission_pwg_full_report_final_issue_1.pdf which discharged the action placed on the Transmission Licensees. The reinforcements identified in this report are based on a range of scenarios that take account of the significant changes anticipated in the generation mix between now and 2020. In particular, the scenarios examined the potential transmission investments with the connection of large volumes of onshore and offshore wind generation required to meet the 2020 renewables target, whilst, at the same time, facilitating the connection of other essential new generation, such as new nuclear that will be needed to reduce carbon emissions and maintain continued security of supply.

The study concluded that, provided the identified reinforcements are taken forward in a timely manner, they can be delivered to required timescales. It should also be noted that the reinforcements identified in this report are designed to facilitate connection of a large volume of different types of generation in a given area, not dependent on a single generation project proceeding, and where the lead time for the combined transmission reinforcements in a given area would exceed the time taken to construct the generation, i.e. lack of transmission capacity would have a potential negative impact in meeting renewable targets and/or accommodating generation required to maintain continued security of supply.

The development of the potential reinforcements are phased to achieve a 2020 delivery date with the initial phase being delivered in 2015 based on the prospective growth of renewables in each region. It is recognised that there will continue to be a degree of uncertainty about the volume and timing of generation growth in any given area. It is therefore proposed to continue to monitor the development of the market and update the scenarios accordingly. The proposed transmission reinforcements will be developed in such a manner as to ensure that the options are maintained at minimum costs. By undertaking pre-construction engineering work, the delivery of each project can be positioned such that construction can be commenced when there is sufficient confidence that the proposed reinforcements will be required. This is the least regrets solution, i.e. the minimum commitment to secure the ability to deliver to required timescales.

Following Ofgem initial consultation phase on strategic investments, funds have been made available to undertake the 2009/10 pre-construction engineering for reinforcements identified by the study and these are being developed without requirements for user commitment.

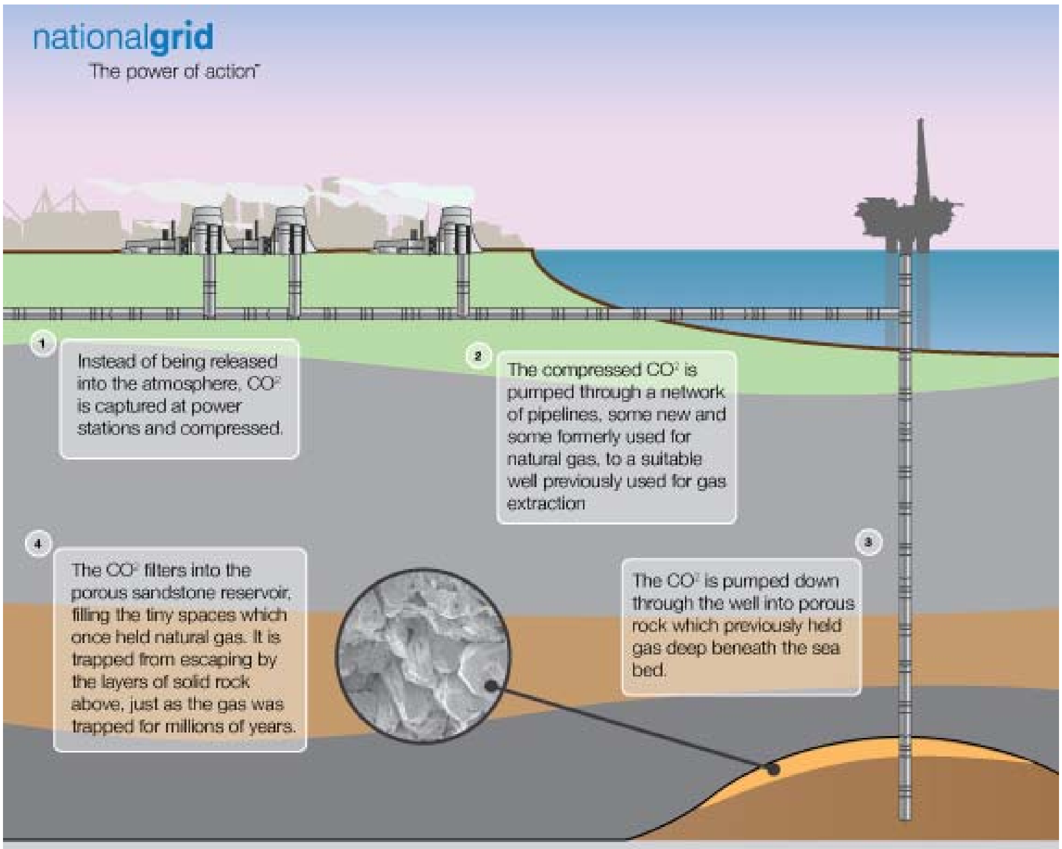
Ofgem have initiated further consultation with regard to funding which will facilitate taking forward the reinforcements identified by the report. In their Initial proposals, Ofgem have reiterated their commitment to ensuring adequate funds are made available to ensure timely investment is undertaken. It is anticipated that Ofgem will publish its final proposals in mid January 2010.

7.4 Carbon Capture and Storage

The UK emits around 600 m tons CO_2e per year, contributing to climate change. Around 30% of this comes from power stations burning fossil fuels. National Grid has modelled how UK 2050 climate change targets might be met; a key message from this (consistent with other studies) is that electricity production needs to largely decarbonise by 2030 in order to enable (more expensive) subsequent decarbonisation of heat and transport sectors. Failure to decarbonise electricity production by 2030 will either mean missing climate change targets or require other measures to be taken, both earlier and at higher cost. One proposed solution is to replace or retrofit existing coal fired plant with modern plant which also captures the CO_2 from the flue gas stream. This CO_2 would then be transported to depleted gas and oil fields or saline formations for long term storage.

National Grid is proposing to help facilitate demonstration and deployment of Carbon Capture and Storage (CCS) in particular through developing CO_2 transportation proposals. National Grid owns and manages the high pressure Gas National Transmission System for the UK, and hence is ideally placed in terms of experience and infrastructure to contribute to transportation of CO_2 – either through new-build pipelines or re-use of existing assets.

FIGURE 7.4 – Overview of CCS



On 8 April 2009, Ofgem published an industry consultation on National Grid's proposal to investigate the possible future reuse of some of its natural gas transmission pipelines in Scotland, from 2013, for the transportation of carbon dioxide from power stations and heavy industry for storage offshore. This would require Ofgem consent.

Scotland, alongside the Humber and Thames regions in England, offers some of the best opportunities for CCS in Europe, with power stations and other heavy industry close to the

North Sea oil and gas fields that, when depleted, could provide storage for their carbon dioxide emissions. CCS networks in Scotland and Humberside could together result in a reduction of up to 78 million tonnes of carbon dioxide per year (60 for Humberside and 18 for Scotland).

Alongside this substantial reduction in emissions, CCS would also bring benefits to security of supply from allowing coal to remain part of a future diverse low carbon energy mix. Coal generation, with its flexible output, could play a valuable role in meeting the UK's future energy requirements alongside a large proportion of intermittent wind generation and large but inflexible nuclear generators.

Ofgem's consultation will allow an industry debate on the extent to which existing natural gas transmission pipelines could be reused for carbon dioxide transport. Declining supplies from the North Sea, and the changing shape of overall supplies to the UK mean that the natural gas capacity needed in certain parts of the system is expected to reduce over the next decade and beyond. In light of this, the pipelines connecting the St Fergus gas terminal on the coast of Scotland to the rest of the network have been identified as potentially available in future for carbon dioxide transportation. Reusing existing pipelines in this way would further reduce the costs of implementing CCS.

CCS is expected to start to play a significant role over the period covered by the Ten Year Statement. Over this period a large portion of existing thermal generating plant will be retired and new generation sourced to make up the shortfall. CCS, whether fitted to coal or gas stations, provides an ability for the market demand for power to be met (even when the wind does not blow) yet not lead to missed emissions targets. Coal+CCS also has the benefit of increasing security of supply as it relies on a different fuel source, with local stockpiles and production contrasting with gas import dependency.

In November 2007 the Government launched a competition to build one of the world's first industrial scale CCS demonstration projects. It has subsequently been stated that up to four projects demonstrating both pre- and post- combustion capture technology may receive financial support. In November 2009 the Department of Energy and Climate Change published "A framework for the development of clean coal – consultation response" which sets out current thinking on the future policy framework.

Among the measures which could improve the economics of CCS and lead to faster or wider scale deployment are:

- development of CCS "clusters" to enable economies of scale in the transport and storage infrastructure;
- a stronger and more stable EU ETS carbon price;
- Some certainty over CCS volume growth (enabling companies to plan for that growth and bring it into their investment plans);
- De-risking of some elements of the supply chain so financing costs are reduced.

A strong policy on CCS could see deployment measures for CCS identified soon, which could see sequestration volumes grow to a cumulative 1 billion tonnes CO2 by 2030. Though mainly outside the 10YS period, such a policy could have a material impact on investment decisions in generation and CCS infrastructure in this period.

For further information on CCS please contact Jim Ward (Jim.Ward@uk.ngrid.com)

7.5 Renewable Gas

As of today, gas carried by the National Transmission System and Distribution Networks is derived solely from fossil sources but we are committed to changing this picture. National Grid is committed to supporting and facilitating the market for renewable gas in the UK. Our vision for injecting renewable gas into our network, thereby displacing fossil gas, supports the UK Government's targets for reducing landfill waste and greenhouse gas emissions and for meeting energy demand from using renewable resources.

There are a number of potential sources for renewable gas and our analysis indicates that a significant proportion of UK gas demand could be met by renewable gas if all of these resources were directed solely to producing gas for distribution in existing networks. When considering the potential to generate biogas from waste, analysis from Ernst and Young for National Grid concluded a central case scenario that 15% of UK domestic gas demand could be met from renewable sources by 2020 (see Figure 7.5B). This scenario however, assumes that renewable gas injection becomes the preferred use of biogas, underpinned by strong government incentives. In the absence of such incentives the somewhat lower contribution of biogas to UK renewable energy reflected earlier in chapter 7 assumes continued use of biogas for power generation.

FIGURE 7.5A – Process flow diagram for renewable gas – generation to injection.

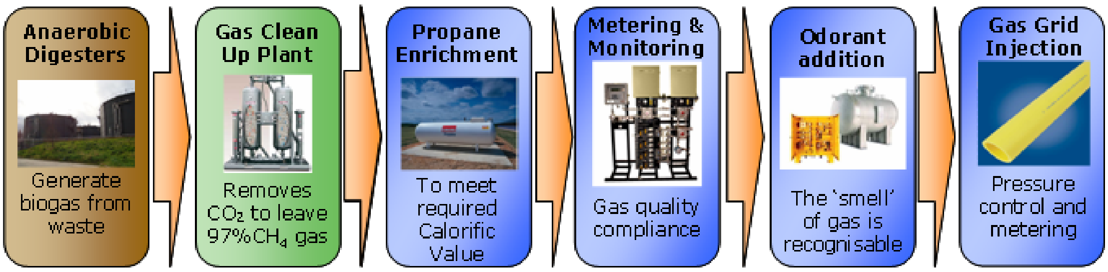
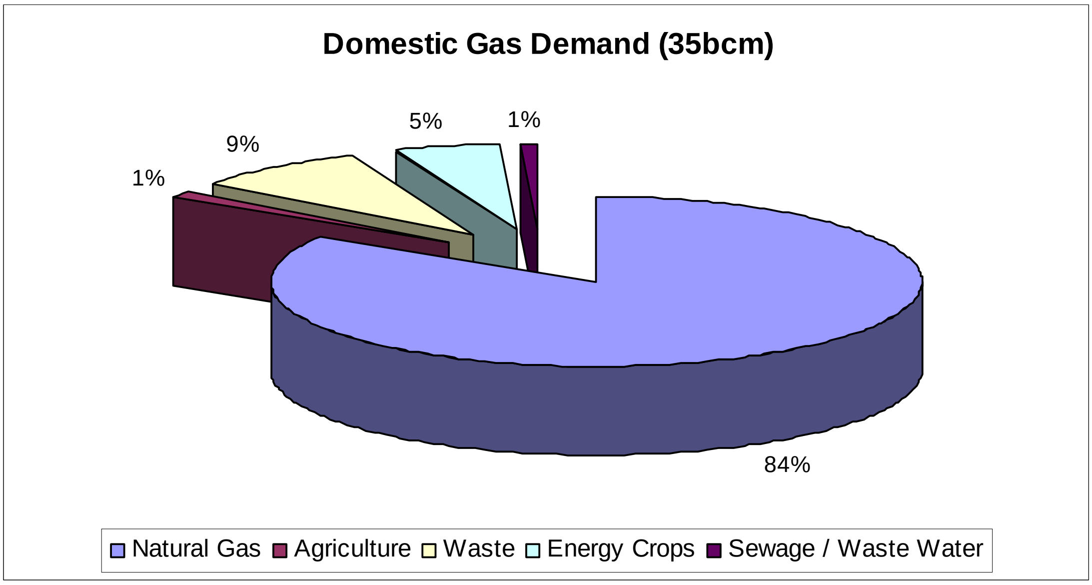


FIGURE 7.5B – Central Case Contribution of Biogas compared to domestic demand (2008).



National Grid is actively lobbying within government and industry for the injection of renewable gas into the gas network as it is usually significantly more efficient than the common alternative; power generation, which achieves efficiencies typically between 30 and 50%, compared to domestic boiler efficiencies averaging 70%[21]. Injection is already carried out in Europe and the US, on a small scale, and key to its deployment in the UK is the introduction of the Renewable Heat Incentive (RHI) in 2011. The incentive, both on its own and when compared with other incentives, needs to ensure that where renewable gas injection is the most efficient use of a resource it is also the most economic.

Even in advance of the RHI there has been a positive response from stakeholders, including potential renewable gas producers, to the prospect of injecting renewable gas into our network for use by consumers in existing household appliances. We are progressing a small number of joint projects with biogas producers to be completed during the next 12 to 18 months to demonstrate the benefits of renewable gas injection and sow the seeds for volume growth over the next few years.

To stimulate delivery of the significant untapped energy potential of household and commercial waste we have developed the concept of "urban energy centres"[22] where compatible technologies are co-located, on sites such as old gas works, to deliver "waste to gas" end to end processing with re-use of process heat and by-products to maximise efficiency and minimise emissions.

Through our demonstration projects and work with government and regulatory stakeholders we are promoting refinements to the current frameworks that define gas quality requirements and investment incentives. In doing so, we seek to make the connection of renewable gas supplies to our network simple and efficient and to ensure that this opportunity is taken to support delivery of UK environmental targets for 2020 and 2050.

For further information on renewable gas please contact Johnny Johnston (Johnny.Johnston@uk.ngrid.com)

[21] Based on (gross) dry gas efficiencies from Heating and Hotwater Industry Council (part of SGBI) boiler population estimates for 2008.

[22] http://www.nationalgrid.com/uk/Media+Centre/PressReleases/2009/08.10.09.htm

Appendix One

Process Methodology

A1.1 Demand

The purpose of this section is to give a brief overview of the methodology that is adopted to develop forecasts of annual and peak demand. The methodology can be categorised into three main modelling areas; annual demand, demand/weather and peak demand modelling. For more information please see our Gas Demand Forecasting Methodology document.

A1.1.1 Annual Demand Modelling

The development of annual gas demand forecasts considers a wide range of factors, from complex econometrics to an assessment of individual load enquiries. For any forecasting process a set of planning assumptions is required, which if necessary can be flexed to create alternative scenarios. In the case of the forecasts presented in this document, assumptions include economic, fuel prices, environmental and tax policies, etc. A number of these assumptions are based on data from independent organisations. Our forecasts are also benchmarked against the work of a number of recognised external sources, such as DECC.

To gain a better understanding of how these assumptions are utilised and the modelling approach adopted it is necessary to consider the LDZ and NTS processes separately.

A1.1.1.1 LDZ Modelling

LDZ demand is split into four market sectors according to load size and supply type (i.e. firm or interruptible). For each sector models have been developed that make allowance for economic conditions, local demand intelligence, new large load enquiries, relative fuel prices, potential new markets and other factors, such as the Climate Change Levy, that could affect future growth in demand.

By adopting this approach we are able to take account of varying economic conditions and specific large loads within different LDZs.

A1.1.1.2 NTS Modelling

Historically, NTS demand (i.e. loads with their own connection to the NTS) was limited to a small number of large industrial sites and chemical works. However, with the advent of gas-fired power generation and interconnectors to Ireland and Continental Europe, a new methodology had to be developed. This methodology can best be described by looking at each sector in turn.

A1.1.1.3 Power Generation

The power generation forecast consists of two main elements, firstly, the capacity available to generate and secondly, how frequently this capacity is in operation.

The first element is developed by comparing information from connections requests and load enquiries with feedback received from the Transporting Britain's Energy (TBE) consultation process and a range of commercial sources. In addition, the influence of commercial arrangements, Government policies and legislation are taken into account when deciding which power stations will be built or closed. The processes employed in this area of the forecast are common with those applied to develop the forecasts of generation appearing in the Seven Year Statement.

To complete the second element, a model has been developed to forecast the demand for electricity generation by fuel type and individual station over the forecast period. The modelling process takes account of station specific operating assumptions, constraints, costs and availability. Actual station data is also used to support the process.

The resultant power generation forecast, encompassing all fuel types, is then used to derive a split between gas-fired stations supplied by the NTS (or embedded within the DNs) and those with their own dedicated pipeline delivering supplies direct from the beach.

A1.1.1.4 Exports

Forecast flow rates to and from Europe via the Belgium Interconnector (IUK) are based on a market assessment between Continental Europe and the UK, allowing for the seasonal variation of UK gas demand.

Exports to Ireland are derived from a sector-based analysis of energy markets in Northern Ireland and the Republic of Ireland, including allowances for the depletion and development of indigenous gas supplies, feedback from the TBE process, commercial sources and regulatory publications.

A1.1.1.5 Industrials

The production of forecasts within this sector is dependent on forecasts of individual new and existing loads based on recent demand trends, TBE feedback, load enquiries and commercial sources.

A1.1.2 Demand/Weather Modelling

Demand models are based on Composite Weather Variables (CWVs) defined and optimized for each LDZ. The CWV combines temperatures and wind speeds into a single weather variable that is linearly related to NDM demand. Seasonal normal CWVs (one for each day and each LDZ) are produced using a 17 year historical weather database. All seasonal normal and average demand forecasts are now based on a 17 year average condition.

A1.1.3 Peak Day Demand Modelling

Once the annual demand forecasts and daily demand/weather models have been developed, a simulation methodology is employed, using historical weather data for each LDZ, to determine the peak day (in accordance with statutory/Licence obligations) and severe winter demand estimates. Where possible, the peak day demand of the NTS supplied loads, such as the power stations, are based on the contractual arrangements. Export demands are treated slightly differently; the Belgian Interconnector is assumed not to be exporting at times of peak demand, due to the high price of British gas, and Irish demand is derived from the market-sector based approach mentioned above.

A1.2 Supply

The main purpose of our supply forecasts is to allow a picture of supply and demand to be derived, which can be used to assess potential NTS investments and other business requirements such as compressor utilisation and security of supply analysis. In the past, this process was dominated by developments in the UKCS, as our assessments of ASEP capacity requirements were dependent on accurate forecasts of UKCS field production. While UKCS data is still an important element of this process, we are increasingly adapting to industry changes; notably the reliance on increasing levels of imported gas and the long-term entry capacity auctions.

In constructing our long-term gas supply forecasts, we continue to rely on information received from market participants, which we supplement with data from commercial sources. This year we have again had an excellent response to our TBE consultation process in relation to UKCS supplies, with information from upstream players again accounting for approximately 90% of the total used to compile our UKCS forecasts. As a result, we believe our 2009 supply forecasts continue to reflect the collective expectations of the upstream UK gas industry.

In terms of future imports we also receive a good response from developers through our TBE consultation. Indeed in aggregate, the total supply capacity of new import projects far exceeds the UK's existing and even future import requirement. On a peak basis the addition of numerous proposals for new storage projects compounds the supply uncertainty as does increasing requirements for network exit capacity from networks, gas fired power stations and for storage injection. In previous years, National Grid has used various supply scenarios to assist our planning process and stimulate industry debate. Due to the completion or near completion of numerous import projects we have developed a "Base Case" supply position, as detailed in Section 4.8. The Base Case should not be seen as a central case or a best view of future supplies but as a starting point to capture the increasing level of uncertainty surrounding on how capacity and therefore supplies may be used in an environment of increasing and even surplus capacity.

A1.3 NTS Capacity Planning

Using the supply/demand match as an input, we use a network analysis software package, to analyse the performance of the transportation system. The network analysis software allows us to identify the location of potential network capacity constraints and helps in the development of suitable reinforcement options that ensure the appropriate level of system security is maintained.

Having identified potential constraints on the system, we evaluate options for adding capacity to the network that represent a safe, economic and efficient solution, whilst maintaining system security. The options available to us to increase capacity include:

- Uprating pipeline operating pressures;
- Changing the way the system is configured (changing flow patterns and reversing flows)

- Constructing new pipelines or compressors;
- Uprating or modifying existing compressors or installing new compressor stations;
- Building additional regulators and offtakes.

Investment options are considered with the primary aim of minimising the net-present costs, in accordance with our “economic” and “efficient” obligations under the Gas Act. The drivers for investment are:

- Provision of 1 in 20 peak day capacity, in accordance with Standard Special Condition A9 of the GT Licence in respect of the NTS;
- Maximisation of incentives income (e.g. provision of entry capacity);
- Reduction of environmental emissions from compressor stations;
- Delivering customer contracted quantities of capacity

The aim of minimising the net-present costs associated with investment requires network analysis to be applied over a long-term (at least ten years) horizon, and many demand conditions (1 in 20 peak day through to summer conditions).

Further information on our investment planning process and how this interacts with commercial processes for capacity release may be found in our Transmission Planning Code, available on our website at http://www.nationalgrid.com/uk/Gas/TYS/.

A1.4 Investment Procedures and Project Management

All investment projects must comply with our Investment and Disposals Guidelines, which set out the broad principles that should be followed when evaluating high value investment or divestment projects. These guidelines are supported by specific guidelines for the UK Transmission and Distribution businesses.

The investment guidelines define the methodology to be followed for undertaking individual investments in a consistent and easy to understand manner. Together with the planning and budgeting methodology, they are used to ensure maximum cost-efficiency is obtained. For non-mandatory projects, the key investment focus in the majority of cases is to undertake only those projects that carry an economic benefit. For mandatory projects, such as safety-related work, the focus is on minimising the net-present cost whilst not undermining the project objectives or the safety or reliability of the network.

The successful management of major investment projects is central to our business objectives. Our project management strategy involves:

- Determining the level of financial commitment and appropriate method of funding for the project;
- Undertaking preliminary studies to ensure projects are feasible and confirm budget estimates.
- Developing the most appropriate purchasing contracts methodology;
- Monitoring and controlling the progress of the project to ensure that financial and technical performance targets are achieved;
- Post project and post investment review to ensure compliance and capture lessons learnt.

When a Transmission project is approved, a multi-discipline team prepares an Invitation to Tender in accordance with the EU Utilities Directive. For major projects, specialist consultants with experience of preparing and evaluating tender documents are used.

Tenders are received and evaluated against previously agreed technical, quality, safety, financial and programme criteria. They are compared on a cost basis with a database of capital projects. An award is then made to the most economically advantageous tender consistent with these criteria.

The successful contractor completes the project in accordance with an agreed programme of works. It remains the contractor's responsibility to manage and supervise the works. We monitor the work on a day-to-day basis and manage the funding of the project by careful cost control. Following completion, a Post Completion Review is carried out to provide feedback to management on project performance and to improve future decision making processes. Our project management of major investment projects is designed to ensure that they are delivered on time, to the appropriate quality standards at minimum cost. The project management process in particular makes use of professional consultants and specialist contractors, all of who are appointed subject to competitive tender. When the project is complete a financial closure report is submitted to the level of management appropriate to the total cost. Lessons learnt are then recorded for future utilisation.

Appendix Two

Gas Demand & Supply Volume Forecasts

A2.1 Demand

TABLE A2.1A – Forecast Annual Demand – Split by LDZ & NTS Load Categories (TWh)

Calendar Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
0 to 73 MWh	362	362	364	363	359	357	355	354	351	351
73 to 732 MWh	52	52	52	51	51	51	51	51	50	50
NDM>732	72	71	71	71	71	71	70	70	70	70
Total NDM	486	485	486	486	481	478	476	475	471	471
DM	117	120	128	132	131	131	130	130	129	129
Total LDZ	602	605	614	618	611	609	606	605	601	600
NTS Power Generation	259	257	267	268	292	299	298	312	308	305
NTS Industrials	29	31	31	31	31	30	30	29	29	28
Exports via Moffat	68	70	48	40	41	46	50	53	56	58
Exports via IUK	70	72	73	72	71	69	67	66	65	63
Total NTS	428	431	419	411	435	444	444	461	458	454
Shrinkage	9	9	8	7	8	8	7	7	7	7
Total Throughput	1039	1045	1041	1037	1055	1061	1058	1073	1066	1062

Gas Supply Year	**08/09**	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**
Total Throughput	1062	1045	1046	1041	1047	1061	1063	1069	1069	1061

Notes

- *Volumes are based on the 17 years of weather data from October 1987 to September 2004*
- *NTS Power Generation includes all large-scale gas-fired plants connected to the NTS but excludes the consumption of those stations supplied by third party pipelines and those embedded within DNs*
- *Figures may not sum exactly due to rounding*

FIGURE A2.1A – Forecast Annual Demand

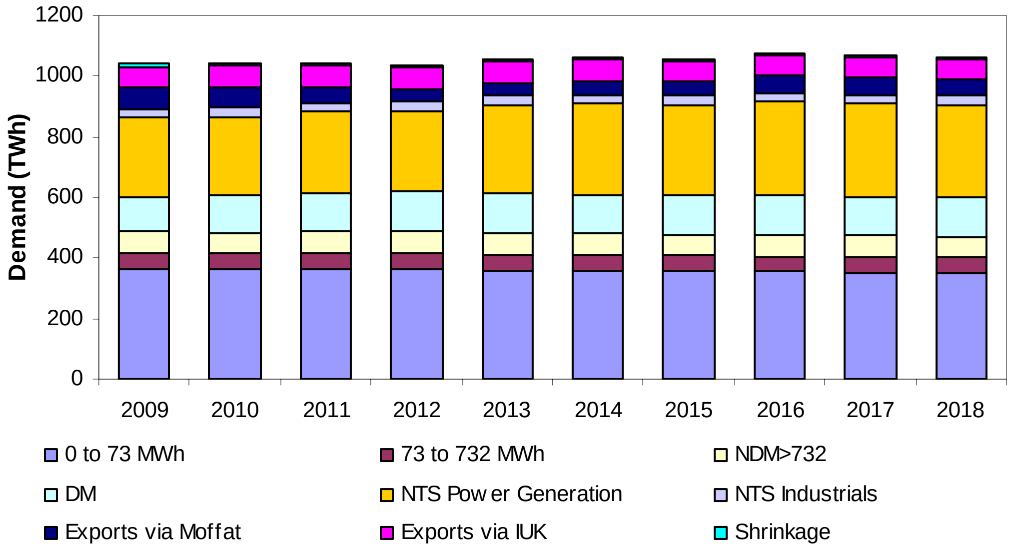


TABLE A2.1B – Forecast 1 in 20 Peak Day Firm Demand – Split by LDZ & NTS Load Categories (GWh)

Gas Supply Year	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
0 to 73 MWh	2885	2828	2843	2839	2818	2797	2784	2764	2749	2747	2747
73 to 732 MWh	459	448	450	448	445	444	443	441	440	439	437
NDM>732	553	534	533	532	530	529	528	526	525	524	524
Total NDM	3898	3810	3826	3819	3793	3770	3755	3732	3713	3710	3708
DM	130	129	158	158	158	158	157	156	156	156	156
Total LDZ	4028	3939	3984	3977	3951	3928	3912	3888	3870	3866	3864
NTS Power Generation	1075	1095	1043	1103	1163	1239	1295	1452	1476	1455	1482
NTS Industrials	132	132	132	132	132	144	139	139	139	139	139
Exports via Moffat	294	310	241	255	257	276	163	169	189	208	225
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0
Total NTS	1500	1537	1416	1490	1552	1658	1597	1760	1804	1802	1846
Shrinkage	54	50	46	43	43	43	42	42	42	42	41
Total Throughput	5582	5526	5445	5510	5546	5630	5552	5690	5716	5709	5751

Notes

- *Peak day data is presented on a gas supply year basis*
- *Figures may not sum exactly due to rounding*
- *LDZ Shrinkage is included in the 'Shrinkage' total.*

FIGURE A2.1B – Forecast Peak Demand

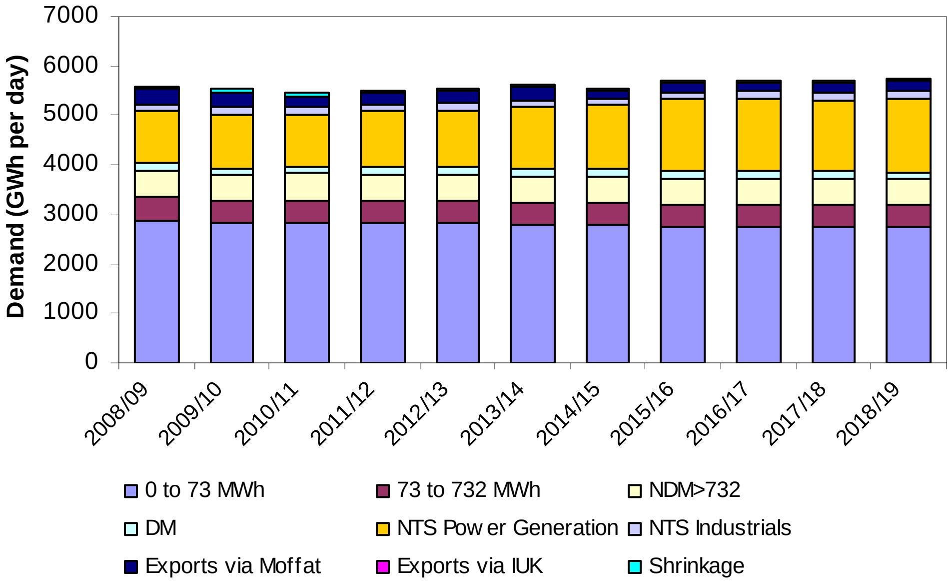


TABLE A2.1C – Forecast 1 in 20 Peak Day Firm Demand by LDZ (GWh per day)

	08/9	09/0	10/1	11/2	12/3	13/4	14/5	15/6	16/7	17/8	18/9
Scotland	313	305	305	305	304	303	302	301	301	301	302
Northern	233	225	226	226	224	223	221	220	219	218	217
North West	473	462	468	468	465	462	459	456	453	453	452
North East	249	242	244	243	242	240	240	239	238	238	239
East Midlands	406	399	405	405	403	400	399	397	395	395	395
West Midlands	388	377	381	382	380	378	377	374	373	373	372
Wales (North & South)	201	199	228	228	227	226	225	224	223	223	223
Eastern	331	324	323	323	323	322	320	319	318	318	318
North Thames	435	425	421	417	413	409	406	403	399	398	397
South East	455	453	450	446	442	438	435	431	427	426	424
Southern	327	318	320	320	319	318	317	315	314	314	315
South West	241	237	238	238	237	236	236	235	235	235	235
LDZ Total	4051	3965	4010	4002	3977	3954	3938	3914	3895	3891	3889

Notes

- *Peak day data is presented on a gas supply year basis*
- *The LDZs are consistent with the Uniform Network Code and are defined in Appendix 4*
- *LDZ figures include shrinkage*
- *Figures may not sum exactly due to rounding*
- *These peak day demand forecasts do not take into account the move to 'universal firm' demand post 2011. The impact of this will be assessed and incorporated into next years' peak demand forecasts.*

FIGURE A2.1C – Forecast 1 in 20 Peak Day Firm Demand

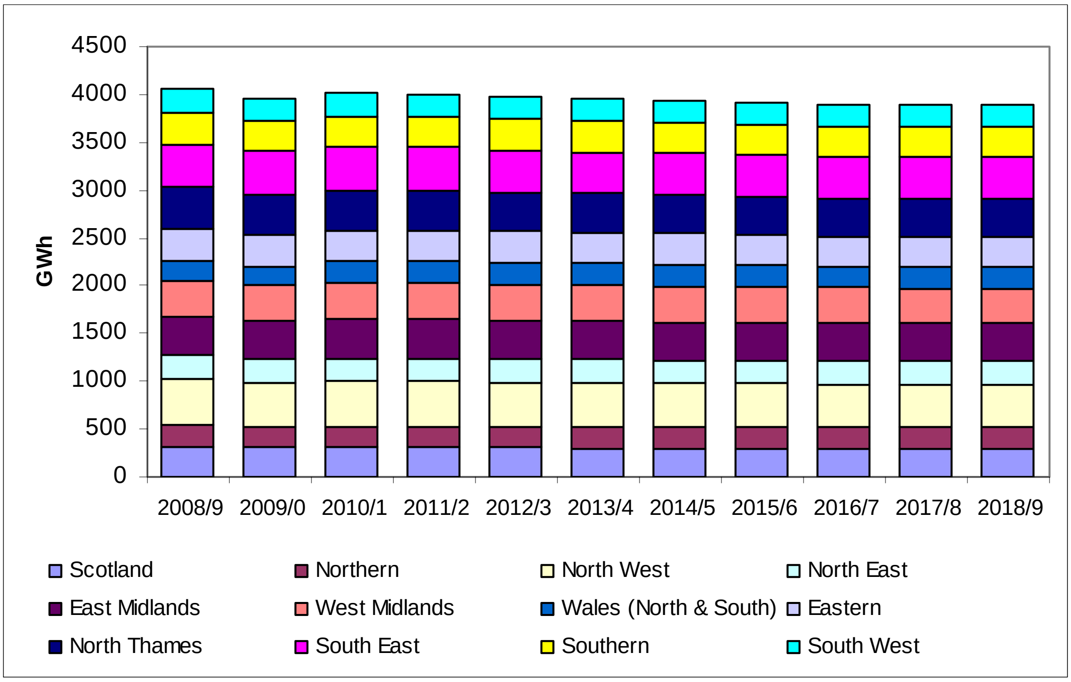
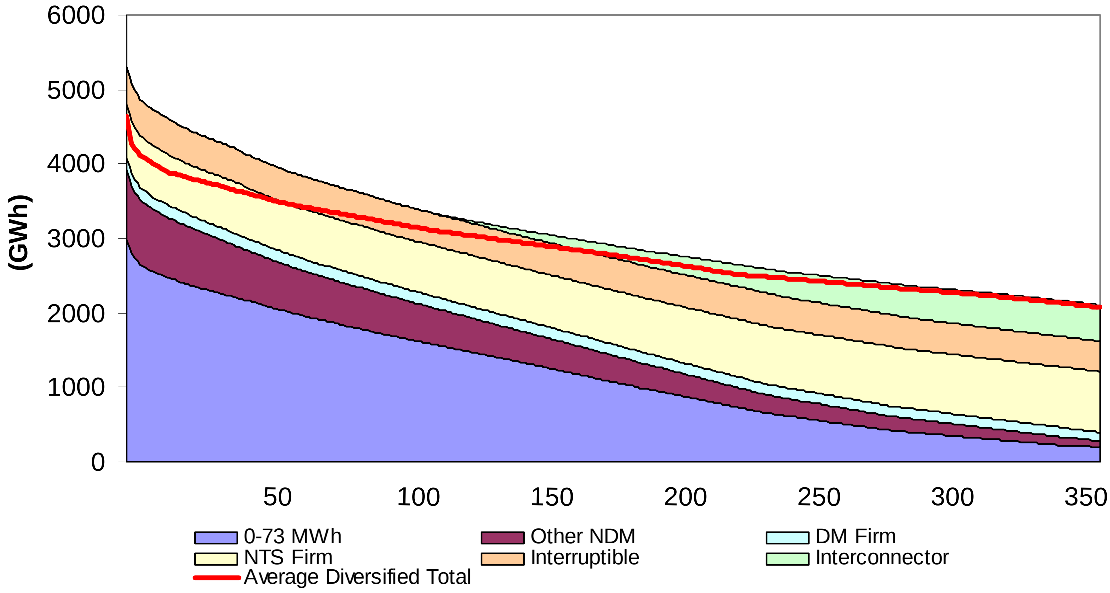


FIGURE A2.1D – 2011/12 Load Duration Curve (1 in 50 Diversified)



Notes

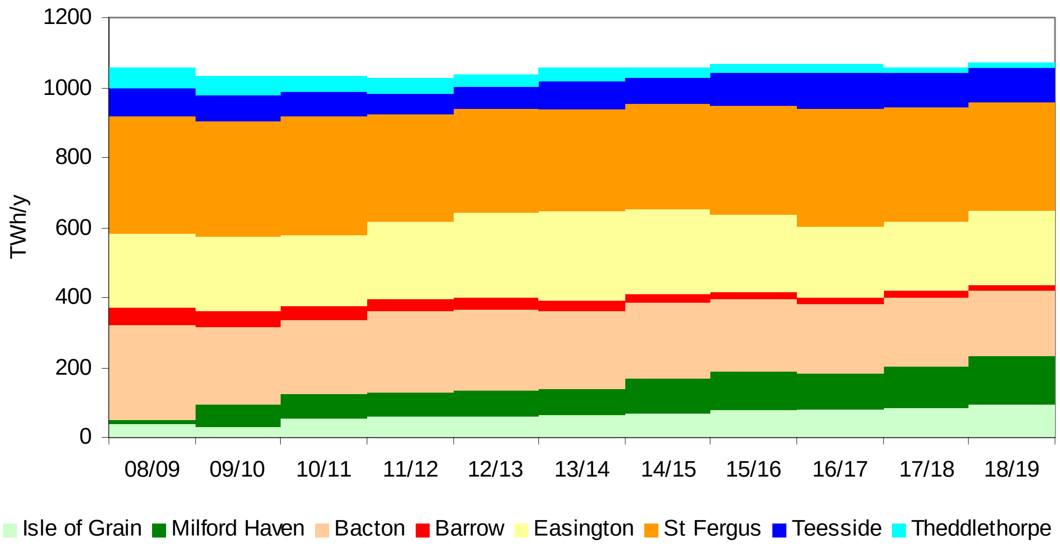
- *Severe 1 in 50 Load Duration Curve, as defined in the Glossary*
- *Average Load Duration Curve, including Belgian Interconnector, is based on the 17 years of weather data from October 1987 to September 2004, with the area under the curve being consistent with the annual demands shown in table A2.1A*
- *These peak day demand forecasts do not take into account the move to 'universal firm' demand post 2011. The impact of this will be assessed and incorporated into next years' peak demand forecasts.*

A2.2 Annual Terminal Supply Scenarios

TABLE 2.2A – Base Case Annual Supplies (TWh/y)

	08/9	09/0	10/1	11/2	12/3	13/4	14/5	15/6	16/7	17/8	18/9
Bacton	270	222	210	229	231	223	216	207	196	195	187
Barrow	50	45	41	37	32	29	27	24	22	20	14
Easington	216	211	200	220	242	253	242	219	202	201	215
Isle of Grain	37	30	57	59	61	63	71	78	77	84	95
Milford Haven	12	61	68	71	74	77	97	108	107	118	136
St Fergus	335	332	344	309	300	295	300	311	336	323	309
Teesside	77	77	66	60	61	75	74	93	103	99	99
Theddlethorpe	60	53	44	44	37	39	32	26	22	17	16
Total	1056	1033	1031	1028	1038	1054	1059	1065	1065	1057	1072

FIGURE 2.2A Base Annual Supplies



Notes

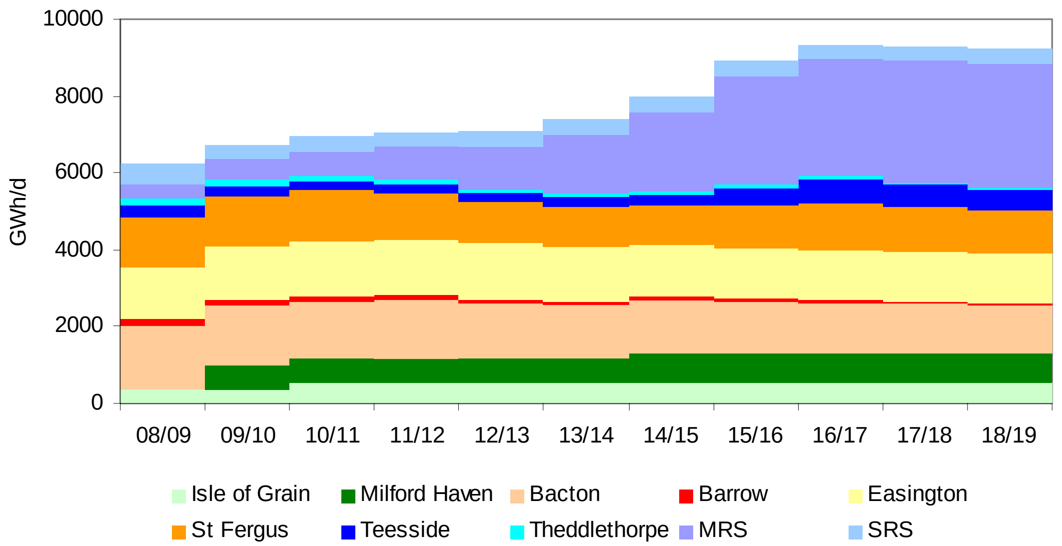
- *Figures may not sum exactly due to rounding*

A2.3 Peak Terminal Supply Scenarios

TABLE 2.3A – Base Case Peak Supplies (GWh/d)

	08/9	09/0	10/1	11/2	12/3	13/4	14/5	15/6	16/7	17/8	18/9
Bacton	1640	1576	1495	1529	1441	1407	1398	1357	1316	1300	1283
Barrow	181	158	142	129	111	101	92	82	74	67	49
Easington	1356	1380	1411	1450	1439	1399	1348	1325	1319	1297	1302
St Fergus	1294	1299	1347	1199	1110	1051	1046	1100	1203	1146	1082
Teesside	293	286	246	217	213	255	254	465	646	611	576
Theddlethorpe	183	162	135	132	108	114	93	74	63	47	44
Isle of Grain	344	344	533	533	533	533	533	533	533	533	533
Milford Haven	33	625	625	625	625	625	757	757	757	757	757
MRS	369	515	609	859	1103	1507	2055	2823	3041	3144	3207
SRS	526	390	390	390	390	390	390	390	390	390	390
Total	6220	6736	6933	7061	7072	7380	7964	8907	9341	9291	9221

FIGURE 2.3A – Base Case Peak Supplies



- *Figures may not sum exactly due to rounding*

A2.4 National Grid Supply Forecasts & Long Term Auction Results

The ranges shown below are for illustrative purposes and are not intended to capture the absolute range of possibilities. They have been derived using a set of assumptions which were based on our core/non-core assumptions for all supply types. The data for “release obligation” captures the maximum amount of capacity that National Grid is obliged to release at any point in the gas year.

Release Obligation	Capacity National Grid is obliged to release
Forecast Range	Range of flows based on core/non-core assessment
Forecast	2009 Base Case Peak Forecast
Actual	Actual maximum flows
Allocated QSEC 2009	Allocated as a result of the September 2009 QSEC auctions
Allocated Previously	Allocated prior to September 2009

FIGURE A2.4A – Peak Bacton Forecast (mcm/d)

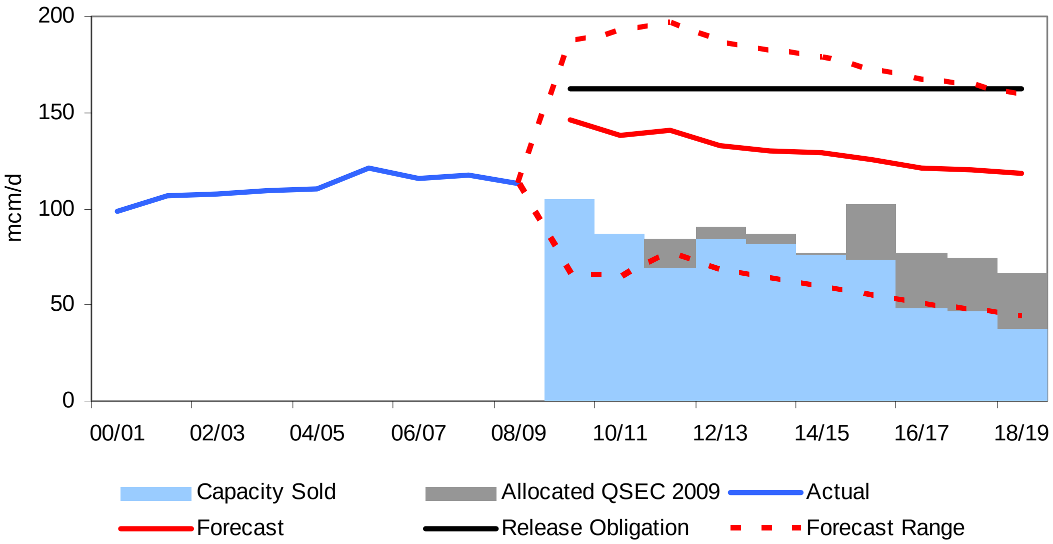


FIGURE 2.4B – Peak Barrow Forecast (mcm/d)

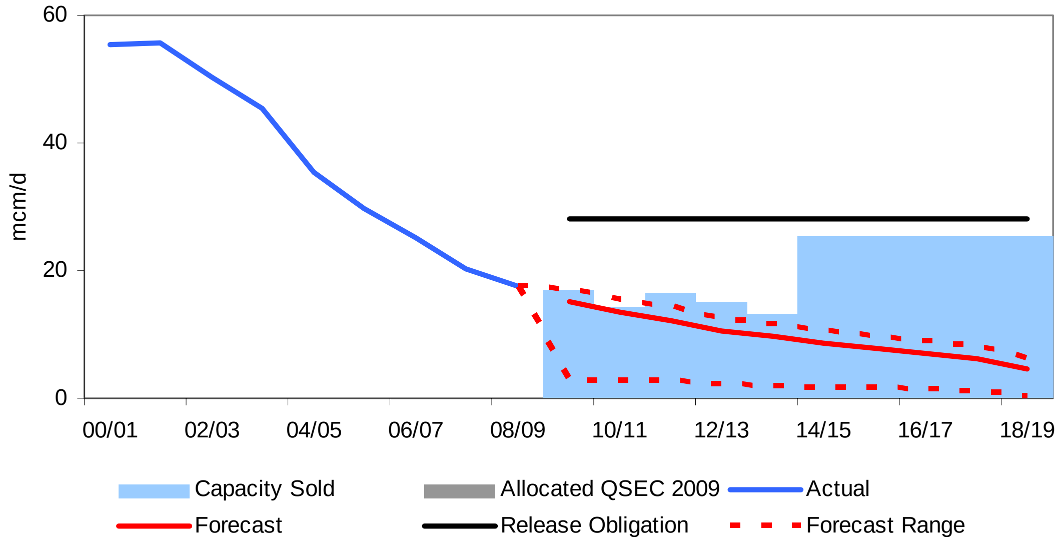


FIGURE 2.4C – Peak Easington Forecast (mcm/d)

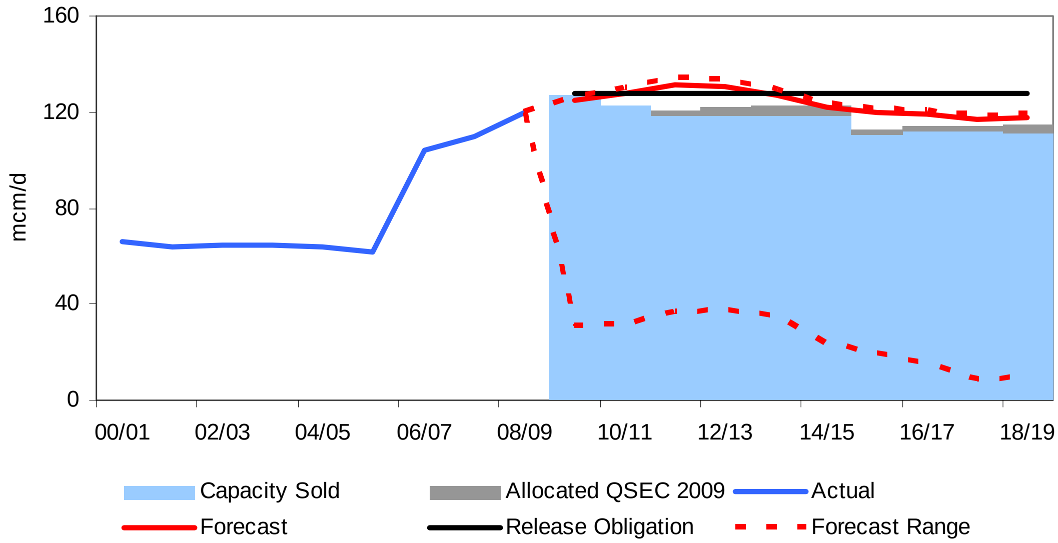


FIGURE 2.4D – Peak Isle of Grain Forecast

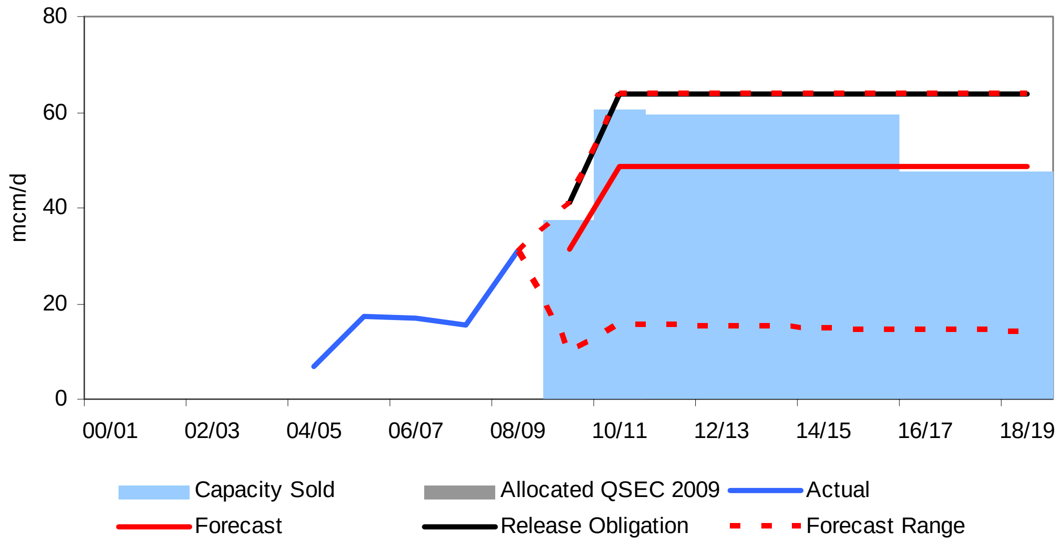


FIGURE 2.4E – Peak Milford Haven Forecast

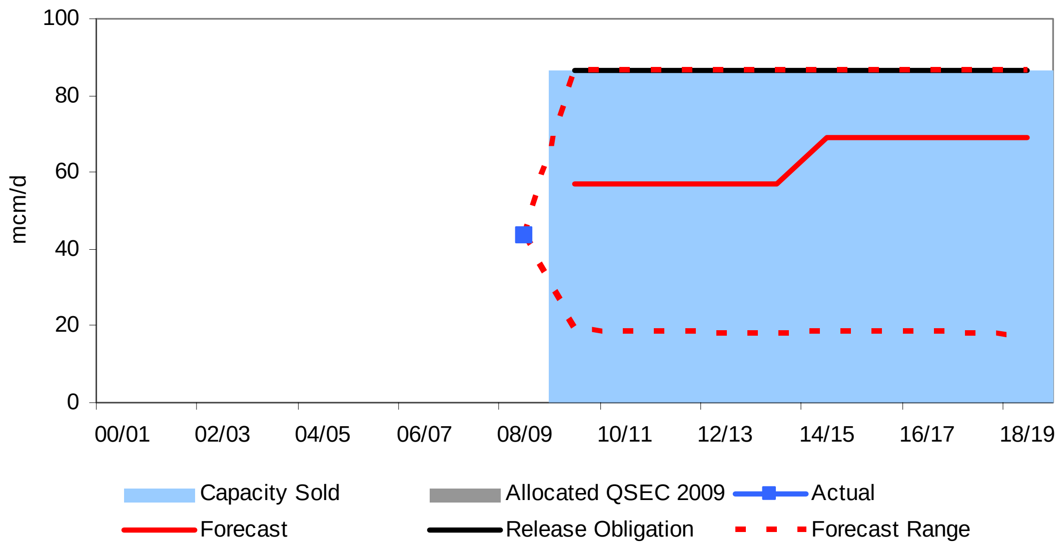


FIGURE 2.4F – Peak St Fergus Forecast

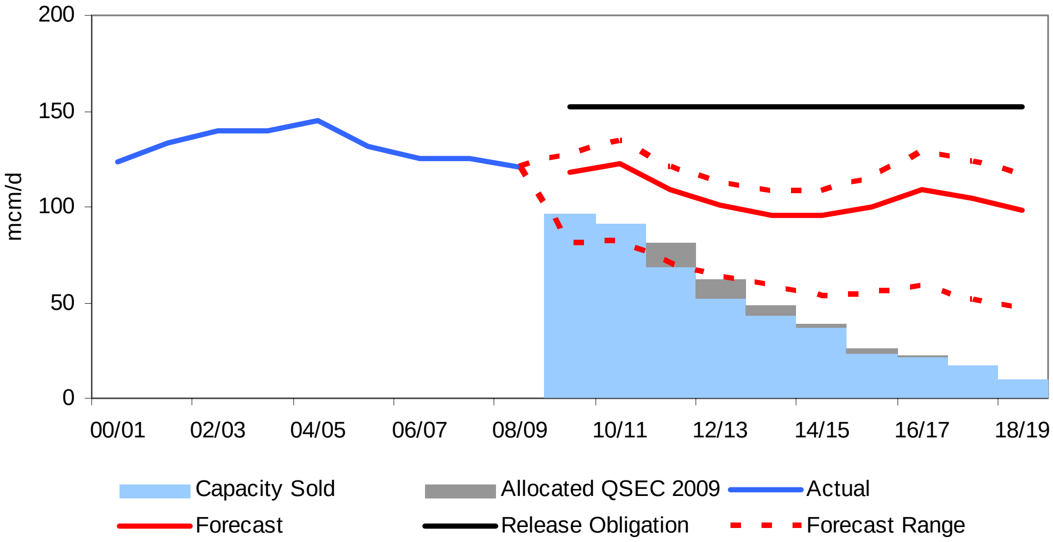


FIGURE 2.4G – Peak Teesside Forecast

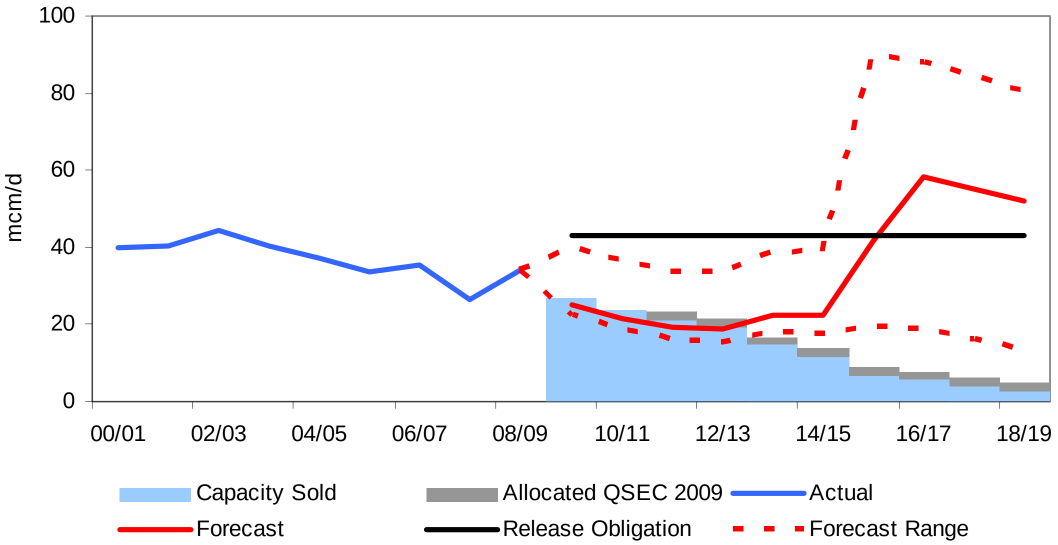


FIGURE 2.4H – Peak Theddlethorpe Forecast

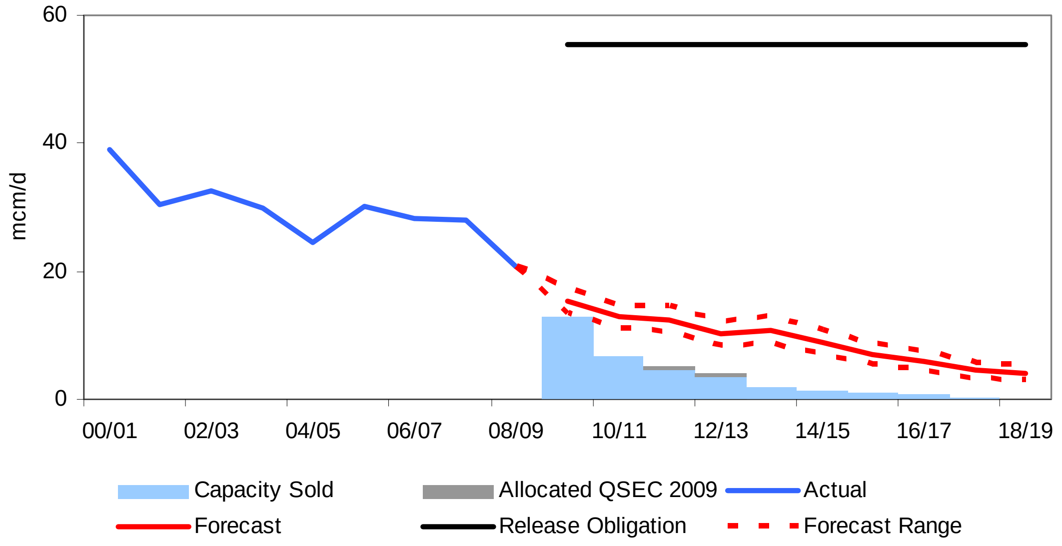
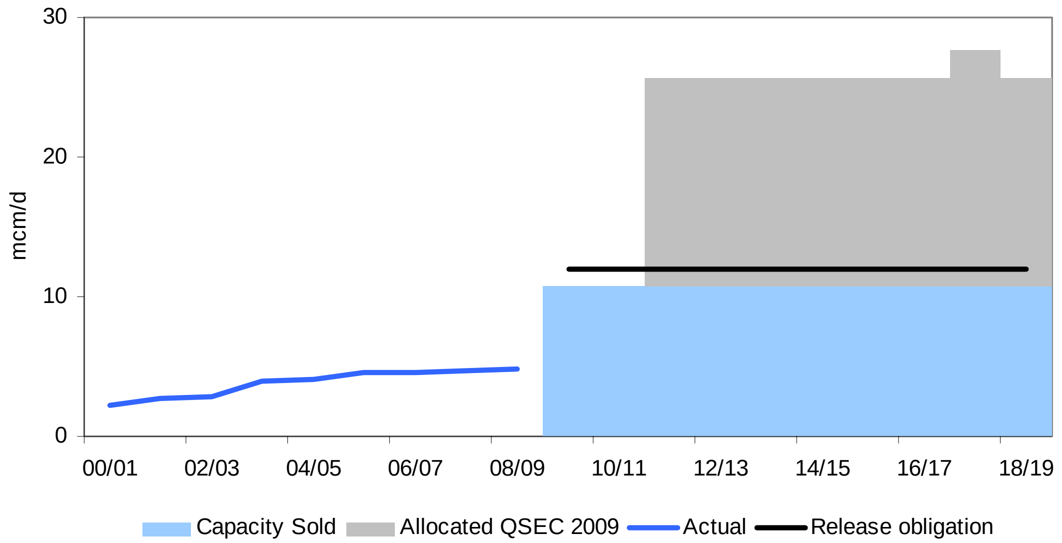


Figure 2.4I – Holehouse Farm (Storage site)



Appendix Three

Actual Flows 2008

This Appendix describes annual and peak flows during the calendar year 2008. Where relevant, more up-to-date data has been included to give gas supply year 2008/09 figures.

A3.1 Annual Flows

Annual forecasts are based on average weather conditions. Therefore, when comparing actual demand with forecasts, demand has been adjusted to take account of the difference between the actual weather and the seasonal normal weather. The result of this calculation is the weather corrected demand. We are currently using a 17-year average weather condition based on the period from October 1987 to September 2004.

Actual demands incorporate a re-allocation of demand between 0 to 73MWh and >73MWh firm load bands to allow for reconciliation, loads crossing between thresholds, etc. The load band splits shown in Table A3.1 are slightly different from those incorporated in the National Grid Accounts.

Table A3.1 provides a comparison of actual and weather corrected demands during the 2007 calendar year with the forecasts presented in the 2007 Ten Year Statement. Annual demands are presented in the format of LDZ and NTS load bands/categories, consistent with the basis of system design and operation.

TABLE A3.1A – Annual Demand for 2008 (TWh) – LDZ / NTS Split

TWh	Actual Demand	Weather Corrected Demand	2008 TYS Forecast Demand
0-73 MWh	382	385	391
73-732 MWh	55	55	58
>732 MWh Firm	124	124	125
Interruptible	84	84	86
LDZ Consumption	645	648	661
NTS Industrial	32	32	32
NTS Power Gen.	287	287	276
Exports	119	119	112
Total	438	438	420
Total Consumption	1,082	1,085	1,081
Shrinkage	10	10	12
Total system demand	**1,092**	**1,095**	**1,093**

Notes

- *Figures may not sum exactly due to rounding*

Table A3.1 indicates that our 1 year ahead forecast for 2008 was accurate to 2% at an LDZ level. The forecast of the NTS Industrial sector was highly accurate. NTS Power Generation and Exports were accurate to 4% and 6% respectively.

A3.2 Compressor Usage

Table A3.2 shows the gas used at each of the compressor stations during the gas year 2008/09. It also shows the maximum fuel usage day for 06th January 2009, the day of the highest level of supplies to the NTS.

TABLE A3.2A – Compressor Usage for Gas Year 2008/09 (mcm)

Compressor	Total 2008/09	Compressor use on Max. Supply Day - 06/01/09
ABERDEEN	38.03	0.22
ALREWAS	1.32	0.03
AYLESBURY	1.93	0.00
AVONBRIDGE EAST	33.11	0.00
AVONBRIDGE WEST	8.86	0.18
BATHGATE	0.02	0.00
BISHOP AUCKLAND	0.00	0.00
CAMBRIDGE	0.21	0.00
CARNFORTH	28.67	0.15
CHELMSFORD	0.02	0.00
CHURCHOVER	8.46	0.10
DISS	0.39	0.00
HATTON	30.70	0.27
HUNTINGDON	9.42	0.19
KINGS LYNN	1.36	0.00
KIRRIEMUIR	14.83	0.00
MOFFAT	2.22	0.00
NETHER KELLET	1.12	0.00
PETERBOROUGH	31.64	0.22
SCUNTHORPE	0.01	0.00
ST FERGUS	87.16	0.33
WARRINGTON	0.59	0.05
WISBECH	0.01	0.00
WOOLER	7.92	0.06
WORMINGTON	0.47	0.00
Total	**308.47**	**1.79**

A3.3 Peak & Minimum Flows

A3.3.1 System Entry – Maximum Day Flows

For Winter 2008/09, the day of highest supply to the NTS was also the day of highest demand. This was 6th January 2009, when 449 mcm of supply fed a demand of 446 mcm. This is about 4 mcm less than the record demand delivered via our system on 7th January 2003.

The day of minimum demand in 2008/09 was 15th August 2009, when NTS demand was 160 mcm. The day of minimum supply was 11th August, when 163 mcm of gas was supplied to the NTS.

TABLE A3.3A – Actual NTS Entry Flows on the Maximum Supply Day of Gas Year 2008/09 (mcm/d)

Terminal	Maximum day 6th Jan 2009	2008 Peak Forecast	Highest Daily for 2008/09
Bacton incl. I/C & BBL	91	155	113
Barrow	16	17	18
Easington (incl. Rough and Langeled)	119	118	120
Isle of Grain	25	19	31
Milford Haven	0	23	44
Point of Ayr	0	1	4
St Fergus	115	119	121
Teesside	23	23	34
Theddlethorpe	18	23	21
Sub-Total	408	498	506
MRS & LNG Storage	41	98	51
Total	449	596	557

Notes

- *The maximum supply day for 2008/09 refers to flows on 6th January 2009. This was the overall highest supply day, but individual terminals may have supplied higher deliveries on other days.*
- *Peak forecast refers to that published in the 2008 Ten Year Statement*
- *Due to linepack changes, there may be a difference between total demand and total supply on the day*
- *Figures may not sum exactly due to rounding*

A3.3.2 System Entry – Minimum Day Flows

TABLE A3.3B – Actual NTS Entry Flows on the Minimum Supply Day of Gas Year 2008/09 (mcm)

Terminal	**Minimum Day 11th August 2009**
Bacton incl. I/C	34
Barrow	2
Easington (excl Rough incl. Langeled)	26
Point of Ayr	0
Isle of Grain	4
Milford Haven	31
St Fergus	33
Teesside	10
Theddlethorpe	18
Sub-Total	158
MRS & LNG Storage	5
Total	163

Notes

- *The minimum supply day for 2008/09 refers to flows on 11th August 2009. This was the overall lowest supply day, but individual terminals may have supplied lower deliveries on other days;*
- *Due to linepack changes, there may be a small difference between total demand and total supply on the day;*
- *Figures may not sum exactly due to rounding.*

A3.3.3 System Exit – Maximum and Peak Day Flows

Table A3.3C shows actual flows out of the NTS on the maximum demand day of gas year 2008/09 compared to the forecast peak flows.

TABLE A3.3C – Actual NTS Exit Flows on Maximum Demand Day of Gas Year 2008/09 (mcm)

LDZ	Maximum Day 6th Jan 2009	1 in 20 Peak for 2008/09
Scotland	26	29
Northern	16	22
North West	39	45
North East	20	24
East Midlands	35	40
West Midlands	29	38
Wales (North & South)	17	20
Eastern	27	32
North Thames	34	42
South East	36	44
Southern	27	32
South West	20	24
LDZ Total	327	392
NTS Loads	119	137
Total	**446**	**528**

Notes

- *The maximum day for gas year 2008/09 refers to 6th January 2009. This was the overall highest demand day, but individual LDZs may have seen higher demands on other days;*
- *NTS actual loads include interconnector demand;*
- *Due to linepack changes, there may be a small difference between total demand and total supply on the day;*
- *Peak forecast refers to the 1 in 20 Peak Day Firm Demand forecast in the 2008 Ten Year Statement;*
- *Figures may not sum exactly due to rounding.*

A3.3.4 System Exit – Minimum Day Flows

TABLE A3.3D – Actual NTS Exit Flows on the Minimum Demand Day of Gas Year 2008/09 (mcm/d)

LDZ	Minimum Day 15th August 2009
Scotland	5
Northern	4
North West	6
North East	4
East Midlands	6
West Midlands	4
Wales	5
Eastern	4
North Thames	5
South East	5
Southern	4
South West	3
LDZ Total	55
NTS Loads	105
Total	**160**

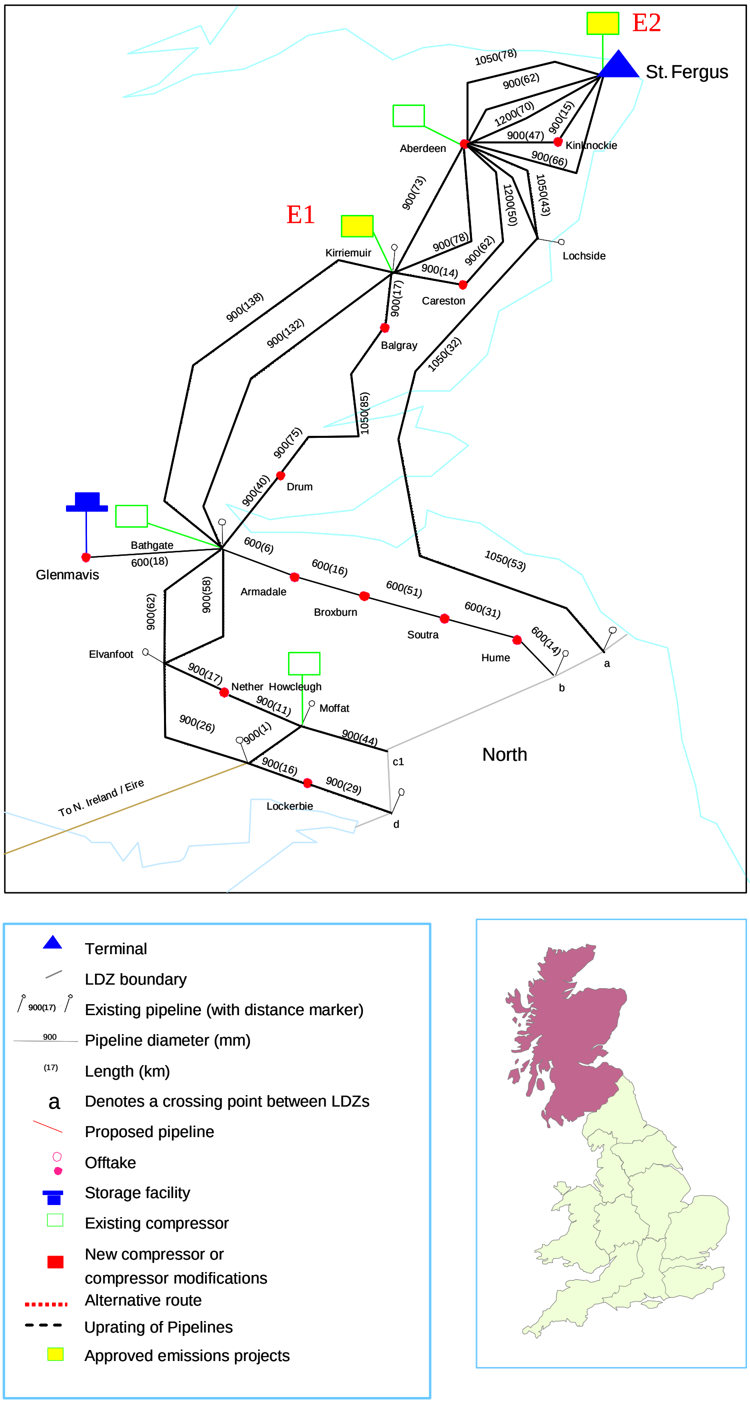
Notes

- *The minimum day for gas year 2008/09 refers to 15th August 2009. This was the overall lowest demand day, but individual LDZs may have seen lower demands on other days;*
- *NTS actual loads include interconnector demand;*
- *Due to linepack changes, there may be a small difference between total demand and total supply on the day;*
- *Figures may not sum exactly due to rounding.*

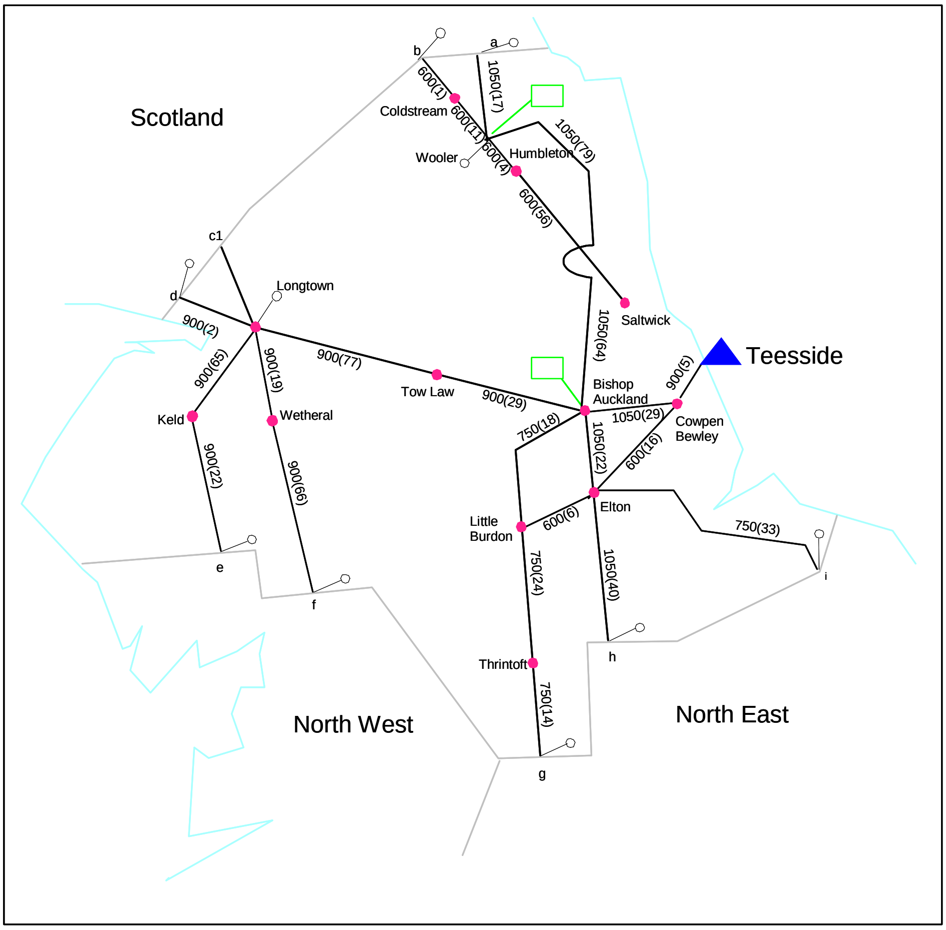
Appendix Four

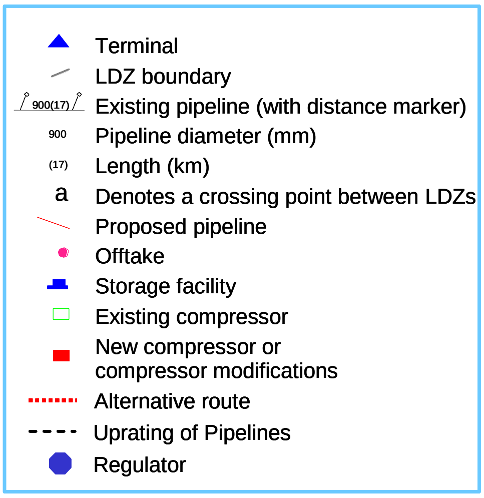
The Gas Transportation System

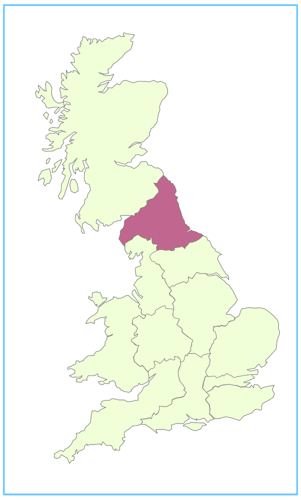
Scotland (SC) – NTS



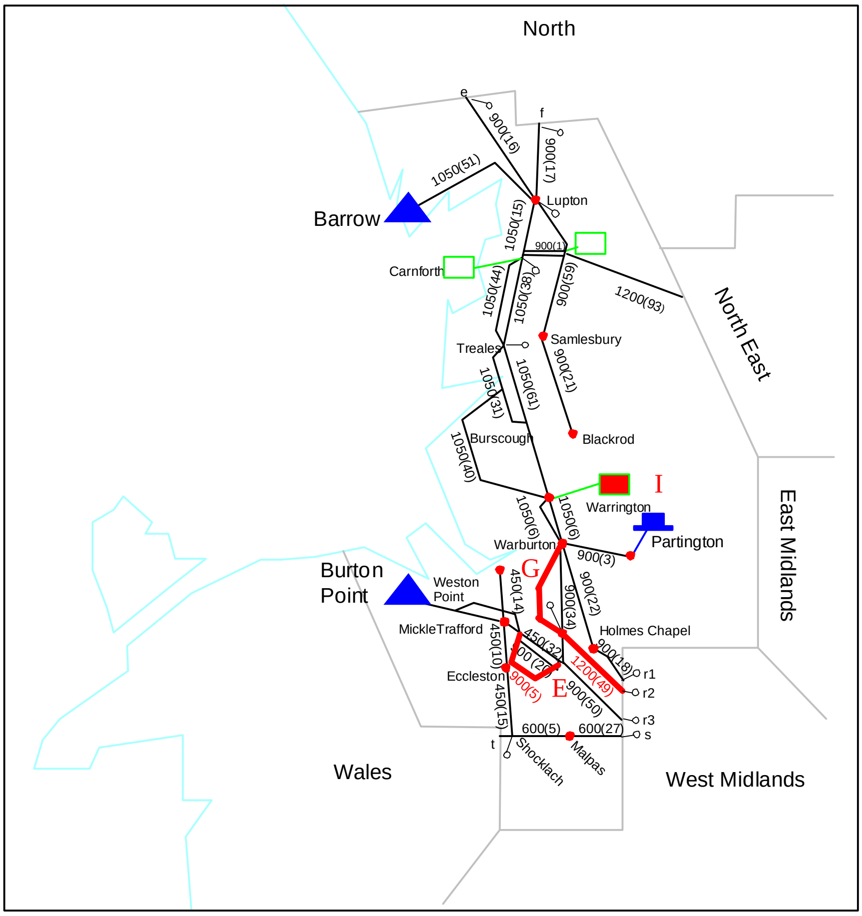
Northern (NO) – NTS

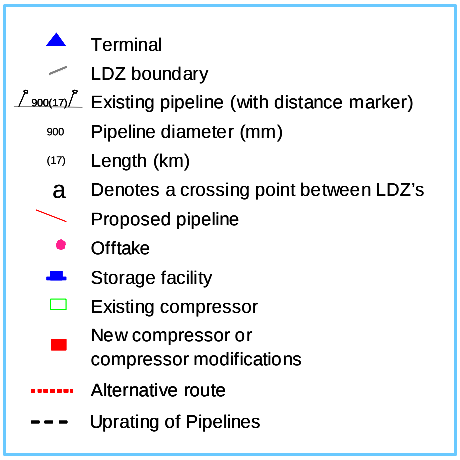


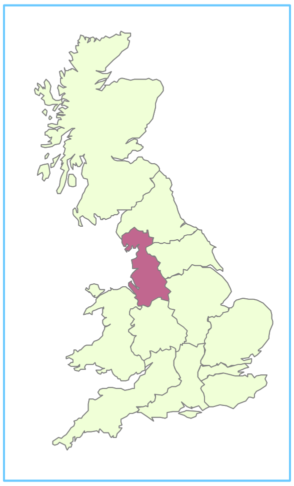




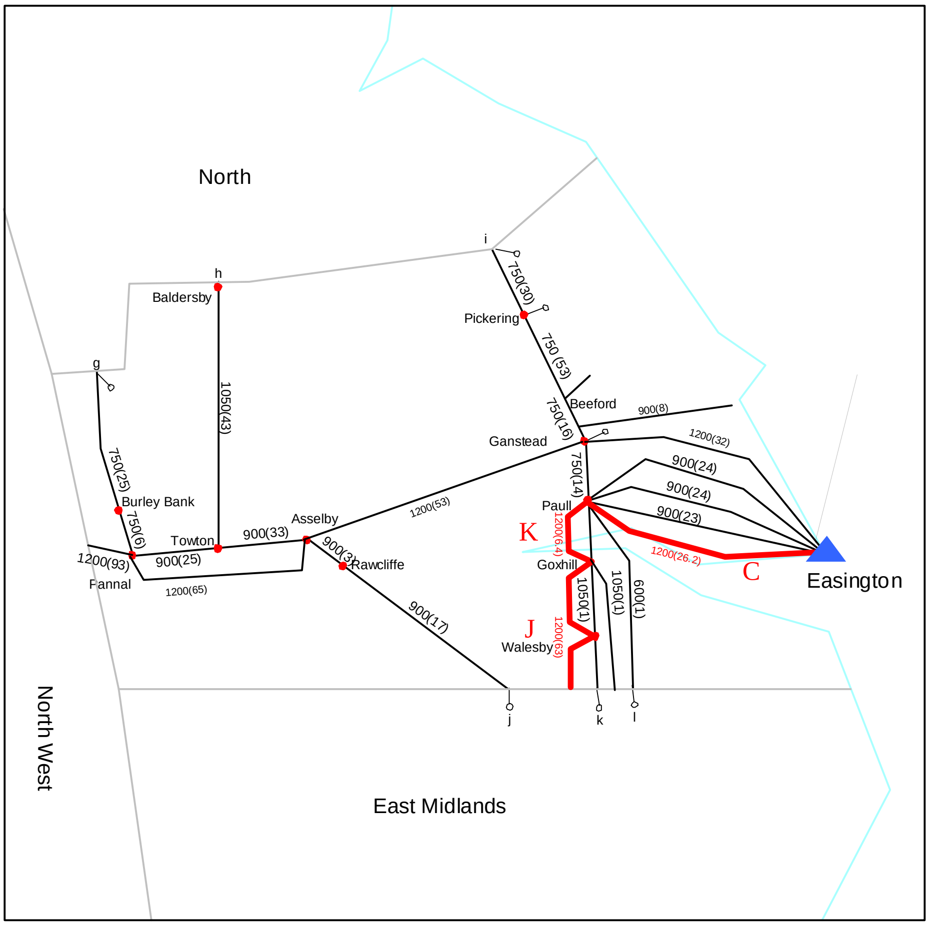
North West (NW) – NTS



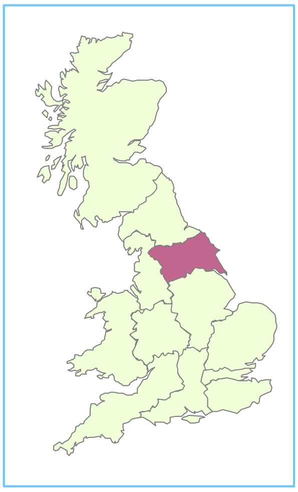




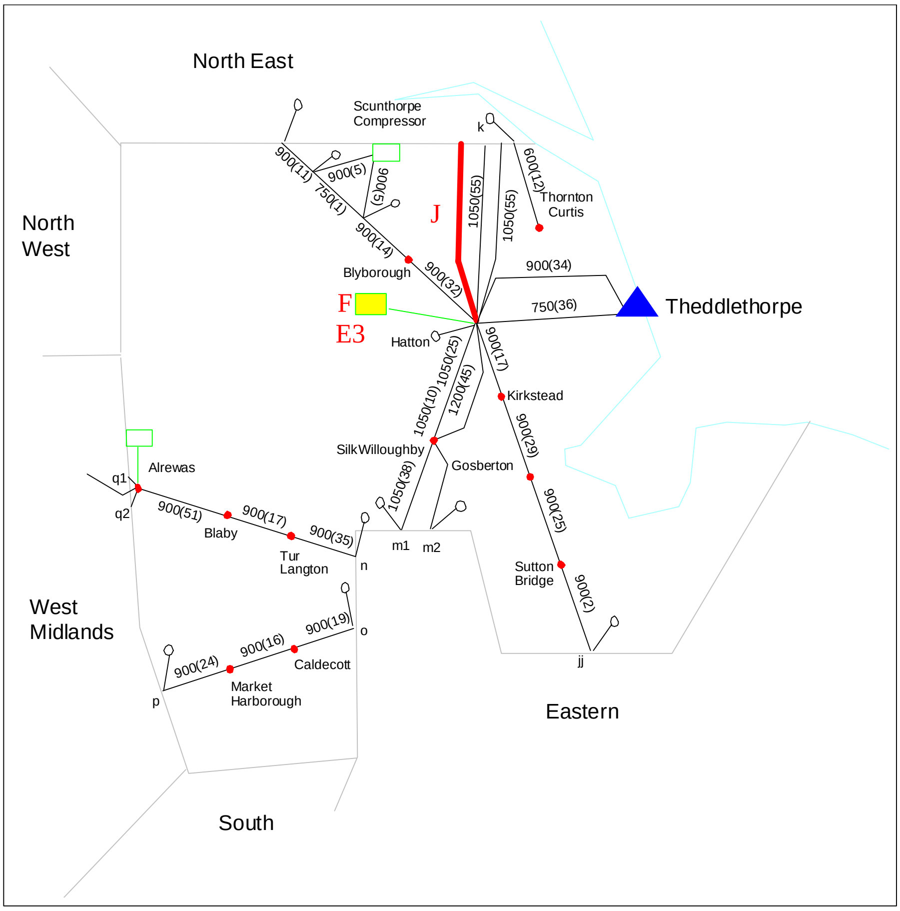
North East (NE) – NTS

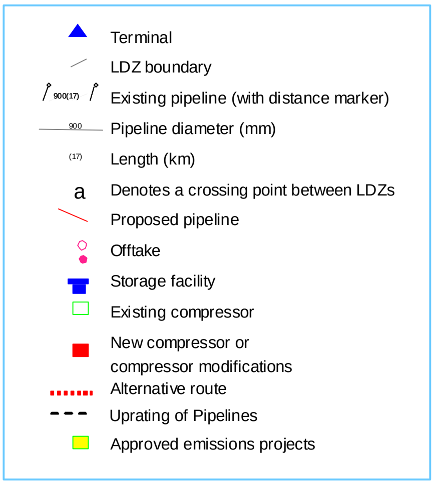


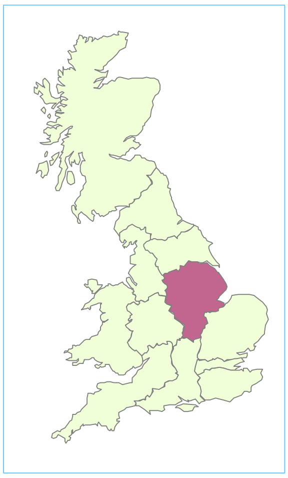
- Terminal
- LDZ boundary
- Existing pipeline (with distance marker)
- Pipeline diameter (mm)
- Length (km)
- a — Denotes a crossing point between LDZs
- Proposed pipeline
- Offtake
- Storage facility
- Existing compressor
- New compressor or compressor modifications
- Alternative route
- Uprating of Pipelines



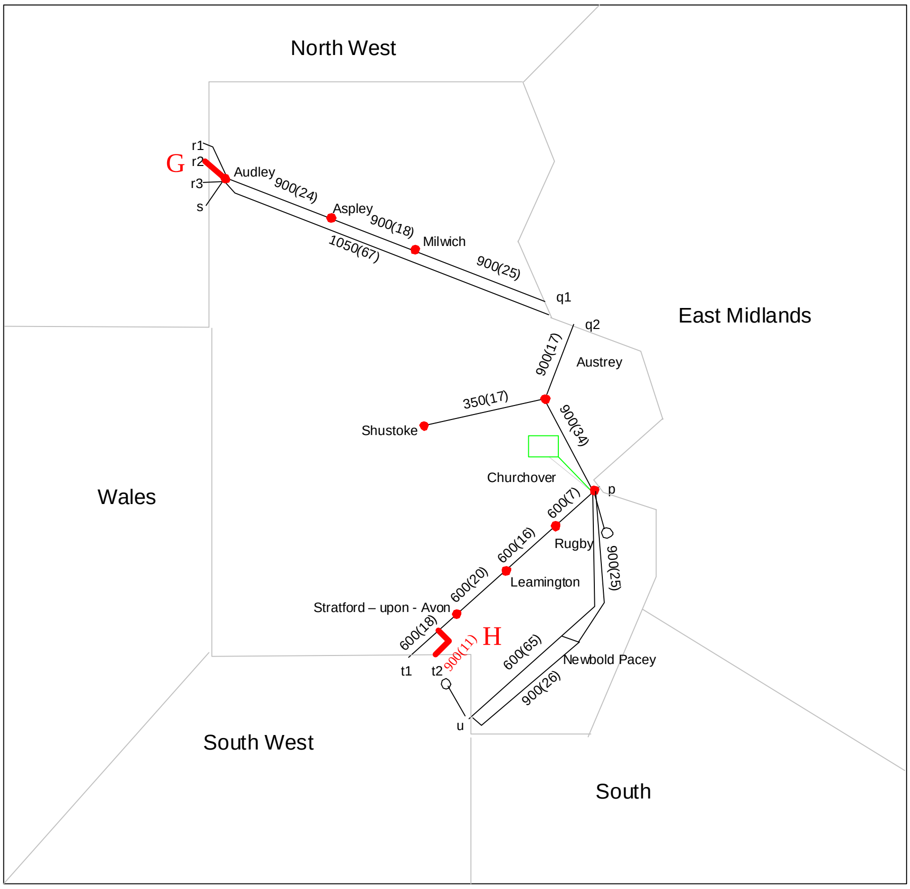
East Midlands (EM) – NTS



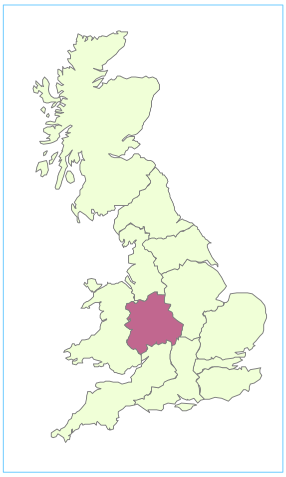




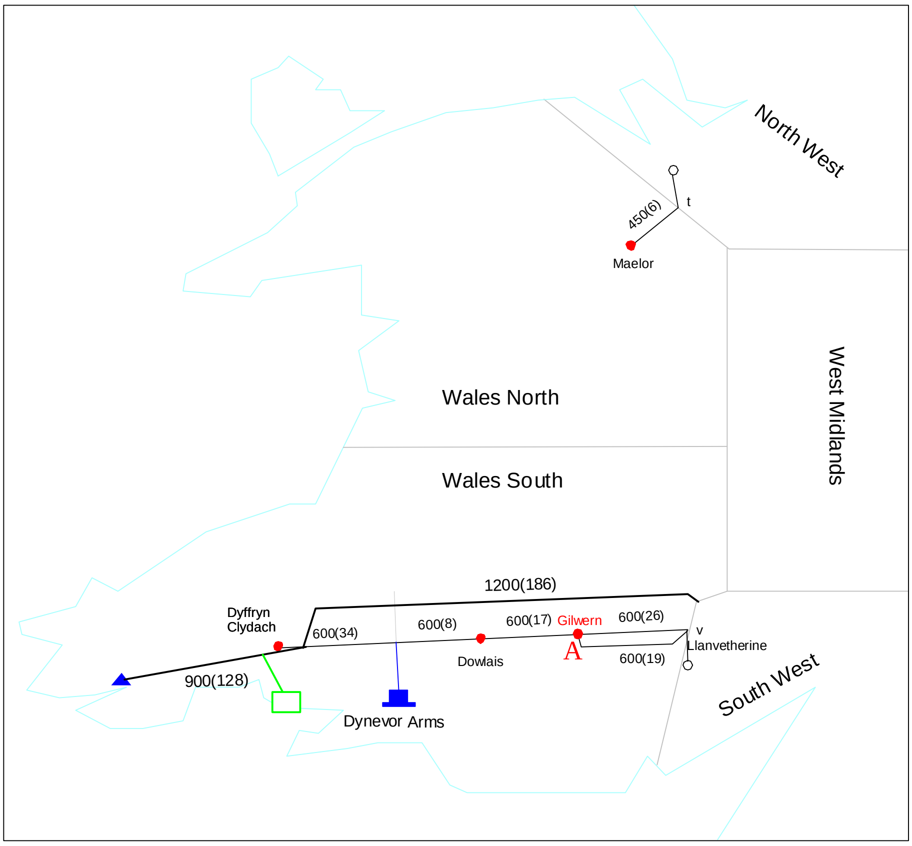
West Midlands (WM) – NTS



Terminal
LDZ boundary
900(17) Existing pipeline (with distance marker)
900 Pipeline diameter (mm)
(17) Length (km)
a Denotes a crossing point between LDZs
Proposed pipeline
Offtake
Storage facility
Existing compressor
New compressor or compressor modifications
Alternative route
Uprating of Pipelines



Wales (WN & WS) – NTS



- Terminal
- LDZ boundary
- 900(17) Existing pipeline (with distance marker)
- 900 Pipeline diameter (mm)
- (17) Length (km)
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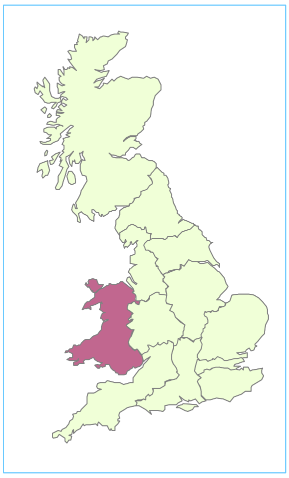
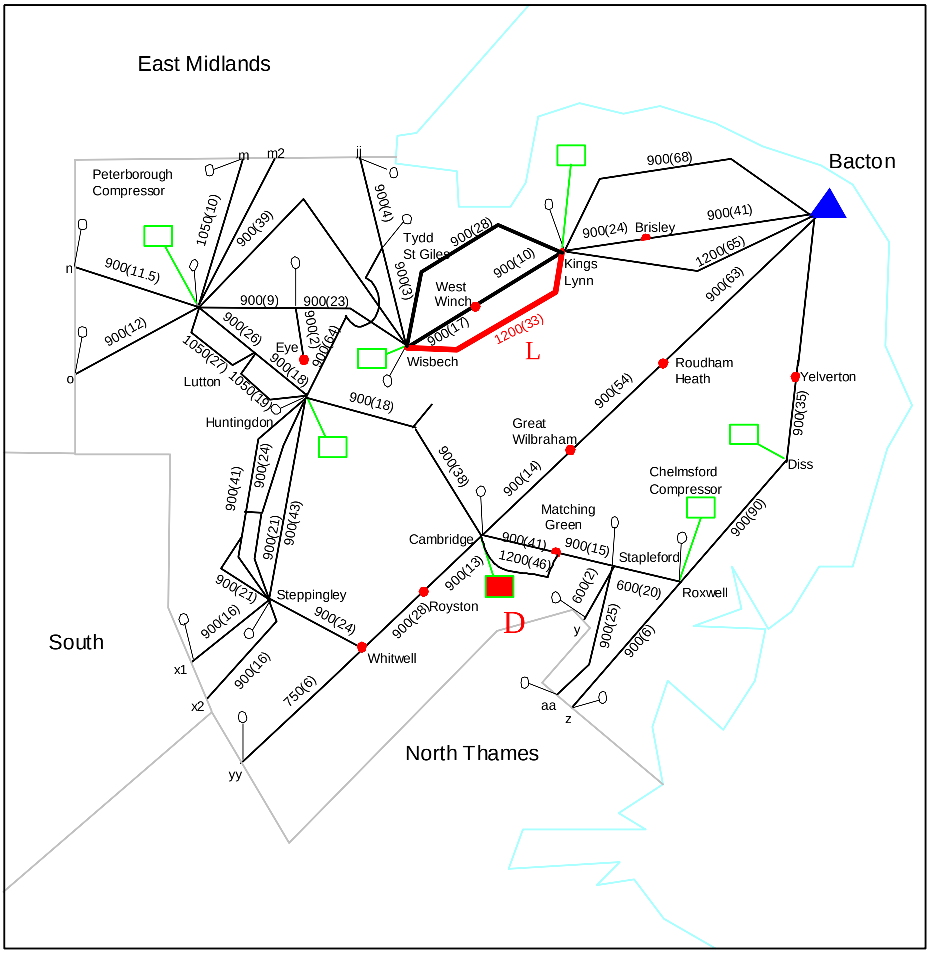
- Proposed pipeline
- Offtake
- Storage facility
- Existing compressor
- New compressor or compressor modifications
- Alternative route
- Uprating of Pipelines



Eastern (EA) – NTS



Terminal

LDZ boundary

900(17) Existing pipeline (with distance marker)

900 Pipeline diameter (mm)

(17) Length (km)

a Denotes a crossing point between LDZs

Proposed pipeline

Offtake

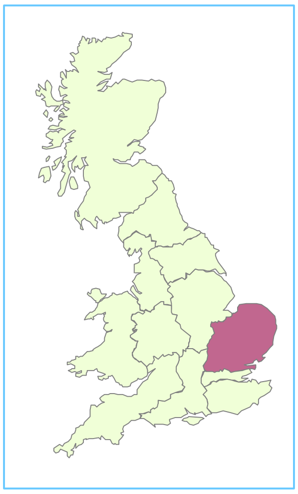
Storage facility

Existing compressor

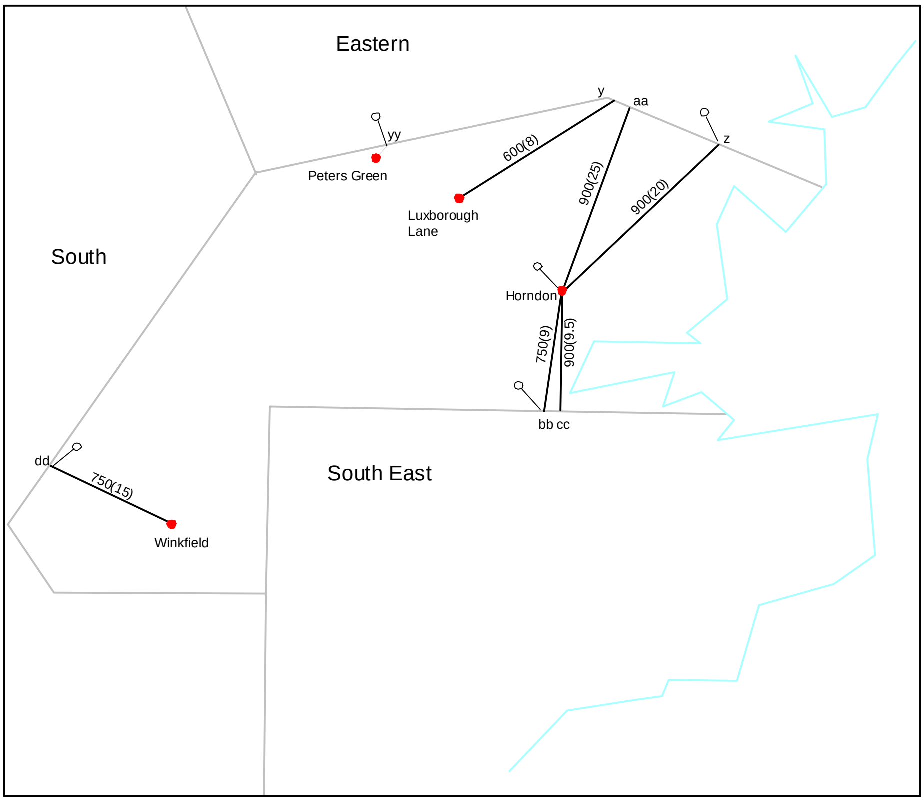
New compressor or compressor modifications

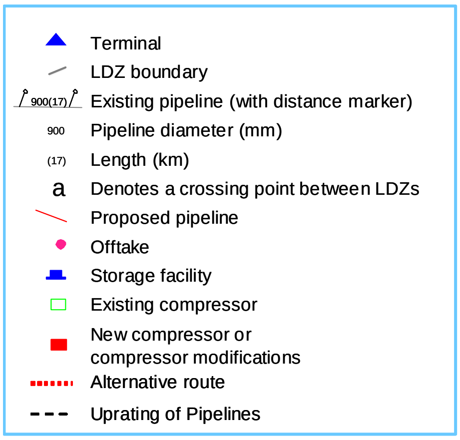
Alternative route

Uprating of Pipelines

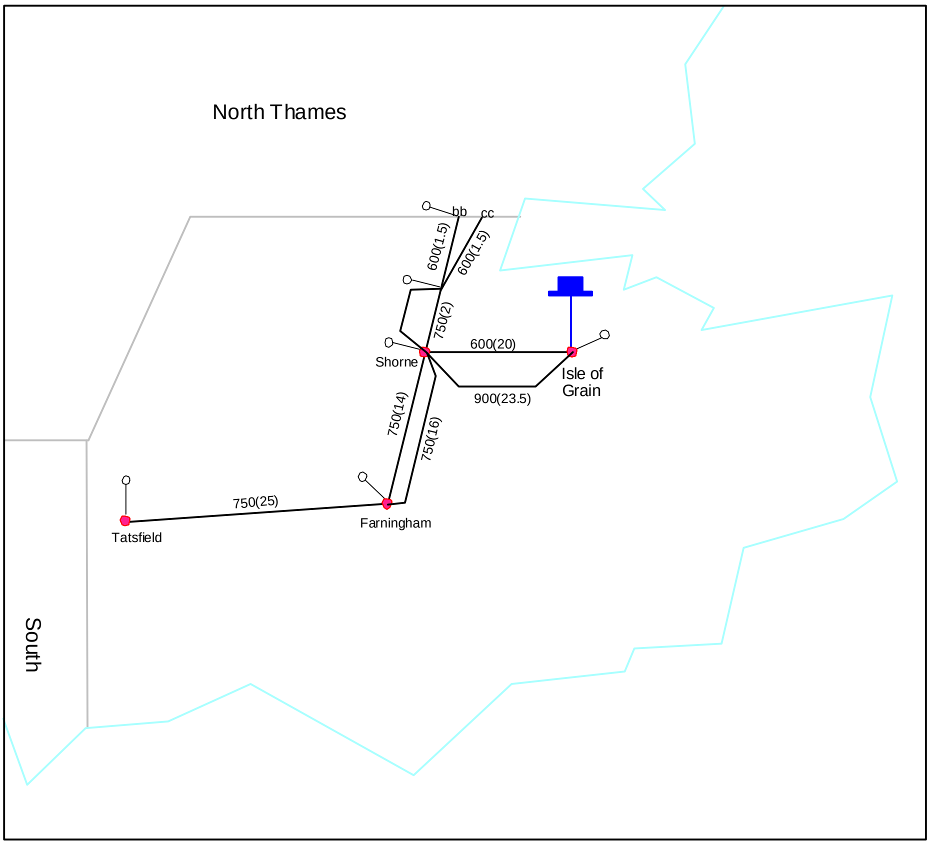


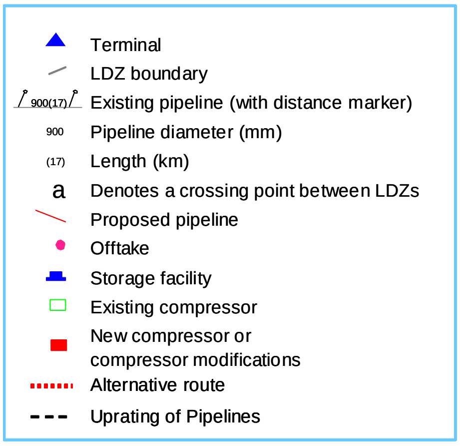
North Thames (NT) – NTS

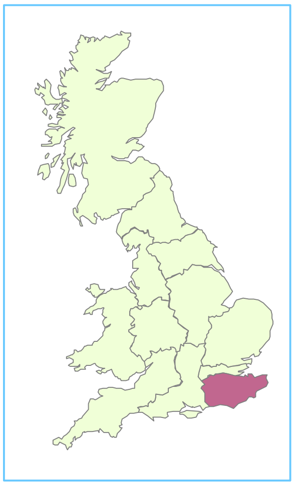




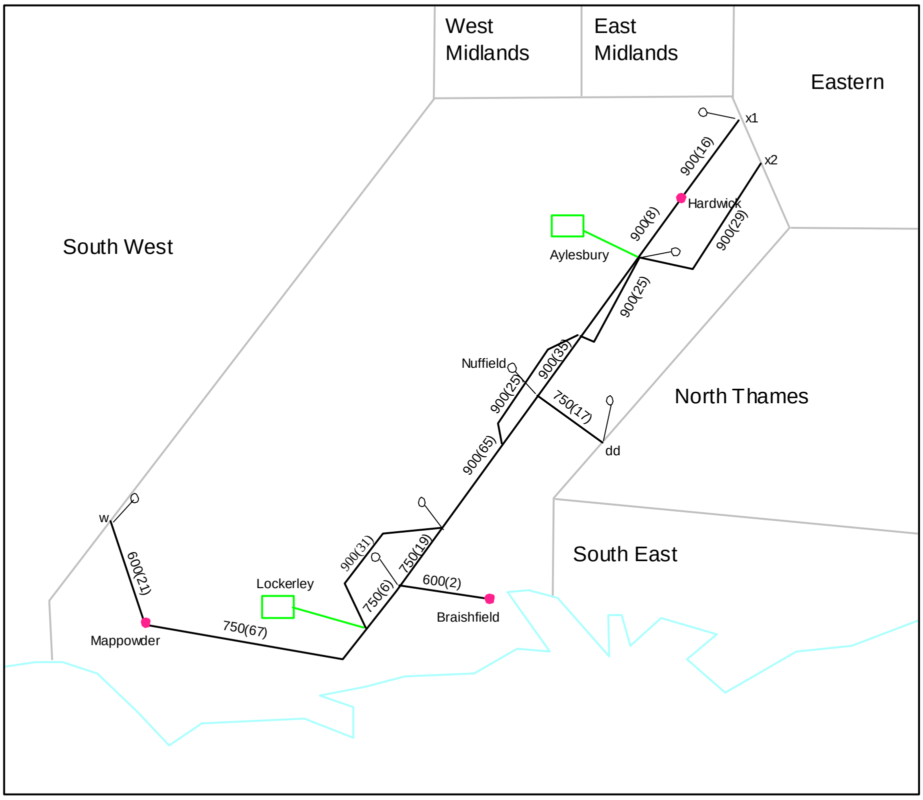
South East (SE) – NTS







South (SO) – NTS


West
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Midlands
Eastern
South West
North Thames
South East
x1
x2
900(16)
Hardwick
900(8)
900(29)
Aylesbury
900(25)
Nuffield
900(35)
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750(17)
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Lockerley
750(6)
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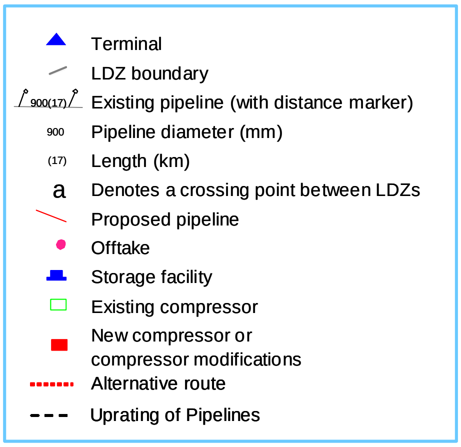
Braishfield
Mappowder
750(67)


Terminal
LDZ boundary
900(17)
Existing pipeline (with distance marker)
900
Pipeline diameter (mm)
(17)
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Storage facility
Existing compressor
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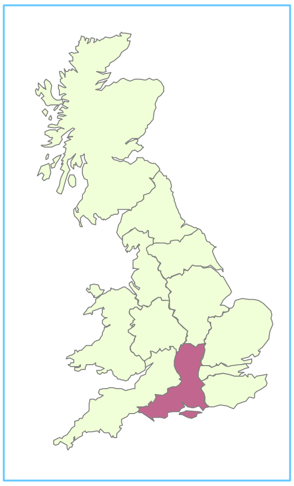
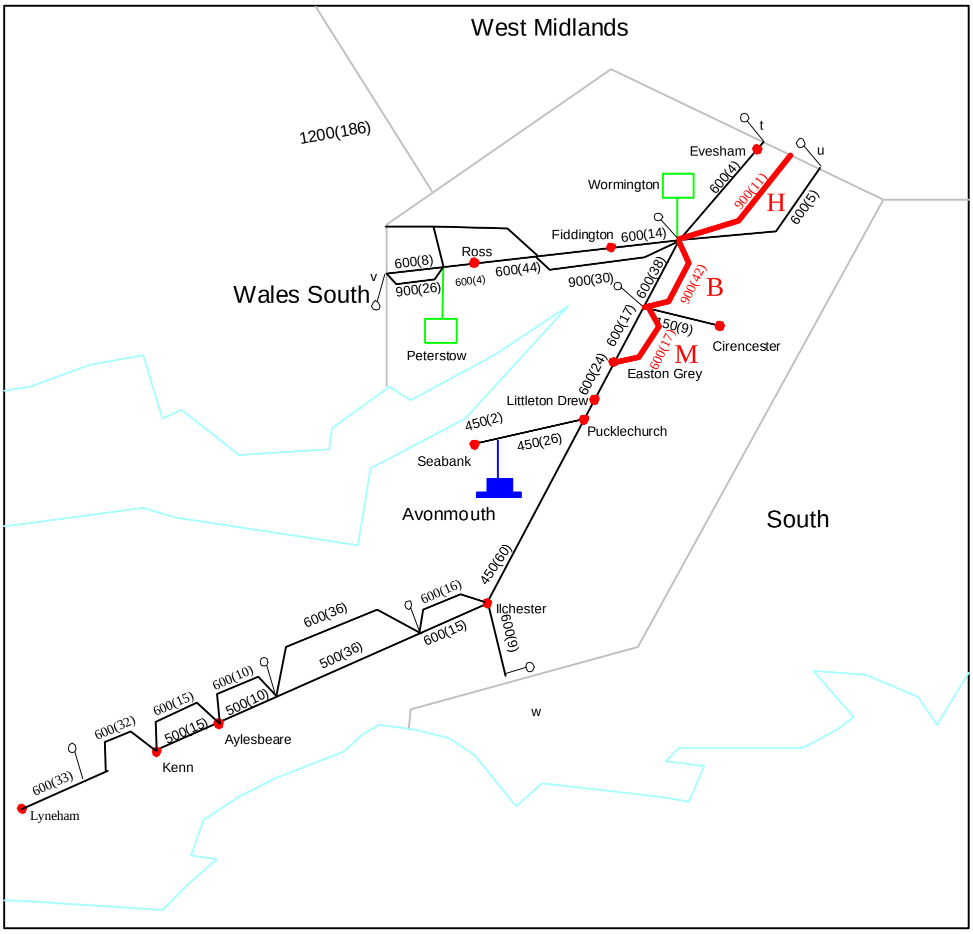
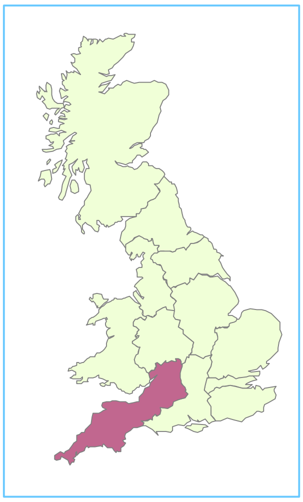
Alternative route
Uprating of Pipelines



South West (SW) – NTS



- Terminal
- LDZ boundary
- 900(17) Existing pipeline (with distance marker)
- 900 Pipeline diameter (mm)
- (17) Length (km)
- a Denotes a crossing point between LDZs
- Proposed pipeline
- Offtake
- Storage facility
- Existing compressor
- New compressor or compressor modifications
- Alternative route
- Uprating of Pipelines



Appendix Five

Connections to the National Transmission System (NTS)

A5.1 Introduction

We, and other gas transporters, continue to offer connection services in line with our Gas Act obligations. However customers and developers have the option to choose other parties to build their facilities, have the connection adopted by the host gas transporter (depending upon circumstances), pass assets to a chosen system operator, transporter, or retain ownership of them.

The following are the generic classes of connection:

- Entry Connections: connections to delivery facilities processing gas from gas producing fields or LNG vaporisation (i.e. importation) facilities, for the purpose of delivering gas into our system;
- Exit Connections: connections that allow gas to be offtaken from our system to premises (a 'Supply Point'), to a Distribution Network (DN) or to Connected Systems (at Connected System Exit Points' (CSEPs)). There are several types of connected system including:
    - A pipeline system operated by another gas transporter;
    - A pipeline operated by a party, who is not a gas transporter, for the purpose of transporting gas to premises consuming more than 2,196MWh per annum.
- Storage Connections: connections to storage facilities for the purpose of temporarily offtaking gas from our system and delivering it back at a later date;
- International Interconnector Connections: connections to pipelines connecting Great Britain to other countries that may both offtake gas from and/or deliver gas to our System.

Please note that Storage and International Interconnector Connections may both deliver gas to the system and offtake gas from the system and therefore specific arrangements pertaining to both Entry and Exit Connections will apply.

Any requirement to change the connection arrangements (e.g. increased supply of gas) at an existing connection will be treated in the same way as for a new connection.

A5.2 General Information Regarding Connections

Information relating to the processes for new connections and changes to existing connections can be found on our website (www.nationalgrid.com, select 'Gas', 'Connections', then 'Transmission Connections').

It should be noted that any person wishing to connect to the NTS or requiring changes to their existing connection arrangements should contact us as early as possible to ensure that requirements can be met in time, particularly as system reinforcements and/or a NTS Licence change may be required as outlined in A5.4.3 below.

Our connection charging policy for all categories of connection is set out in the publication "The Statement and Methodology for Gas Transmission Connection Charging" which complies with the "Licence Condition 4B Statement". A link to this document can be found within the connection information on our website referred to above.

A5.3 Additional Information Specific to System Entry, Storage and Interconnector Connections

We require a Network Entry Agreement, Storage Connection Agreement or Interconnector Agreement, as appropriate, with the respective operator of all delivery, storage and interconnector facilities to establish, among other things, the gas quality specification, the physical location of the delivery point and the standards to be used for both gas quality and the measurement of flow.

A5.3.1 Renewable Gas Connections

National Grid Transmission has a commitment to environmental initiatives that combat climate change. Recently we have started to receive an increasing number of customer requests regarding entry into our pipeline system for biomass derived renewable gas. In addition, we have also received a number of requests for gas entry from unconventional sources such as coal bed methane.

National Grid welcomes these developments and is willing to facilitate the connection of such supply sources to the network, however it must be identified that all existing network entry quality specifications as detailed in Section A5.3.2 still apply.

It should be recognised that biomass derived renewable gas may need to be connected to the Gas Distribution Networks instead of the National Transmission System, due to the pressure requirements. For information regarding connections to the Gas Distribution Networks please see the relevant documentation for the relevant Distribution Network (DN).

The twelve LDZs are managed within eight gas distribution networks. Following the sale by National Grid of four of the distribution networks, the owners of the distribution networks are now:

North West, London, West Midlands and East of England (East Midlands LDZ & East Anglia LDZ) are owned and managed by National Grid. To contact National Grid owned DNs about new connections please see Section 6 of the Long Term Development Plan, (directly via link or navigate from www.nationalgrid.com, select 'Gas', 'Ten Year Statement', then 'Long term Development Plan').

Scotland & South of England (South LDZ & South East LDZ) are owned and managed by Scotia Gas Networks – operating as Scotland Gas Networks and Southern Gas Networks respectively. For further information visit http://www.scotiagasnetworks.co.uk/

Wales and the West (Wales LDZ & South West LDZ) is owned and managed by Wales and West Utilities. For further information visit http://www.wwutilities.co.uk/

North of England (North LDZ & Yorkshire LDZ) is owned by Northern Gas Networks, who have contracted operational activities to United Utilities Operations. For further information visit http://www.northerngasnetworks.co.uk/

A5.3.2 Network Entry Quality Specification

For any new entry connection to our system, the connecting party should notify us as soon as possible as to the likely gas composition. We will then determine whether the gas can be accepted taking into account our existing statutory and contractual obligations. Our ability to accept gas supplies into the system is affected by, among other things, the composition of the new gas, the location of the system entry point, volumes entered and the quality and volumes of gas already being transported within the system. In assessing the acceptability of any proposed new gas supply, we will take account of:

a) Our ability to continue to meet statutory obligations (including, but not limited to, the Gas Safety (Management) Regulations 1996 (GS(M)R));

b) The implications of the proposed gas composition on system running costs; and

c) Our ability to continue to meet our contractual obligations

For indicative purposes, the specification set out below is usually acceptable for most locations. This specification encompasses but is not limited to the statutory requirements set out in the GS(M)R and was considered by the Government in the "Future Arrangements For Great Britain's Gas Quality Specifications" consultation (the 3-phase gas quality exercise)[23].

1. Hydrogen Sulphide
   - Not more than 5mg/m^3
2. Total Sulphur
   - Not more than 50mg/m^3
3. Hydrogen
   - Not more than 0.1% (molar)
4. Oxygen
   - Not more than 0.001% (molar)
5. Hydrocarbon Dewpoint
   - Not more than -2°C at any pressure up to 85barg
6. Water Dewpoint
   - Not more than -10°C at 85barg
7. Wobbe Number (real gross dry)
   - The Wobbe Number shall be in the range 47.20 to 51.41MJ/m^3
8. Incomplete Combustion Factor (ICF)
   - Not more than 0.48
9. Soot Index (SI)
   - Not more than 0.60
10. Gross Calorific Value (real gross dry)

[23] http://www.berr.gov.uk/consultations/page15294.html

- The Gross Calorific Value (real gross dry) shall be in the range 36.9 to 42.3MJ/m^3, in compliance with the Wobbe Number, ICF and SI limits described above. Subject to gas entry location and volumes, we may set a target for the Calorific Value within this range.

11. Carbon Dioxide
    - Not more than 2.5% (molar)
12. Contaminants
    - The gas shall not contain solid, liquid or gaseous material that may interfere with the integrity or operation of pipes or any gas appliance within the meaning of regulation 2(1) of the Gas Safety (Installation and Use) Regulations 1998 that a consumer could reasonably be expected to operate
13. Organo Halides
    - Not more than 1.5 mg/m^3
14. Radioactivity
    - Not more than 5 Becquerels/g
15. Odour
    - Gas delivered shall have no odour that might contravene the statutory obligation not to transmit or distribute any gas at a pressure below 7 barg, which does not possess a distinctive and characteristic odour
16. Pressure
    - The delivery pressure shall be the pressure required to deliver natural gas at the Delivery Point into our Entry Facility at any time taking into account the back pressure of our System at the Delivery Point as the same shall vary from time to time
    - The entry pressure shall not exceed the Maximum Operating Pressure at the Delivery Point.
17. Delivery Temperature
    - Between 1°C and 38°C

Note that the Incomplete Combustion Factor (ICF) and Soot Index (SI) have the meanings assigned to them in Schedule 3 of the GS(M)R.

In addition, where limits on gas quality parameters are equal to those stated in GS(M)R (Hydrogen Sulphide, Total Sulphur, Hydrogen, Wobbe Number, Soot Index and Incomplete Combustion Factor), we may require an operational tolerance to be included within an agreement to ensure compliance with the GS(M)R.

Due to continuous changes being made to the system, any undertaking made by us on gas quality prior to signing an agreement will normally only be indicative.

A5.3.3 Gas Quality Developments

The UK Government's 3-phase gas quality exercise, initiated in 2003, concluded in 2007 with the Government reaffirming that it will not propose to the Health and Safety Commission to make any changes to the GB gas specifications contained in the GS (M)R. The Government's forward plan proposed continued engagement with the European Commission and Member States on the issue of gas quality, with particular regard to the CEN (Comité Europeén de Normalisation, European committee for standardisation) mandate, of which the first phase will establish a better understanding of appliance performance and design and is on schedule to report in December 2010. The Government has indicated that it may consider reviewing its current policy position in light of evidence and conclusions from this first phase.

The Government also expressed strong support for Ofgem's current work in exploring the commercial flexibilities for the GB gas market to handle gases of different specifications. Following a series of workstreams on gas quality scenario development and economic regulation during 2006, Ofgem issued a consultation document in July 2007 setting out key issues and initial thoughts on the economic regulation of gas processing facilities.

This year, a number of factors have combined to provide a fresh stimulus to work in this area. These include continental developments that could, under some circumstances, combine to limit the UK's ability to import gas due to differences in prevailing gas quality specifications between the UK and continental Europe, expectations about the growth of unconventional sources of gas supplies within the UK such as coal bed methane and biomethane and their potential impacts on the Calorific Value (CV) regime and the potential gas quality issues caused by the decline of the UKCS. We look forward to further exploring these issues and potential solutions with the relevant authorities and the industry.

A5.4 Additional Information Specific to System Exit Connections

Any person can contact us to request a connection, whether a shipper, operator, developer or consumer. However, gas can only be offtaken from that new Supply Point if it has been confirmed by a shipper, in accordance with the Uniform Network Code.

A5.4.1 National Transmission System (NTS) Offtake Pressures

The Applicable Offtake Pressure for the NTS, as referred to in the Uniform Network Code Section J 2.1 is normally 25barg. Although system pressure is typically higher, it will be subject to variation over time and location on the network. We currently plan normal NTS operations with start of day pressures no lower than 33barg, but such pressure cannot be guaranteed as pressure management is a fundamental aspect of the operation of an economic and efficient system.

NTS offtake pressures at any location will vary due to:

- gas demand
- gas supply pressures at entry points
- compressor operation
- pipeline sizes and maximum operating pressures
- special operations such as maintenance and system development works

Offtake pressure also varies within day, from day to day, season to season and year to year. As a general rule, NTS offtake pressures tend to be higher at pressure sources such as entry points and outlets of operating compressors, and lower at the system extremities and inlets to operating compressors.

Our policy is to provide, on reasonable request, forecast information and illustrative historical records for specific NTS connection enquiries.

Notwithstanding the above, shippers may request a "specified pressure" for any Supply Meter Point, connected to any pressure tier, in accordance with the Uniform Network Code Section J 2.2.

A5.4.2 Connecting Pipelines

Where a party wishes to lay their own connecting pipeline from the NTS to premises expected to consume more than 2,196MWh per annum, ownership of the pipe shall remain with that party. This is National Grid's preferred approach for connecting pipelines.

However, the "The Statement and Methodology for Gas Transmission Connection Charging" describes alternative options regarding installation and ownership of connecting pipelines, though the costs of the pipeline remain with the connecting party for all options.

A5.4.3 Reasonable Demands for Capacity

Operating under the Gas Act 1986 (as amended 1995), we have an obligation to develop and maintain an efficient and economical pipeline system and, subject to that, to comply with any reasonable request to connect premises, provided that it is economic to do so.

In many instances, specific system reinforcement may be required to maintain system pressures for the winter period after connecting a new supply or demand. Details of how we charge for reinforcement and the basis on which contributions may be required can be found in the publication "The Statement and Methodology for Gas Transmission Connection Charging" . Please note that dependent on scale, reinforcement projects may have significant planning, resourcing and construction lead-times and that as much notice as possible should be given. In particular, we will typically require three to four years' notice of any project requiring the construction of high pressure pipelines or plant, although in certain circumstances, project lead-times may exceed this period.

Appendix Six

Industry Terminology

Advanced Reservation of Capacity Agreement (ARCA)

An agreement between us and Shippers relating to future NTS pipeline capacity for large sites in order that Shippers can book NTS Exit Capacity in accordance with Uniform Network Code provision to meet gas requirements of large projects at a later date.

Annual Quantity (AQ)

The AQ of a supply point is its annual consumption over a 365-day year, under conditions of average weather.

Balgzand – Bacton Line (BBL)

Interconnector pipeline connecting Balgzand in the Netherlands to Bacton in the UK. This pipeline is currently uni-directional and flows from the Netherlands to the UK only.

Bar

The unit of pressure that is approximately equal to atmospheric pressure (0.987 standard atmospheres). Where bar is suffixed with the letter g, such as in barg or mbarg, the pressure being referred to is gauge pressure, i.e. relative to atmospheric pressure.
One millibar (mbarg) equals 0.001 bar.

Barrel

The unit of volume that oil is bought and sold in. 1 barrel is equal to approximately 35 gallons in volume terms and 56 therms in energy terms.

BERR

Business Enterprise and Regulatory Reform. A government department that used to have a responsibility over energy matters, however these energy responsibilities have now moved to the new Department for Energy and Climate Change. Some references to BERR still exist and some energy related publications still reside on the BERR website, although the responsibility now resides with DECC.

British Electricity Transmission and Trading Arrangements (BETTA)

The introduction of a Great Britain-wide electricity market, with a single set of wholesale electricity transmission and trading arrangements, based on the New Electricity Trading Arrangements (NETA) introduced in England and Wales in 2001.

Calorific Value (CV)

The ratio of energy to volume measured in Megajoules per cubic metre (MJ/m^3), which for a gas is measured and expressed under standard conditions of temperature and pressure.

Climate Change Levy (CCL)

Government tax on the use of energy within industry, commerce and the public sector in order to encourage energy efficient schemes and use of renewable energy sources. CCL is part of the government's Climate Change Programme (CCP).

Composite Weather Variable (CWV)

A single measure of weather for each LDZ, incorporating the effects of both temperature and wind speed. A separate composite weather variable is defined for each LDZ.

Combined Cycle Gas Turbine (CCGT)

A Combined Cycle Gas Turbine is a unit whereby electricity is generated by a gas powered turbine and also a second turbine. The hot exhaust gases expelled from the first turbine are fed into the heat exchanger to generate steam, which powers the second turbine.

Carbon Capture and Storage (CCS)

The process by which carbon dioxide emissions from a carbon dioxide emitter (generally considered to be a powerstation or large industrial unit) are separated from the exhaust gasses and transported to a storage facility (usually depleted oil or gas fields) in order to reduce its effect on climate change. This is a very new process. It is covered more in Chapter 7.4

CO_2e

Carbon Dioxide equivalent. A term used relating to climate change that accounts for the "basket" of greenhouse gasses and their relative effect on climate change compared to Carbon Dioxide. For example UK emissions are roughly 600 m tonnes CO_2e. This constitutes roughly 450m tonnes CO_2 and less than the 150m tonnes remaining of more potent greenhouse gasses such as Methane; which has 21times more effect as a greenhouse gas, hence its contribution to CO_2e will be 21 times it mass.

Combined Heat and Power (CHP)

The simultaneous generation of electricity and heat for use within buildings or processes, by recovery of the heat produced in the power generation process. As such, CHP represents the highest efficiency means of generating electricity.

Compressor Station

An installation that uses gas turbine or electricity driven compressors to boost pressures in the pipeline system. Used to increase transmission capacity and move gas through the network.

Connected System Exit Point (CSEP)

A connection to a more complex facility than a single supply point. For example a connection to a pipeline system operated by another Gas Transporter.

Cubic Metre (m^3)

The unit of volume, expressed under standard conditions of temperature and pressure, approximately equal to 35.37 cubic feet. One million cubic metres (mcm) are equal to 10^6 cubic metres, one billion cubic metres (bcm) equals 10^9 cubic metres.

Daily Flow Notification (DFN)

A communication between a Delivery Facility Operator (DFO) and us, indicating hourly and end of day entry flows from that facility.

Daily Metered Supply Point

A supply point fitted with equipment, for example a datalogger, which enables meter readings to be taken on a daily basis. Further classified as SDMC, DMA, DMC or VLDMC according to annual consumption.

Datalogger

An electronic device that automatically records, stores and transmits meter readings (such transmission usually being via PSTN lines).

DECC

Department of Energy and Climate Change. DECC was formed in 2008 from the Energy Division of BERR and parts of DEFRA. Some references to BERR still exist and some energy related publications still reside on the BERR website, although the responsibility now resides with DECC.

Delivery Facility Operator (DFO)

Operators of the reception terminals, which process and meter gas deliveries from offshore pipelines before transferring the gas to our system.

Distribution Network (DN)

An administrative unit responsible for the operation and maintenance of the local transmission system (LTS) and <7barg distribution networks within a defined geographical boundary. There are currently eight DNs, each consisting of one or more LDZs, supported by a national Emergency Services organisation.

Distribution System

A network of mains operating at three pressure tiers: intermediate (2 to 7barg), medium (75mbarg to 2barg) and low (less than 75mbarg).

Diurnal Storage

Gas stored for the purpose of meeting, among other things, within day variations in demand. Gas can be stored in special installations, such as gasholders, or in the form of linepack within transmission, i.e. >7barg, pipeline systems.

European Union Emissions Trading Scheme (EU ETS)

European Union market based policy commencing on 1st January 2005 to tackle emissions of carbon dioxide and other greenhouse gases, in order to help combat climate change.

Exit Zone

A geographical area (within an LDZ) that consists of a group of supply points that, on a peak day, receive gas from the same NTS offtake.

Gas Balancing Alert (GBA)

The purpose of the Gas Balancing Alert (GBA) is to indicate a potential requirement for demand response.

Gas Transporter (GT)

Formerly Public Gas Transporter (PGT). GTs, such as National Grid, are licensed by the Gas and Electricity Markets Authority to transport gas to consumers.

Gasholder

A vessel used to store gas for the purposes of providing diurnal storage.

Gas Supply Year

A twelve-month period commencing 1st October, also referred to as a Gas Year.

Interconnector

A pipeline transporting gas to another country. The Irish Interconnector transports gas across the Irish Sea to both the Republic of Ireland and Northern Ireland. The Belgian Interconnector transports gas between Bacton and Zeebrugge. The Belgian Interconnector is capable of flowing gas in either direction. The Dutch Interconnector (BBL) transports gas between Balgzand in the Netherlands and Bacton. It is currently capable of flowing only from the Netherlands to the UK.

Interruptible Service

Gas transportation service where the transporter has rights to interrupt the supply of gas to customers in certain circumstances.

Kilowatt hour (kWh)

A unit of energy used by the gas industry. Approximately equal to 0.0341 therms. One Megawatt hour (MWh) equals 10^3 kWh, one Gigawatt hour (GWh) equals 10^6 kWh, and one Terawatt hour (TWh) equals 10^9 kWh.

Large Combustion Plant Directive (LCPD)

European Union directive, effective from 2008, which aims to control emissions of sulphur dioxide, nitrogen oxides and dust from large combustion plants, including power stations.

Linepack

The volume of gas within the National or Local Transmission System at any time.

Liquefied Natural Gas (LNG)

Gas stored and / or transported in liquid form.

Load Duration Curve (1 in 50 Severe)

The 1 in 50 severe load duration curve is that curve which, in a long series of years, with connected load held at the levels appropriate to the year in question, would be such that the volume of demand above any given demand threshold (represented by the area under the curve and above the threshold) would be exceeded in one out of fifty years.

Load Duration Curve (Average)

The average load duration curve is that curve which, in a long series of winters, with connected load held at the levels appropriate to the year in question, the average volume of demand above any given threshold, is represented by the area under the curve and above the threshold.

Local Distribution Zone (LDZ)

A geographic area supplied by one or more NTS offtakes. Consists of LTS and distribution system pipelines.

Local Transmission System (LTS)

A pipeline system operating at >7barg that transports gas from NTS offtakes to distribution systems. Some large users may take their gas direct from the LTS.

Long Term System Entry Capacity (LTSEC)

NTS entry capacity available on a long-term basis (up to 17 years into the future) via an auction process. Also known as Quarterly System Entry Capacity (QSEC).

National Balancing Point (NBP)

A notional point which represents the NTS for balancing purposes.

National Transmission System (NTS)

A high-pressure system consisting of terminals, compressor stations, pipeline systems and offtakes. Designed to operate at pressures up to 85 bar. NTS pipelines transport gas from terminals to NTS offtakes.

National Transmission System Offtake

An installation defining the boundary between NTS and LTS or a very large consumer. The offtake installation includes equipment for metering, pressure regulation, etc..

NISM

Notice of Inadequate System Margin. A electricity market notice, published by National Grid that intends to trigger extra electricity generation or demand reduction.

Non-Daily Metered (NDM)

A meter that is read monthly or at longer intervals. For the purposes of daily balancing, the consumption is apportioned, using an agreed formula, and for supply points consuming more than 73.2MWh pa, reconciled individually when the meter is read.

Odourisation

The process by which the distinctive odour is added to gas supplies to make it easier to detect leaks. We provide odourisation at NTS offtakes.

Office of Gas and Electricity Markets (Ofgem)

The regulatory agency responsible for regulating Great Britain’s gas and electricity markets.

On the day Commodity Market (OCM)

This market enables anonymous financially cleared on the day trading between market participants.

Operating Margins

Gas used by us to maintain system pressures under certain circumstances, including periods immediately after a supply loss or demand forecast change, before other measures become effective and in the event of plant failure, such as pipe breaks and compressor trips.

Own Use Gas (OUG)

Gas used by us to operate the transportation system. Includes gas used for compressor fuel, heating and venting.

Price Control Review (PCR)

Ofgem's periodic review of our allowed returns. The next PCR will set returns for the period April 2012 to March 2017.

Peak Day Demand (1 in 20 Peak Demand)

The 1 in 20 peak day demand is the level of demand that, in a long series of winters, with connected load held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters, with each winter counted only once.

QSEC

Quarterly System Entry Capacity – see LTSEC

ROC

Renewable Obligation Certificate. Administered by Ofgem. Awarded to owners of renewable projects for renewably generated electricity. Large electricity generators are required to have a minimum amount of electricity generated from renewable generation, any less and ROCs have to be bought to cover the shortfall, any excess can be sold via ROCs.

Safety Monitors

The Total Firm Monitors is illustrative and designed to identify the storage (space) requirements to meet firm demand under severe conditions. There is now only one firm monitor for all storage facilities. The firm monitor is determined by National Grid to meet its Uniform Network Code requirements. The Firm monitor is illustrative for shippers to determine their storage needs through the winter, National Grid does not take any action in order to prevent a breach of the firm monitors.

GS(M)R Safety Monitors in terms of space and deliverability are minimum storage requirements to protect loads that can not be isolated from the network and also to support the process of isolating large loads from the network. The resultant storage stocks or monitors are designed to ensure that sufficient gas is held in storage to underpin the safe operation of the gas transportation system under severe conditions. There is now just a single safety monitors for space and one for deliverability. These are determined by National Grid to meet its Uniform Network Code requirements and the terms of its Safety Case. Total shipper gas stocks should not fall below the relevant monitor level (which declines as the winter progresses). National Grid is required to take action (which may include use of emergency procedures) in order to prevent a breach of these monitors.

Seasonal Normal Composite Weather Variable (SNCWV)

The seasonal normal value of the CWV for a LDZ on a day is the smoothed average of the values of the applicable CWV for that day in a significant number of previous years.

Shearwater Elgin Area Line (SEAL)

The offshore pipeline from the Central North Sea (CNS) to Bacton.

Shipper or Uniform Network Code Registered User (System User)

A company with a Shipper Licence that is able to buy gas from a producer, sell it to a supplier and employ a GT to transport gas to consumers.

Shrinkage

Gas that is input to the system but is not delivered to consumers or injected into storage. It is either Own Use Gas or Unaccounted for Gas.

Supplier

A company with a Supplier's Licence contracts with a shipper to buy gas, which is then sold to consumers. A supplier may also be licensed as a shipper.

Supply Hourly Quantity (SHQ)

The maximum hourly consumption at a supply point.

Supply Offtake Quantity (SOQ)

The maximum daily consumption at a supply point.

Supply Point

A group of one or more meters at a site.

Therm

An imperial unit of energy. Largely replaced by the metric equivalent: the kilowatt hour (kWh). 1 therm equals 29.3071 kWh.

Transporting Britain's Energy (TBE)

Our annual industry-wide consultation process encompassing the Ten Year Statement, targeted questionnaires, individual company and industry meetings, feedback on responses and investment scenarios.

Unaccounted for Gas (UAG)

Gas lost during transportation. Includes leakage, theft and losses due to the method of calculating the Calorific Value.

Uniform Network Code (UNC)

The Uniform Network Code replaced the Network Code and, as well as covering the arrangements within the Network Code, covers the arrangements between National Grid and the Distribution Networks.

UKCS

United Kingdom Continental Shelf.

Appendix Seven

Conversion Matrix

To convert from the units on the left hand side to the units across the top multiply by the values in the table.

	To: Multiply	**GWh**	**Mcm**	**Million therms**	**Thousand toe**
From:	**GWh**	1	0.091	0.034	0.086
	Mcm	11	1	0.375	0.946
	Million Therms	29.307	2.664	1	2.520
	Thousand toe	11.630	1.057	0.397	1

Note: all volume to energy conversions assume a CV of 39.6 MJ/m^3

GWh = Gigawatt Hours
mcm = Million Cubic Metres
Thousand toe = Thousand Tonne of Oil Equivalent

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