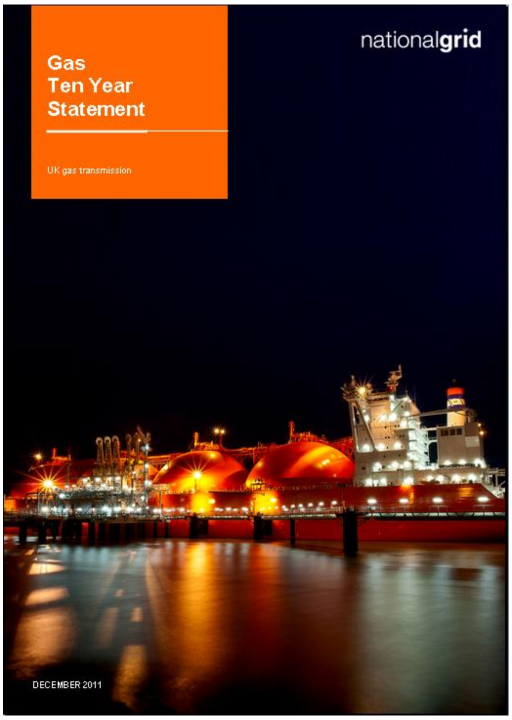
nationalgrid

Gas Ten Year Statement

UK gas transmission

DECEMBER 2011

Cover Picture



- Ship name - "Arctic Princess" - Phase 3 Commissioning cargo docking at the Isle of Grain LNG[1] terminal 17th November 2010.
- When built, the Arctic Princess was the largest LNG ship ever built. It has a capacity around 147,000 m^3 of LNG. It is 288m long and 49m wide.
- LNG is natural gas cooled to $-162^{O}C$ and takes up approximately 600 times less space than when in a gaseous state. This equates to total capacity around 88mcm[2] for this ship, which is approximately 1,000 GWh, the total annual demand[3] of about 65,000 average UK households.

[1] Liquefied Natural Gas

[2] Million Cubic Metres

[3] Weather corrected actual

Foreword

Welcome to the 2011 edition of the Gas Ten Year Statement. I hope that you find it an informative and useful document. As in previous years, 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 operation of the gas transmission network, and subsequent investment requirements.

The layout of this year's document has been adjusted to make our key messages clearer and to be easier to read. Consequentially some of the detail behind our scenarios is now explained in our new publication, UK Future Energy Scenarios[1], which was published in November 2011.

As with last year, we detail two demand scenarios side by side, throughout. These scenarios are Gone Green and Slow Progression:

- Gone Green is constructed in such a fashion renewable energy and carbon emissions targets are always achieved. Analysis is carried out in four sectors, Residential, 'Service' (equivalent to the Digest of Energy Statistics (DUKES[2] categories Public Administration and Commercial), Industry and Transport and uses a bottom-up approach that starts at the finest level of detail practical.
- In contrast to the bottom-up approach used in Gone Green, Slow Progression uses econometric modelling at a sector level for both gas and electricity projections. Demand is related to a number of factors, including fuel price, economic growth and number of houses. Adjustments are made for increased levels and appliance efficiency.

The purpose of this approach is to make an assessment of the impacts of demand and supply on the gas transmission network as the UK moves towards the 2020 renewables target.

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

Richard Smith

Future Transmission Networks Manager

National Grid

1 http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/

2 www.decc.gov.uk/en/content/cms/statistics/publications/dukes/dukes.aspx

Disclaimer

This Statement is produced for the purpose of and in accordance with National Grid Gas plc's obligations in Special Condition C2[6] 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.

For the purpose of this of the remainder of this statement, National Grid Gas plc will be refereed to as National Grid.

While we have not sought to mislead any party as to the contents of this Statement and, whilst such content represents our best views as at the time of publication, readers should not place any reliance on the contents of this Statement. The contents of this Statement (including, without limitation, information as regards capacity planning, future investment and the resulting capacity) must be considered as illustrative only and no warranty can be or is made as to the accuracy and completeness of such contents, nor shall anything within this Statement constitute an offer capable of acceptance or form the basis of any contract. Other than in the event of fraudulent misstatement or fraudulent misrepresentation, we do not accept any responsibility for any use which is made of the information contained within this Statement.

The Statement explains our latest volume forecasts, system reinforcement projects and investment plans. It has been published at the end of the 2011 planning process following a re-appraisal of our analysis of the market and expands on the work published in our "Transporting Britain's Energy2011: Development of Energy Scenarios" document in July 2011. 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 2012 planning process.

[6] 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.

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Demand and Supply Outlook

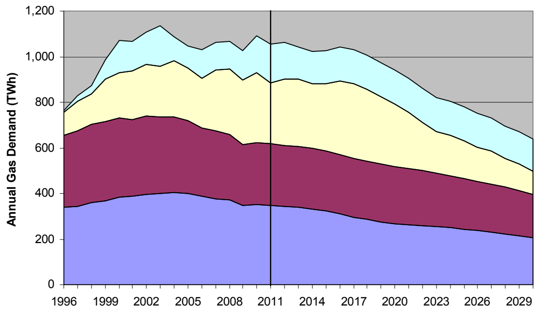
Demand

- Total gas demand for both scenarios is relatively flat until around 2018 when they diverge:
  - Gone Green reduces significantly from around 2018, mainly due to lower domestic demand (from efficiency gains) and power generation demand reductions as a result of more low carbon generation.
  - Slow Progression reduces post 2021 mainly due to reductions in power generation demand as a result of a later arrival of low carbon generation than in Gone Green. Domestic demand remains relatively stable as lesser efficiency gains are offset by demand from new houses.
- Peak gas demand forecasts are not materially different in either scenario due to the assumption that gas fired generation will provide back up capacity for wind intermittency.

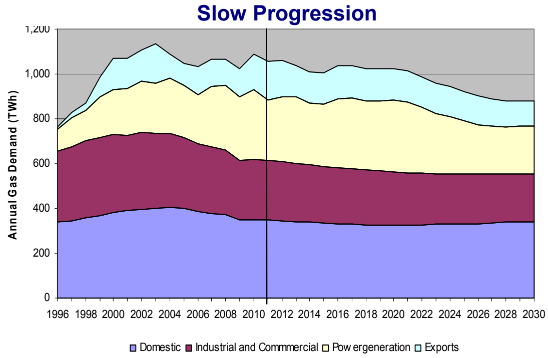
Supply

- The power generation mix in Gone Green necessitates more responsive and flexible supply components than Slow Progression.
- Under both scenarios, supply sources are similar.
- Both supply scenarios show a continuing decline in UKCS production from just under half of total supply today to just over a quarter in 2020.
- LNG is forecast to make up the shortfall in UKCS supply increasing from around a quarter of total supply today to 40% in 2020.

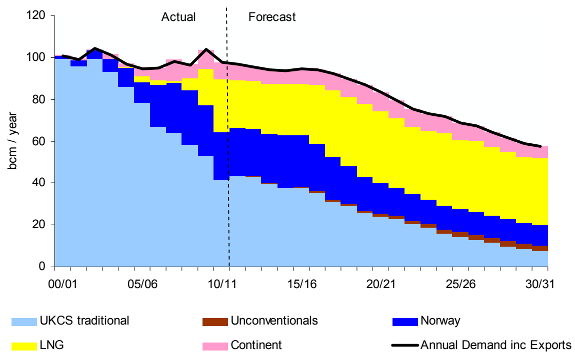
Annual Gas Demand
Gone Green



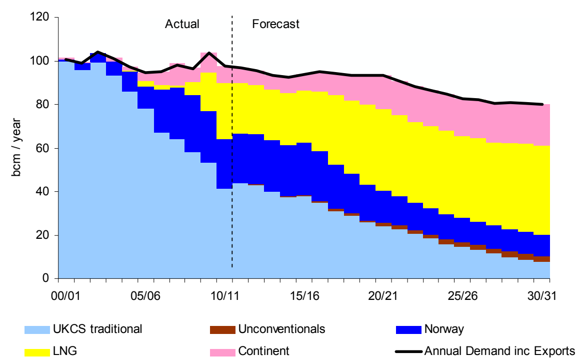
Slow Progression



Annual Gas Supply Sources
Gone Green



Slow Progression



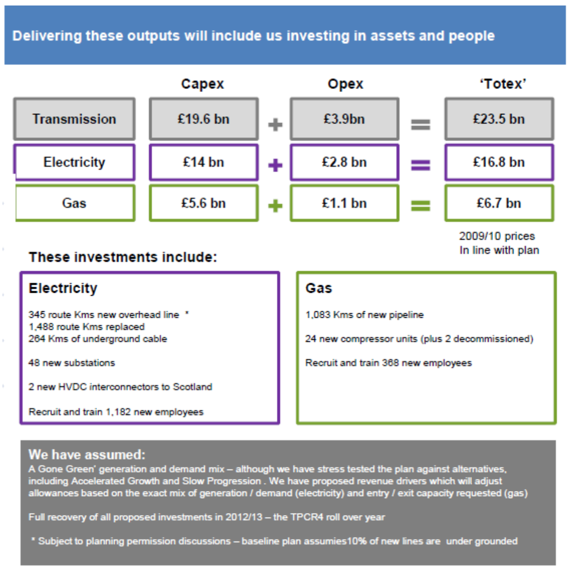
Executive Summary

The required flexibility is anticipated to be delivered from those supplies that are best placed to respond, notably gas storage and possibly also from Liquefied Natural Gas (LNG) imports and through existing or modified gas interconnectors with the Continent. A further consequence of more flexible / responsive supplies is the need for a gas network capable of accommodating greater flow variations, both within the gas day and from one day to the next.

Investment Implications

- Under both scenarios, changing supply and demand patterns will require greater network flexibility (net-flex) from the gas transmission network to accommodate variable flows.
- The issues surrounding changing supply and demand patterns, where possible, will be accommodated operationally.
- Operational behaviour will not be enough to manage the increased net-flex requirements of the NTS and so physical assets will need to be built to enhance operational capability.

Our RIIO-T1[7] submission is calibrated to Gone Green (headlines shown to the right), which would trigger £6.7bn[8] totex (capex plus opex) over the RIIO-T1 period for new infrastructure and replacement of old.



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[7] The first Transmission price control under Ofgem's new model of regulation running from April 2013 to March 2021.

[8] Stated in 09/10 prices to align with our RIIO-T1 submission

Executive Summary

The adjacent graph shows the total ex ante[9] expenditure proposed for the RIIO-T1 period (depicted by the orange line).

We have taken a view of the amount of the incremental capacity that is likely to be required over and above our proposed ex ante funding and have included this within our baseline plan.

This accounts for over 46% of our totex baseline plan. It would be driven by future incremental entry and exit capacity signals, which we have proposed should be funded through revenue drivers; which will only be triggered when the capacity is signalled. This is shown in the light orange shading and has not been included in the proposed ex ante funding amount.

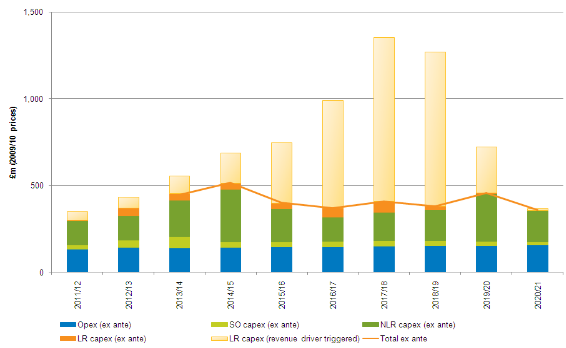
In reality, the actual profile of investment has the potential to be quite different, if customer signals ultimately differ from those currently anticipated or activities required to secure planning permission delay construction deliverables.

The blue shaded area on the adjacent chart depicts what we believe to be the credible range of outcomes / scenarios. The orange line shows the proposed level of ex ante funding included in our July submission.

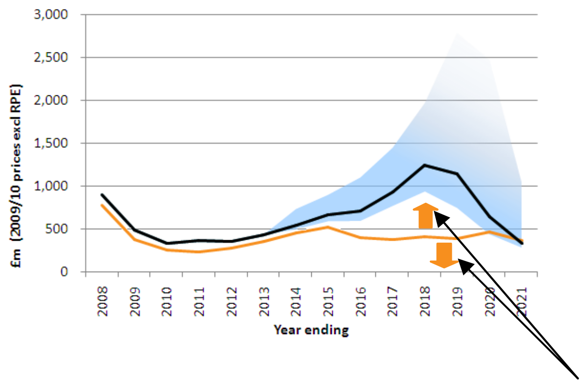
The black line shows our proposed ex ante funding plus the additional funding we anticipate being triggered. This is our RIIO-T1 baseline plan

Our proposed uncertainty mechanisms will increase or decrease our funding, i.e. move the orange line up or down, depending on what actually happens within the RIIO-T1 period.

Proposed total expenditure included within our July RIIO submission



Anticipated credible range of expenditure, mapped against our proposed ex ante funding from our July submission



Uncertainty mechanisms can increase or decrease the ex ante funding (apart from revenue drivers which only increase it)

[9] Agreed before the Price Control period

Chapter Two

Document Scope

2.1 Overview of "Transporting Britain's Energy" Process

The production of the Gas Ten Year Statement (G-TYS) is the conclusion to the planning process for the current planning cycle. Our "Transporting Britain's Energy" (TBE) consultation will initiate the planning process for 2012. As described in Section 2.2, National Grid has revised the content of the TYS, as well as publishing a new document, UK Future Energy Scenarios. The 2012 consultation will have a wider remit recognising the increasing interactions between gas and electricity in the journey towards 2020 renewables targets and the high levels of uncertainty with respect to the UK's longer term future energy mix. The consultation will include a mixture of meetings and workshops to ensure we receive as broad a range of feedback as possible. The feedback will inform the development of the 2012 scenario analysis and feed into the resultant network investment options.

Shortly after the publication of the G-TYS, targeted questionnaires will be circulated to a range of industry stakeholders (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 is as follows:

- Publish 2011 Ten Year Statement – December 2011
- Circulate 2012 Consultation questionnaires – January 2012
- Receive responses to questionnaires – February 2012
- Hold consultation meetings and workshops – February/March 2012
- Provide feedback on responses received – May/June 2012
- Publish 2012 UK Future Energy Scenarios, highlighting our latest view of energy scenarios for both gas and electricity, released at an industry seminar – September 2012
- Publish 2012 Ten Year Statement (including an assessment of the 2012 LTSEC auctions) – December 2012

2.2 Structure of Document

The structure of the document has changed this year to reflect the publication, in November, of our UK Future Energy Scenarios. G-TYS is therefore able to concentrate on the implication of the scenarios for the development of the gas network.

The changes to this year's Gas Ten Year Statement are:

- There is less detail on the Supply and Demand Scenarios, which now form one section. This is because the detail of these scenarios can be found in the UK Future Energy Scenarios publication, which is new this year.
- There is a new section specifically describing the operational changes in the last few years, and those expected, describing how National Grid plans to manage changes operationally before looking to invest in new gas infrastructure.

- The document is shorter and hopefully easier to read, better highlighting our key messages.

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.

The major demand and supply data shown in this year's document can be found in an Excel spreadsheet file on our website, published as part of the 2011 TBE consultation.

http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/docs/2011/

2.2.1 Distribution Network Long Term Development Statements

The Ten Year Statement concentrates solely on the gas 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

2.3 Government Targets

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

1. The first of these targets is part of the EU's integrated energy/climate change proposal and sets a target for 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 its low starting point, economic strength and its high potential for renewable generation i.e. significant wind, wave and tidal resource.
2. The second target, 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). It has been incorporated in the 2008 Climate Change Bill and sets a target of 80% reduction in GHGs from the 1990 levels by 2050. There is a set of carbon budgets set periodically before. The next budget is a 34% reduction from 1990 levels in 2020.

Clearly the size of this challenge will require Government policies and changes to regulatory frameworks to incentivise the construction of the necessary infrastructure and maximise energy efficiency measures.

2.4 Scenario Introduction

This document details two main scenarios. These are:

- **Gone Green -** This scenario is constructed in such a fashion renewable energy and carbon emissions targets are always achieved. Analysis is carried out in four sectors, Residential, 'Service' (equivalent to the Digest of Energy Statistics (DUKES[10] categories Public Administration and Commercial), Industry and Transport and uses a bottom-up approach that starts at the finest level of detail practical.
- **Slow Progression** - In contrast to the bottom-up approach used in Gone Green, Slow Progression uses econometric modelling at a sector level for both gas and electricity projections. Demand is related to a number of factors, including fuel price, economic growth and number of houses. Adjustments are made for increased levels and appliance efficiency.

For further information on our Scenarios please consult our UK Future Energy Scenarios Document available on National Grid's website at – UK Future Energy Scenarios

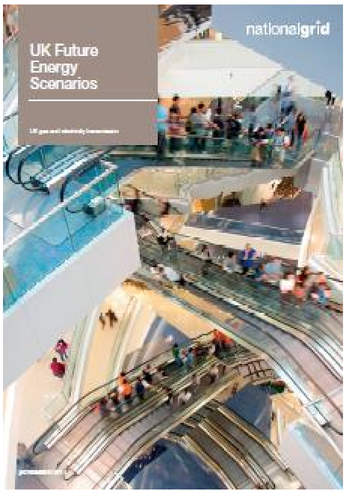
2.5 Other Publications

This document details the implications of gas investment from our demand forecast scenarios. We have a suite of other documents relating to scenarios and energy investment. These include:

2.5.1 Future Energy Scenarios Document

This document represents a new stage in our consultation process. Here we describe in detail the scenarios finalised in the first half of 2011 and presented to the industry at the TBE event in July. Early in 2012 we will be seeking feedback on our scenarios in an annual consultation. This Future Energy Scenarios document is intended to provide the detail on the scenarios previously presented in the Ten Year Statement and Offshore Development Information Statement, enabling these documents to concentrate on the implications of the scenarios on the development of the gas and electricity networks.

UK Future Energy Scenarios



[10] www.decc.gov.uk/en/content/cms/statistics/publications/dukes/dukes.aspx

2.5.2 RIIO-T1 Overview

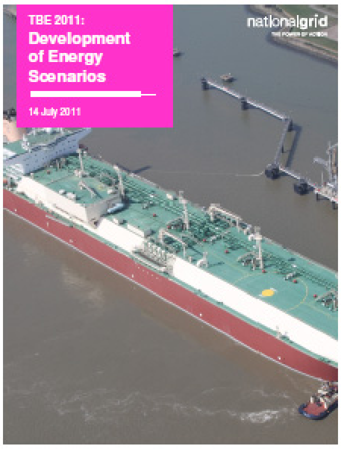
RIIO-T1 is the first Transmission price control under Ofgem's new model of regulation and will run from April 2013 to March 2021. This document summarises our Gas Transmission business plan for this period. Further information on National Grid's Business plans can be found at:

Talking networks - Business plans

2.5.3 TBE – Development of Energy Scenarios

Our forecast scenarios are initially introduced and published at the TBE summer event, in our Development of Energy Scenarios document. We held our 11th annual industry seminar "TBE 2011: Future Energy Dynamics" on Thursday 14th July 2011, as part of its Transporting Britain's Energy (TBE) consultation process. The event was attended by 200 energy professionals and provided an opportunity for not only National Grid to present its latest scenarios and forecasts but also for the audience to hear other stakeholders views and to debate a range of other energy issues.

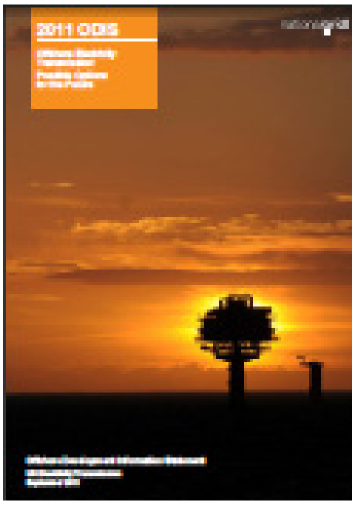
Development of Energy Scenarios



2.5.4 Offshore Development Information Statement

The aim of the Offshore Development Information Statement is to help facilitate the development, in offshore waters, of an efficient, coordinated and economical system of electricity transmission. Based on a wide range of energy scenarios, the document contains information related to the development of the NETS in offshore waters including applicable technology, potential offshore transmission design and onshore transmission co-ordination.

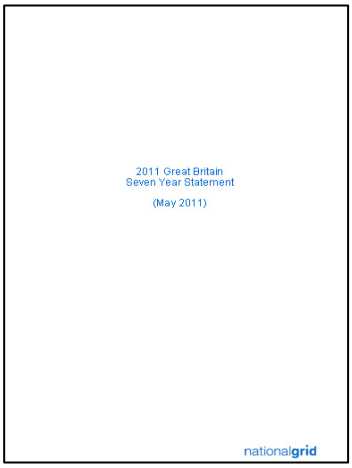
Offshore Development Information Statement



2.5.5 Seven Year Statement

The National Electricity Transmission System Seven Year Statement (NETS SYS) contains a wide range of technical and non-technical information relating to the NETS. The principal aim of the document is to assist existing and prospective new users in assessing opportunities available for them when making new or additional use of the NETS in the competitive electricity market. It is important to bear in mind that this document is based on a *contracted* background which is likely to change frequently and is not a forecast or scenario of the future market.

NETS Seven Year Statement



Chapter Three

Gas Supply and Demand Scenarios

3.1 Overview

1. This section details our latest view of gas supply and demand in the Slow Progression and Gone Green scenarios, with the key similarities and differences between the two scenarios highlighted. National Grid's publication UK Future Energy Scenarios details the gas supply and demand forecasts behind the Gone Green and Slow Progression demand scenarios, so this document will only cover the key points and the implication of the scenarios.

2. There are 2 key drivers for investment in transportation infrastructure:

    a. The forecast level of 1 in 20 peak day gas demand

    b. Network flexibility requirements

    This chapter covers our assessment of annual and peak demand and the key drivers associated with these demands.

3.2 Demand

3.2.1 Annual Demand

3.2.1.1 Overview

The key variables that are likely to influence gas demand in the future are gas prices and gas-fired power generation, with the electrification of heat potentially having an impact in the longer-term.

In the traditional demand sectors of domestic, industrial and commercial, we envisage increasing fuel prices leading to a continuation of demand reduction via behavioural changes and increased energy efficiency. Extra demand from new housing completions is expected to offset this to a degree.

In the power generation sector, forecasts of new gas-fired generation capacity in both scenarios leads to an increase in demand over the near term, with a decline later in the medium to long term as the power generation fuel mix changes and gas' role incorporates backup to wind generation.

This leads to a situation where total annual gas demand is relatively flat in both scenarios for a number of years. Thereafter, demand starts to reduce in both scenarios, but the degree and timing of this differs between scenarios.

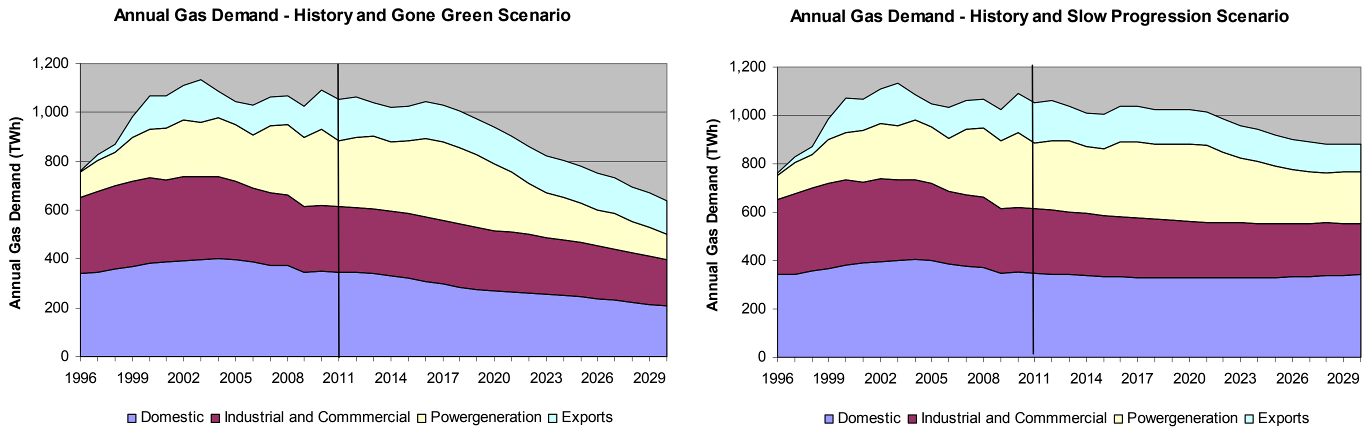
3.2.1.2 Summary of gas demand in each scenario.

Slow Progression:

- Behaviour change, insulation and efficiency savings in the residential and small I&C sectors is very nearly offset by the increase in number of houses, leaving demand almost flat to 2030. The impacts of electrification of heat have very little impact on domestic gas demand.

- Demand in the large non-power sector is also fairly flat. There is comparatively limited scope for energy saving in this sector, especially as there are few options for replacing gas in the high temperature heat market. It is worth noting that significant energy savings have already been made in this sector.
- Power generation demand remains fairly flat to 2020 with gas-fired power generation capacity increasing, although average load factors fall due to increases in renewable generation. Post 2020, new nuclear capacity and increasing renewable capacity starts to erode gas share of the power generation market.

FIGURE 3.2A - Annual Gas Demand Scenarios including history
Source: National Grid



Gone Green:

- Demand in the residential and small I&C sector falls steadily to 2030, reflecting more aggressive assumptions on insulation, boiler efficiency and the roll-out of heat pumps.
- Demand in the large non-power sector displays similar performance to Slow Progression, reinforcing the view that there are fewer opportunities for savings in this sector.
- In the short term, gas demand in the power generation sector remains stable as new gas capacity is commissioned. Demand falls steadily from around 2018 onwards in response to substantial offshore wind development and the first new nuclear station around 2020, with this trend continuing out to 2030.

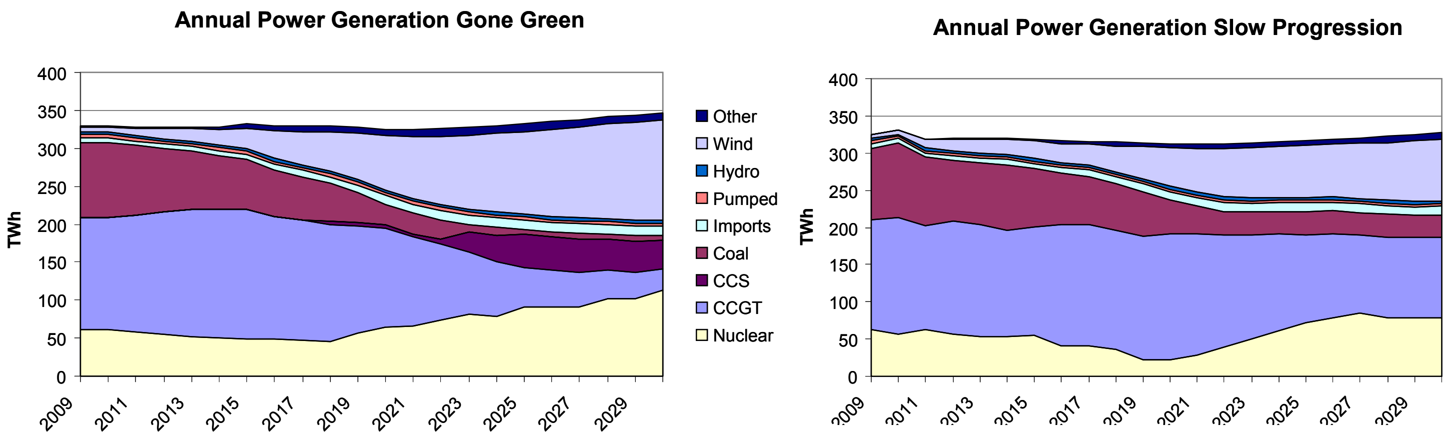
The two main differences between the scenarios are:

- **Gas fired power generation** – gas demand is marginally higher in Gone Green than Slow Progression (as gas is used more than coal in the medium term) until around 2018 when this trend reverses significantly as a higher level of low carbon generation is connected.
- **Domestic demand** – Gone Green has greater demand reductions due to higher energy efficiency and more electrification of heat.

3.2.1.3 Power Generation

As previously mentioned, gas demand in Gone Green diverges from Slow Progression not only due to differing levels of gas-fired generation capacity but also the operation of gas-fired plants, with older plants in particular being lower in the merit order in the Gone Green scenario due to more low carbon generation being connected. The operation of power generation plant provides the main difference between the two views in the short-term, with the lower level of capacity in the Gone Green scenario adding to the divergence towards the end of the forecast period. Gone Green has significantly more wind than Slow Progression in the medium and long term 2020 and beyond. This means significantly less demand from gas fired power generation on an annual basis.

FIGURE 3.2B - Annual power generation for various sources for both scenarios
Source: National Grid



3.2.1.4 Electrification of Heat

We have carried out extensive research to formulate scenarios on electrification of domestic heat to understand the scale of electrification and the impact this could have on gas demand. Our conclusions are that in both scenarios the effect of electric heat pumps on overall gas demand is very small before 2020. This is largely due to the fact that whilst the installation of electric heat pumps could be reasonably significant in terms of numbers, the overwhelming majority are anticipated to be installed in houses that do not have gas-fired central heating, as the potential cost benefit in these houses is likely to be higher. Beyond 2020, this trend continues in the Slow Progression scenario, with the Gone Green scenario including a greater number of heat pumps that begin to displace gas central heating. This contributes to greater reductions in domestic gas demand beyond 2020 in the Gone Green scenario.

3.2.1.5 Sensitivities

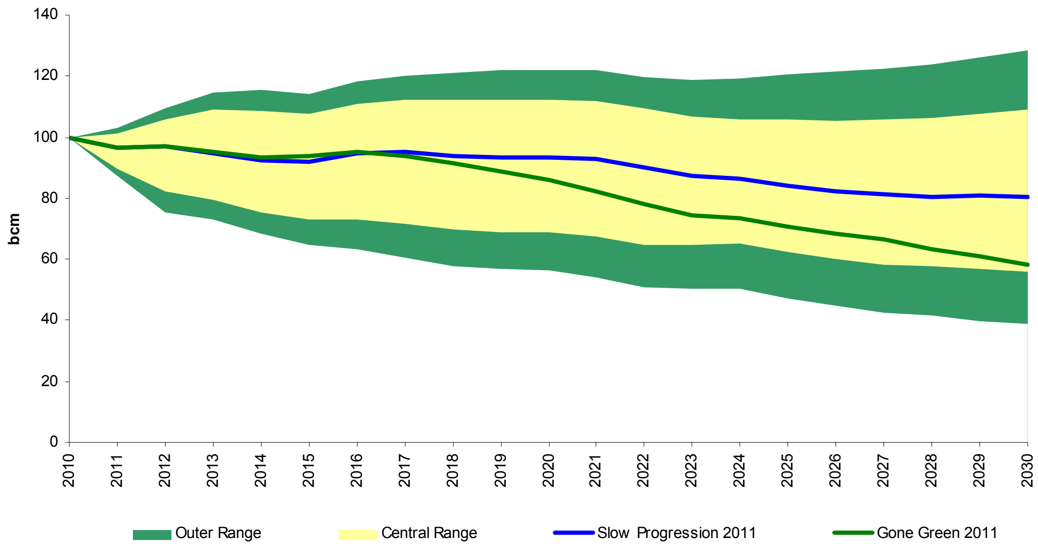
There is significant uncertainty surrounding the future level of gas demand. We have assessed a number of sensitivities by looking at high and low cases (in relation to the Slow Progression scenario) for fuel prices, exports, power generation, economic growth, household numbers and energy efficiency, This is illustrated in figure 3.2C

In addition to the demand in the Slow Progression and Gone Green scenarios, the chart shows an outer fan (illustrating a simple summation of all sensitivities) and an inner fan illustrating combinations of sensitivities more likely to occur together. For example, the highest levels of demand shown in the charts are likely to be reached only if relevant factors affecting demand (such as the rate of economic growth or low gas prices) were all stimulating demand growth and no factors were acting to reduce demand. In practice it is unlikely that they would all combine to push gas demand in one direction. A narrower central range of more probable demand levels has therefore been highlighted on the chart. However, even within this range, there are still significant variations. The demand associated with the National Grid 'Gone Green' scenario falls within the central band.

Our view is that the key driver behind this uncertainty is the potential variation in the power generation sector. As reflected in the difference between the scenarios, there are two main aspects to this sensitivity:

- The amount of gas-fired generation capacity that is connected in the future. This will be driven by underlying electricity demand, environmental legislation, government policy and the role of other fuel types such as nuclear and wind generation.
- The relative fuel prices. The relationship between gas, coal and carbon prices will determine the fuel mix going forward and whether gas or coal-fired generation is used as base load generation. The Slow Progression case assumes a balance between gas and coal on an annual basis with gas the baseload fuel in the summer months and coal the baseload fuel in the winter months.

FIGURE 3.2C – Annual Gas Demand Forecast Range
Source: National Grid



3.3.1 Peak demand

Peak demand has traditionally been derived from annual demand via an established methodology detailed in the Gas Demand Forecasting Methodology document. However the relationship has gradually been changing over some years, with demand generally becoming more weather sensitive.

Domestic annual gas demand has been reducing since 2004. While the peak demands have also been falling, they have not been decreasing as much as annual demand. This is due to a number of factors. The main factor is considered to be because the domestic heating season is generally becoming a little shorter as a result of households wanting to reduce heating costs. However when sustained periods of cold weather occur, domestic consumers revert to running their heating without so much concern for cost, as the priority is to stay warm. This means as it gets colder, more homes run heating with less consideration to cost, accentuating the more “peaky” nature of demand we see in cold weather, thus resulting in a greater ‘cold weather upturn’ in domestic gas demand. Allowance has been made for increased weather sensitivity that has been seen in recent years, but we have not gone as far as to predict that this behaviour will continue to increase in the future.

The advent of more CCGT being used as a backup for wind is also likely to increase the “peakiness” of gas demand. As discussed earlier in this section this is accounted for in our forecasts as more wind generation is built and connected to the electricity system.

There is an increase in renewable generation in both scenarios, albeit to a greater degree in the Gone Green scenario. Both our scenarios assume that gas-fired power stations will provide back-up generation for wind intermittency. Annual gas demand in the power sector therefore reduces as low carbon generation increases. Peak gas demand capacity, however does not change at a commensurate rate due to the requirement for this capacity when intermittent generation is not available. The table below summarises the relationship between annual and peak demand in the two scenarios.

Table 3.2D – Demand from NTS connected gas-fired power stations
Source: National Grid

		Gone Green	Slow Progression
Annual Gas Demand (TWh)	2010	309	309
	2020	273	319
	2030	102	215
Peak Gas Demand @ Full Capacity (GWh/d)	2010	1,675	1,675
	2020	1,807	2,214
	2030	1,926	2,335

The table shows peak gas demand assuming all gas-fired power stations at maximum output (undiversified demand). In reality, of course, there will be a great deal of diversity which is reflected in our ‘diversified’ peak gas demand figures. A major challenge will be dealing with both the amount and location of this demand.

In summary, annual demand has traditionally been used to determine peak demand. This concept is still valid, however in both scenarios the relationship is changing to a more ‘peaky’ demand due to the need for gas fired generation to act as a backup for wind.

The flexibility required to back up wind generation with gas fired generation, is anticipated to be delivered from those supplies that are best placed to respond, notably gas storage and possibly also from Liquefied Natural Gas (LNG) imports (from gas held in LNG storage tanks) and through existing or modified gas interconnectors with the continent. A further consequence of more flexible / responsive supplies is the need for a gas network able to accommodate greater flow variations including those from one day to the next. This is further detailed in Sections 4 and 5.

3.3 Supply

National Grid's publication UK Future Energy Scenarios details the gas supply forecasts behind the two Gone Green and Slow Progression demand scenarios. Rather than replicate this information, the supply section of the 2011 Ten Year Statement contains:

- A summary of the basis and assumptions for the supply forecasts, including charts detailing both annual and peak forecasts for the two demand scenarios
- Some background on the historic changes of gas supply
- An update on the Long Term System Entry Capacity (LTSEC) auctions (March 2011)
- Supplementary high level analysis for gas supply sources
- A gas supply infrastructure update for Europe, UK imports and UK storage
- A longer term UK security of supply assessment

Table 3.3A summarises the supply assumptions behind the supply forecasts for the 2011 Gone Green and Slow Progression demand scenarios.

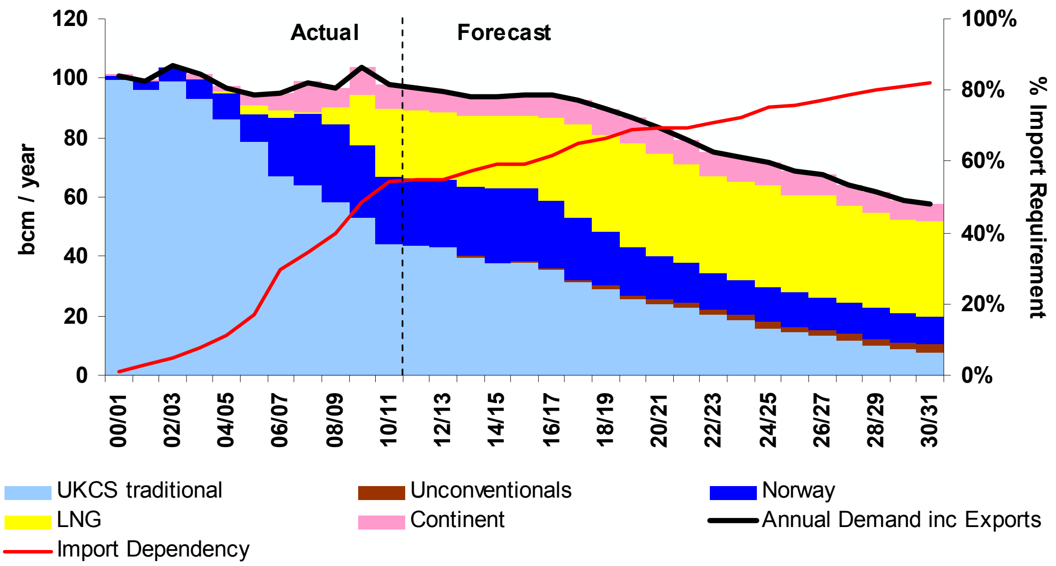
TABLE 3.3A – Supply Assumptions for Gone Green and Slow Progression Demand Scenarios
Source: National Grid

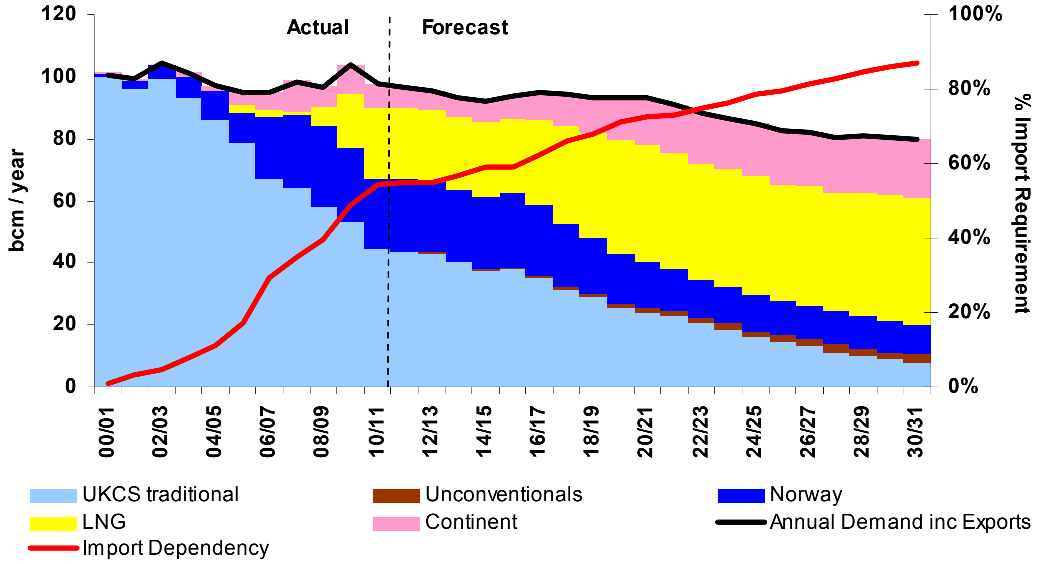
	Gone Green	**Slow Progression**
Continental Demand	The Continent also meets environmental targets, hence little or no growth in Continental gas demand.	Modest growth in Continental gas demand, primarily through increased gas for power generation.
Gas prices	Incentives to meet environmental targets distorts gas prices relative to renewables, at times of low wind gas prices are at a premium. Therefore increased day to day price volatility. For Continent, oil indexation is eroded.	UK gas prices slowly increase but remain between low US and higher Continental prices. For Continent, oil indexation remains though sales of spot gas continues to increase.
US	Growth in US unconventional gas production continues, some gas price recovery in US but still below oil indexation. This leads to limited US LNG imports and export of US LNG. US environmental targets focus on carbon reduction, thus promotes gas use over coal.	
UKCS	Essentially the same for both demand scenarios. West of Shetland developments limit the rate of UKCS decline as do other new developments. UKCS not well suited to provide flexible / responsive supplies	
Norway	Imports from Norway to UK are similar in both demand scenarios. Norwegian exports to UK are maintained until 2015 then are assumed to decline albeit slowly as total Norwegian production is also assumed to slowly decline and Norwegian exports to the Continent are maintained. As Norwegian flows to the UK are forecast to decline, the opportunity for Norwegian flows to provide 'flexible' supplies to UK increases. However this is may be subject to factors such as; further EU market liberalisation, contractual conditions and access to Continental transmission and storage.	
LNG	Due to the absence of long term supply contracts and exposure to global conditions, namely LNG production and demand in alternative markets, notably Asia, and to a lesser extent Europe and the Americas there is considerable uncertainty in the LNG forecasts for both demand scenarios. LNG is assumed to be the major long term supply source to the UK. Flows are similar in both demand scenarios until the demand needs of Slow Progression increases LNG imports above Gone Green post ~2017. **No new LNG import projects are specifically identified but the increase in LNG load factors (especially for Slow Progression) highlights the need for new import infrastructure.**	

BBL	There is some uncertainty over future flows through BBL after the Centrica contract expires ~2016. Forecast flows through BBL are similar in both demand scenarios (similar to recent years) until the demand needs of Slow Progression increases BBL imports above Gone Green post ~2017.
IUK	IUK remains a key source of responsive / flexible supply for the UK for both demand scenarios. The weighting of imports to exports through IUK are similar in both demand scenarios (similar to recent years) until the demand needs of Slow Progression slowly shift to more imports above Gone Green post ~2017.
Storage	Despite a considerable number of storage proposals, new storage projects are limited to those currently under construction. Whilst these have limited space, total deliverability could nearly double towards 200 mcm/d. **The changing dynamics of gas demand notably through the expected use of gas to provide generation cover for wind intermittency and the increase of 'supply concentration' provides great opportunities for new storage. Whilst no new storage proposals are included in the supply forecasts, some of these are expected and to 'avoid picking winners' these are assessed on a case by case basis.**
Uncon-ventional Gas	Development of unconventional gas (noticeably coal bed methane (CBM) and biogas) is restricted due to planning, costs, drilling resources and issues over mineral rights. 2020/21 forecasts for biogas and CBM are 0.7 and 0.6 bcm respectively. Forecasts for unconventional gas are subject to considerable uncertainty, shale gas represents a further upside to the forecasts.

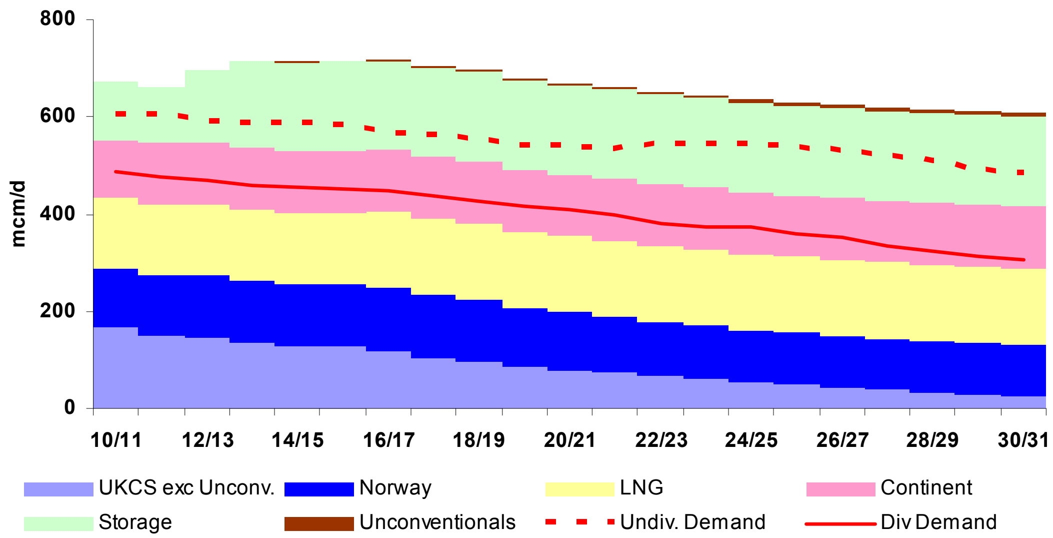
The following four charts (Figures 3.3A – D) show the annual and peak supply forecasts for Gone Green and Slow Progression. As detailed previously the basis for these forecasts is detailed in our UK Future Energy Scenarios document.

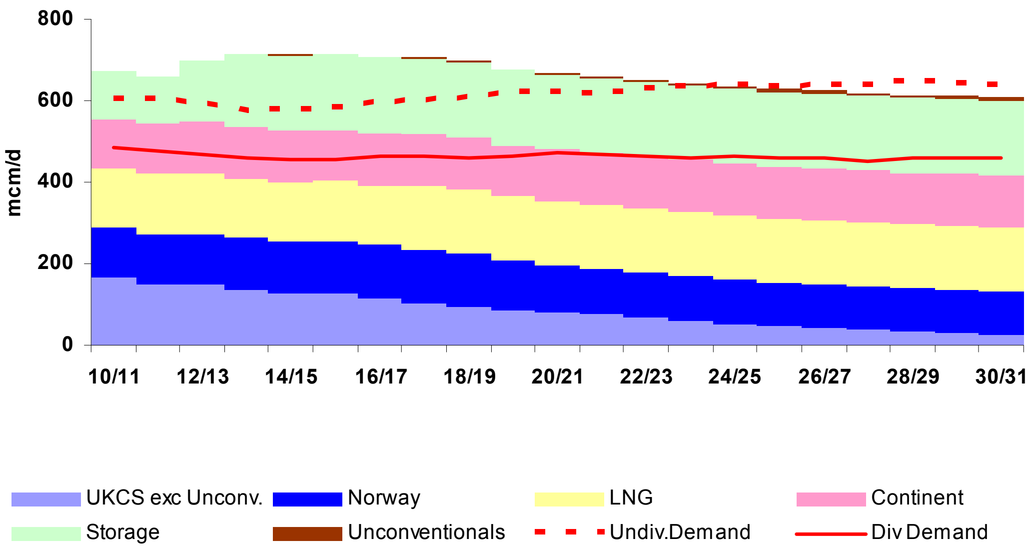
FIGURES 3.3A & B – 2011 Annual Supply Forecasts for Gone Green and Slow Progression
Source: National Grid





FIGURES 3.3C & D – 2011 Peak Supply Forecasts for Gone Green and Slow Progression
Source: National Grid





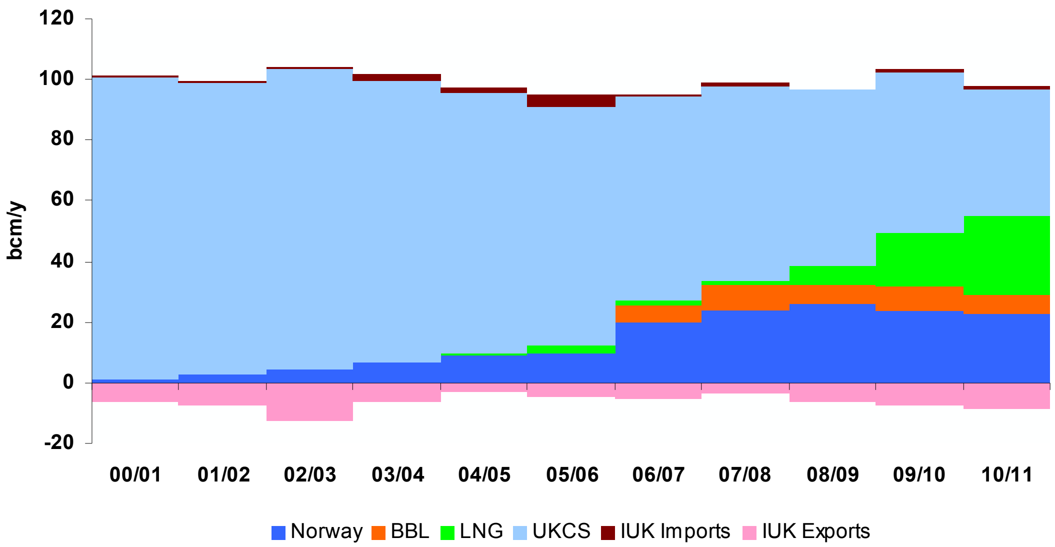
3.3.1 UK supplies since 2000

The changing nature of gas supplies to the UK since 2000 provides a good insight of how future supply patterns may develop. Until 2003/04 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 the recent experience of higher Asian demand
- 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), nuclear power plant outages in Japan (global LNG), and US hurricanes (pricing behaviour and Atlantic LNG)

Figure 3.3E below shows the changing mix of annual gas supplies to the UK[11] since 2000, the chart also shows exports through IUK.

FIGURE 3.3E – Historic annual UK gas supplies & IUK exports
Source: National Grid



The chart highlights:

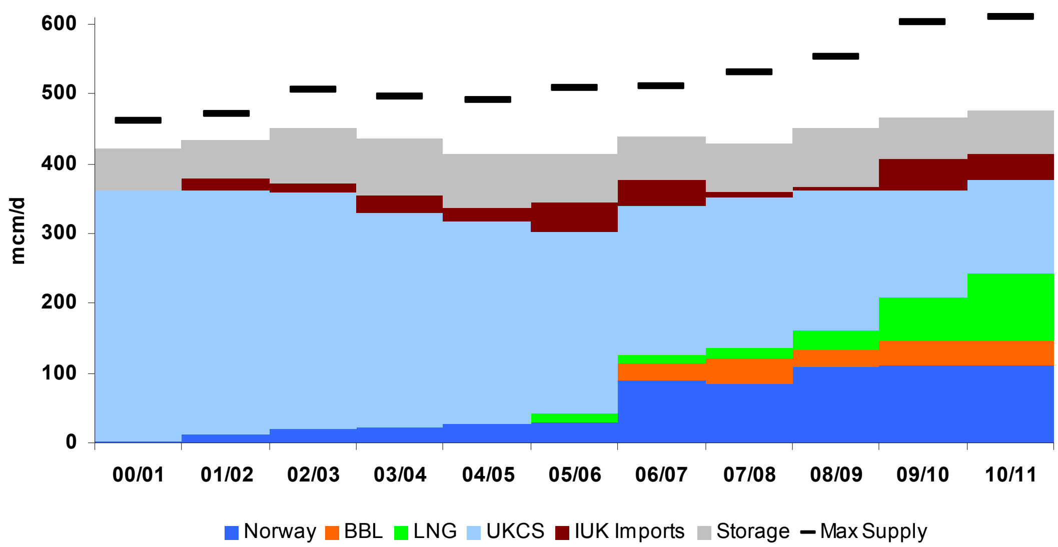
- UK self sufficiency followed by the decline of UKCS production. UKCS represented 41% of NTS inputs in 2010/11 (49% in 2009/10)
- The increase in Norwegian gas supplies, notably post 2006/07 (Langeled)
- Imports through BBL from 2006/07

[11] Gas supplied to the NTS

- Continued exports through IUK despite increasing import dependency
- LNG imports commencing in 2005/06 (Grain 1), with further increases in 2008/09 (Grain 2), 2009/10[12] (South Hook 1 & 2 and Dragon) and 2010/11 (Grain 3)

The make up of supplies for the highest demand day for each winter since 2000 is shown in Figure 3.3F. This shows similar trends to Figure 3.3E, but also emphasises the contribution of storage and on occasion IUK import volumes. Also shown on the chart is the maximum supply, namely the aggregated peak flow from each terminal for UKCS, imports for each import pipeline, LNG facilities and all storage sites. This chart clearly shows how the level of maximum supply far exceeds the highest demand day and since the onset of increased import capacity in 2006/7, this level of supply has rapidly increased from about 500 to over 600 mcm/d. This highlights the need for increased network capacity and operational flexibility to reflect the needs of available supply rather than just peak day demand.

FIGURE 3.3F – Historic peak gas supplies & IUK exports
Source: National Grid



3.3.2 2011 LTSEC Auctions

Appendix 2 details our peak flow forecasts and flow ranges for all major entry terminals for both demand scenarios. 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 March 2011 (LTSEC) and February 2011 (AMSEC). For ease of conversion from energy to volume, all capacity data on these charts (release obligation, sold capacity) assume a calorific value (CV) of 39.6 MJ/m^3 rather than using terminal specific CV forecasts.

In the 2011 LTSEC auctions there was some bidding activity at most ASEPs[13] but not sufficient for the release of any further entry capacity. The next LTSEC auctions are expected to be held in March 2012.

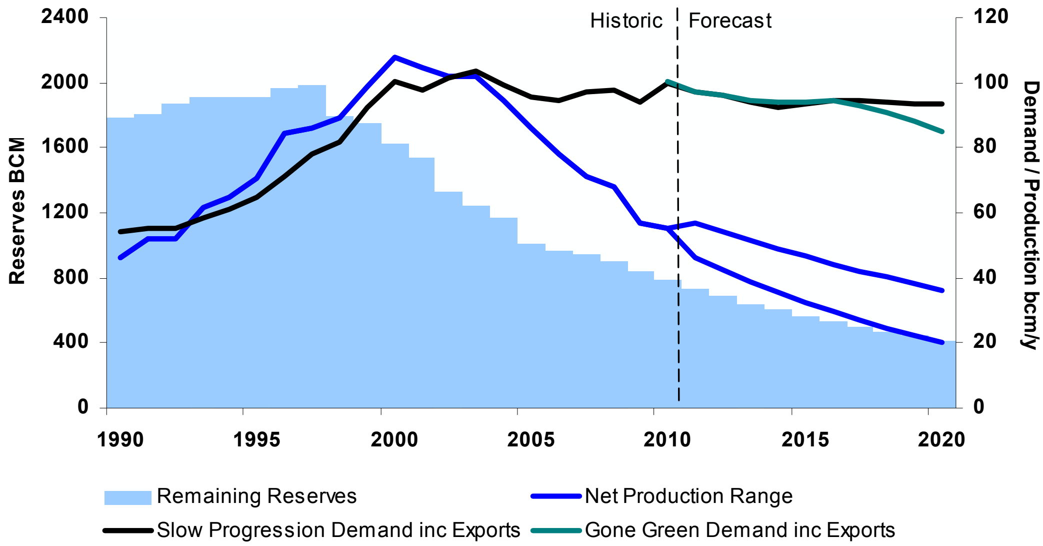
[12] South Hook 1 and Dragon commissioned in gas supply year 2008/09 but after the winter

[13] Aggregate System Entry Point

3.3.3 UKCS Reserves

Historic data for 2010, published by official UK sources (Figure 3.3G) shows the continued decline of UKCS gas reserves between 1997 and 2011. This has been driven by production levels that were greater than discovery rates and routine revisions to reported reserves. Since 2000, remaining reserves have been declining by ~7% per annum. For context, the chart also shows historic figures for NTS demand and net UKCS production[14].

FIGURE 3.3G – UKCS remaining gas reserves (Proven, Probable, Possible)
Source: Office for National Statistics (ONS), DECC, National Grid



In 2010, total remaining reserves in the main 3 categories (proven, probable, possible) fell to 781 bcm, compared with 840 bcm in 2009. Net gas production in 2010 was 55 bcm, compared to 57 bcm in 2009.

In the forecast area of the chart, trend analysis has been used to assess future remaining reserves and production out to 2020. This enables a comparison to be made with our UKCS forecasts albeit there are reporting differences including some gas that flows direct to power stations rather than entering the NTS.

The trend analysis is little changed from last year and suggests that UKCS production in 2020 could be between 20 and 40 bcm/y, similar to National Grid forecasts (Figure 3.3H) of approximately 26 bcm. Remaining reserves are calculated as a 300 - 500 bcm range. Based on our UK demand scenarios of approximately 86 - 94 bcm in 2020, this indicates import dependency of between 58 - 78%.

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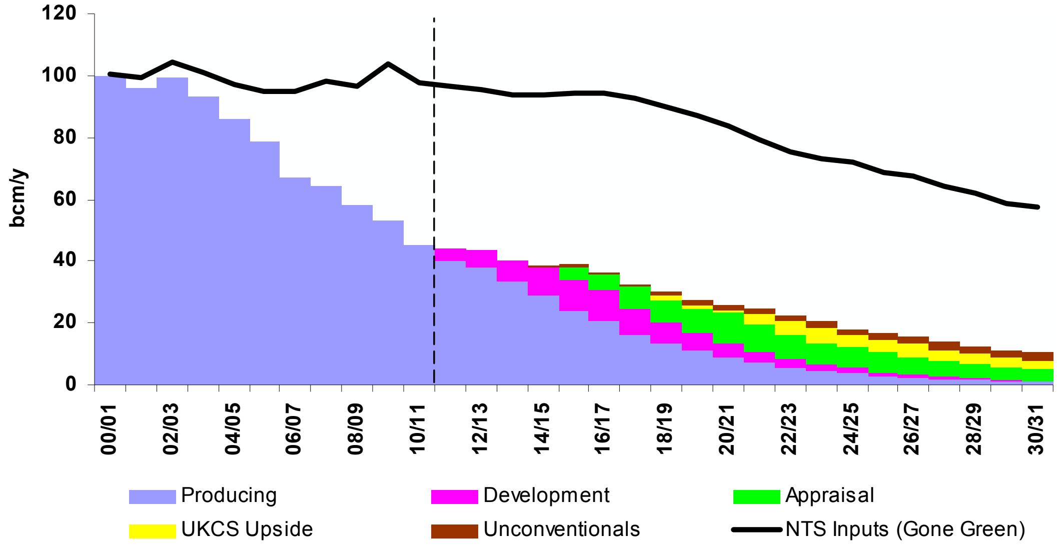
[14] Net production published by the ONS & DECC is a measure of the gas available for consumption after taking into account flaring and gas consumed in production operations. National Grid data for forecast annual demand is shown for comparative purposes these include Irish and Continental exports but exclude non-NTS gas to power stations.

3.3.4 UKCS Forecast

Figure 3.3H shows National Grid's 2011 UKCS forecast. This is essentially the same for both demand scenarios. The forecast is broken down into supply components.

FIGURE 3.3H – UKCS Forecast
Source National Grid



The chart shows that fields currently producing will be mostly depleted by 2020/21, highlighting the importance of new field developments. By 2020/21, most gas is forecast to come from fields currently under development or being considered for development (appraisal). UKCS upside is an indication of what gas could come from currently undiscovered fields.

Sustained high global prices for oil and gas have encouraged the global exploration and development of unconventional gas sources such as coal-bed methane (CBM) and shale gas, particularly in the US but also in other countries. In the UK, small scale coal-bed methane projects are under development, and shale exploration / evaluation is also in progress. In late 2011, Cuadrilla Resources announced the discovery of a large shale gas formation in Lancashire which could add to UK reserves in future. Considerable potential reserves of 5600 bcm were announced by the company, however these are subject to further evaluation and recovery rates. Evaluation of shale is also in progress in other areas in the UK.

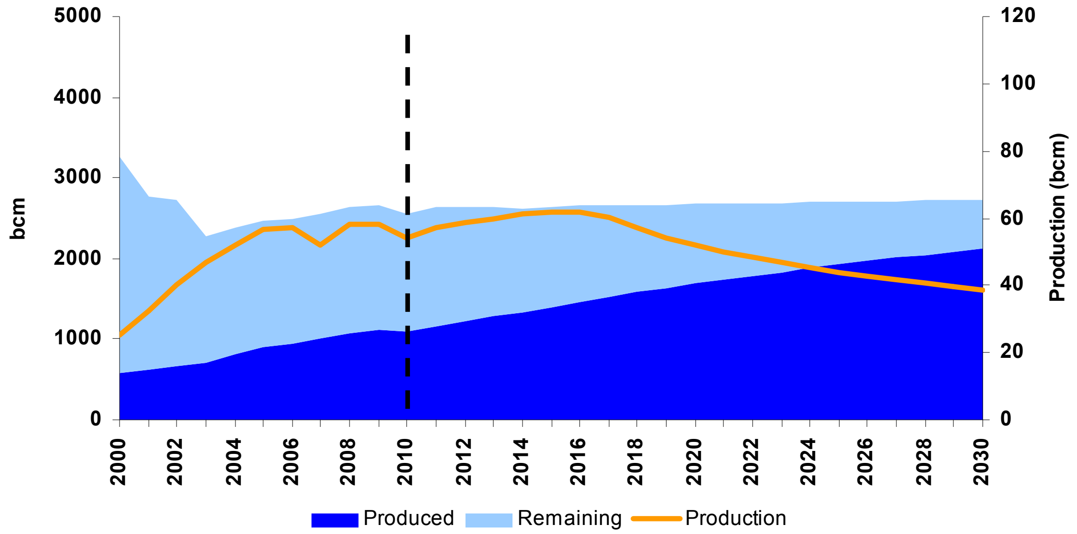
Currently the unconventional forecast only assumes some CBM and biogas developments, hence shale gas provides an upside that may be included in future forecasts.

3.3.5 Norway

National Grid's forecast of Norwegian production levels is based on a trend analysis of previous production along with an assessment of remaining reserves. In order to assess the total size of Norwegian reserves a factor is applied to the different categories of reserves to reflect the likelihood of production. Due to their size and impact on the forecast, production from the Troll and Ormen Lange (T&OL) fields is assessed separately.

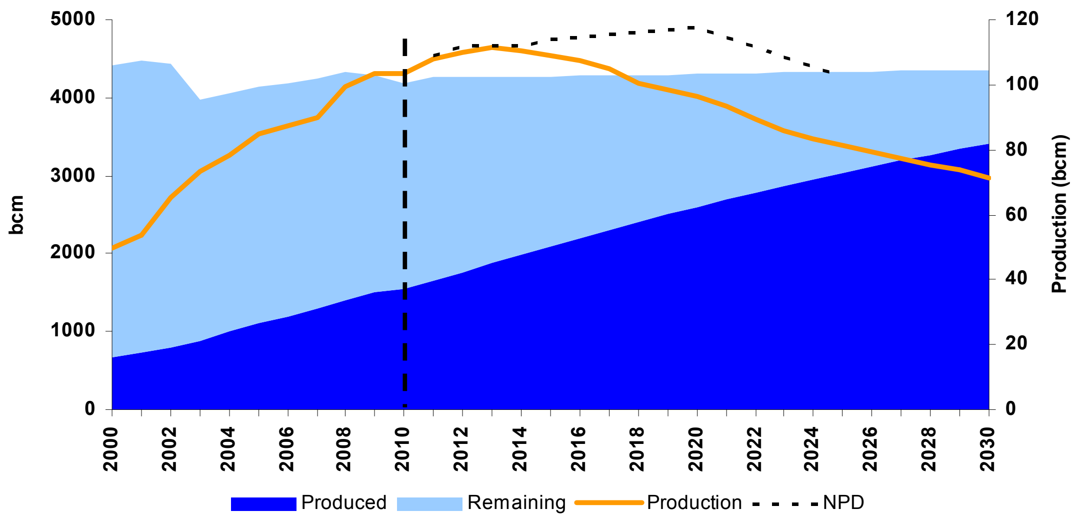
Figure 3.3I shows the Norwegian forecast excluding T&OL. This indicates a general decline in production from around 2017 when approximately 50% of the reserves (excluding T&OL) have been produced. By comparison the UKCS also reached peak production of 108 bcm in 2000 when about 50% of reserves had been produced. In the subsequent decade the decline of UKCS production has been about 7% per annum. For Norway (excluding T&OL) a lower rate of decline is assumed to reflect a lower proportion of peak production relative to reserves.

Figure 3.3I Cumulative Norwegian Production & Reserves (Excl Troll & Ormen Lange)
Source NPD, Wood Mackenzie, National Grid



The overall forecast, with Troll and Ormen Lange included, in Figure 3.3J shows overall production levels being maintained for longer as Troll production is not expected to decline during the forecast period. Production from Ormen Lange is forecast to decline from 2014 onwards though additional compression may delay this further.

Figure 3.3J Cumulative Norwegian Production & Reserves
Source NPD, Wood Mackenzie, National Grid



The latest Norwegian Petroleum Directorate (NPD) production estimates from their FACTS 2011 document indicate a later decline from 2020 onwards. The key uncertainty in our Norwegian production forecasts is the amount of undiscovered resources that will end up being produced. The recent major oil discovery at Avaldsnes/Aldous highlights the potential for significant finds in the Norwegian sector, including in areas close to existing infrastructure. A discovery of a similar scale gas field could alter the forecasts significantly, although depending on the location commercial production may take up to a decade to realise.

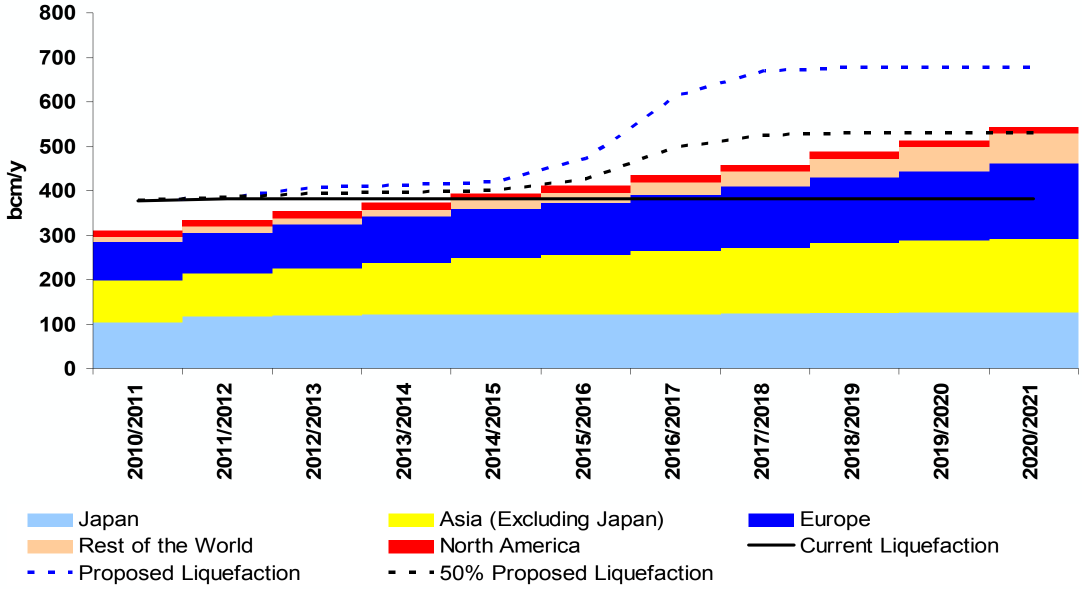
3.3.6 LNG

Global LNG trade increased from 242 bcm in 2009 to 297 bcm in 2010. This was mainly due to a 25 bcm increase in LNG to Asia and an 18 bcm increase to Europe. The growth market for Europe has recently been the UK, where LNG imports rose from 10 bcm in 2009 to 18 bcm in 2010.

Global LNG remains dominated by imports to Asia, notably Japan and to a lesser extent South Korea, Taiwan and an emerging China. In 2010 Spain remained the largest European LNG importer, but during spring 2011 the UK's LNG imports increased above those of Spain.

Figure 3.3K shows projected global supply and demand to 2020. Demand is split by region, with the main growth markets being Asia and Europe.

FIGURE 3.3K – Projected Global Supply and Demand of LNG
Source: National Grid, LNG journal, GIIGNL, BP, NATS PAN-EURASIAN, OIES[15], Various



The chart shows no new liquefaction capability after 2017, reflecting the information currently available to us. In reality some of the projects under construction and proposed may slip or may not be built, hence the indicative capacity line if 50% of the proposals are built. Beyond 2017 further new developments are expect to proceed.

The chart shows that there is very little new liquefaction capacity expected in the next few years before numerous developments post 2016 (primarily Australian). With global LNG demand rising the market for LNG may become increasingly tight before new production is brought on stream. Under these conditions those markets that rely on spot or non contracted supplies (including the UK) may have difficulty in attracting LNG unless 'global market prices' are paid.

New LNG production facilities are expected in Australia, Algeria, Angola and Indonesia over the next two years, with a surge in new production in Australia being commissioned after 2016. Other sources of new liquefaction include the USA, Nigeria and Indonesia. The commencement of US LNG exports, essentially some of the surplus of indigenous (unconventional) production, could have a market impact both in the US and globally with the potential to create higher US gas prices and increased LNG trade.

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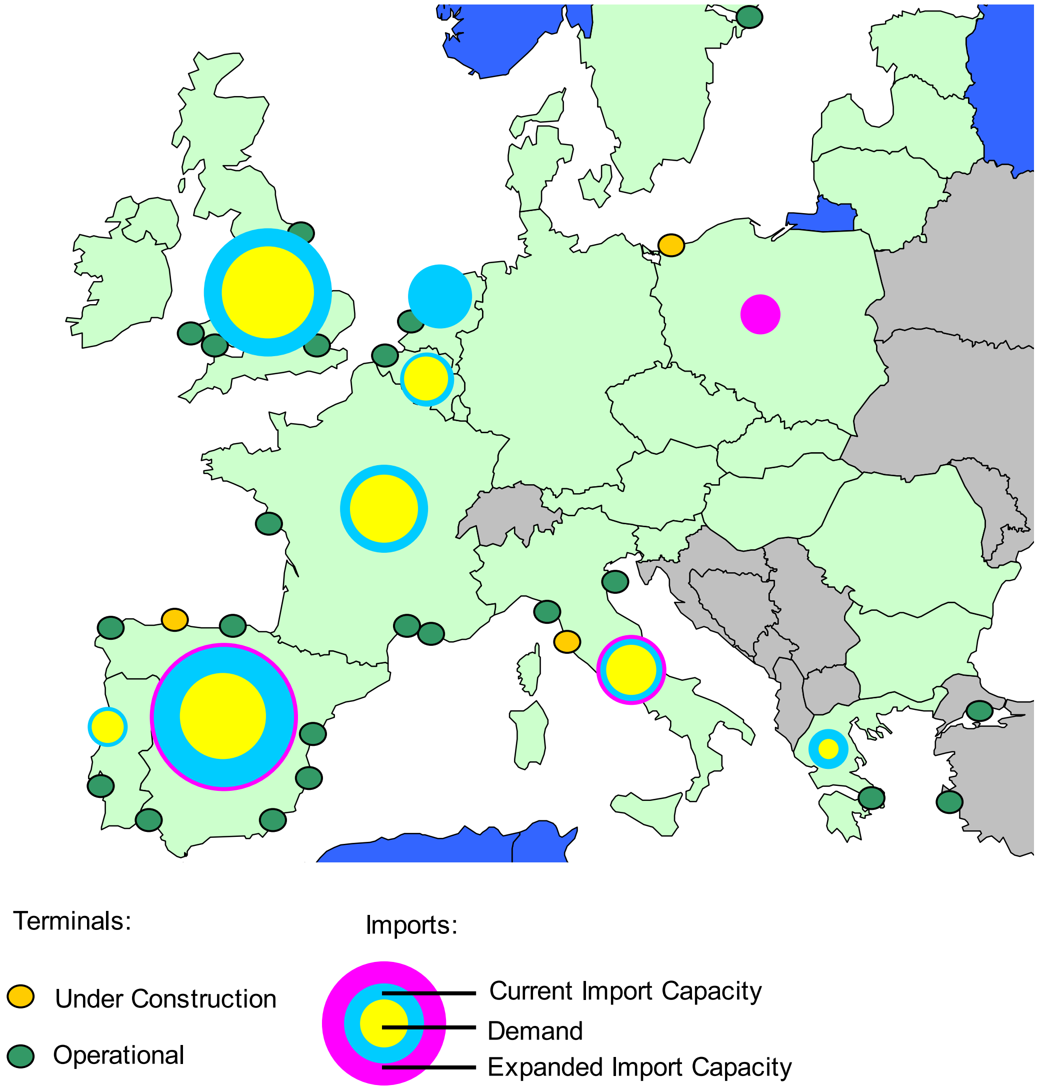
Figure 3.3L shows a map of the completed and under construction LNG terminals in Europe. The chart also shows, as represented by the areas of the coloured circles for each country (not the diameters), the LNG imports and import capacity for the 12 months to August 2011.

FIGURE 3.3L – European LNG Terminals, Imports and Capacity
Source: National Grid, GIIGNL, BP, NATS PAN-EURASIAN, Various

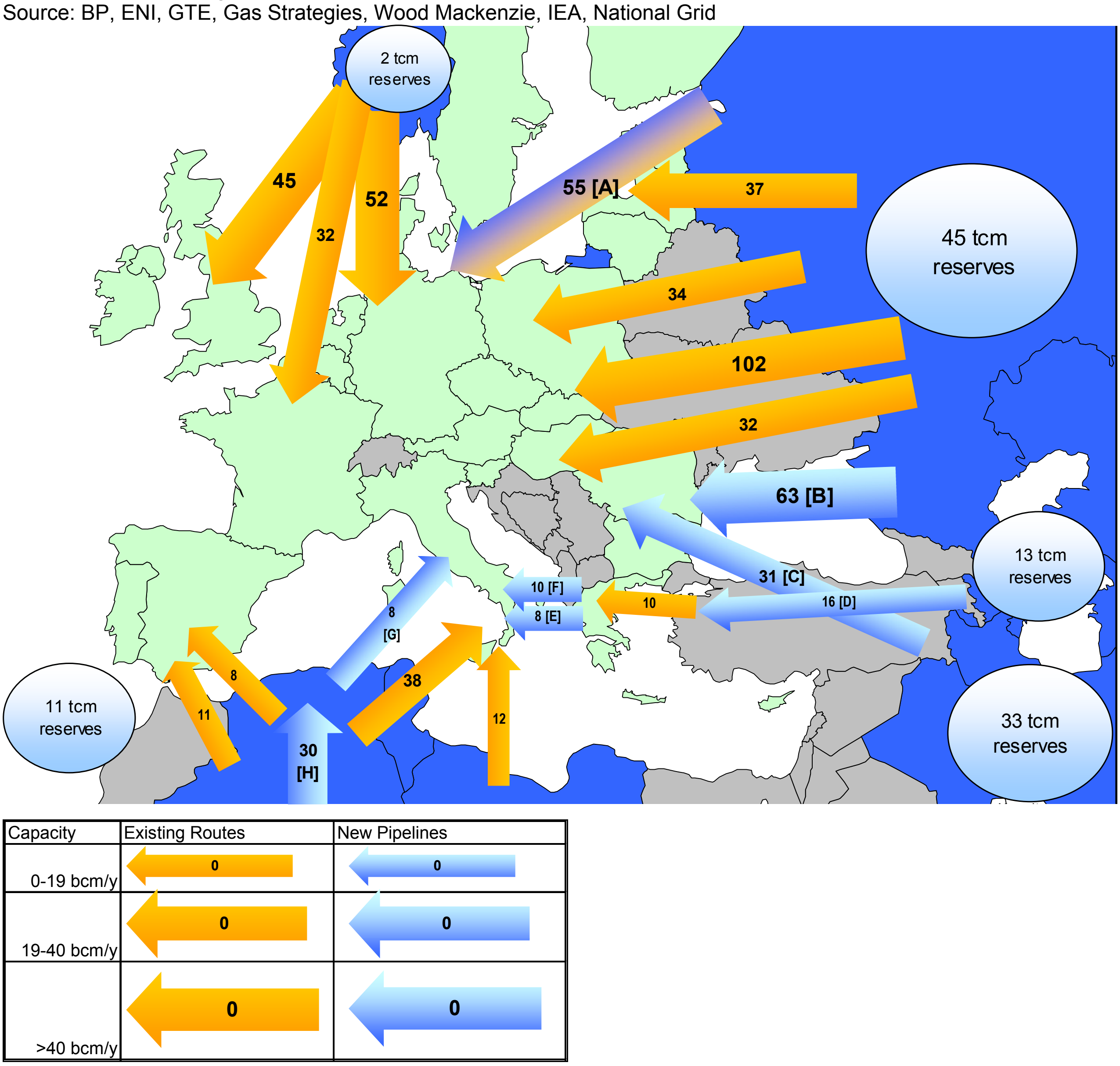


Recent LNG developments include the commissioning of the Gate facility in September 2011 with a capacity of 12 bcm/y. This is the first LNG import terminal for the Netherlands. A LNG facility is now under construction in Poland. This will have a capacity of ~5 bcm per year and is expected to be commissioned in 2014.

3.3.7 European Pipeline and LNG Infrastructure

Excluding indigenous supplies and LNG imports, the European Union has three major sources of supply; Russian/Central Asian supplies from the East, North African from the South and Norwegian from the North West. Figure 3.3M highlights existing and proposed pipeline capacities from these sources.

FIGURE 3.3M - Existing import routes and planned new pipelines
Source: BP, ENI, GTE, Gas Strategies, Wood Mackenzie, IEA, National Grid



Norwegian gas exports are a key component of the European supply mix, particularly for North Western Europe. There are currently 9 pipelines with a capacity of approximately 130 bcm, 5 of these connecting into continental Europe with a further 4 connecting to the UK. While there are currently no additional Norwegian import pipeline projects under construction there are plans to increase the capacity and flexibility of the existing export infrastructure.

There are numerous existing pipeline routes for Russian and Central Asian gas to Europe via the Ukraine and Belarus, directly to the Baltic States and with the completion of the first phase of the Nord Stream pipeline directly across the Baltic Sea to Germany.

Existing capacity for all of these routes is estimated at 230 bcm with approximately 133 bcm through Ukraine, 45 bcm through Belarus, 26 bcm directly to the Baltic countries and 27 bcm through the first phase of Nord Stream. There are major plans for additional capacity from Russia and Central Asia with the emphasis on achieving diversified supply options and reducing the reliance on transit countries. The planned import routes from Russia and Central Asia on the above map are detailed below, with the exception of Nord Stream, none of the projects are under construction:

- [A] Nord Stream two 27.5 bcm pipelines from Russia under the Baltic Sea to Germany, phase I opened 7th November, phase II due to open 2012
- [B] South Stream, 4 pipelines totalling 63 bcm from Russia to Bulgaria and then on to Central and Southern Europe. Currently in design phase, final investment decision expected by the end of 2012, construction from 2013 with first gas in late 2015.
- [C] Nabucco connecting feeders from Georgia and Iraq through Turkey, Bulgaria, Romania and Hungary to Baumgarten in Austria, planned capacity of 31 bcm, construction due 2013 with first gas due 2017 and full capacity available from 2019
- [D] Anatolian Transit Gas Pipeline Project (TANAP) was announced on 17th Nov 2011 by Socar[16] designed to export Shah Deniz phase II volumes to Europe, capacity 10-16 bcm.
- [E] IGI Poseidon – 8 bcm pipeline connecting Italy and Greece, links to the Interconnector Turkey-Greece (ITG) which opened in 2007 and the Turkish grid to access gas from the Caspian and Middle East
- [F] TAP – Trans Adriatic Pipeline 800 km pipeline running from Greece to Italy via Albania, planned capacity of 10 bcm due to open to coincide with Shah Deniz II in 2016/17

Gas from North Africa is currently exported through 4 pipeline routes to Italy and Spain. Existing pipeline capacity is approximately 70 bcm. There are currently 2 projects proposed to increase existing capacities and establish new routes:

- [G] Galsi an 8 bcm pipeline connecting Algeria to Italy through Sardinia, having completed much of the preparatory works is awaiting a FID before construction proceeds, due for completion in 2014
- [H] 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 still face significant hurdles before they can be completed, with most facing one or more of the following challenges;

- Securing the required funding
- Technical challenges of the project
- Securing regulatory/governmental approval
- Access to sufficient gas supplies

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.

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[16] Azeri state oil and gas company

In addition to importation projects there are many interconnection projects at various stages of development, these may receive funding through the "Connecting Europe" package which has allocated €9bn funding for energy projects of "Common Interest"[17]

3.3.8 UK Importation Projects

Since late 2010 two import projects (both expansions) have been completed; the BBL pipeline (an incremental 3.4 bcm/y) and the third phase of expansion at Grain (an additional 8.1 bcm/y).

Whilst there are proposals for further import projects, for the first time for approximately a decade there are now no UK import projects under construction. The UK's import capacity is now 156 bcm/y, this is split into three near equal sources, the Continent (46.4 bcm/y), Norway (53.7[18] bcm/y) and LNG (55.9[19] bcm/y). Hence the UK is now well served through a diverse set of import routes from Norway, Holland, Belgium and from other international sources through LNG.

Table 3.3B shows completed UK import projects and Table 3.3C proposals for further import projects.

TABLE 3.3B – Existing UK Import Infrastructure
Source – National Grid

Import Project	Operator / Developer	Type	Location	Capacity (bcm/y)
Interconnector	IUK	Pipeline	Bacton	26.9[a]
BBL Pipeline	BBL Company	Pipeline	Bacton	19.5[b]
Isle of Grain 1-3	Isle of Grain LNG	LNG	Isle of Grain	20.3
GasPort	Excelerate	LNG	Teesside	4.1
South Hook 1&2	Qatar Petroleum & ExxonMobil	LNG	Milford Haven	21.0
Dragon 1	BG Group / Petronas	LNG	Milford Haven	10.5
Langeled	Gassco	Pipeline	Easington	25.3
Vesterled	Gassco	Pipeline	St Fergus	13.1
Tampen	Gassco	Pipeline	St Fergus	9.1
Gjøa	Gassco	Pipeline	St Fergus	6.2
			Total	**156.0**

[a]Adjusted for UK standard conditions. Value reported on interconnector.com is 25.5bcm/y at normal conditions.
[b]Adjusted for UK CV and standard conditions. Value reported on bblcompany.com is 20.6GWh/h at CV of 35.17MJ/m3 (normal).

[17] They should display economic, social and environmental viability and involve at least two Member States. http://ec.europa.eu/news/energy/111019_en.htm

[18] Norwegian import capacity through Tampen and Gjøa is limited by available capacity in the UK FLAGS pipeline

[19] For 2011/12 LNG import capacity is reduced by approximately 6.6 bcm/y (200 GWh/d) due to network capacity restrictions, full capacity should be available from 2012/13

TABLE 3.3C – Proposed UK Import Projects[c]
Source - National Grid

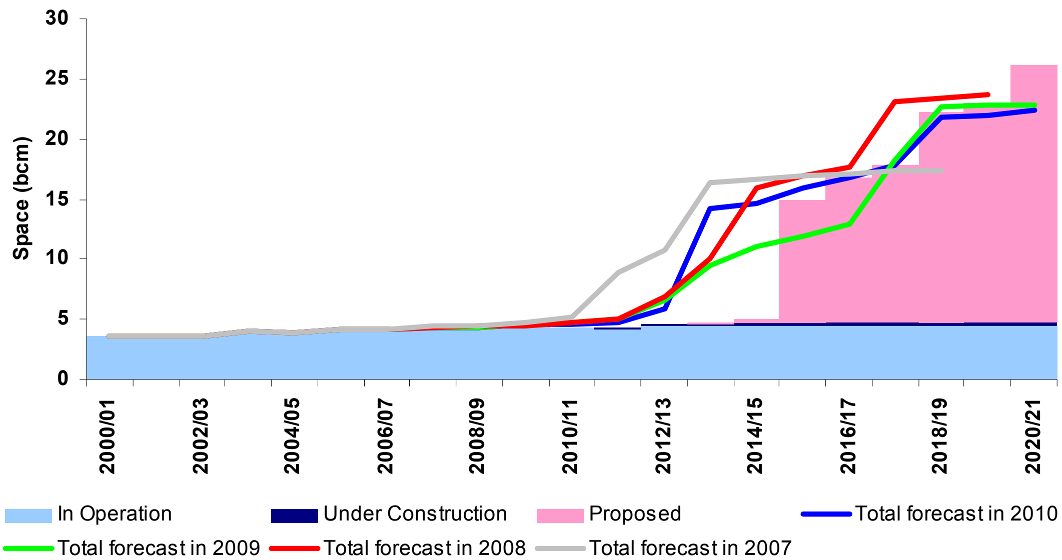
Storage Project	Operator / Developer	Type	Location	Date[d]	Capacity (bcm/y)	Status
Dragon 2	BG Group / Petronas	LNG	Milford Haven	2016 +	3 - 6	Planning granted, no FID[e]
Isle of Grain 4	Isle of Grain LNG	LNG	Isle of Grain	n/a	n/a	Open Season
Norsea LNG	Partners	LNG	Teesside	2016 +	~20	Planning granted, no FID
Port Meridian	Hoegh LNG	LNG	Barrow	2013 +	~6	Planning granted, no FID
Amlwch	Halite Energy	LNG	Anglesey	TBD	~20	Approved onshore
				Total	**50+**	

[c] This list is by no way exhaustive, other import projects have at times been detailed in the press
[d] Based on IPC consultations, it is anticipated that major infrastructure projects will take a minimum of 5 years to be completed
[e] FID - Final Investment Decision

3.3.8 UK Storage Developments

Figure 3.3N shows historic storage levels, the current status of potential storage developments in the UK and views (at the time) of storage developments since 2007. Despite all the proposals for new storage developments, actual storage capacity has only increased by around 1 bcm since 2000. During this period storage deliverability has stayed broadly the same 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 closures of Dynevor Arms LNG in 2009 and Partington LNG in 2011.

FIGURE 3.3N – Potential UK storage developments
Source – National Grid



The chart shows views of storage developments (at the time) since 2007. These show a general trend of slippage of many projects from one year to the next. The space in the chart includes almost 15 bcm of proposed offshore developments, none of these have yet received a Final Investment Decisions (FID).

Many of the proposed storage sites may not be built and to avoid picking 'winners and losers' the supply forecasts only include existing storage sites and those under construction. For network investment purposes the proposed storage sites are evaluated on a site by site basis or are assessed collectively alongside demand sensitivities such as wind intermittency.

3.3.9 UK Storage Data

As in previous years there has been considerable activity regarding storage developments, however the rate of progress from proposals to construction has again been slow with no proposals attaining a FID for subsequent construction.

The following four tables details UK storage in terms of existing storage sites, those under construction and those with and without planning consents.

TABLE 3.3D - Existing UK storage
Source – National Grid

Storage Project	Operator	Location	Space (bcm)	Delivery[f] (mcm/d)
Rough	Centrica Storage	Southern North Sea	3.3	45
Aldbrough I	SSE / Statoil	Yorkshire	0.2	12
Hatfield Moor	Scottish Power	Yorkshire	0.1	2
Holehouse Farm	EDF Trading	Cheshire	0.06	7
Hornsea	SSE	Yorkshire	0.3	17
Humbly Grove	Star Energy	Hampshire	0.3	7
LNG Storage[g]	National Grid LNGS	Avonmouth	0.08	13
		Total	**4.4**	**103**

[f] Maximum observed delivery since 1996.
[g] 13 mcm/d represents maximum capability.

Note, due to operational considerations, the space and deliverability may not be fully consistent with that used for operational planning as reported in our 2011 Winter Outlook Report.

TABLE 3.3E - Storage Under Construction
Source – National Grid

Storage Project	Operator	Location	Space (bcm)	Deliverability (mcm/d)	Planned Start-up
Aldbrough I (portion under construction)[h]	SSE / Statoil	Yorkshire	0.2	25	2012
Hill Top Farm	EDF Energy	Cheshire	0.1	15	2011/12
Holford	E.ON	Cheshire	0.2	22	2011/12
Stublach[i]	Storengy UK	Cheshire	0.4	32	2013/14
		Total	**0.8**	**95**	

[h] Aldbrough space 0.33bcm and delivery of 40mcm/d when fully commissioned.
[i] All phases. Phase 1 expected 2013/14, all phases expected by 2015/16.

A number of storage projects have received planning permission, if these were all to proceed to construction they could contribute a further 11 bcm storage capacity. Since last year's Ten Year Statement two offshore projects, Deborah and Baird have gained planning consents.

TABLE 3.3F - Storage with Planning Permission[j]
Source - National Grid

Storage Project	Operator	Location	Space (bcm)	Planning Granted	Status
Aldbrough II	SSE / Statoil	Yorkshire	0.3	May-07	No FID[k], under review
Bains	Centrica	Irish Sea offshore Barrow	0.6	Jun-09	No FID
Caythorpe	Centrica	East Yorkshire	0.2	Feb-08	No FID
Gateway Storage	Stag Energy	Irish Sea offshore Barrow	1.5	Nov-08	No FID
Hatfield West	Scottish Power	Yorkshire	0.06	Feb-10	Some consents needed
King Street	King Street Energy	Cheshire	0.3	Jan-10	No FID
Portland	Portland Gas Ltd	Dorset	1.0	May-08	No FID
Saltfleetby	Wingaz	Lancashire	0.7	Sep-10	No FID
Deborah[l]	Eni	Offshore Bacton	4.6	2010	No FID
Baird	Centrica / Perenco	Offshore Bacton	1.7	2010	No FID
		Total	**11.1**		

[j] In some cases not all consents may have been secured

[k] FID - Final Investment Decision

[l] All permission in place, waiting for Gas Storage Development Plan Approval

A number of storage projects have some planning consents or may have applied for planning permission that has not yet been granted, many of these have resulted in public enquires. The table below includes some of these projects, these include more offshore storage proposals that if built would significantly increase the amount of UK storage space. Though not detailed there are other offshore (and onshore) fields that have been mentioned in the press as possible future storage projects.

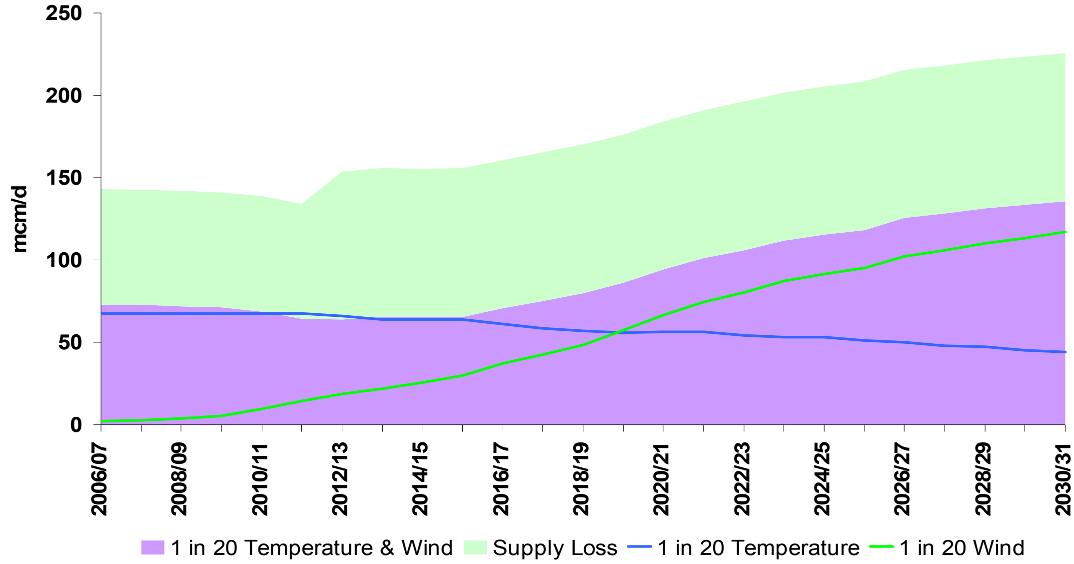
TABLE 3.3G - Storage awaiting Planning Permission
Source - National Grid

Storage Project	Operator	Location	Space (bcm)
White Hill Farm	E.ON	Yorkshire	0.4
Preesall	Halite Energy	Fleetwood	1.2
Esmond Gordon	Encore Oil	Offshore Bacton	4.0
Corvette	Shell / Esso	Offshore Bacton	2.5
Islandmagee	InfraStrata & Mutual Energy	Northern Ireland	0.5
		Total	**8.6**

3.3.4 Security of Supply

This year, rather than developing a new model to analyse gas security of supply in great detail, a simplified approach has been used combining some metrics from this year's Ten Year Statement, as well as some output from our ongoing impact of wind intermittency analyses. This approach, whilst not sophisticated, does easily allow some high level conclusions to be drawn. Figure 3.4A below encapsulates the approach taken.

Figure 3.4A Potential maximum day to day variation in daily national demand
Source - National Grid



The blue line represents the maximum potential day to day variation in daily national demand due to variations in temperature that might be expected to occur once every 20 years. In the Gone Green forecast this reduces from approximately 70 mcm/d to 45 mcm/d by 2030/31, as less gas is used for domestic heating and further efficiency savings are made. The green line represents the maximum potential day to day variation in daily national demand due to variations in wind load factor, i.e. a reduction in wind load factor results in additional gas demand through gas fired power generation. In the Gone Green scenario, this steadily increases due to a progressive build up in wind generation capacity out to 2030/31. By 2030/31, the potential day to day variation in national demand due to wind intermittency could be above 100 mcm/d. The lavender shaded area shows the combined potential day to day variation in demand due to both temperature and wind load factor variation. This is calculated at approximately 140 mcm/d by 2030/31. This is less than simply adding the effects of temperature and wind due to diversity effects. The green area represents the potential impact on non storage supplies (NSS) due to the loss of a major piece of supply infrastructure. This supply loss is assumed at 70 mcm/d up to 2011/12, representing a loss of maximum supply through the Langeled pipeline or the IUK Interconnector, and 90 mcm/d from 2012/13 onwards, representing the loss of the pipeline from Milford Haven. These are the current values used within the N-1 calculations for EU security of supply assessment.

The top of the green area represents the maximum day to day variation in daily national supply demand balance due to the combined effects of a demand increase due to the coincident effects of a reduction in temperature and wind load factor, and a supply loss. In the extreme, this value could exceed 200 mcm/d by 2030/31.

This approach clearly represents an extremely unlikely worst case scenario, with the coincidental occurrence of a one in 20 event and a major loss of supply. However it does provide an illustration of the levels of supply and demand response that may be required, and a clear indication that additional supply flexibility will be required going forward.

There are a number flexible supply (and demand) upsides and downsides going forward:

- One upside is new storage. There are a number of new storage sites already under construction which will when constructed provide additional storage, most noticeably additional deliverability which will be beneficial for managing increasing demand volatility as a consequence of increasing wind capacity. Most of these new sites are fast cycling, with modest storage space, so they are less suited to providing a response to a sustained supply loss. There are however a large number of additional storage facilities at the proposal stage. Some of these would offer large storage space and the potential for sustained volumes over a long period, for example months rather than days.
- One downside is, rather counter-intuitively, the increase in supplies from LNG imports. This has the effect of increasing LNG load factors with the result that there may be a reduction in potential supply flexibility from LNG sites (as they are more likely to be supplying).
- The corollary of the above is the upside caused by the forecast long term decrease in Norwegian imports. As Norwegian imports decline, and load factors decrease, this could provide greater supply flexibility, as flows to the UK could possibly increase when required.
- Two other flexible supply sources are the BBL and IUK Interconnectors which may in the future provide increasing levels of flexibility as the UK market becomes more volatile and there is possible greater access to Continental storage and transmission.
- Another downside is the reduced demand side response (DSR) capability from gas-fired generation as the level of wind generation increases. As the volumes of wind capacity increase, greater levels of CCGT will be acting as backup, with the result that when the CCGTs are running, they may not be able to provide any DSR, or there will be potential supply demand imbalance on the electricity network. Conversely, when wind load factors are high, and CCGTs could turn down, they will not be required to run and hence will not be taking gas in the first place. In the longer term, this downside might be partially negated by advances in smart grids, enabling consumers to react to variations in electricity prices, leading to a reduction in electricity demand peaks and a subsequent lowering of gas demand for CCGTs running as backup.

In summary:

- Potential maximum day to day demand variations may increase as additional wind generation is connected to the electricity transmission network and gas fired power stations provide backup for wind intermittency
- Increasing day to day (and within day) demand variations are likely to be met by a combination of flexible supplies, including imports and storage. Demand side response from CCGT may be limited but smart grids could contribute

Chapter Four

System Operation Challenges

4.1 Overview

Our primary responsibility as System Operator is to transport gas from supply to demand, on behalf of our customers, but in doing this we have a number of overriding obligations which are focussed on ensuring safety for employees and the wider community. The key elements of this are:

- Ensuring that pressure within the NTS is maintained within safe limits, such that pressure does not exceed safety limits or fall below the minimum level to ensure the security of downstream networks
- Ensuring that the quality of gas transported through the NTS meets the criteria defined within the Gas Safety (Management) Regulations
- Operation of compressor fleet within environmental site specific permits
- Ensuring that capabilities and processes are in place to effectively manage a Network Gas Supply Emergency

In addition to these overriding safety requirements, we have a range of responsibilities associated with operating the network and with facilitating the effective and efficient operation of the UK gas market. We must continue to make entry and exit capacity available in line with obligations and contractual rights, meet pressures contractually agreed with our customers, balance the network and signal significant shortfalls in supply, procure energy to run our compressor fleet, source Operating Margins gas to support the network in times of "distress", and manage gas quality (Calorific Value) at a zonal level to ensure consumers are fairly billed for the gas they use.

The decline in UKCS supplies and subsequent increase in import capacity from non-domestic supply sources has materially changed the UK's gas supply landscape. Indeed, the resulting high (surplus) capacity of importation sources has fundamentally changed the dynamics of supply from that of near predictability to considerable uncertainty. This trend is anticipated to continue through increased imports, more fast cycle storage, and in the longer term gas from unconventional sources such as coalbed methane and potentially shale gas. This uncertainty will be compounded by increased within day and between day demand variation due to an increase in gas fired generation, more price arbitrage across energies, intermittency effects of increasing renewable energy driving dynamic operation of CCGTs, and increasing utilisation of the European interconnectors in response to maturity of EU energy market reforms.

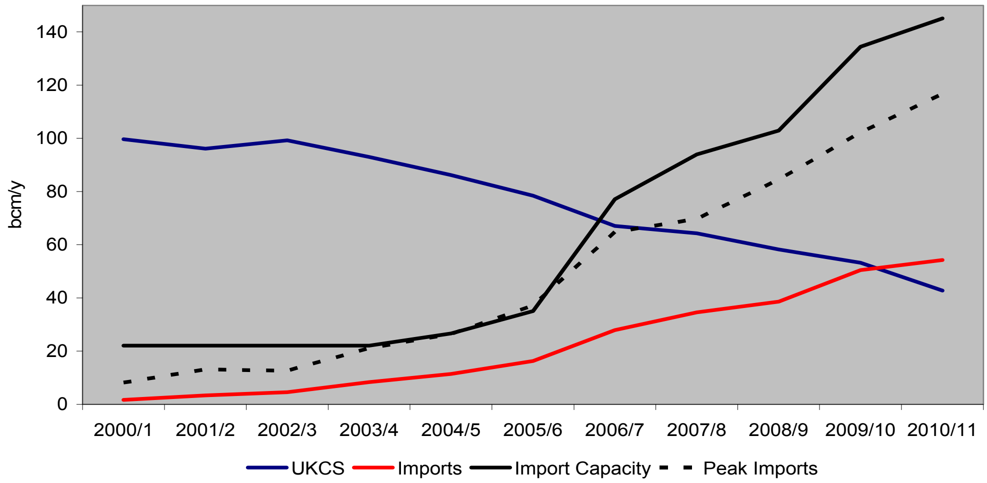
On an operational level, we are now experiencing flow patterns and underlying user requirements which create an increasing challenge for the operation of the NTS. We are responding to this by developing strategies, tools and capabilities to mitigate risk and ensure the continued safe and reliable transportation of gas while continuing to meet customer needs.

Over the next ten years we expect this trend to continue, leading to fundamental changes in the way gas is supplied to, and taken from, the NTS.

4.2 How Network Gas Flows have changed

Supply sources have changed as UKCS has declined and imports increased. The dramatic change in the supply environment is shown in Figure 4.2A.

Figure 4.2A - UKCS vs. Imports
Source National Grid

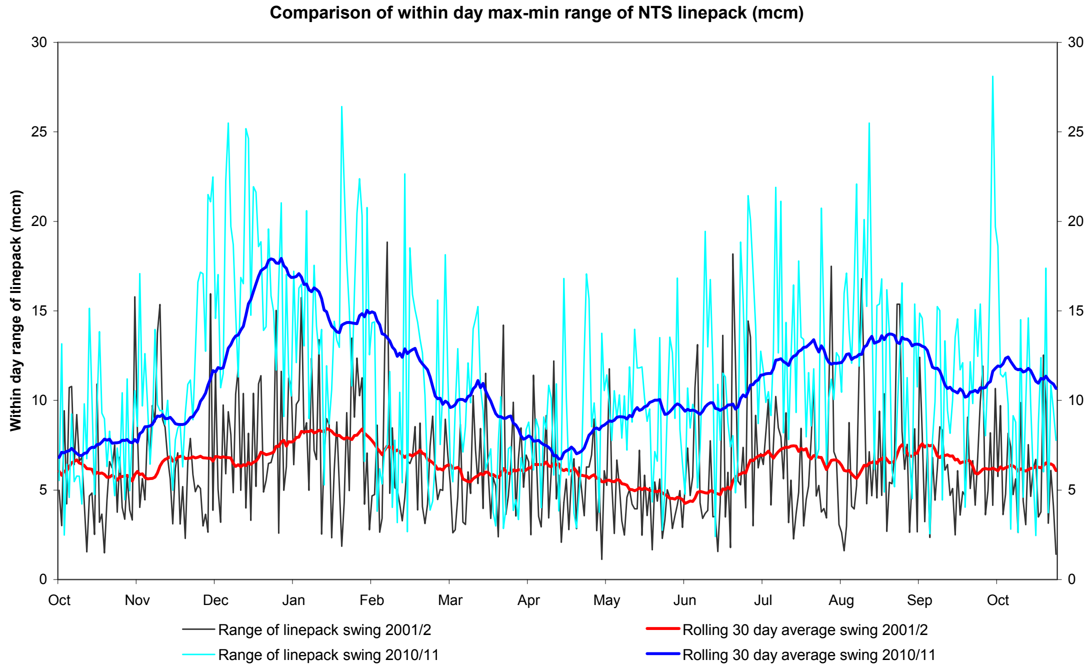


The chart shows total imports exceeded indigenous UKCS supplies for the first time in 2010/11. The chart also shows the rapid growth in import capacity and import margin across the period 2000 – 2011. The peak imports line shows the maximum amount of gas that could potentially flow based upon aggregated peak flows seen from import facilities in each year. With facilities able to operate at full capacity all year round, network capacity far in excess of annual demand has been made available. However flexibility in network transmission capability must become a key design consideration for future developments if we are to continue to meet the more flexible operating dynamics and freedom demanded by our customers.

Comparing the day to day capacity utilisation at terminals highlights a significant variation in supply to a far greater extent than we have traditionally experienced for supplies from UKCS. Currently we see the greatest variability from LNG and IUK but as our forecasts for Norway indicate a future decline, there is an expectation that it will also become a more flexible supply source, particularly if Europe continues along its path of market liberalisation.

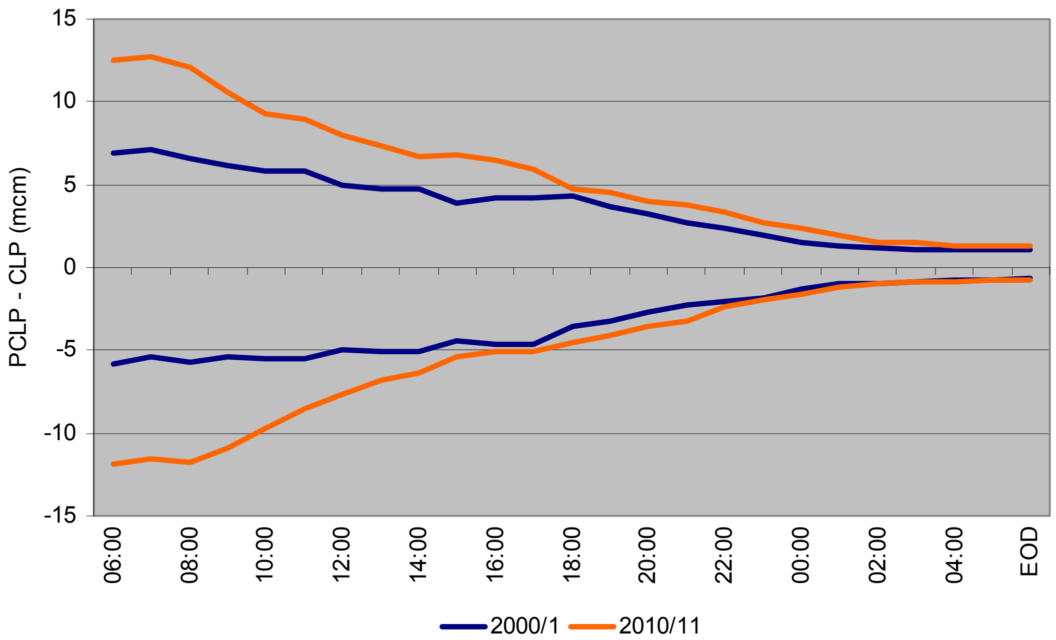
The continuing increase of this trend has led to greater operational challenges, manifesting particularly with respect to the management of within-day linepack and managing NTS pressures within safe and agreed operational tolerances. Figure 4.2B clearly shows the increased frequency and magnitude of linepack variations over the last ten years with the rolling 30 day average linepack swing more than doubling during the winter period from 8 mcm in 2000/01 to 18 mcm in 2010/11.

Figure 4.2B - Within-day Linepack Variations
Source National Grid



An associated trend can be seen in Figure 4.2C, network user notifications that feed into the end-of-day market indicator of Projected Closing Linepack (PCLP). In the past ten years, there has been a notable trend towards a reduction in the accuracy of the start of day offtake and flow notifications provided by network users which has an adverse effect on the forecast performance of PCLP, a vital balancing requirement indicator.

Figure 4.2C - Performance of PCLP – CLP (Closing Linepack)
Source National Grid



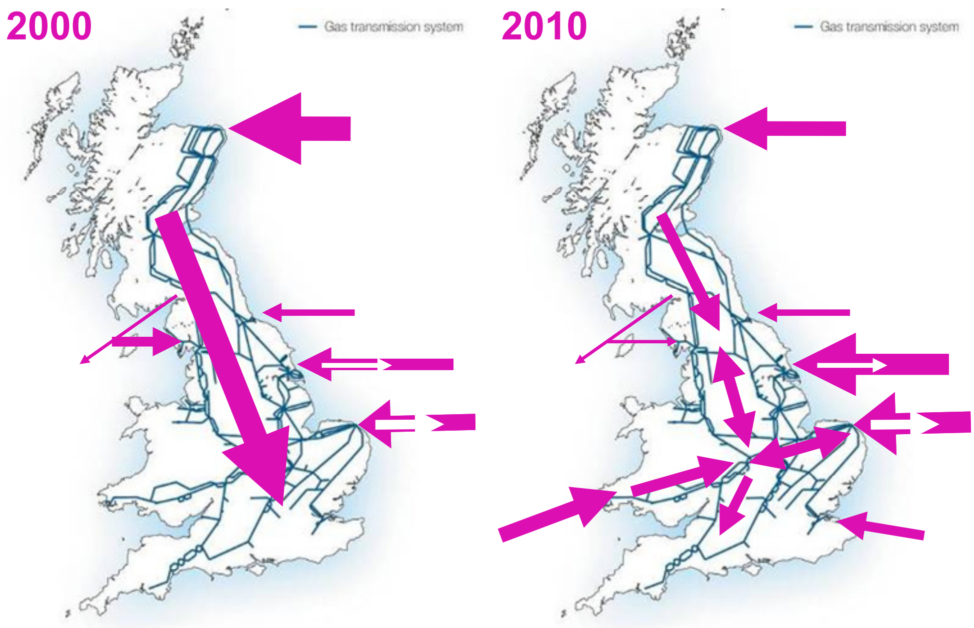
The chart shows the underlying market imbalance at the start of the gas day and the time taken for the network to balance. It shows on average the PCLP at the start of the gas day is around twice as far out of balance compared to ten years ago.

These figures are material evidence of how users are changing the way that they use the network; the charts above demonstrate the greater operational challenge associated with a combination of increasing uncertainty where supplies will arrive, a much higher degree of supply profiling within day and reduced accuracy of aggregate user notifications .

4.2.1 How the general flow patterns have changed in the NTS

A positive consequence of this supply transition has meant that sources are much more distributed around the UK. This has brought supplies (that have the ability to significantly increase flows) closer to the demand centres, thus aiding security of supply, and enabling opportunities to better optimise compressor fuel management. However this brings associated operational challenges due to an increased risk of credible supply loss and the variability of supply patterns from day to day. This has fundamentally changed the flow patterns of gas in the NTS, which is clearly illustrated in Figure 4.2D. The dominant flow pattern in 2000 was characterised by high UKCS supplies at St Fergus with the challenge of moving large quantities of gas from Scotland to the areas of high demand in the South. By 2010 this pattern had changed substantially with much lower supplies at St Fergus and much larger supplies further south with the commissioning of LNG import terminals at the Isle of Grain and Milford Haven together with Norwegian gas imports at Easington. This results in differing flow patterns to the network design. This change in flow pattern brings about challenges in real time operational planning of the NTS. It now has to embrace a much wider set of credible conditions for both steady state and unplanned significant dynamic changes. As a further consequence the use of physical assets on the network has evolved from their original design parameters resulting in higher maintenance and corresponding system access requirements.

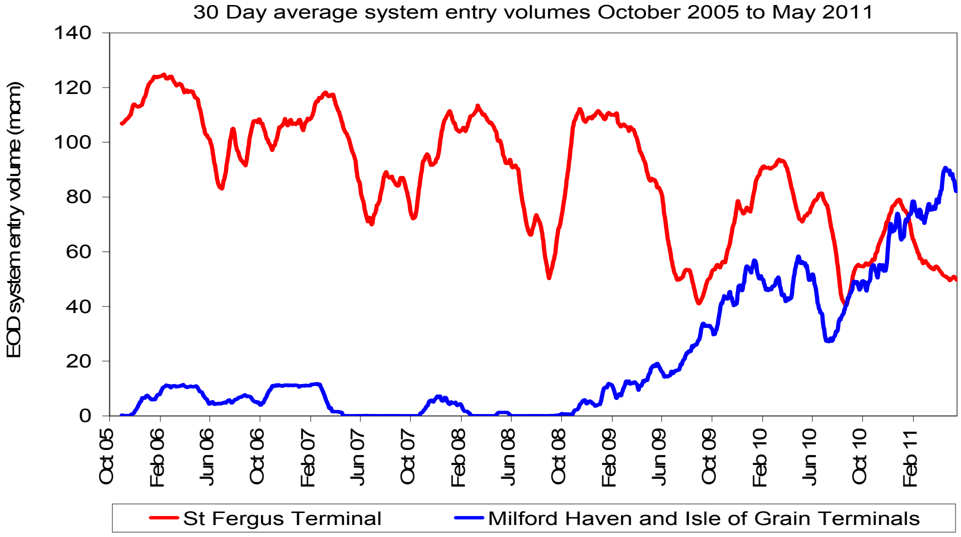
Figure 4.2D - Flow patterns in the NTS
Source National Grid



The decline in St Fergus supplies has been widely publicised. This decline creates issues relating to the lack of ability to move gas north towards Scotland to meet demand. To meet this challenge a proposal of work has been suggested through the RIIO Stakeholder Network

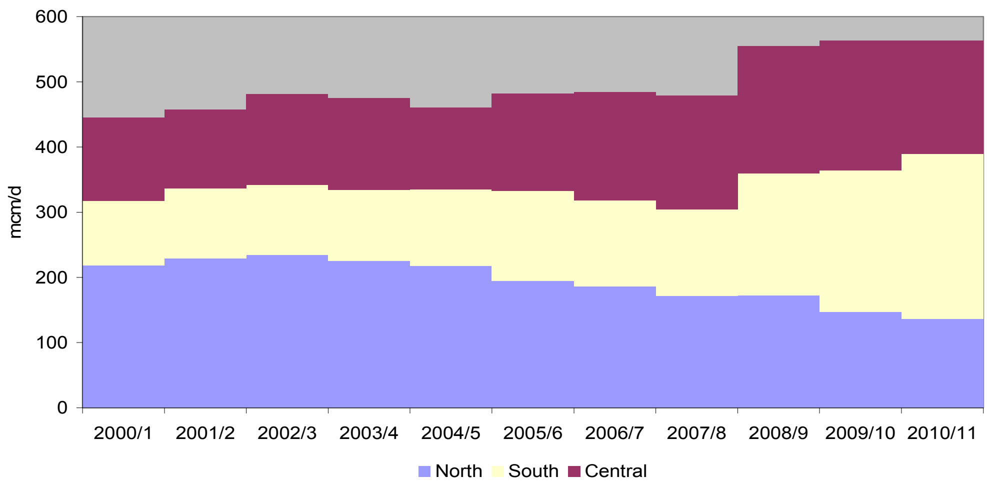
Flexibility workshops. Interestingly, winter 2010/11 saw LNG inputs (specifically Milford Haven and Grain terminals) exceeding St Fergus flows for the first time (see Figure 4.2E):

Figure 4.2E - St Fergus and Milford Haven Supply Volumes
Source National Grid



In addition to the need for increased network flexibility and capacity utilisation, brought about by imports and to a lesser extent storage, the dynamics of user behaviour has (and continues to) change considerably. Figure 4.2Fshows this change based on peak terminal flows aggregated in terms of North (St Fergus, Teesside and Barrow), Central (Easington, Theddlethorpe and most storage) and South (Bacton, Grain and Milford Haven).

Figure 4.2F - Peak Terminal Flows
Source National Grid

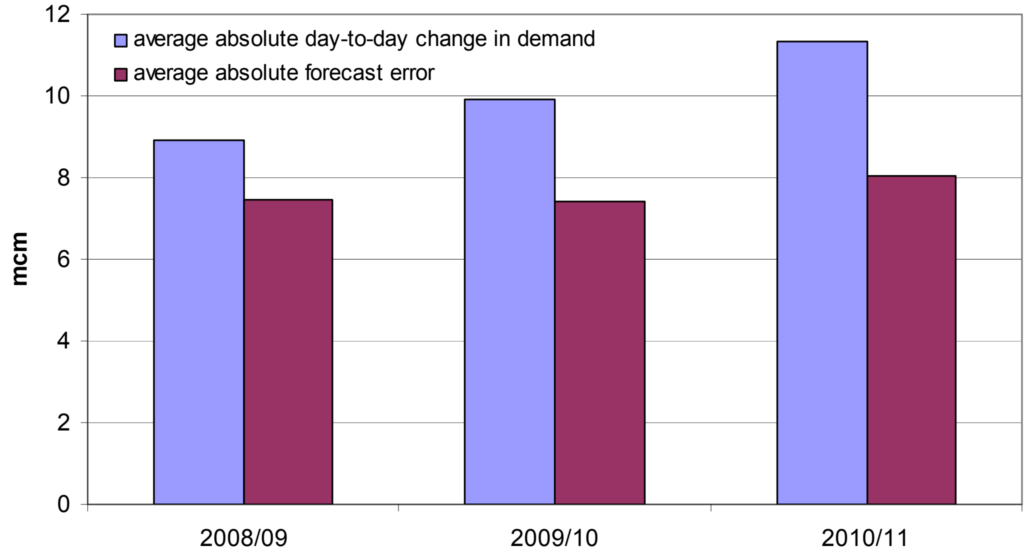


The chart clearly shows the decline in northern supplies from over 230 mcm/d to approximately 130 mcm/d and the material increase in southern supplies from below 100 mcm/d to over 250 mcm/d. For central supplies the change has been less pronounced but still represents an increase of approximately 50%. These changes in entry flows have a considerable impact in terms of the need for network capacity, flexibility and fundamentally impact how the network must be operated.

4.3 Evolution of demand

New LNG supplies coupled with an increase in fast cycle storage and the impact of interconnector demand has already resulted in an increase in the proportion of price responsive demand. This has led to a trend of growing demand volatility making demand harder to forecast. Figure 4.3A illustrates the current trend of growing NTS demand volatility over the past three incentive years.

Figure 4.3A Day to Day demand volatility and D-1 13:00 forecast error
Source National Grid



The graph shows the absolute change in demand between days (mcm) averaged over each year. The graph also shows the absolute average error of the D-1 13:00 demand forecast. This shows the day to day demand volatility has steadily increased year on year, and this trend is expected to continue. It also shows that an increase in volatility results in a greater challenge in terms of demand forecasting with an increased error in demand forecasting over the same period. However the rate of increase in error is less than that of the volatility, as we address the challenges in improving forecasts. However, this will become increasingly challenging as demand becomes more volatile and unpredictable.

To balance the closure of end of life nuclear plant and plant closures driven by emissions legislation on the electricity system, CCGT connection capacity is forecast to increase by around 20% by 2015. It will remain broadly at this level through to 2020 (see Figure 4.3B). Demand from these sites will become increasingly intermittent as they become a source of balancing for wind generation on the electricity system.

Figure 4.3B Generation capacity for CCGTs and Wind including likely load factor[20]
Source National Grid

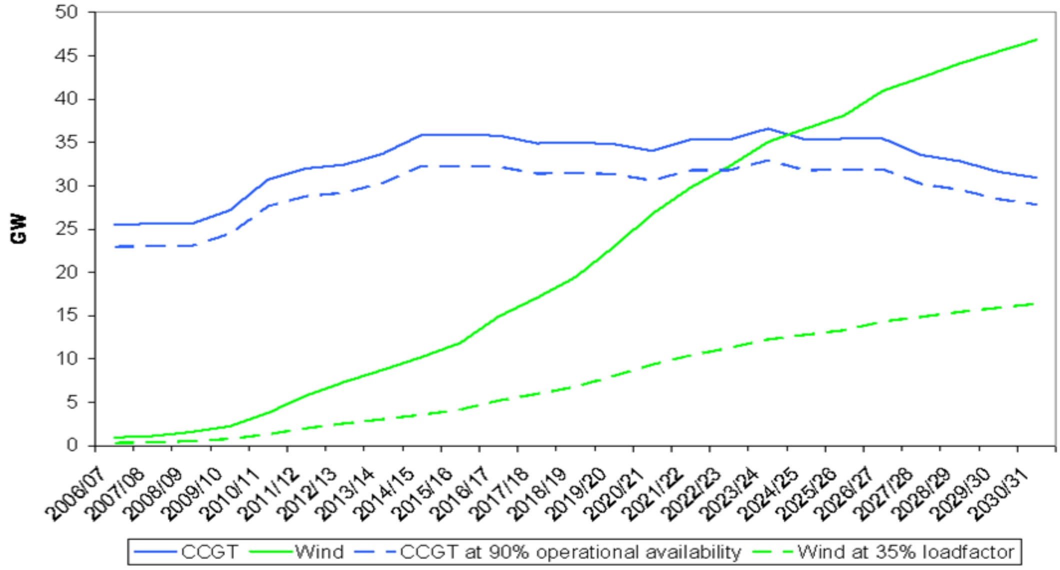
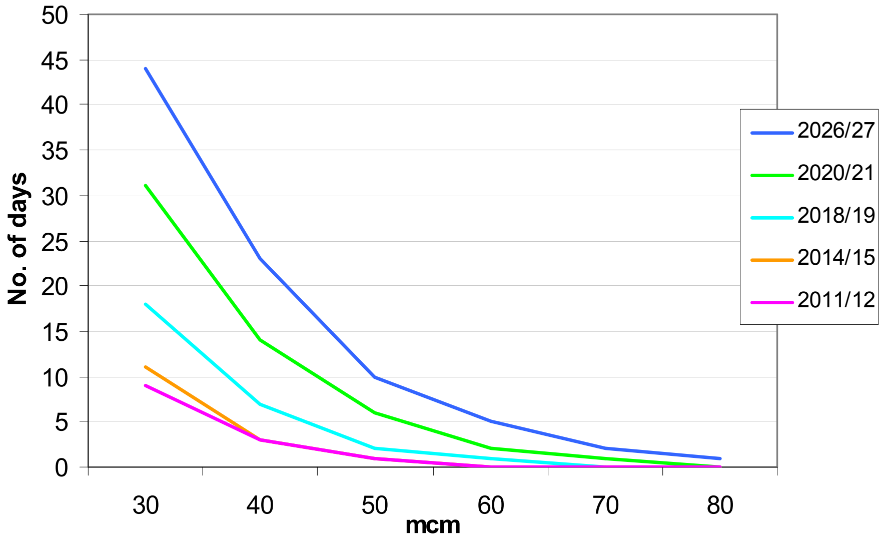


Figure 4.3C below our forecast of the number of significant demand swing days (where daily demand moves away from the 1/24th daily demand per hour flat profile) plotted over a number of years.

Figure 4.3C Frequency & magnitude of wind induced CCGT demand variation into the future[20]
Source National Grid



Volatility of demand causes operational challenges and requires enhanced system operation capabilities and quick reconfiguration of the NTS to ensure gas supplies can be transported to the points of demand. Our modelling predicts that in 2011/12 we will experience a small number of demand swings (<10 per annum) of 30mcm and would expect only one swing of 50mcm in the year. By 2020 we are likely to see a very different situation, with demand swings of 30mcm occurring at least 30 times in the year and maximum swings of 70mcm experienced on more than one occasion. This previously unseen level of demand profiling on the NTS would create unprecedented challenges for the System Operator to manage the network and continue to meet pressure obligations.

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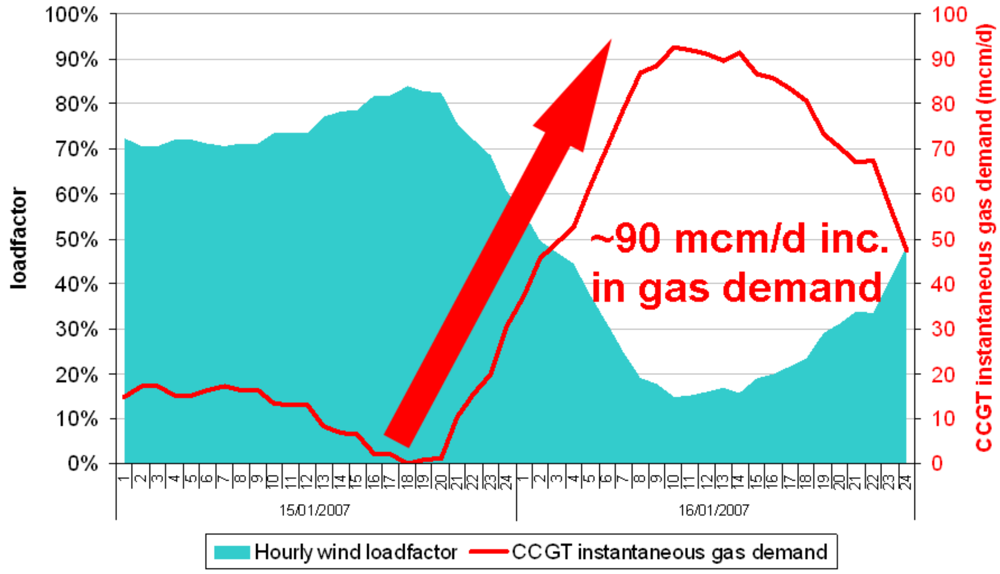
[20] Based on the Gone Green scenario

For extreme events, the magnitude of change will be far greater. Figure 4.3D, is taken from the July 2011 TBE process. It shows an extreme event in 2020/21 with total wind generation at 30GW. Over a period of 15 hours, wind load factor decreases from 84% to 15%. If we assume all the reduction in generation from wind is met by an upturn in CCGT generation, then this equates to an increase in instantaneous gas demand of roughly 90 mcm/day.

Figure 4.3D Gas demand in response to intermittency of 30GW of wind generation
Source National Grid



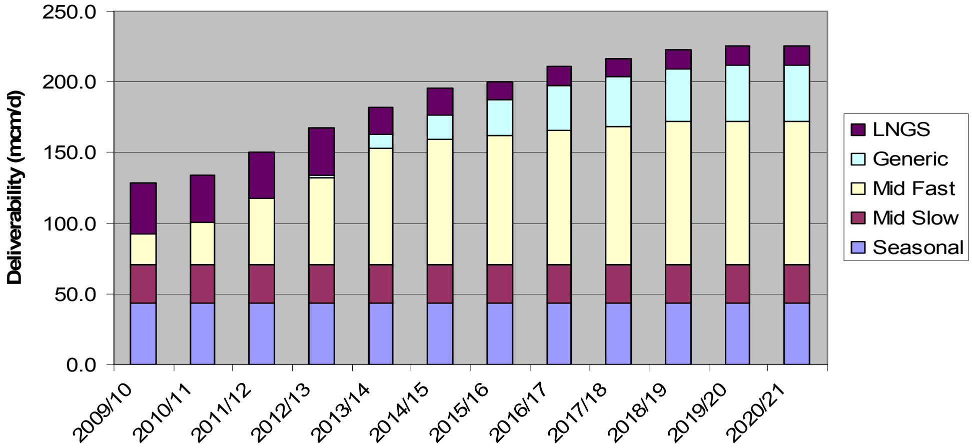
This modelling is sensitive to the number and behaviour of CCGTs over the period. However, maintaining today's level of demand volatility would require an extreme scenario of either very limited wind generation connecting to the electricity network, or an alternative generation fuel used to balance the intermittent nature of wind generation. Should the deployment of wind generation be slower than expected, it is likely the requirement to enhance some of the system operations capabilities identified below will be deferred.

There are also a number of other developments which shall have an impact on demand requirements off the NTS from the Distribution Networks (DNs). There is an expectation that flexibility demanded from the NTS by the DNs will increase as gas holders and other local storage are decommissioned and not replaced. Further, although initially low impact, there is growth of unconventional sources of gas supply from biogas and coalbed methane, which is assumed to be predominantly fed directly into the Distribution Networks. Particularly with biogas the yield can vary due to the nature of the production process. This combined with a reduction in DN storage capability creates uncertainty over the level and profile of the gas that the networks will demand from the NTS day to day.

4.4 Impact of storage flow capabilities

By 2020 we anticipate there will be further storage import capacity and that deliverability from storage sites may increase significantly, with the potential for further increases if the commercial environment is seen as beneficial. This increase in storage deliverability is expected to be predominantly from mid-range fast cycle plants. These are anticipated to increase from 30mcm/d in 2010/11 to over 100mcm/d by 2021, with most of this in place by 2015 (see Figure 4.4A). The operating regime of these storage plants may create a number of challenges for us as they are responsive to small price differentials and may therefore reprofile their flows (i.e. move between injection and withdrawal) more frequently and provide less certainty over their flow patterns within and between days.

Figure 4.4A Actual and forecast storage by type[21]
Source National Grid



Should additional storage not materialise, it is likely that LNG importation will provide the additional deliverability required to meet the more volatile demands from CCGT operation. The effect on the NTS under either scenario will be the same; with greater demand volatility at short notice, we will see greater volatility in supplies.

The combined effect of these changes in supply and demand will continue to alter flow patterns on the NTS further away from a relatively steady state, predictable, north - south bulk flow to far less consistent and predictable flow patterns which change far more frequently.

Key drivers of change and impacts on operations are summarised below:

<table>
<tr><th>Drivers</th><th>Evolving driver behaviour</th><th>Outcome</th><th>Impact on operations</th><th>Consequences</th></tr>
<tr><td>DN diurnal flex</td><td>Uncertain, but will be driven by DN investment decisions</td><td>Within day demand profiling</td><td rowspan="6">1) Supply pattern substantially at variance to that expected by NGG (or notified to us), leading to system configuration not being aligned, compressor fleet set up incorrectly, linepack disposition/level inappropriate, with substantial time required to re-optimise flow patterns
2) Profiling at range of supply points leading to national and zonal linepack levels exceeding operational limits
3) Localised supply rates exceed level that can be transported away or absorbed into zonal linepack
4) Localised offtake rates exceed level that can be met by local supplies and utilisation of local linepack</td><td rowspan="6">• Ability to maintain National Balancing
• Ability to meet zonal linepack targets
• Ability to meet pressure obligations
• Ability to meet capacity rights at entry and exit
• Ability to meet users required supply and demand profiles
• Ability to manage gas quality / CV shrinkage requirements
• Ability to ensure Safe Control of Operations
• Ability to forecast demand</td></tr>
<tr><td rowspan="2">Price responsive behaviour</td><td rowspan="2">Increasing in magnitude and frequency due to more price sensitive/reactive supply and storage sites (notably LNG and MRS) and interactions with Europe</td><td>Within day demand profiling</td></tr>
<tr><td>Interday NTS flow pattern variation</td></tr>
<tr><td>Credible supply losses</td><td>Increasing frequency of significant magnitude events, as supply is clustered into smaller number of single large providers</td><td>National balancing issues, supply redistribution</td></tr>
<tr><td>CCGT intermittence</td><td>New, but forecast to grow significantly over next decade as volumes of renewable generation increase on electricity system</td><td>Local/zonal demand profiling storage and supply reaction</td></tr>
</table>

[21] Chart from 2011 RIIO submission

4.5 System Operator challenges

There will be instances when the timing and quantity of supply and demand profiles requested by customers cannot be accommodated from a system pressure or linepack perspective, but may remain acceptable from an end of day national balance perspective. When this situation occurs, we will need to take time-bound and locational actions to resolve it (for example, to meet pressure requirements and ensure capacity rights can be delivered to users). The customers' ability to see the NTS as a single balancing point will reduce as the physical restrictions of the system limit our capability to allow customers to flow gas in an unrestricted manner (through restriction of flexibility or utilisation of commercial tools).

Whilst it is possible for these issues to arise today, it is rare given:

- The current drivers and capabilities on supply and demand
- The robustness of the system that has been built to meet existing design assumptions
- The proactive stance taken by transmission and distribution operators in utilising all available operational tools to maximise system flexibility for users

This is to some extent enabled by the physical tools available to the operator at both entry (Terminal Flow Advice) and exit (interruption) which can be used as a physical 'backstop' if other measures have failed. The anticipated changes in supply and demand behaviour, coupled with the changes to exit constraint management tools (through the introduction of UNC modification 195AV) change the future risk profile. This may drive us to take on a much more active role in managing system risk, through commercial and operational actions.

Through our RIIO stakeholder engagement process, our stakeholders have indicated a preference for limiting new products and complexity.

“” *They believe that having a lot of different products would add too much complexity to the market; it is important to look at other solutions.*
Stage two workshop Brunswick report, 2nd March 2011

An alternative approach would be to develop the commercial rules and the incentives on customers to incentivise them to minimise their profile of supply and/or demand. This could materially impact both customers' ability to flow gas as they have indicated they wish to and the ability of the electricity system to accommodate significant volumes of wind generation. During the RIIO stakeholder engagement process, customers made it clear that they did not wish to see this form of restriction, with one stakeholder offering the view that if we were to hold them rigidly to their current contractual rights and obligations, this would preclude them from participating in the electricity Balancing Mechanism.

Against this restriction, managing the increasing volatility of supply and demand will require a combination of the following:

Network Operability

Physical infrastructure vs. Commercial regime

Commercial (Rules)

Shape commercial regime, products, tools and incentives to better align cost of customer actions, to encourage efficient behaviour and allow flexibility of usage desired

Operational (Tools)

Enhance capabilities and tools to enable optimal use of the NTS under evolving rapid dynamic within day conditions

Investment (Assets)

Targeted investment to NTS to support dynamic operation at strategic points on the network in order to meet customer requirements

4.5.1 System Operator capabilities

From the RIIO stakeholder engagement there is the agreement that safety is the number one priority for operation of the NTS, but the capability of customers to flow in line with their commercial capacity rights and not to be constrained is also highly valued. As System Operator we need to ensure that we have sufficient operational control to ensure safety, security of supply and a reliable service to customers. As both supply and demand become more dynamic and unpredictable, we need to ensure we can continue to assess risk and take appropriate actions in the necessary timescales to achieve the best operational and commercial outcomes. This will be dependent on the network capability, available at the time, to meet the dynamic requirements required from it.

The key outputs in this area relate to ensuring that, in the face of the changing supply and demand landscape, the NTS can continue to be utilised up to, but not beyond, the boundaries of its' safe operation. Results of the RIIO stakeholder engagement indicate we should maintain current reliability performance. This requires us to enhance some of our key capabilities, processes and IT tools to allow us to do this as the operating environment changes.

"National Grid should avoid any reductions in reliability."
Stakeholder comment, stage one workshop, 11th January 2011

Improvement in or confidence in non-deterioration of reliability performance can only be achieved when the operational capability is developed as part of a holistic solution. This solution needs to consider:

- Targeted network investment to deliver flexibility
- Development of the commercial regime to reflect the changing needs of users

Irrespective of the level of NTS investment that this dynamic behaviour and the requirement for increased system flexibility may drive, the System Operator will need to ensure it can meet its obligations and commitments to ensure the system is operated in an optimal manner to mitigate physical and commercial risks to customers and ourselves. This is to some extent independent of what the system build entails, unless it is reinforced to such an extent as to remove all balancing and constraint risks, which is unlikely to be the most efficient option.

4.5.2 Development Phases

When describing the developments of systems and the need for incremental resources to meet our evolving processes, we have split the develpment into four sequential phases. It is worth noting that there are many overlapping requirements, with essential tools and capabilities needed in multiple phases. We have detailed these deliverables in the earliest phase in which they are needed:

Phase 1 – Near Term

Introduction of exit reform in October 2012 will change the way exit risks are managed on the NTS, with the introduction of a capacity release/buyback commercial regime as opposed to interruptible physical arrangements. When meeting exit capacity and associated pressure obligations, the System Operator must take a balanced view of the operational and commercial options available across exit, entry and balancing arrangements to find the optimal resolution between risk and cost. Commercial actions have greater uncertainty around cost and availability than interruption; therefore we will modify our constraint management approach.

Phase 2 – Short Term

In the short term we expect to see increasing volatility and uncertainty of flows in the network, driven by market behaviour at gas importation facilities and fast cycle storage sites (our baseline plan assumes fast cycle storage projects, many of which are under construction, are likely to have total deliverability around 3 times current levels). This will create increasing issues in meeting our operational and contractual commitments.

Phase 3 – Medium Term

In the medium term we will see a growing impact of wind intermittency on the electricity system creating increasingly dynamic behaviour of CCGT plant. This will also impact on the operation of supply and storage sites, as shippers look to balance their portfolios within day, which will in turn create issues in meeting national balance requirements on a daily basis, locational and zonal capacity, and pressure commitments. Alternative scenarios where growth of wind generation is slower, wind intermittency will still drive these challenges, albeit at a slightly slower pace. Enhancement of our capabilities to manage these issues is therefore a low risk option as this investment has a very high probability of being required in the future.

Phase 4 – Long Term

If the UK is to achieve its climate change commitments by 2020, the long term period will see a move to a position where supply is dominated by imports operating to commercial models to maximise value across and within days, both within the UK and between competing markets. There will be high levels of demand volatility within and between days driven by wind intermittency on CCGT plant, DN flexibility requirements (potentially also being impacted by unconventional gas) and the behaviour of storage sites and interconnectors.

To manage these requirements the System Operator will need the ability to continually re-optimise the network and commercial actions as the conditions change. We also recognise that under these circumstances customers will face increasing challenges in managing their daily balance positions and we will have a key role to play in supporting them in this through further information provision.

To mitigate these risks, we are considering developing the following capability areas:

- Enhanced demand and supply forecasting
- Enhanced capability within the control room environment to consolidate and optimise the operational and commercial strategies via:
    - Enhanced analysis and risk assessment process ahead of the day and at key points during the gas day
    - Enhanced post event analysis to support continuous improvement of operational strategy
    - Enhanced real time network capability analysis and optimisation capability
    - Enhanced decision support strategy and offline capability to provide guidance on the optimal use of commercial tools to manage wind related intermittency risks
- Enhanced after the day analysis of user compliance with contractual requirements and information accuracy, and associated stakeholder engagement
- Enhanced data provision and interfaces

As previously stated, what cannot be managed by these capability areas will require network investment.

Chapter Five

NTS Capacity Provision and Investment

5.1 Overview

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

It presents the currently sanctioned NTS reinforcement projects, those that are presently under construction for 2012 and indicative investment options for later years, consistent with the supply Gone Green scenario detailed in UK Future Energy Scenarios document and signals received in the recent entry capacity auctions. The information in this section is consistent with that presented in our RIIO-T1 business plan although it should be noted that financial totals will not align due to the different time periods considered, (the next ten years in this document; the eight year RIIO-T1 period in our RIIO-T1 business plan).

The annual planning process performs a critical role in allowing National Grid to prepare for likely future investment requirements whilst also ensuring that historical investment decisions that have not yet progressed to construction remain valid in light of the latest supply and demand information. Maps showing the current NTS and approved future investments are presented in Appendix 4.

The 2011 planning process, although taking place against the wider background of our preparation for our RIIO-T1 price control submission, has been undertaken on a fundamentally similar basis to that conducted in previous years, with the TBE consultation process providing the primary source of information, supplemented by auction signals.

The pace of development of the NTS, when judged by investment in incremental capacity, has slowed in recent years in response to wider energy market and macro-economic conditions; this is evidenced in the relative lack of customer signals received, notably in the 2011 QSEC auction. In contrast to the level of signals, however, the number of connection enquiries we are receiving is far higher than in the past.

It is also notable that user requirements from the NTS continue to change and evolve beyond that which has been traditionally seen, for example:

- increased DN flex capacity requirement (against a background of reduced DN flat capacity requirements)
- increased requirement for South to North flows as a result of declining St Fergus flows
- increased requirement to rapidly switch between 'West-to-East' and 'East-to-West' flow directions in the heart of the Network

In our RIIO stakeholder engagement, we have already discussed with the industry whether these changes (and others) merit re-examining the existing design standards against which we plan the Network. With the Transmission Planning Code due for review during 2012, this is an important opportunity to continue this discussion.

Looking forward, as wider energy market processes move towards conclusion, (in particular the Electricity Market Reform process) and more stringent environmental legislation is introduced, we are seeing strong indications of an upcoming period of significant change and renewed development activity.

This likely activity makes it even more important that we work together with our stakeholders and customers to ensure that the right combination of rules, tools and assets are in place to meet on-going customer requirements.

5.2 Recent Developments

5.2.1 Planning Act 2008

The Planning Act 2008 introduced a number of changes to the planning system. The establishment of a single consenting regime streamlines 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.

The Act also made statutory the inclusion of pre-application consultation. Using a range of methods to help stakeholders understand the proposal (for example, using 3D virtual modelling to demonstrate developments) has shown that pre-application consultation is fundamental to ensuring effective community engagement. This, coupled with definitive timescales for consultation responses for the formal consultation stages of the planning process, should provide greater certainty for delivery of nationally significant energy projects

The situations where the requirements of the Planning Act 2008 may apply to our gas pipeline projects (new pipelines or diversions) are set out in section 20 of the Act:

a. the pipeline must be wholly or partly in England; and

b. either:

   i. the pipeline must be more than 800 millimetres in diameter and more than 40 kilometres in length, or

   ii. the construction of the pipeline must be likely to have a significant effect on the environment; and

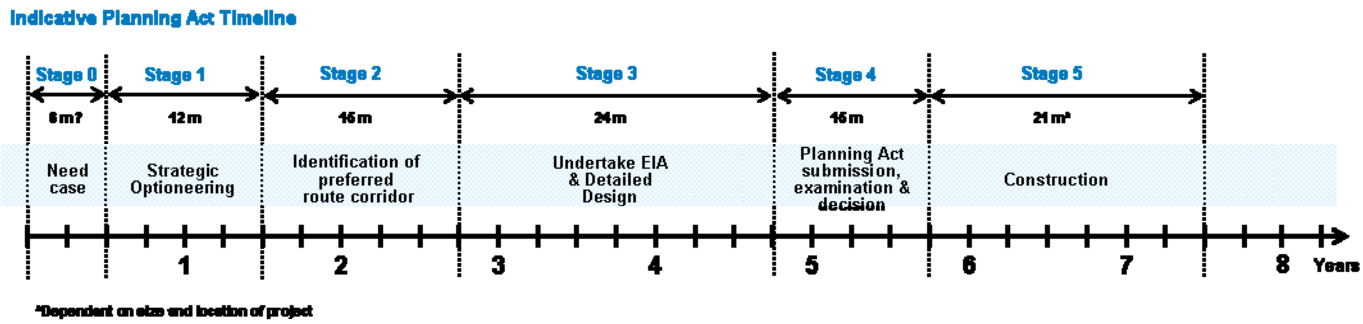
c. the pipeline must have a design operating pressure of more than 7 bar gauge; and

d. the pipeline must convey gas for supply (directly or indirectly) to at least 50,000 customers, or potential customers, or one or more gas suppliers

5.2.1.1 Project Lead Times

National Grid project 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. Due to the new processes the expected end-to-end build time for new projects could be up to eight years. This is illustrated in the figure 5.2A:

Figure 5.2A – Indicative Planning Act Timeline
Source - National Grid



We recognise that this timeframe is not consistent with the timeframes included within existing industry processes governing the provision of new capacity on the Network and that this inconsistency is of great concern to many of our customers. We have started to discuss this issue with our stakeholders during our recent RIIO workshops and are committed to continuing to work with our stakeholders toward developing solutions to this situation.

5.2.3 Planning Consents

Since the publication of the 2010 Ten Year Statement some storage facilities have obtained planning permission; notably the Baird and Deborah storage projects (both intending to connect to Bacton terminal) have both secured the majority of their onshore and offshore planning permissions/licences.

Halite Energy are planning to submit their application for the Preesall storage project, (formerly known as the Fleetwood storage facility), to the Infrastructure Planning Commission during 2011.

5.2.4 Entry Capacity – Auction Results Summary

The Quarterly System Entry Capacity auctions (QSEC) opened on Monday 14th March 2011 and closed on Tuesday 15th March 2011.

In order for incremental obligated entry capacity to be released, sufficient bids for this incremental obligated entry capacity must be received during the QSEC auctions to pass an economic test.

During the March 2011 QSEC auctions, bids were received for incremental entry capacity at the Barrow (for Q1 2015, 2016 and 2017) and Easington (for Q1 2013, 2015, 2018, 2019, 2020 and 2021) Aggregate System Entry Points (ASEPs). The bids received were insufficient to pass the economic test for the release of incremental obligated entry capacity, however following a risk assessment process non-obligated entry capacity was released to meet all the bids at Barrow and selected bids at Easington (for Q1 2013 and Q1 2015) as the incremental risk created by volumes requested, over the specific periods in question, was identified as being operationally manageable and unlikely to lead to disproportionate commercial risk.

Bids received at all other ASEPs were satisfied from current unsold obligated levels for future quarters and no incremental obligated entry capacity was released.

5.2.5 Entry Capacity – Investment Implications

No direct investment were identified or triggered since no incremental bids received at the QSEC 2011 could pass the economic test.

5.2.6 Exit Capacity – User Commitment Summary

In the Transitional Period aggregate NTS Exit (Flat) Capacity allocations for Distribution Network exit points are similar to levels previously signalled, however in the Enduring Period aggregate NTS Exit (Flat) Capacity allocations have reduced by approximately 5% compared to levels previously signalled. This reduction in NTS Exit (Flat) Capacity has countered with a marked increase (20-30%) in aggregate NTS Exit (Flex) Capacity, facilitated through both the NTS Exit (Flat) Capacity reduction and reductions in key Assured Offtake Pressures across the NTS.

The tables below detail the percentage change between Exit Capacity allocated to each LDZ in the 2010 and 2011 Exit Capacity Allocation Processes. A negative number indicates a reduction in allocated capacity agreed between the NTS and DNs. The tables compare bookings for the same gas year across the 2010 and 2011 planning cycles, therefore DN's where previous NTS Exit (Flex) Capacity allocations were close to zero (North West, North Thames and South East) show a large increase in percentage terms.

TABLE 5.2A– Percentage change between exit capacity allocated in the 2010 and 2011 Exit Capacity Allocation processes
Source - National Grid

LDZ	NTS Exit (Flat) Capacity (% Change)					
	Transitional	Enduring				
	11/12	12/13	13/14	14/15	15/16	16/17
Scotland	-2.68	0.32	-0.45	-0.51	-0.51	-0.51
North	-4.28	0.10	-0.58	-0.18	-0.24	-0.24
North East	-3.67	0.43	-0.67	-0.71	-0.79	-0.79
North West	1.55	-8.23	-8.94	-8.94	-8.94	-8.94
East Anglia	2.96	-5.44	-5.44	-5.44	-5.44	-5.44
East Midlands	0.65	-8.77	-10.08	-10.08	-10.08	-10.08
West Midlands	2.65	-11.23	-11.23	-11.23	-11.23	-11.23
North Thames	2.53	-8.57	-8.57	-8.57	-8.57	-8.57
Wales North	-1.02	-11.68	-11.68	-11.68	-11.68	-11.68
Wales South	1.48	-9.20	-9.20	-9.20	-9.20	-9.20
South	0.94	-0.10	-0.51	-0.73	-0.73	-0.73
South East	1.60	0.75	-0.04	0.05	0.05	0.05
South West	-1.64	-12.10	-12.10	-12.10	-12.10	-12.10

LDZ	NTS Exit (Flex) Capacity (% Change)					
	Transitional	Enduring				
	11/12	12/13	13/14	14/15	15/16	16/17
Scotland	2.39	5.20	1.13	-1.69	2.03	2.09
North	-2.02	-2.58	-3.64	-4.68	-6.03	-6.32
North East	11.86	10.47	8.61	7.43	6.22	5.84
North West*	18.50	76.94	72.10	73.85	160.57	156.95
East Anglia	33.86	-16.58	-20.06	-20.86	-24.28	-24.99
East Midlands	15.59	16.16	10.63	5.08	-1.36	-2.34
West Midlands	19.70	38.10	36.92	22.62	21.46	16.00
North Thames*	1793.94	1772.96	1632.91	1620.91	1606.47	1710.33
Wales North	0.00	0.00	0.00	0.00	0.00	0.00
Wales South	0.00	0.00	0.00	0.00	0.00	0.00
South	-6.55	3.75	-0.49	-3.68	-5.61	10.36
South East*	381.38	153.56	84.06	n/a	875.29	1048.25
South West	-11.91	-12.56	1.76	1.69	1.72	1.65

* Previous NTS Exit (Flex) Capacity allocations were close to zero thus revised allocations represent a large increase when shown in percentage terms

TABLE 5.2B – Total Exit Capacity allocated to DNs through the 2011 Exit Capacity Allocation Process
Source National Grid

Aggregate DN Allocations	NTS Exit (Flat) Capacity					
	2011 Exit Capacity Allocation Process					
	Transitional	Enduring				
	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Total (GWh/d)	4476.360	4621.380	4615.427	4621.863	4627.672	4627.672
Change from 2010	0.45%	-5.34%	-5.83%	-5.81%	-5.82%	-5.82%

Aggregate DN Allocations	NTS Exit (Flex) Capacity					
	2011 Exit Capacity Allocation Process					
	Transitional	Enduring				
	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Total (GWh/d)	256.850	247.038	246.384	246.081	266.873	271.978
Change from 2010	22.05%	24.52%	20.8%	24.7%	32.05%	34.58%

All obligated NTS Exit (Flat) Capacity requests from DNs have been allocated in full. Requested increases in non-obligated NTS Exit (Flat) Capacity and NTS Exit (Flexibility) 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).

5.2.7 Exit Capacity – Ad Hoc OCS process

National Grid NTS and Distribution Network Operators (DNO) are subject to concurrent price control reviews RIIO-GD1 and RIIO-T1 which will set price controls for the period 1 April 2013 to 31 March 2021.

In order to ensure that each company's RIIO business plan included the consideration of economic trade-offs between networks, National Grid NTS and DNOs undertook an informal OCS process to consider the impact of requests for increased levels of NTS Exit (Flexibility) Capacity which fell outside of the gas years covered by the formal OCS process (Y+1 to Y+6) but within the years covered by RIIO price control (Y+7 to Y+10).

This process identified where the release of increased levels of NTS Exit (Flexibility) Capacity would trigger system constraints requiring NTS reinforcement and whether this could be mitigated by the agreement of reduced Assured Offtake Pressures without triggering further reinforcement within the distribution networks.

This analysis showed that in the majority of cases, the release of increased NTS Exit (Flexibility) Capacity could be facilitated through the reduction of associated Assured Offtake Pressures (AOPs). In some cases, namely in Scotland, reinforcement to support the provision of AOPs is required as a result of reduced forecast gas supplies at the St Fergus ASEP. However, as a result of the reductions in AOPs agreed through this process we have been able to reduce the amount of investment required.

5.2.8 Recently Commissioned Projects

Only one major project was completed in 2011:

a. Feeder 15 Warmingham to Wheelock

The Warmingham to Wheelock pipeline (formerly referred to as the Warmingham to Elworth pipeline), triggered by long term entry auction signals in 2010, has been constructed to enable increased capacity flows to cater for the Hill Top Farm storage facility, which is an expansion of the Hole House Farm storage facility. The 3.2km 900mm pipeline has been completed and is to be commissioned shortly.

5.3 Future Investment

5.3.1 Transmission Planning Code

The Transmission Planning Code is a document which describes National Grid's approach to planning and developing the NTS in accordance with its duties as a Gas Transporter and other statutory obligations relating to safety and environmental matters, and is published in accordance with Special Condition C11 of National Grid's Gas Transporter Licence in respect of the NTS.

Special Condition C11 requires that National Grid prepares and maintains a Transmission Planning Code that describes the methodology used to determine the physical capability of the system. It is intended to inform parties wishing to connect to and use the NTS of the key factors affecting the planning and development of the system.

National Grid must review the Transmission Planning Code at least every two years, after consultation with the gas industry. The next review is scheduled for 2012. Modifications to this code must be approved by the Gas and Electricity Markets Authority (GEMA) before they are implemented.

National Grid undertakes investment planning up to a ten year planning horizon on an annual basis. The investment plan is developed using long term forecasts of supply and demand informed by information gathered through the commercial processes to reserve capacity on the system.

National Grid will commence its annual planning cycle after the initial data has been gathered through the TBE process and will use this data to compile long term supply and demand forecasts. The planning process will consider those investments that may be required to respond to potential entry and exit capacity signals from the market. National Grid will use detailed network models of the NTS under different supply and demand scenarios in order to understand how the system may behave under different conditions up to the ten year planning horizon.

During this process, Distribution Network Operators (DNOs) and Shippers can apply for exit capacity from the NTS to support their long term needs, and Shippers may signal their requirements in the long term entry capacity auctions, under rules set out in the Uniform Network Code (UNC). The information received from these commercial processes will be used to decide the final set of investments that are necessary to develop the system.

National Grid will consider long term signals received for additional capacity above the prevailing obligated/contracted capacity levels and long term capacity bookings/reservations within obligated/contracted capacity levels within the same annual planning process.

Commercial options available to National Grid will also be considered 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, supply turn up contracts, buy-back contracts and interruption contracts.

Given recent industry and regulatory developments, the Transmission Planning Code review and consultation during 2012 will include but not be limited to consideration of the impact of the Industrial Emissions Directive, the European Union Third Package, the Planning Act 2008, and the Capacity and Connections processes.

5.3.2 Investment Planning Scenarios

Chapter 3 discussed the uncertainties in future supply mix that arise from both existing supplies and potential new developments 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.

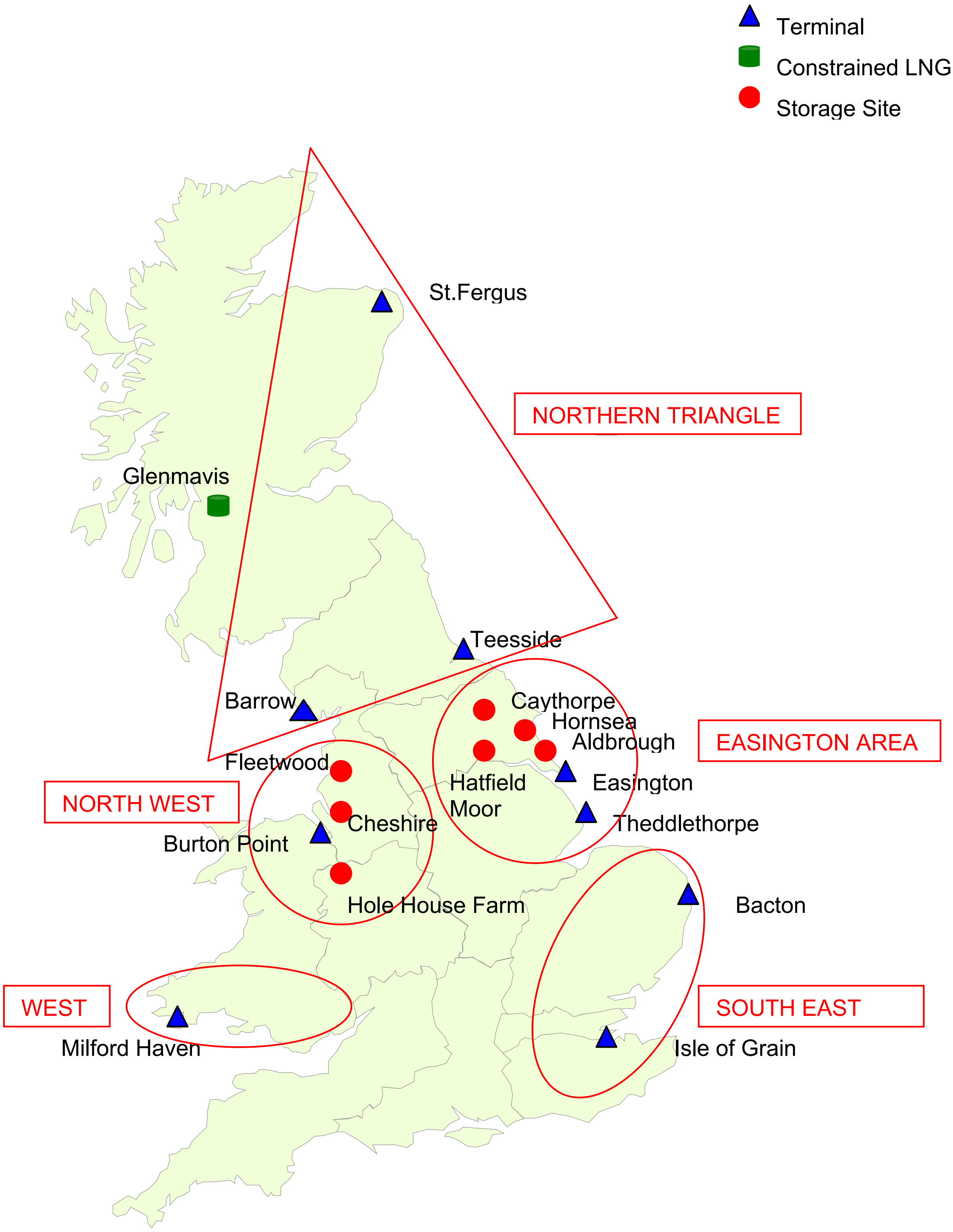
National Grid continues to develop its processes to better manage the risks that arise from such uncertainties. The approach applied is described further in the Transmission Planning Code and considers range of sensitivities around the Default Case scenario (see section 3.3), as well as the obligations placed on National Grid to release capacity to shippers.

In order to aid understanding of entry capability, we have used to the concept of entry zones which contain groups of ASEPs (Figure 5.3A). 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 Milford Haven and Bacton, or Easington and Bacton entry points.

The commonly used zonal groupings 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 reach major demand centres in the Midlands and South of the country
- West UK – this zone enables sensitivity analysis around potential supplies from Milford Haven
- North West Corridor – includes storage at Hole House Farm and Cheshire

Figure 5.3A Zonal grouping of interacting supplies
Source National Grid



An example of this approach is that the analysis of the South East could consider higher flows from the Bacton and Isle of Grain entry points whilst reducing the other supplies to create a demand balance for the day being considered.

Key scenarios examined through the investment planning process include:

- High West-East flows generated by increased entry flows in the West travelling east across the country to support demands in the East and South east of the UK.
- High South-North flows created by reduced entry flows into St. Fergus with a corresponding increase in entry flows in the South requiring gas to be moved from South to North.

In addition to the traditional geographical scenarios, several commercially driven sensitivities are also investigated. For example a sensitivity with a reduction in imported gas requiring high MRS (Medium range storage) entry flows to meet winter demand.

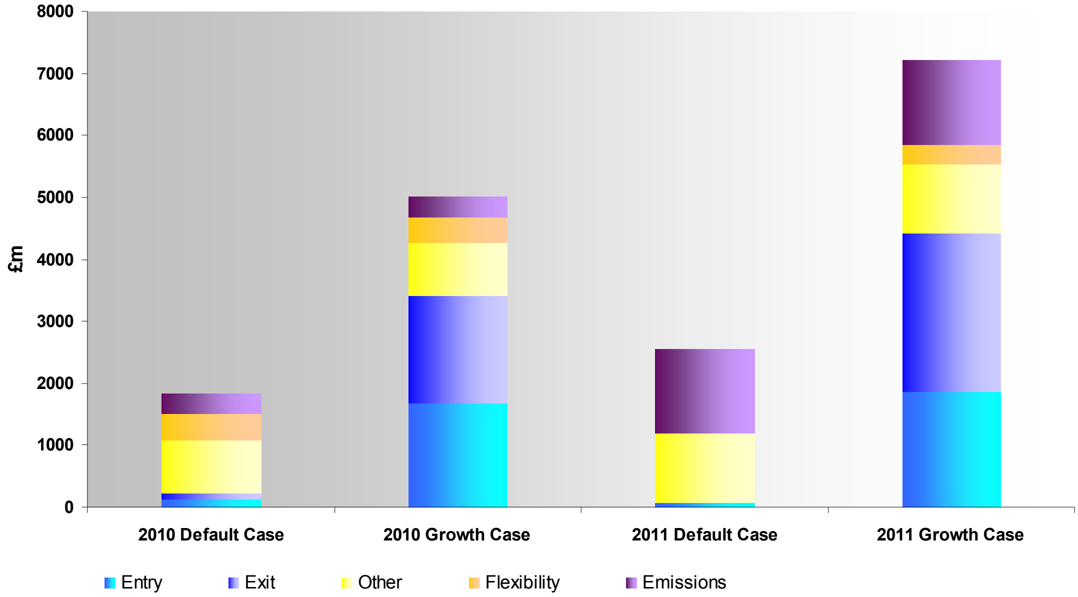
Historically these scenarios have been considered on an individual basis using ‘steady state’ gas flows consistent with an overall ‘end of day’ energy balance. As user requirements from the Network evolve, it is increasingly necessary to consider the ability of the system to switch between different flow scenarios, explicitly considering ‘transient’ (changing) flows on the Network.

Where this technique indicates future requirements from the Network that are outside of current capability, a range of possible solutions (regulatory, commercial and physical) are investigated. This ensures that a broad spectrum of potential solutions are identified allowing, where investment in assets is the optimum solution, further optioneering to develop appropriate solutions to be developed through the planning consents framework

5.3.3 Investment in forecast period

The chart below shows our view of the investment required over the ten year forecast period, compared to the same forecast from 2010.

Figure 5.3B Forecast spend by Investment Category for the 2011 compared to 2010
Source National Grid



The 'Default Case' represents the investment we would expect to undertake on the Network if no user signals for incremental capacity are received. The 'Growth Case' sensitivities represent views of potential investment required as a result of receiving user signals for incremental capacity. The 2011 scenarios are consistent with our RIIO-T1 business plans, although as already noted, financial totals will not align precisely due to the different time frames considered. The Default Case aligns with the ex-ante funding which we are seeking under RIIO-T1; the Growth Case is aligned to our 'base' RIIO-T1 plan which includes both ex-ante and indicative incremental user signals.

2011 Default Case scenario

In the graph above, 'Entry' relates to approved investment currently being undertaken to meet entry auction signals and the 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 exit capacity requirements. This considers the commitments made under the exit capacity allocation processes, contracted loads and forecast directly connected loads over the period. 'Other' investment includes 'non-load' related (e.g maintenance) 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 ten year period decreases from the previous year. This is due to the following reasons:

- The majority of the investment for Milford Haven has been completed
- The Warmingham to Wheelock pipeline is nearing project completion

- There have been no further investments triggered as a result of long term entry auction signals.

Further reinforcement of the NTS may be required to support new storage projects and large new power stations should signals be received from users under the commercial arrangements for releasing additional NTS exit capacity. Such projects are not included in our Default Case scenario but are included in the Incremental sensitivities shown in the graph above.

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 other priority sites.

The general base level of emissions investment over this next period significantly increases from the previous year. This is due to the anticipated effect of the Large Combustible Plant Directive (LCPD) on the compressor fleet as applicable under the Industrial Emissions Directive (IED).

2011 Growth Case

There exists a significant uncertainty relating to entry, exit and storage projects (and associated investment requirements) in the latter half of the 10 year period considered. The '2011 Growth Case' shown in Figure 5.3B considers the potential impact of this uncertainty on investment requirements.

National Grid has seen a recent upturn in entry, CCGT and storage connection enquiries to the NTS. Whilst the Default Case scenario includes a selection of new CCGT plants to meet future generation requirements, investment is sensitive to the location of these facilities and the requirement for firm capacity rights. Should any of the potential new exit connections require firm capacity in the constrained South East, Southern or South West areas of the system then it is likely significant investment will be required. Large storage sites requiring firm exit capacity in the North West will also trigger significant investment.

National Grid has also increased exit capacity obligations arising from the introduction of the enduring exit regime. Increased levels of firm capacity requirements in the constrained areas can arise from traditionally interruptible loads (including industrial, power generation, interconnector and storage sites on the NTS and loads within Distribution Networks) and may result in additional investment.

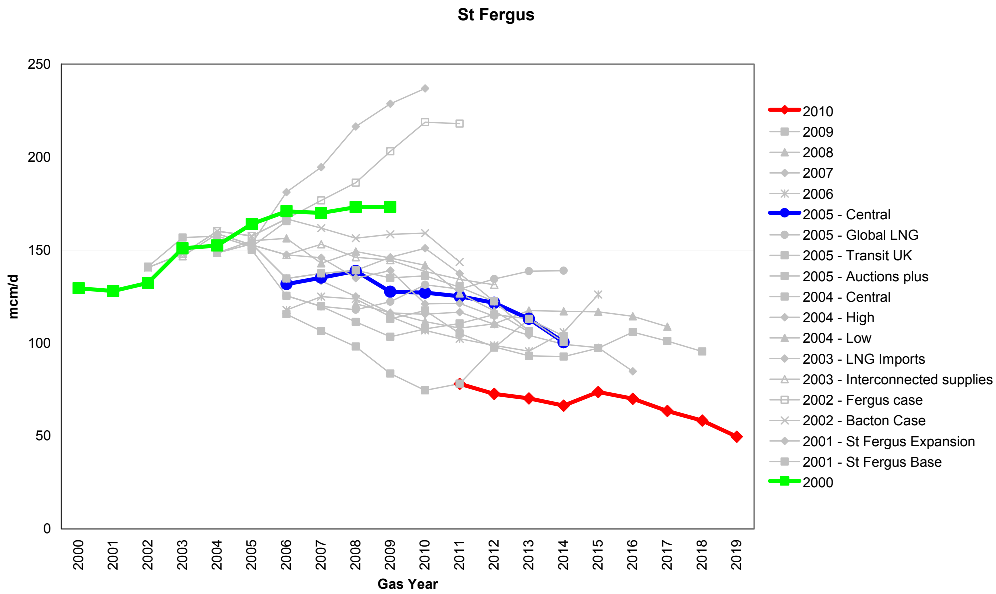
The factors mentioned provide a significant potential upward pressure to exit and entry investment compared to the '2011 Default Case' and is shown within the '2011 Growth Case'. This scenario is consistent with the level of customer enquiries for connection to the Network that we are currently seeing.

Section 5.3.3.6 gives more detail on where we believe network reinforcement may be required over the next ten year period if user signals for incremental capacity are received.

5.3.3.1 1-in-20 Obligation for Scotland

The figure below shows ten years of forecast gas supplies at St Fergus as informed by our industry consultative processes. It clearly shows that supplies are dropping away far quicker than anyone (including the shippers bringing the gas to shore) had previously anticipated.

Figure 5.3C – Forecast flows from the St Fergus ASEP
Source - National Grid



Against this backdrop of falling supplies, demand in Scotland (and Ireland via the Moffat interconnector) has risen, reaching the point where on some days this demand is already marginally greater than the supplies from St Fergus. This situation is forecast to worsen over the coming years as existing UKCS supplies through St Fergus continue to decline.

The reduction in supply at St Fergus has been compensated for by additional supplies at Southern ASEPs. To maintain supplies in Scotland it will therefore be increasingly necessary to route gas 'South to North' within the network. The Network has historically been designed around high St Fergus gas flows and hence significant 'North to South' flows; it presently has very limited physical capability to actively move gas 'South to North'. Our planning analysis shows that we are approaching a point where, without additional network capability to deliver 'south to north' flows, we will not be able to meet our 1 in 20 demand obligations in Scotland.

As noted above, the reduction in St Fergus flows has been compensated for by additional supplies at Southern ASEPs however we have not seen signals for incremental capacity sufficient (either individually or in combination) to trigger these projects through the existing industry processes. As the current regime is based on customer commitment underpinning the provision of incremental capacity and this situation has arisen through changing / decremental flows there is no clear trigger mechanism to identify these projects and provide funding for a solution (be it commercial, operational or asset based).

We have identified a number of modifications to the Network designed to enhance the capability to provide 'south to north' flows. Taking account of our licence obligations and having considered non-investment options (for example reduction of AOPs - see section 5.2.7), we believe that these projects represent the optimum solution.

We have sought ex-ante funding for these projects under both our TPCR4 Rollover and initial RIIO-T1 price control submissions (delivery of these projects would take place through both price control periods) against the new category of Network Flexibility due to the absence of an existing funding mechanism. In response to feedback received during our RIIO stakeholder consultation process we will still be seeking ex-ante funding for these projects in our final RIIO-T1 submission, but will be re-categorising them as '1 in 20 Licence Obligation'.

We are already actively progressing these projects through our internal governance processes towards approval for construction to ensure that we continue to meet our obligations.

5.3.3.2 Network Flexibility

As previously described in Sections 3 and 4 we are already seeing a significant change in user requirements from the NTS, resulting in very different gas flow patterns than those for which the Network was originally designed. Again, as already described above, the current regime is based on the concept of user commitment to support the provision of incremental capacity. There is no existing mechanism to trigger the enhancement of system capability required specifically in response to changing and/or reducing flows of gas in the Network.

Our planning analysis continues to identify a number of projects which are required to improve Network capability to meet these changing flow requirements. We included these projects for the first time in our TPCR4 rollover submission under the category of 'Network Flexibility'.

Currently identified Network Flexibility investments mainly comprise modifications to existing compressors and the installation of flow control valves to enable greater control and configuration of the NTS to meet emerging user requirements from the system. These projects increase the resilience of the network to meet variations in supply and demand patterns, including response to unforeseen events such as major supply outages. They provide the System Operator with enhanced capability to operate the network in the flexible manner which users are indicating that they require.

One example of this is our proposals to enhance the capability in the 'Central Corridor'[22] of the network. The Network was designed around East to West flows of gas in this area, with later incremental additions to allow the supply of gas from the West. We are now seeing that our users increasingly require the ability to vary their individual gas flows such that net gas flows through this part of the Network are required to switch between 'West to East' and 'East to West' regularly, (and rapidly), even within the gas day. The current Network infrastructure was not designed to provide this directional switching on such a regular or rapid basis.

As noted in 5.3.3.1 above, in response to stakeholder feedback we have reviewed our proposals for Network Flexibility, aggregating projects according to specific drivers. This has resulted in projects required to meet our licence obligations being separated out (specifically Scotland 1 in 20 as noted above), however a number of specific Network Flexibility projects to manage changing network flows remain.

Having considered alternative solutions (e.g use of commercial contracts, existing 'tools' for managing the system etc.) we believe that these projects still provide the best solutions to meet the requirements of Network users and our wider stakeholders. In our final RIIO-T1 submission we will be requesting sufficient ex-ante funding to progress the initial design of these projects. We have committed to continue direct engagement with stakeholders to

[22] The area broadly covered by the Midlands, East Anglia and South East, i.e. between the Milford Haven ASEP in the West and Bacton & Isle of Grain ASEPs in the East.

discuss this issue further through the appropriate industry processes. If agreement is reached that these projects are necessary, we will then seek appropriate funding through the RIIO-T1 period using an Uncertainty Mechanism. This solution recognises the long lead times for asset based solutions and by allowing front-end work to progress keeps these options open (within the required timeframe) at minimum cost.

It is important to note that our current Network Flexibility proposals do not address the potential future changes in flows on the Network as a result of the projected increased variability of future demand (e.g. from gas fired generation in response to variable wind generation) and the corresponding supply side response. These potential changes are discussed in detail in section 4. We intend to use the stakeholder consultation processes discussed above to investigate the impact of these changes on the Network and, where investing in assets is agreed to be the required solution, will seek funding for the RIIO-T1 period through an Uncertainty Mechanism.

We believe that if we do not undertake these projects, there will be both the potential for significant additional constraints on the system and that we will not be able to operate the system in the flexible manner that users have indicated that they value. This will result in increased costs for users (and hence ultimately for end consumers) both through direct constraint management costs and through any additional costs incurred by users as a result of not being able to operate in the manner they require.

5.3.3.4 Emissions related Investment

National Grid uses a number of gas turbines as power sources at the gas compressor stations required to move gas around the NTS. We are committed to the monitoring and reduction of emissions from these machines whilst ensuring the safe and secure transportation of natural gas across the UK.

Compressor utilisation is largely driven by gas supply and demand patterns across the Network which, as already outlined above, are increasingly uncertain into the future. Some compressors that traditionally operated with high duty have already experience reduced or reversed flows as supply patterns changes; this will consequently affect investment decisions into the future. Reduced flows can be both beneficial and adverse to emissions depending on unit type and network configuration required.

To meet our statutory obligations, it essential to develop and maintain a robust strategy for the operation, maintenance and replacement of our compressor fleet. This is key to the delivery of efficient, economic investment and effective operation of the compressor fleet.

The objectives of this strategy are to;

- deliver improvements to resource efficiency at NTS compressor stations, which will drive benefits to the end consumer through reduced operating costs and,
- ensure maximum benefit to the environment, through continuing emissions reduction.

As a consequence of changing gas flows and hence changing compressor utilisation levels, this strategy and the priority sites for investment to reduce local air emissions are reviewed on a regular basis.

Emissions related investment is currently progressing at the following sites:

- St Fergus – Completion of the Electric Drives to take up bulk duty, currently anticipated to be operational by 2012.
- Kirriemuir – Completion of the Electric Drive to take up bulk duty, currently anticipated to be operational by 2012.
- Hatton – Continued progression of Electric Drive solution, currently anticipated to be operational by 2012.

The latest information relating to forecast utilisation and cost assumptions, based on recent and current compressor investment schemes, continues to confirm the next priority sites after these as Peterborough & Huntingdon.

Peterborough is the next priority site for investment to reduce emissions; evaluation of the investment solution and investment programme is being progressed. Investment to reduce emissions at Huntingdon while maximising the efficiency of Peterborough investment is being considered in parallel. These two sites remain relatively high utilisation sites with some interchangeability. Their respective utilisation is highly dependant on the operation of new supply points to the NTS.

5.3.3.4.1 Industrial Emissions Directive

A new European Directive (The Industrial Emissions Directive - IED) will be transposed into UK Law in January 2013. The major implication of the IED is that a number of the larger gas turbines operated by National Grid may need modifying or replacing between 2016 – 2023 in order to meet the emission limit values for mono-nitrogen oxides (NOx) and carbon monoxide (CO). There is a concession that allows National Grid to implement a phased replacement strategy to achieve compliance with dates set in the directive.

The precise details of how the Directive will be transposed into UK law are not yet certain, however based on the minimum standards set by the Directive an initial total of 21 of National Grid’s existing gas turbines will need to be replaced by 2023.

The European Commission has committed to reviewing this directive by December 2012 with a view to its application to smaller lower powered machines. If enacted, this extension to smaller machines could impact additional National Grid gas turbines.

5.3.3.5. Projects Approved for Construction in 2012 onwards

The tables below indicate the status of existing construction projects. Those identified as ‘Load related’ were triggered by incremental capacity release during the current price control.

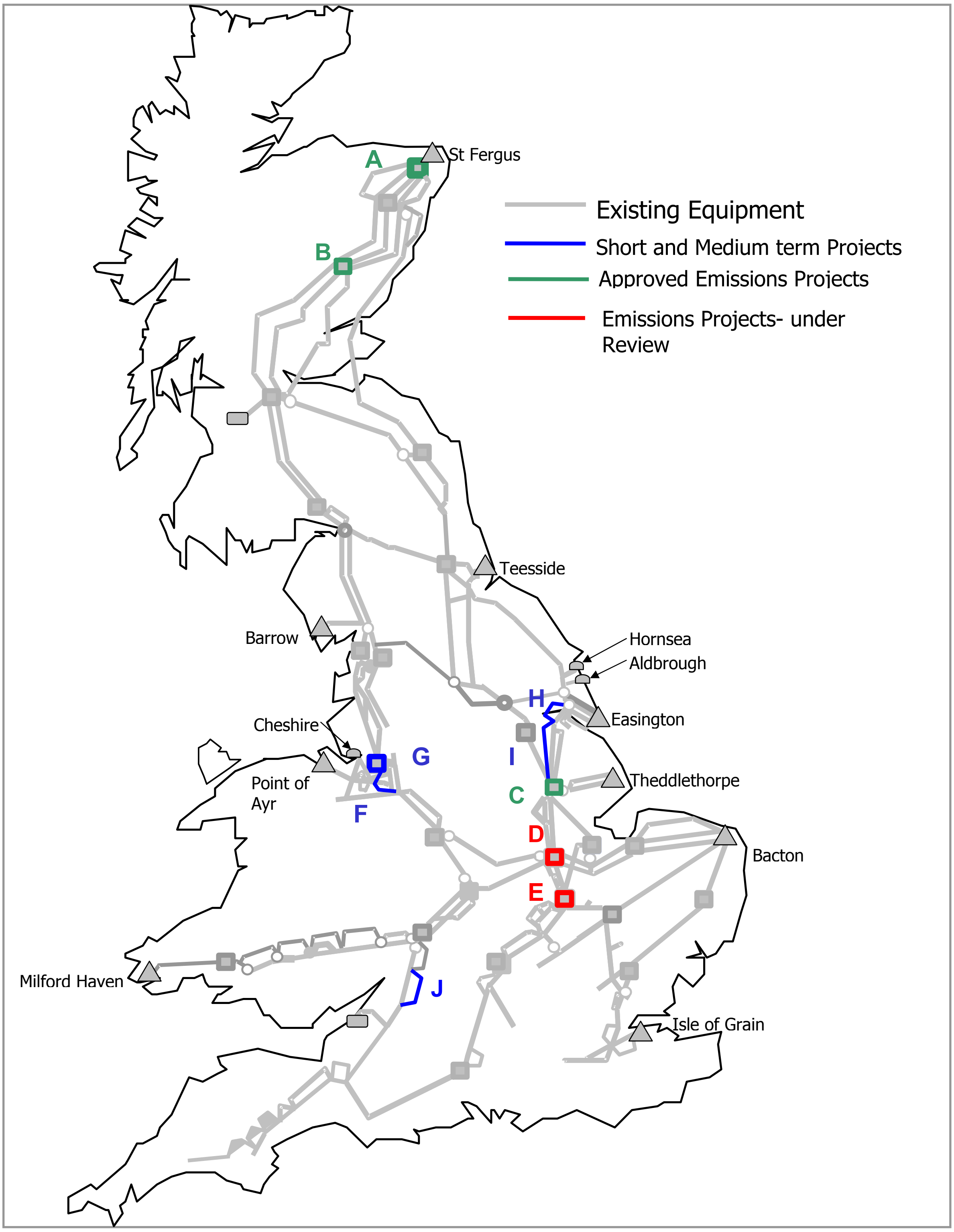
Projects Approved for Construction in 2012 onwards

Map ref.	Project	Scope	Driver
A	St. Fergus Compressor Station	New Unit	Emissions Reduction
B	Kirriemuir Compressor Station	New Unit	Emissions Reduction
C	Hatton Compressor Station	New Unit	Emissions Reduction

Projects Under Review
(note that locations are indicative and subject to change as we progress through the planning process)

Map ref.	Project	Scope
D	Peterborough Compressor Station	New Unit (Emissions Reduction driven)
E	Huntingdon Compressor Station	New Unit (Emissions Reduction driven)
F	Warburton to Cheshire to Audley Pipeline	49km x 1200mm (Load related)
G	Warrington Compressor Station	Modifications for higher flows (Load related)
H	Paull to Goxhill Pipeline	6.4km x 1200mm (Load related)
I	Goxhill to Hatton Pipeline	63km x 1200mm (Load related)
J	Sapperton to Easton Grey Pipeline	16.7km x 900mm (Load related)

Figure 5.3D – NTS Projects, Completed Approved and Under Review
Source – National Grid



5.3.3.6 Longer term Projects

A key part of our planning process is understanding what system reinforcements may be necessary to meet future customer requirements as a result of the enquiries we receive for new connections to the network. This process enables us to give a view on where there may be spare capability in the system, (to meet new connection requests without reinforcement), and conversely where the system is operating close to its current capability and any new connection will likely result in a requirement for reinforcement.

If physical reinforcement were to be identified as the required solution, longer term NTS projects (i.e. those after 2012) that would be considered to provide capacity beyond the requirements of medium term supply patterns include:

- Reinforcement across the Midlands and East Anglia for new storage connections on the East Coast of England.
- Reinforcement in the South East of England for new power station connections.
- Reinforcement in the North West of England for potential increased levels of supply.
- Reinforcement in the South East of England for potential increased levels of supply.
- Reinforcement in South Wales for potential increased levels of supply.
- Reinforcement of the feeder in the South West of England to meet the long term requirement for Operating Margins as LNG Storage may not be able to continue to provide reliable services, and potentially no service at all beyond the end of the TPCR4 period.
- As discussed above in section 5.3.3.2, we are also considering the need for projects to increase the flexibility of the network in response to changing supply and demand patterns, including the impact of intermittency in wind power generation.

It is important to stress that these projects are indicative and dependent on the receipt of appropriate user signals. The timing of such projects will, in part, be dependent on the effect of entry and exit capacity substitution but will be endorsed by the signals received through entry and exit commercial processes. 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.

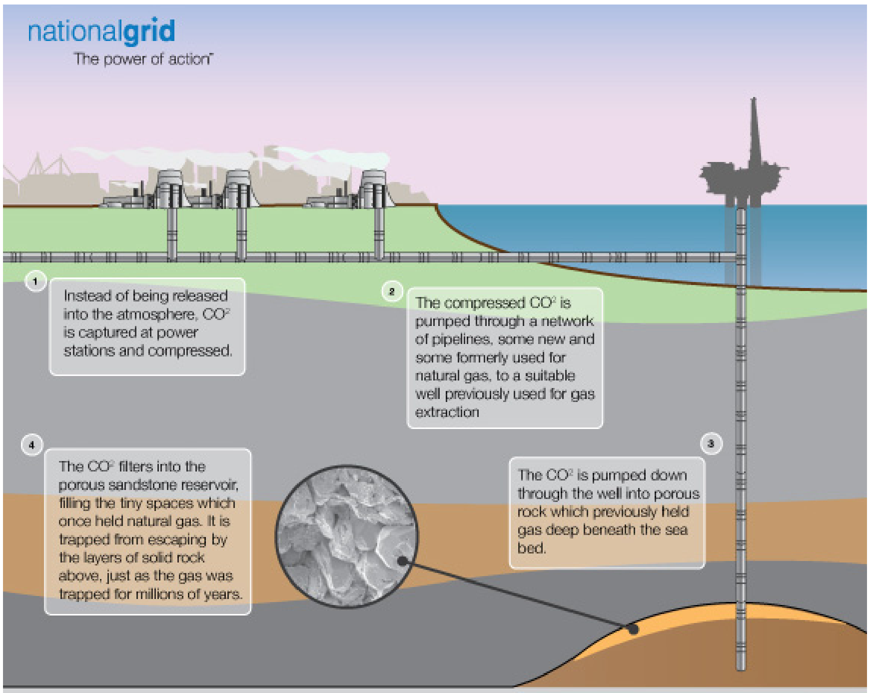
5.4 Carbon Capture and Storage (CCS)

Carbon Capture and Storage (CCS) is a fairly new technology that involves the capture, transport and storage of carbon emissions. CCS is considered to be a potentially powerful tool for tackling climate change whilst allowing continued use of fossil fuel generation. This technology could significantly contribute to meeting the UK's carbon emissions reduction targets, along with other solutions such as renewable and nuclear generation.

"CCS must be part of the global solution to tackling climate change. Without carbon capture and storage, the cost would be 70% higher."
Chris Huhne, 22nd June 2011 (Speech to Carbon Capture & Storage Association reception)

Currently, the UK contributes to climate change by emitting around 650m tons of CO_2e[23] per year - approximately 30% of this comes from power stations burning fossil fuels. CCS uses chemical processing technology to capture the CO_2e from large fossil fuel powered generators and industrial plants, for transportation to stores beneath the seabed. To add context to the potential impact of deploying CCS, CO_2 networks in Scotland and Humberside could result in a reduction of around 78m tons of CO_2e per year (60 in Humberside and 18 in Scotland) - equivalent to taking nearly all of Britain's cars off the road.

Figure 5.4A – High-level overview of the CCS process.
Source National Grid.



CCS can benefit security of electricity supply by allowing fossil fuel generation to remain part of the future, low carbon, energy mix. Flexible fossil fuel generation is anticipated to be a valuable contributor to the UK's future energy requirements, alongside intermittent wind, and less flexible nuclear generation. National Grid is committed to the development of CCS from concept, through commercial scale demonstration, to the development of networks able to significantly reduce the UK's CO_2e.

[23] Carbon Dioxide equivalent

National Grid could play a key role in enabling CCS as a successful climate change strategy in the UK through application of its core skills and expertise in developing, building and operating safe gas pipeline networks. As CCS is closely aligned to National Grid's wider and fundamental remit, of ensuring a secure energy supply whilst meeting environmental targets, National Grid Carbon was formed in 2009 to undertake CCS activities and is currently working with partners in industry, government, academia, and influential institutions.

"Climate Change is not one company or industry's problem. This is a fundamental and unique market challenge that CCS has to overcome."
Jim Ward, Head of CCS, National Grid Carbon

National Grid Carbon has to date secured CCS development funding through competitions, and consequently expanded its understanding of CCS. This transferrable knowledge is expected to play a vital role in progressing other projects. In addition to securing co-funding, National Grid has self-funded work across a number of schemes, and continues to progress a safety research programme. The research work could help to inform a legislative framework for future construction and operation of carbon dioxide transportation infrastructure.

National Grid Carbon was involved in the Longannet project in DECC's UK CCS Demonstration Competition and is currently working on the Don Valley (formerly Hatfield) project in Humberside. The Longannet project in Scotland secured funds from the UK Government for Front End Engineering Design (FEED) studies, and Don Valley secured a funding contribution from the European Energy Programme for Recovery (EEPR). In Humber, National Grid Carbon's role is to provide onshore/offshore transportation and facilitate the development of a storage solution. During Summer 2011, it conducted an initial stakeholder and public consultation for a proposed new-build carbon dioxide pipeline route to serve the Yorkshire and Humber area. The outcome and preferred route, along with associated maps and documents, can be found at:

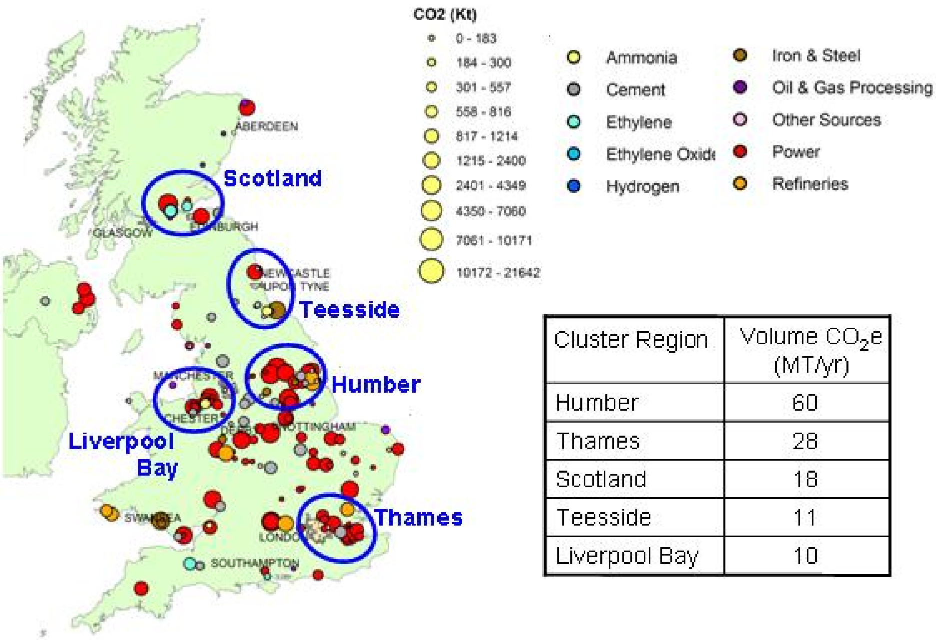
http://www.ccshumber.co.uk/default.aspx.

On 19th October, DECC announced its decision to not continue with the Longannet project - the sole remaining entry in its first competitive process. The FEED studies confirmed the technical viability of CCS, and transferrable knowledge is being disseminated globally by DECC to inform other CCS developers. The Longannet project was based upon reuse of an existing natural gas pipeline, made possible by the multiple pipelines running from St Fergus, alongside declining North Sea gas. There is potential to reuse this pipeline in other projects.

Following the Longannet decision, the UK Government confirmed that the £1bn committed in the Comprehensive Spending Review (2010) to fund the commercial-scale demonstration of CCS, is still available to pursue other CCS projects in the UK. National Grid Carbon's future work will involve developing alternative proposals with a number of partners. In addition to future DECC competition and the EEPR work at Don Valley, National Grid Carbon is also supporting a number of projects that have submitted proposals for EU funding through the New Entrant Reserve (NER) scheme. Further opportunities are being presented across the UK that will be pursued where possible to do so.

The UK's potential to demonstrate CCS results from historic industrial development, whereby emission sources have largely formed in natural clusters. These clusters have been identified as offering some of the best opportunities to deploy CCS in Europe. Power stations and other heavy industry are predominately close to the North Sea oil and gas fields that, when depleted, could provide suitable storage for captured CO_2. Saline formations offer alternative storage with potentially far greater capacity. National Grid Carbon is working with industry experts to assess the potential of specific storage sites, with a view to developing solutions that could serve a cluster, or clusters, of emitters.

Figure 5.4B – Natural clusters of emitters in the UK.
Source IEA Greenhouse Gas R&D Programme

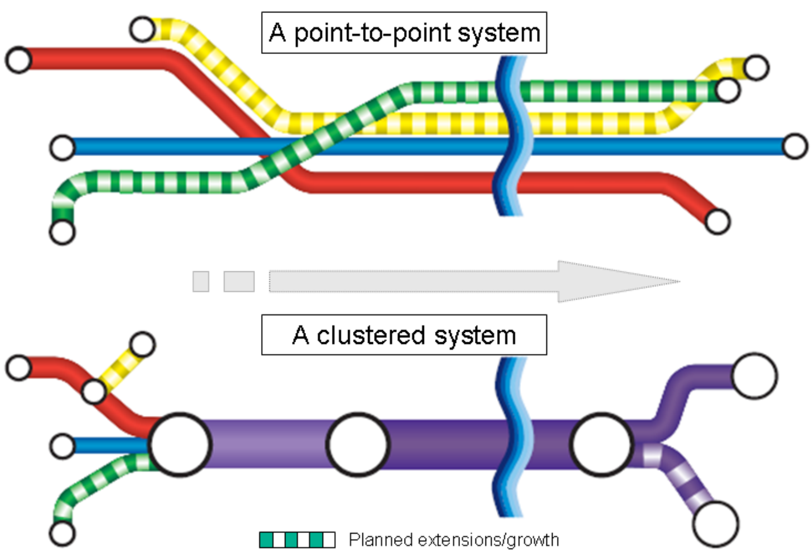


Cluster Region	Volume CO_2e (MT/yr)
Humber	60
Thames	28
Scotland	18
Teesside	11
Liverpool Bay	10

CCS is expected to start to play a significant role in the period covered by the Ten Year Statement. To deliver CCS at the level needed to contribute to climate change targets, there is a need for deployment at scale. By 2030, the Gone Green scenario assumes 13GW of CCS-fitted generation capacity, reduced to 8.3GW in the Slow Progress scenario. To achieve these levels there is a need to develop clusters. The economy of scale achieved through a clustered transport system could save upwards of 25% capital expenditure over multiple point to point systems, depending on the scale of the cluster.

Figure 5.4C shows the different infrastructure necessary for CCS on a point-to-point versus clustered solution. The clustered approach is similar to that employed on our electricity and gas networks. A main transportation line allows for growth capacity, allowing the connection of smaller emitters for whom point to point solutions may be too expensive.

Figure 5.4C – Illustration of infrastructure alternatives showing efficiency of clustered approach.
Source National Grid



Clusters present a more efficient way in which to develop a longer-term solution, though presents a number of challenges. National Grid Carbon will look to secure sufficiently strong signals from emitters to construct correctly-sized infrastructure at the outset. The recently developed “Storage of Carbon Dioxide (Access to Infrastructure) Regulations 2011” support an open access regime which aims to ensure carbon dioxide transport and storage capacity is made available to third parties on a fair, non-discriminatory basis.

Other measures that will influence the economic viability of CCS, and consequential speed, scale and breadth of deployment, include:

- Electricity Market Reform, encouraging a low carbon economy
- Carbon Price Floor, impacting the commercial viability of coal-fired stations
- The EU ETS price, being sufficiently strong and stable
- Establishment of an Emissions Performance Standard (EPS), to encourage carbon capture
- DECC’s next demonstration process, encouraging collaboration between parties to develop efficient solutions

Chapter Six

Industry Frameworks Developments

6.1 Overview

National Grid remains committed to the development of commercial arrangements that encourage timely and appropriate market responses to secure energy supply demand balances. This chapter reflects ongoing industry discussions, the detail of which can be found on our website or the relevant industry code administrators' website. 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:

- Enduring NTS Exit Capacity Arrangements
- 2007 Transmission Price Control Review Changes
- Transmission Charging
- Entry Capacity Regime Developments
- European Developments
- Special Condition C27 – Balancing Arrangements
- Facilitation of new types of NTS entry facilities
- SO incentives
- Security of Supply - Significant Code Review
- UNC[24] Modification 0373 "Governance of the NTS Connection processes"

6.2 Enduring NTS Exit Capacity Arrangements

Ofgem implemented UNC Modification 0195AV "Introduction of Enduring NTS Exit Capacity Arrangements" in January 2009, effective from 1st April 2009. These enduring arrangements allow users to purchase NTS Exit Capacity effective from the 1st October 2012 onwards.

In summary, the implemented UNC Modification introduced (but is not limited to) the following arrangements for all NTS offtakes (inclusive of NTS/LDZ Offtakes):

- An Annual July Application process to increase and/or decrease Enduring Annual NTS Exit (Flat) Capacity, subject to defined lead times.
- An Annual July Application process allowing Users to apply for, in annual tranches, any Unsold Firm NTS Exit (Flat) Capacity.
- Adhoc processes allowing Users to increase or decrease their Enduring Annual NTS Exit (Flat) Capacity.
- Revised ARCA (Advanced Reservation Capacity Agreement) arrangements
- Daily NTS Exit (Flat) Capacity auctions, including provisions for Off-peak NTS Exit (Flat) Capacity

[24] Uniform Network Code

- NTS Exit (Flat) Capacity constraint management tools
- Full assignment of Firm NTS Exit (Flat) Capacity
- Transfer of Firm NTS Exit (Flat) Capacity
- NTS Exit (Flat) Capacity Overrun arrangements

The initialisation process and first Annual July processes were held offline in 2009. The first and second phases of the Gemini Exit Reform system are now live enabling certain enduring activities to be conducted on line, including the July Annual application processes, Ad-hoc/ARCA NTS Exit (Flat) capacity applications, Transfer, Full Assignment and longer term NTS Exit (Flat) Capacity Buyback processes. Further functionality will be introduced through a future phased release of the Gemini Exit Reform system including the introduction of Daily NTS Exit (Flat) Capacity, shorter term NTS Exit (Flat) Capacity, Commercial Constraint Management, NTS Exit (Flat) Capacity Overrun arrangements and Invoicing.

Further UNC Modifications to the Enduring Exit regime were implemented in 2011. These include Modifications

- 0342 - “Amendment to the DN Adjustment Window.”
- 0347v – “Amend NTS Exit Capacity Assignment Start Date”
- 0381 – ” Removal of the NTS Exit (Flat) Capacity “deemed application” process

6.3 2007 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 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 UNC Modification 187A and the Entry Capacity Trade and Transfer Methodology Statement were raised and subsequently approved.

This process has operated successfully since August 2008 (a temporary solution was in place for winter 2007/08) with offline processes being replaced by a full system solution in May 2009.

Entry Capacity Trade and Transfer are now established processes with the methodology statement subject to annual review. National Grid amended the timeline for the RMTTSEC (Rolling Monthly Transfer and Trade System Entry Capacity) auction in June 2011 (in respect of capacity for July 2011). This amendment puts the capacity auction window nearer to the start of the month for which capacity is released. We committed to this amendment when UNC Modification 187A was put forward, but subject to experience of undertaking analysis of potential capacity transfers and trades. Notwithstanding that there has been no requirement to transfer or trade capacity in recent years and hence no experience gained, we believed that this change, to meet customer expectations, was justified.

6.3.2 NTS Entry Capacity Substitution

In the 2007-12 Price Control Review Ofgem placed an obligation on National Grid Transmission 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.

This obligation has been established to encourage National Grid to make efficient use of the existing network infrastructure prior to undertaking any further investment in the network. Hence National Grid will substitute entry capacity, in accordance with the Entry Capacity Substitution Methodology Statement, before releasing funded incremental obligated entry capacity at the entry point.

National Grid submitted its proposed NTS Entry Capacity Substitution Methodology Statement to the Authority. Along with the methodology statement, UNC Modification 0265 was raised and a change to the Transmission Transportation Charging Methodology proposed. These proposals were approved ahead of the QSEC auction held in March 2010.

Entry Capacity Substitution has operated successfully since the March 2010 QSEC auction and is now established within the entry capacity release regime.

6.3.3 NTS Exit Capacity Substitution and Revision

In the 2007-12 Price Control Review Ofgem introduced obligations for National Grid to undertake NTS Exit Capacity Substitution and NTS Exit Capacity Baseline Revision. These obligations would only apply from 1st October 2012 onwards i.e. the enduring exit period.

Under these obligations unsold NTS baseline exit capacity at exit points may be substituted to other exit points where obligated incremental exit capacity is required to be released. In addition, NTS baseline exit capacity at exit points may be revised where the release of funded incremental obligated entry capacity has a positive impact on the availability of exit capacity. These obligations have been established to encourage National Grid to make efficient use of the existing network infrastructure prior to undertaking any further investment in the network. Hence National Grid will seek to substitute exit capacity, before considering investment in the release of NTS obligated incremental exit capacity.

Industry workshops were held throughout 2010 to discuss the most appropriate way to introduce these obligations. Following industry consultation, National Grid submitted its proposed methodology to the Authority for approval. Approval was received in April 2011 and the methodology was applied to the July 2011 exit capacity application window.

6.4 Transmission Charging

Following the implementation of the Ofgem Industry Codes Review final conclusions, which resulted in the NTS Transportation and Connection Charging Methodologies being included in the UNC, the UNC facilitated NTS Charging Methodologies Forum ("NTS CMF") is now the industry forum that reviews gas transmission charging arrangements. All Shippers and those conferred materially affected party status can now raise changes to the charging methodologies via a UNC Modification Proposal.

During 2011, the review of enduring NTS Exit Capacity price setting continued to review the identified issues that ultimately led to exit price variability. The issues were:

- The total modelled demand, based on the obligated exit capacity levels, exceeded available supplies
- Changing supply patterns

- The obligated exit capacity level (baseline plus incremental) may no longer reflect "connected load" (as was the intention of using this data within the charging methodology)

UNC Modification 0356 has been raised to seek to address these issues by using forecast demand data as the input to the Transportation Model for setting NTS Exit (Flat) Capacity charges from 1st October 2012. An alternative Modification Proposal 0356A has also been raised to seek to address these issues by using booked NTS Exit (Flat) Capacity data as the input to the Transportation Model. A decision is anticipated early in 2012 such that actual prices for gas year 2012 and indicative prices for later years can be set prior to 1st May 2012.

National Grid has continued the review of entry charging principles. This was in response to continued industry concern about the increasing rate of the TO entry commodity charge. National Grid analysed the existing and potential future entry capacity procurement and consulted on the removal of the zero entry capacity reserve prices and discounts for daily capacity. These proposals were vetoed by Ofgem and so work continues on alternative solutions. Potential solutions will need to take account of EU developments on charging including the development of EU network codes on capacity allocation, congestion management and harmonised transmission tariff structures.

The NTS CMF has continued to review all aspects of the NTS Entry and Exit Charging arrangements with initiatives 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 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 Entry Capacity Regime Developments

6.5.1 Force Majeure

National Grid raised UNC Modification 0262, "Treatment of Capacity affected by Force Majeure", in August 2009. This Proposal sought 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. The Modification proposed that Users registered as holding firm capacity (quarterly, monthly capacity at an ASEP and Annual NTS Exit (Flat) Capacity at an NTS Exit Point) would receive a Force Majeure rebate. On 9th December 2009 Ofgem issued a notice of non-implementation. A new UNC Modification 0349 "Introduction of a Force Majeure Capacity Management Arrangement" was introduced by another party on the 11th November 2010. The Modification was then issued for consultation on the 18th November 2010 and approved by Ofgem on the 16th August 2011, with an implementation date agreed of the 1st September 2011.

Modification 0349 introduced the concept of a Force Majeure Capacity Management Arrangement specifically for NTS Entry Capacity. In instances of Force Majeure where there is a NTS Entry Capacity impact, National Grid is required as part of the Force Majeure Capacity Arrangement, to put in place one or more Force Majeure Option Arrangements. Each affected holder of Registered NTS Entry Capacity will have a Force Majeure Option Arrangement/s for an amount of Firm NTS Entry Capacity, that are in aggregate, equal to the level of NTS Entry Capacity that is constrained by the Force Majeure. National Grid will only exercise these options where the amount of NTS Entry Capacity held by the affected users is greater than the flow that can be accommodated as a result of the Force Majeure Notification.

Each Force Majeure Option arrangement may be for a period of 1 Day/Month/Quarter and will have an Option price that equates to the Weighted Average Price of that User's Long Term Capacity at the affected ASEP. All Days within the Force Majeure Option period are exercisable and the Exercise Price will be zero.

6.5.2 Interruptible Reverse Flow service at Moffat Interconnector

In July 2011 National Grid raised UNC Modification 0352 "the Introduction of an Interruptible Reverse Flow Service at Moffat Interconnector" which was subsequently directed for implemented by the Authority in October 2011. The implemented proposal allows Users to nominate gas into the NTS through the Moffat Interconnector in the absence of the capability at Moffat to physically deliver gas into the NTS.

Moffat has been included as an ASEP with a zero baseline within the Gas Transporters Licence in respect of the NTS specifically to facilitate the Interruptible Reverse Flow Service. This primarily enables National Grid to make available Daily Interruptible NTS Entry Capacity, at its discretion, to Users wishing to use the service.

Users wishing to utilise the service must accede to the Moffat Ancillary Agreement, the details of this process and further additional information on the service can be found on the National Grid website via the following link:

http://www.nationalgrid.com/uk/Gas/OperationalInfo/operationaldocuments/MoffatVirtualReverseFlow/

6.6 European Developments

In September 2009 the European Commission's "Third Package" of legislative proposals for gas and electricity markets entered into force, becoming applicable from 3rd March 2011. They outline a new energy framework to better enable progress towards liberalised and open European energy 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 of the regulation is the establishment of a European Network of Transmission System Operators for Gas (ENTSOG), which was created on 1st December 2009. European Transmission companies, certified under the Third Package, have a formal obligation to cooperate through ENTSOG. ENTSOG has been designated with a number of key tasks, through the Third Package legislation which will require the support of all the ENTSOG membership, these tasks include:

- The drafting of 12 European Network Codes, based on framework guidelines produced by ACER[25]
- Annual European winter and summer supply outlook reports
- The bi-annual creation of a European Ten Year Network Development Plan (TYNDP)
- Enhancing the provision of information to the market and delivering common network operational tools to coordinate network operation

[25] Agency for the Cooperation of Energy Regulators

ENTSOG is now comprised of 39 TSOs from 23 European countries.

6.6.1 Capacity Allocation Mechanism

On 21st June 2011 ENTSOG published the first draft of 1 of 12 European Network Codes. The draft Capacity Allocation Mechanism (CAM) Network Code was developed after an extensive and interactive stakeholder dialogue and represents the first priority area of European Network Code Development.

On 3rd August 2011, the Agency for the Cooperation of Energy Regulators (ACER) submitted the final CAM Framework Guideline to the EU Commission for its review, as a result an additional six weeks was added to the plan. Also on 3rd August, ENTSOG closed the consultation on its draft CAM Network Code. 56 responses were received and analysed. A second consultation commenced on 24th October, the consultation covered those issues that have changed in the final ACER Framework Guideline and issues on which ENTSOG had re-evaluated its positions following feedback to the original consultation. Delivery of the final CAM Network Code is expected by 9th March 2012.

6.6.2 Congestion Management Procedures

After the consultation on the last year's (9th September 2010) version of the Congestion Management Procedures (CMPs) Comitology Guideline, the Commission presented the results on the 7th July 2011 to the Member States. The EU Commission is working on a respective Impact Assessment which will support the final CMP Guideline. For this Impact Assessment, the EU Commission asked ENTSOG to gather TSOs' data on the booking situation at various European cross-border Interconnection Points to assess the relevance of CMPs. The final version of this data was sent to the EU Commission in early September. A new CMP Comitology Guideline version is expected by January 2012.

6.6.3 European Gas Balancing Code

A European gas balancing network code represents the second EU Commission priority area, the gas balancing network code will include rules on nomination procedures, imbalance charges and operational balancing between Transmission System Operators (TSOs) systems.

Following a consultation with stakeholders on the draft Framework Guidelines for Gas Balancing, ACER prepared a final version of the document which was submitted to the EC on 19th October 2011. The publication of the Framework Guidelines was the trigger for the European Commission to request ENTSOG to start the 12 month code development process. The EC officially issued ENTSOG with an invitation to prepare a gas balancing network code on 4th November 2011. ENTSOG will include an extensive consultation process involving all relevant market participants in the code developed phase. National Grid will have 12 months to comply with the European network code once it has been adopted into UK law but, subject to the extent and complexity of any changes required, we may seek to utilise an option to approach our National Regulatory Authority (NRA) for an additional 12 months to enable us to change existing contracts, the UNC and any associated IT systems.

6.6.4 Interoperability European Network Code

Interoperability represents the third priority area of European Network Code Development, and refers to the ability of diverse transmission networks to work together (inter-operate) so as to facilitate the exchange of gas across the EU. The aim of the Code is introduce greater harmonisation in a number of areas of TSO operation that have been identified as potential barriers to the smooth functioning of the EU gas market.

It is envisaged that the Interoperability Code will establish rules to deliver greater levels of harmonisation in the following areas;

- The nomination and renomination regime
- Interconnection agreements
- Harmonisation of units
- Gas quality
- Methods of data exchange between TSOs, and between TSOs and shippers
- Calculation of technical and available capacity and maintenance programme publication

In respect of gas quality, the Code is expected to foresee the implementation of harmonised ranges or standards for both natural gas and biomethane, however its focus is expected to be to address contractual constraints and commercial rules rather than defining standards. Standards are being progressed separately via the EC mandates M/400 (natural gas) and M/475 (biomethane) given to CEN, the European standards body. It is envisaged that the Framework Guideline for Interoperability will be issued for consultation by ACER in mid December 2011 and the subsequent Code development work conducted by ENTSOG during 2012-13 to enable it to become legally binding on TSOs by 2014. Following comitology, ACER contemplates a maximum timeframe of three years for TSOs to be compliant with this Code.

6.6.5 Security of Supply Regulation

The EU Regulation Concerning Security of Gas Supplies (Regulation 994/2010/EC) has been produced and became legally binding on 2nd December 2010, and a number of key milestones have been met during 2011.

- DECC have been designated as the Competent Authority for the UK, and made this public through a written ministerial statement in January 2011.
- A definition of 'protected customers' has been agreed and the commission notified.
- All inter-governmental agreements with Norway have been submitted to the Commission.
- The required information on long term contracts with 3rd countries, should be provided to the Commission in the specified timeframe.
- The Risk Assessment has been published (the UK being the first Member State to do so).
- A Market Assessment Test has been completed to see if there was any market demand for physical reverse flow at Moffat.

There will be a considerable number of challenges to be faced in 2012 from the Security of Gas Supply regulation, none more so than:

- Publication of a Preventative Action Plan
- Publication of an Emergency Action Plan
- TSO to submit a proposal for Physical Reverse Flow or an Exemption at Moffat and BBL

6.6.6 Energy Infrastructure Package

The European Commission released of a proposal for an energy infrastructure regulation on 19th October 2011, the proposal was based on the Commission's communication on 'energy infrastructure priorities for 2020' published in November 2010. The key points of the proposed regulation are:

- Creation of Projects of Common Interest
- Improving Permitting Procedures
- Improving Regulatory Treatment
- Improving Financial Conditions

The text is currently at the draft phase with the final text expecting to be approved late 2012.

6.7 National Grid Gas NTS Licence: Special Condition C27 – Balancing Arrangements

Ofgem introduced a new NTS Licence Special Condition C27 ('C27') in April 2010 that obligated National Grid to use reasonable endeavours to introduce updated values to the default System Marginal Prices (SMPs) and to develop, consult on and, where directed to do so by the Authority, implement a linepack product.

In order to meet these obligations, National Grid developed, in conjunction with the industry two UNC modifications.

UNC Modification 0333 was raised in September 2010 and looked to update the default System Marginal Prices (SMP). In addition, the modification outlined a new methodology that would update the default SMPs on an annual basis. This modification was implemented on 1st October 2011. These default marginal prices apply on days where National Grid has not taken any market balancing actions. The revised prices are:- System Sell Price of SAP less 0.0263p/kWh (previous value was 0.0324p/kWh)) and System Buy Price of SAP plus 0.0263p/kWh (previous value was 0.0287p/kWh).

UNC Modification 0337 was raised in October 2010 and looked to develop a linepack product that could be used by the industry. In a letter published on 13th April 2011 (Authority view on UNC Modification Proposal 0337), Ofgem determined that UNC Modification 0337 should proceed no further and should be allowed to lapse in accordance with paragraph 12.8.3 of the UNC Modification Rules. Ofgem's premise for this direction was the lack of Industry demand for a Linepack Product. The Joint Office issued the 'Notice of Closure' for UNC Modification 0337 on the 14th April 2011.

6.8 Facilitation of new types of NTS entry facilities

Since summer 2010, National Grid has worked with the industry to consider and develop new commercial arrangements that could facilitate the connection and delivery of a new and unconventional source of gas - coal bed methane (CBM) - to the NTS. The developer of the first CBM project in the UK has requested, and National Grid NTS agreed, in principle, to facilitate the project by constructing two NTS connections , one for NTS exit and the other for NTS entry. This would facilitate the offtake of GS(M)R[26] compliant gas from the NTS through the exit connection to the coal bed methane facility where it would be commingled by the facility operator with non – GS(M)R compliant coal bed methane gas. Where the resulting blended gas met GS(M)R compliance, this gas could then enter the NTS via another pipeline linking the coal bed facility to the entry connection.

To further facilitate this project, in February 2011 National Grid raised UNC Modification 0363 "Commercial Arrangements for NTS Commingling Facilities". This Modification seeks to introduce the concept of an "NTS Commingling Facility" into UNC whose charging and allocation arrangements would be based on the net daily flows of gas measured at the exit point and the entry point. At the time of writing, the consultation period for the Modification had recently closed, with industry opinion broadly supportive of the proposed approach. An Ofgem decision on the Modification is expected in late 2011/early 2012. For more information please refer to the Joint Office of Gas Transporters website at http://www.gasgovernance.co.uk/0363.

6.9 SO incentives

For incentive year 2011/12 National Grid consented to the revision of schemes for two specific system operation activities, these being operating margins[27] and greenhouse gas emissions from compressors[28]. Both of these schemes will expire at the end of March 2013. A summary of all seven of the existing SO incentive schemes is available on the National Grid website[29].

For incentive year 2012/13, in conjunction with Ofgem and the industry, National Grid is developing revised arrangements for the remaining five System Operator (SO) incentive schemes which expire at the end of March 2012. Ofgem hosted an industry workshop to discuss its initial view of the incentive proposals in October 2011 and expects to issue its final proposals later this year. The duration of these revised schemes will be for a single year such that all seven SO incentive schemes expire concurrently at the end of March 2013, prior to commencement of revised arrangements for the next price control period 2013 - 2021.

SO incentives for the 2013 - 2021 period are subject to a separate development process which commenced with an initial consultation[30] issued by Ofgem in June 2011. Ofgem's Initial Proposals are expected to be issued in summer 2012.

[26] Gas Safety (Management) Regulations

[27] Gas used to maintain NTS pressures in the immediate period following operational stresses and before market balancing measures become effective.

[28] Formerly known as the "Environmental incentive" this scheme incentivises consideration of the environment when venting from NTS compressors

[29] http://www.nationalgrid.com/NR/rdonlyres/D51340E1-5868-41BA-A567-8D1BBA92DDDC/47330/Incentive_Summary11_12.pdf

[30] http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/SO%20incentives%20from%20April%202013%20Inital%20Views%20Consultation.pdf

6.10 SCR Security of Supply - Significant Code Review

Ofgem initiated a Significant Code Review on the arrangements governing a gas deficit emergency in January 2011. This review looks to improve the current security of supply. As part of the SCR process, Ofgem are considering the emergency cash out arrangements and payments for involuntary reduction of firm demand. Ofgem's Draft Policy Decision[31] document outlines the proposed arrangements. Ofgem are planning to publish their Final Proposals in spring 2012.

In addition to the SCR proposals, Ofgem are considering a number of additional measures that could be developed that would aim to increase security of supply. These are, increased information provision, improved demand side management arrangements and an increase in storage.

The proposals outlined in Ofgem's Draft Policy Decision document do not have a major impact on operation of the system or on system safety. However, depending on what additional measures are adopted, there could be an impact on system operation. It is not known at this time which option(s) will be taken forward.

6.11 UNC Modification 0373 "Governance of the NTS Connection processes"

E.ON raised UNC Modification 0373 in March 2011 on the basis of implementing a framework that provides transparency, is clearly defined, robust and time-bound insofar as a formalised NTS Connections process for; Application, Offer, Application Fee and information publication.

National Grid is fully supportive of 0373 and has been engaged in the industry discussion and development that has taken place within the 0373 Workgroup (May 2011 to-date).

The proposer is requesting a 0373 implementation date of 1st April 2012 to which National Grid is fully committed and, is working to define the underlying processes and procedures that are required to implement the framework.

[31] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Pages/GasSCR.aspx

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 scenarios of annual and peak demand.

A1.1.1 Slow Progression

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.

A1.1.1.1 Annual Demand Modelling

The development of annual gas demand scenario considers a wide range of factors, from complex econometrics to an assessment of individual load enquiries. For any scenario process a set of planning assumptions is required, which if necessary can be flexed to create alternative scenarios. In the case of the scenarios 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 scenarios 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.

A1.1.1.1.1 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.

A1.1.1.1.2 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.

A1.1.1.1.3 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.

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.

A1.1.1.1.4 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.

A1.1.1.1.5 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.

A1.1.1.2 Demand/Weather Modelling

Demand models are based on Composite Weather Variables (CWVs) defined and optimised 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 the EP2 methodology, which adjusts seasonal normal weather for climate change. All seasonal normal and average demand forecasts are now based on an EP2 average condition.

A1.1.1.3 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. For the post exit undiversified peak day there is an obligated peak day based on contractual obligations and a forecast peak day which reflects actual consumption of the NTS supplied loads.

A1.1.2 Gone Green

The Slow Progression methodology can be categorised into three main modelling areas; annual demand, demand/weather and peak demand modelling. Gone Green is constructed by an entirely different mechanism, and from a totally different view point. The main premise of the Gone Green scenario is that the targets for renewable energy and greenhouse gas reduction (for example 15% of energy from renewable sources and a 34%

reduction in emission by 2020) are met. Different technologies are deployed in the electricity generation, heat and transport sectors to ensure that this is so. Gone Green is a scenario, not a forecast, and demonstrates one way that targets can be met.

The Gone Green model works entirely on an annual basis and so does not have any weather/demand model and consequently no directly modelled peak demand, though peak demands can be estimated based on characteristics of power stations and assumptions on load factors in the end user sectors. In contrast to slow Progression, Gone Green data are all for UK rather than GB, as the renewable and greenhouse gas targets are set at UK level.

The market sectors used in Gone Green do not correspond directly to the sectors used in Slow Progression, but are derived from publicly available information in the Digest of UK Energy Statistics (DUKES). Forecasts for each sector are created from the bottom up, in considerable detail, but based on the same research that underpins Slow Progression. 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. Economic forecast inputs are of less importance in Gone Green than in Slow Progression other than the extent to which fuel prices affect the electricity generation merit order.

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 continue to adapt our processes to manage increasing levels of imported gas. In terms of network design and operation it is not just about the increasing level of imports but how the supply diversity brought about by a combination of surplus of import capacity and potential storage developments will be utilised.

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 2011 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. Our 2011 supply forecasts cover both of our current demand scenarios. These are Gone Green where Government 2020 targets for renewables are met and Slow Progression where progress is made in terms of meeting 2020 targets, but these are not achieved within the 2020 time frame. For the two demand scenarios, we have created two different supply forecasts, in the short term these are near identical. In the longer term, as the demand scenarios diverge, the supply forecasts also deviate to reflect changing supply requirements. The characteristics of the demand scenarios influence the make up of the supply forecasts, consequently the supply components in meeting Gone Green need to be more responsive or flexible in terms of meeting gas demand than in Slow Progression. This flexibility is anticipated to be delivered from those supplies that are best placed to respond, notably gas storage and possibly also from LNG imports (from gas held in LNG storage tanks) and through existing or modified gas interconnectors with the Continent. A further consequence of more flexible / responsive supplies is the need for a gas network able to accommodate greater flow variations including those from one day to the next to the extent that the level of supply that now needs to be accommodated is appreciably higher than peak demand.

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/TPC.

A1.4 Investment Procedures and Project Management

All investment projects must comply with our Transmission Investment Management Procedure, 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 A2.1.1 – Gone Green Annual Demand – Split by Load Categories (TWh)

Calendar Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
0-73.2 MWh	347	343	338	331	322	309	297	285	276	268	263	259	255	249	244
73.2-732 MWh	47	46	46	45	45	44	44	43	43	43	42	41	39	38	37
NDM > 732 MWh	69	69	69	69	69	68	68	67	66	66	65	64	62	60	58
Total NDM	463	458	454	446	436	422	408	396	385	376	370	363	356	348	339
Total DM	119	118	116	115	114	113	112	110	108	106	102	99	96	94	90
LDZ Shrinkage	4	4	4	4	4	4	3	3	3	3	3	3	3	3	3
Total LDZ	585	580	573	565	554	539	524	510	497	486	476	465	455	444	432
NTS Industrial	30	31	30	30	29	29	29	29	29	28	28	28	28	28	27
Exports to Ireland	70	63	40	40	43	48	51	52	54	56	58	60	62	65	66
NTS Power Generation	269	287	295	284	296	324	324	313	296	273	245	210	181	176	162
NTS Consumption	369	381	365	354	369	401	404	394	378	358	331	298	271	269	256
NTS Shrinkage	7	6	6	6	6	7	7	7	7	7	7	7	7	7	7
Total excluding IUK	961	968	944	925	929	946	934	911	882	850	813	770	732	720	694
IUK	100	100	100	100	100	100	100	98	96	94	92	90	88	86	84
Total including IUK	1061	1068	1045	1026	1029	1047	1034	1009	977	944	905	860	820	806	779

- *Volumes are based on the EP2 basis as described in Section 3.8*
- *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 - Gone Green

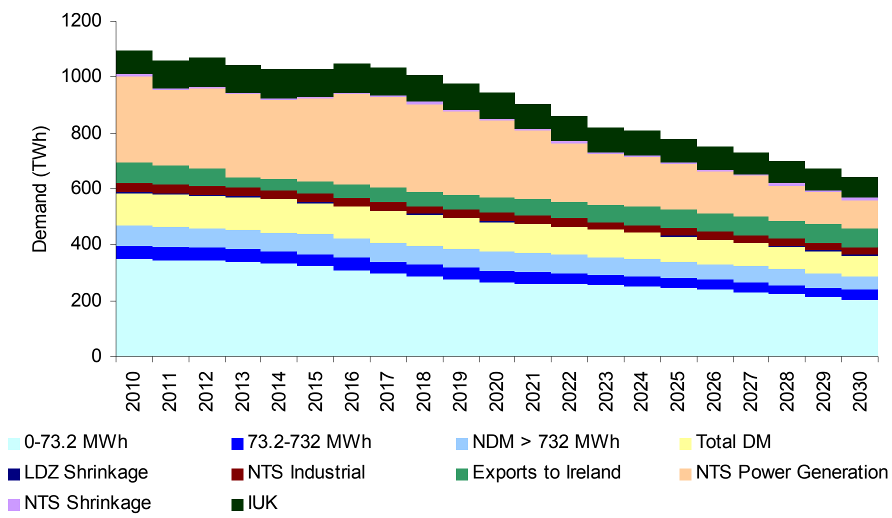


TABLE A2.1.2 – Slow Progression Annual Demand (TWh)

Calendar Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
0-73.2 MWh	347	344	341	338	335	331	329	328	327	327	327	327	328	329	330
73.2-732 MWh	47	46	45	44	43	43	42	41	41	41	40	40	39	39	38
NDM > 732 MWh	69	69	68	67	66	66	65	64	64	63	63	62	62	61	61
Total NDM	463	458	454	449	444	439	436	434	432	431	429	428	429	429	429
Total DM	118	117	114	112	109	108	106	104	103	101	98	97	96	95	94
LDZ Shrinkage	4	4	4	3	3	3	3	3	3	3	3	3	3	3	3
Total LDZ	585	578	571	564	557	551	546	541	538	535	530	528	528	527	526
NTS Industrial	30	31	30	30	29	29	29	29	29	28	28	28	28	28	27
Exports to Ireland	70	63	40	40	43	48	51	52	54	56	58	60	62	65	66
NTS Power Generation	269	287	295	276	277	309	317	310	314	319	316	294	267	255	237
NTS Consumption	369	381	365	346	350	386	398	391	396	404	402	382	357	348	331
NTS Shrinkage	7	6	6	6	6	7	7	7	7	7	7	7	7	7	7
Total excluding IUK	960	966	942	916	913	944	950	939	941	946	940	917	891	881	864
IUK	100	100	100	100	100	99	95	91	87	84	80	76	72	68	64
Total including IUK	1061	1067	1043	1016	1013	1043	1045	1031	1028	1029	1019	992	963	949	927

- *Volumes are based on the EP2 basis as described in Section 3.8*
- *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 A2.1B – Forecast Annual Demand – Slow Progression

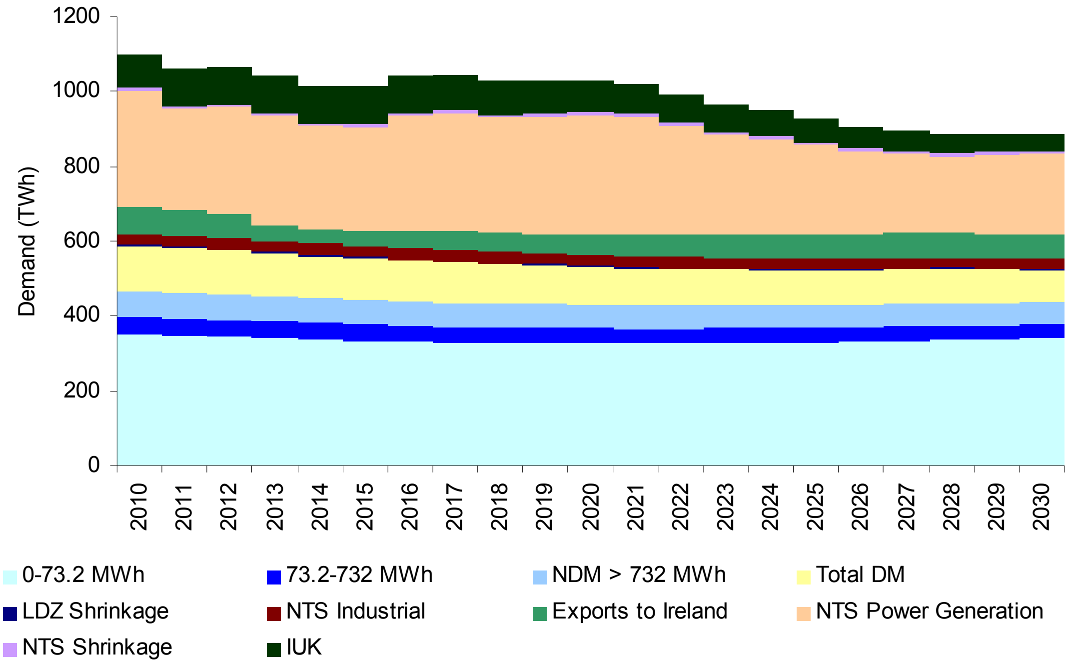


TABLE A2.1.3 – Gone Green 1 in 20 Peak Day Undiversified Demand (GWh/day)

National	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Scotland	339	336	335	332	327	318	311	303	296	290	286	283	278	272	267	261
Northern	252	248	246	242	237	229	223	216	210	204	201	198	193	188	183	178
North West	508	505	504	497	487	470	457	443	431	419	412	405	396	385	376	367
North East	265	264	262	258	252	244	237	230	224	218	216	212	207	201	197	192
East Midlands	452	445	441	434	425	411	399	387	376	365	359	353	346	337	330	322
West Midlands	389	381	377	370	361	349	337	327	317	307	303	297	290	282	275	268
Wales North	47	47	46	45	45	43	42	41	40	39	38	38	37	36	35	35
Wales South	220	219	217	215	211	206	195	191	187	183	180	177	175	171	168	165
Eastern	362	358	358	354	348	337	329	320	312	304	300	295	289	283	277	271
North Thames	467	460	459	452	444	429	417	406	395	384	378	371	363	353	346	336
South East	492	484	479	472	462	446	433	420	408	396	392	385	376	367	359	350
Southern	348	343	341	338	333	323	315	307	300	292	290	286	280	274	269	263
South West	258	255	254	251	247	240	233	226	220	214	212	208	204	199	195	191
Total LDZ	**4399**	**4343**	**4317**	**4260**	**4179**	**4046**	**3929**	**3816**	**3716**	**3615**	**3567**	**3506**	**3434**	**3348**	**3279**	**3199**
NTS Industrial	152	151	151	151	152	147	147	147	147	147	147	147	147	147	147	147
NTS Power Generation	1675	1741	1741	1741	1786	1881	1779	1827	1870	1775	1807	1807	1951	2044	2083	2083
Exports via Moffat	411	409	285	301	328	346	354	373	380	398	410	421	438	438	468	475
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**2237**	**2301**	**2177**	**2193**	**2265**	**2375**	**2280**	**2347**	**2397**	**2320**	**2364**	**2376**	**2537**	**2628**	**2699**	**2706**
Total	**6636**	**6644**	**6494**	**6453**	**6444**	**6421**	**6209**	**6163**	**6113**	**5935**	**5931**	**5882**	**5971**	**5976**	**5977**	**5904**

Notes

- *Undiversified peak day is calculated for each LDZ and for each load connected to the NTS. Storage sites and IUK are currently assumed to have zero gas demand on a peak day. Undiversified peak day demand is used where location is important.*

Figure A2.1C – Gone Green Forecast 1 in 20 Undiversified Peak Day Demand

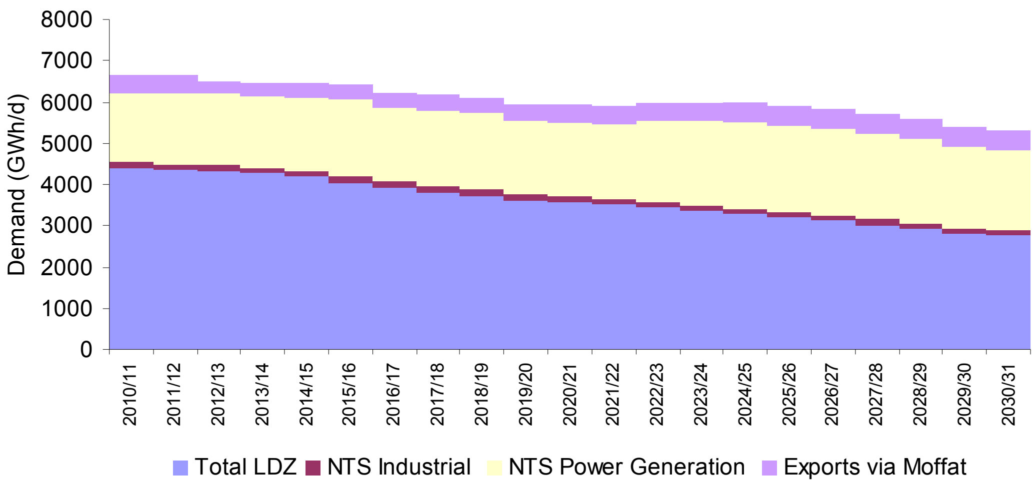


TABLE A2.1.4 – Slow Progression 1 in 20 Peak Day Undiversified Demand (GWh/day)

National	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Scotland	339	335	334	331	329	326	325	324	324	323	324	324	325	325	327	329
Northern	252	248	245	242	239	234	232	230	227	225	225	224	223	222	222	222
North West	508	504	503	497	491	482	479	475	472	468	465	464	463	461	461	461
North East	265	264	261	258	254	250	249	247	246	244	245	244	244	242	243	243
East Midlands	452	444	440	434	429	422	419	416	413	410	407	407	406	405	406	406
West Midlands	389	381	376	370	365	359	356	353	350	347	348	346	345	343	343	343
Wales North	47	47	46	45	45	44	44	44	43	43	43	43	43	43	43	43
Wales South	220	219	216	214	212	209	202	201	200	199	198	197	197	197	197	198
Eastern	361	358	358	354	351	347	345	344	343	341	340	340	340	340	342	343
North Thames	466	460	458	452	447	441	438	436	433	430	428	426	425	424	425	425
South East	492	484	479	473	468	461	458	456	453	450	451	449	449	446	447	448
Southern	348	342	341	339	337	333	332	331	330	329	330	330	331	330	332	333
South West	258	254	253	252	251	247	247	245	245	243	244	244	244	243	244	245
Total LDZ	**4397**	**4339**	**4310**	**4263**	**4217**	**4154**	**4126**	**4102**	**4079**	**4052**	**4049**	**4038**	**4036**	**4022**	**4031**	**4040**
NTS Industrial	152	151	151	151	152	147	147	147	147	147	147	147	147	147	147	147
NTS Power Generation	1675	1741	1741	1619	1664	1760	1904	1987	2071	2219	2214	2202	2316	2362	2362	2327
Exports via Moffat	411	409	285	301	328	346	354	373	380	398	410	421	438	438	468	475
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**2237**	**2301**	**2177**	**2072**	**2144**	**2253**	**2405**	**2507**	**2598**	**2764**	**2770**	**2770**	**2901**	**2947**	**2978**	**2950**
Total	**6635**	**6640**	**6487**	**6335**	**6361**	**6407**	**6531**	**6609**	**6676**	**6815**	**6819**	**6808**	**6938**	**6969**	**7009**	**6989**

Notes

- *Undiversified peak day is calculated for each LDZ and for each load connected to the NTS. Storage sites and IUK are currently assumed to have zero gas demand on a peak day. Undiversified peak day demand is used where location is important.*

Figure A2.1D - Slow Progression Forecast 1 in 20 Undiversified Peak Day Demand

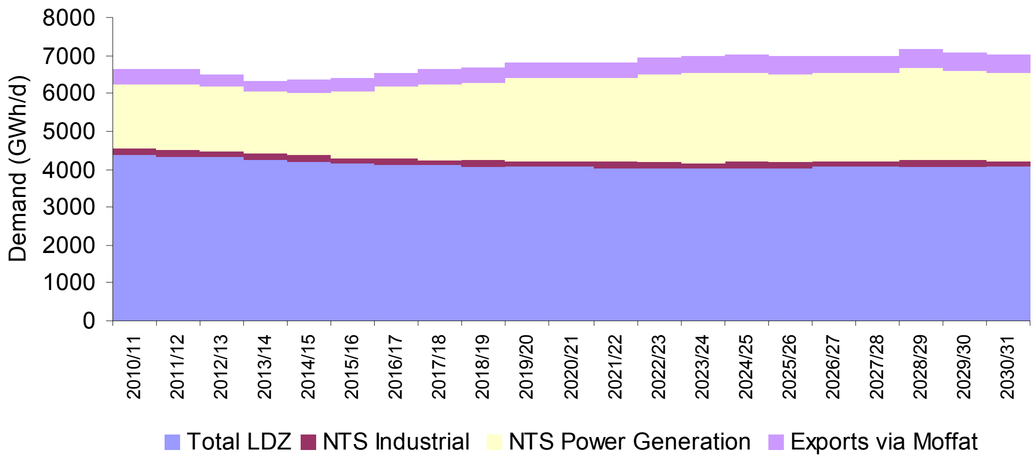


TABLE A2.1.5 – Gone Green Forecast 1 in 20 Peak Day Diversified Demand (GWh/day)

	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
0-73.2 MWh	2941	2898	2862	2803	2727	2635	2538	2434	2341	2243	2229	2193	2158	2104	2057	2012
73.2-732 MWh	384	376	380	379	377	366	362	359	357	359	349	340	330	319	313	303
NDM > 732 MWh	442	439	449	454	456	438	437	436	439	439	425	419	405	394	390	378
Total NDM	3767	3713	3691	3635	3560	3438	3336	3229	3137	3041	3003	2951	2893	2817	2759	2693
Total DM	485	479	472	468	467	462	459	454	445	435	423	410	397	386	375	360
LDZ Shrinkage	10	10	10	10	10	10	10	10	9	9	9	9	9	8	8	8
Total LDZ	**4262**	**4202**	**4172**	**4113**	**4036**	**3909**	**3805**	**3692**	**3591**	**3485**	**3435**	**3370**	**3299**	**3212**	**3142**	**3060**
NTS Industrial	85	85	85	85	83	82	81	81	80	80	79	79	78	77	77	77
Exports to Ireland	266	255	180	141	157	172	188	195	198	206	216	223	229	239	248	250
NTS Power Generation	720	682	713	681	706	782	825	810	802	783	764	687	581	551	640	537
NTS Consumption	1071	1022	978	907	946	1035	1095	1085	1081	1068	1058	989	888	868	965	864
NTS Shrinkage	21	18	18	17	17	18	18	18	18	18	18	18	18	18	18	18
Total excluding IUK	5355	5242	5168	5038	4999	4962	4918	4796	4690	4572	4512	4377	4204	4098	4125	3942
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**5355**	**5242**	**5168**	**5038**	**4999**	**4962**	**4918**	**4796**	**4690**	**4572**	**4512**	**4377**	**4204**	**4098**	**4125**	**3942**

- *Diversified peak day demand is calculated for the whole country and is used where location is not important, such as matching gas supply to demand.*
- *Peak day data is presented on a gas supply year basis*
- *All years are total demand*
- *LDZ Shrinkage is included in the 'Shrinkage' total*

Figure A2.1E – Gone Green Forecast 1 in 20 Peak Day Diversified Total Demand

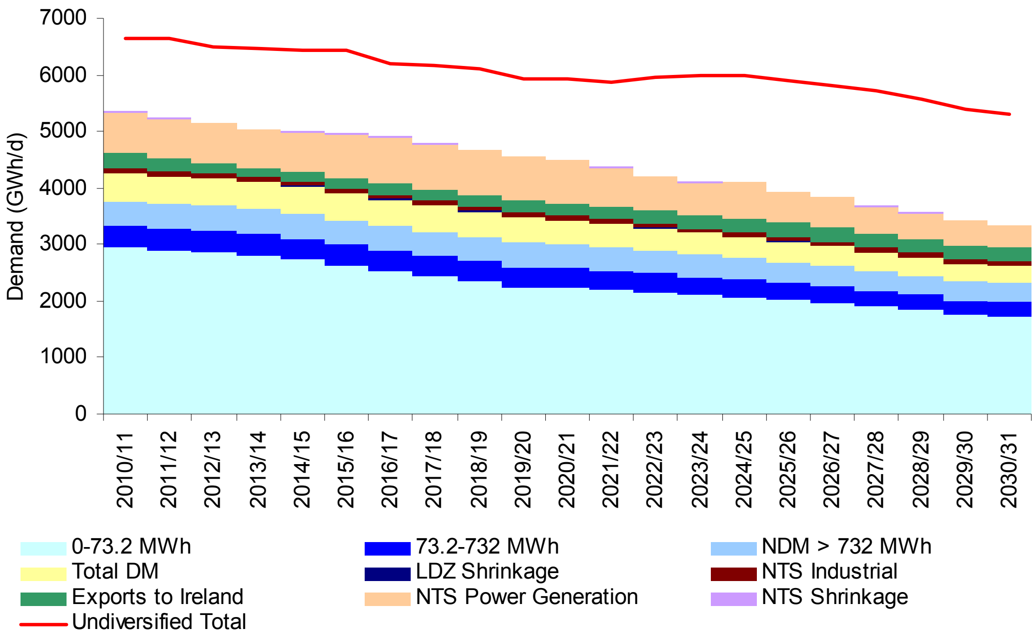


TABLE A2.1.6 – Slow Progression Forecast 1 in 20 Peak Day Diversified Demand (GWh/day)

	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
0-73.2 MWh	2942	2903	2879	2844	2816	2800	2787	2771	2756	2736	2767	2766	2780	2773	2768	2786
73.2-732 MWh	384	374	371	367	360	347	343	341	338	336	328	323	317	315	319	315
NDM > 732 MWh	441	435	440	439	437	413	414	413	413	411	394	392	387	385	395	392
Total NDM	3766	3712	3690	3650	3613	3560	3545	3525	3506	3483	3489	3481	3484	3472	3483	3493
Total DM	483	477	465	456	447	439	434	426	419	411	401	394	389	384	381	378
LDZ Shrinkage	10	10	10	10	10	9	9	9	9	9	9	9	9	8	8	8
Total LDZ	**4259**	**4198**	**4165**	**4115**	**4069**	**4009**	**3988**	**3960**	**3934**	**3903**	**3899**	**3884**	**3881**	**3865**	**3872**	**3880**
NTS Industrial	85	85	85	85	83	82	81	81	80	79	79	79	78	77	77	77
Exports to Ireland	266	255	180	141	157	172	188	194	198	206	215	223	229	240	248	251
NTS Power Generation	720	682	713	680	679	746	831	838	842	878	983	936	877	853	880	808
NTS Consumption	1071	1022	978	906	919	1000	1100	1113	1120	1163	1277	1237	1184	1170	1205	1135
NTS Shrinkage	21	18	18	17	17	18	18	18	18	18	18	18	18	18	18	18
Total excluding IUK	5351	5238	5160	5039	5005	5026	5106	5092	5073	5085	5194	5139	5083	5053	5095	5033
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**5351**	**5238**	**5160**	**5039**	**5005**	**5026**	**5106**	**5092**	**5073**	**5085**	**5194**	**5139**	**5083**	**5053**	**5095**	**5033**

- *Diversified peak day demand is calculated for the whole country and is used where location is not important, such as matching gas supply to demand.*
- *Peak day data is presented on a gas supply year basis*
- *All years are total demand*
- *LDZ Shrinkage is included in the 'Shrinkage' total*

Figure A2.1 F– Slow Progression Forecast 1 in 20 Peak Day Diversified Total Demand

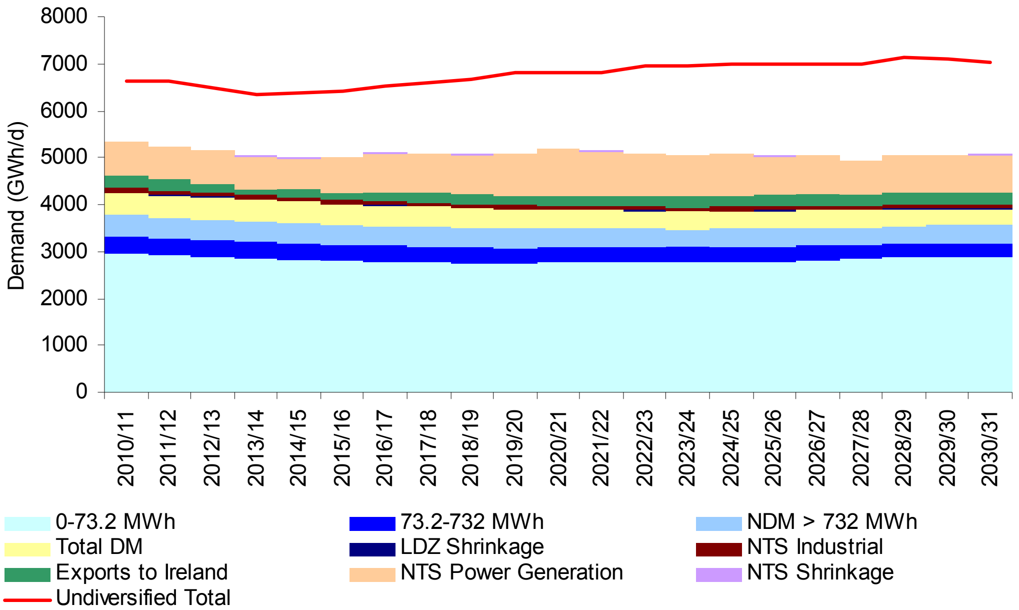


Figure A2.1D - 2011/12 Load Duration Curve – Gone Green

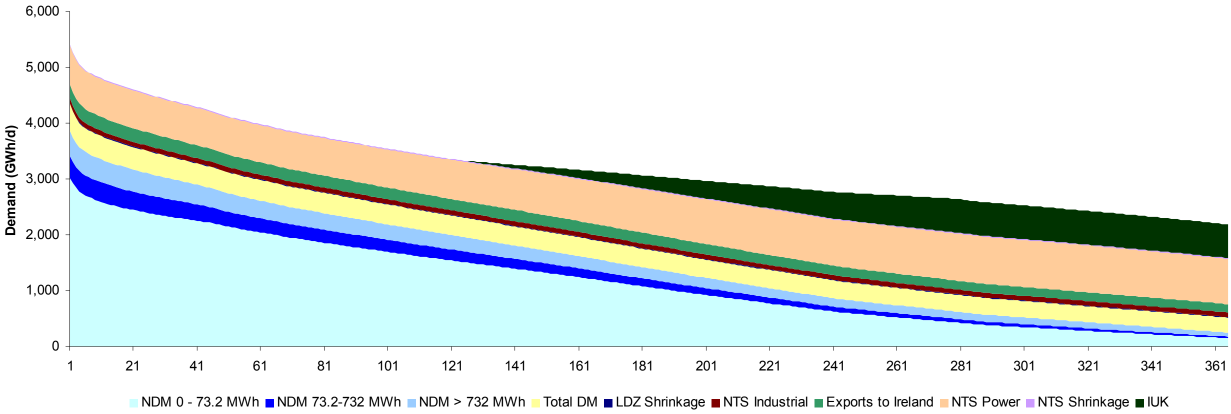
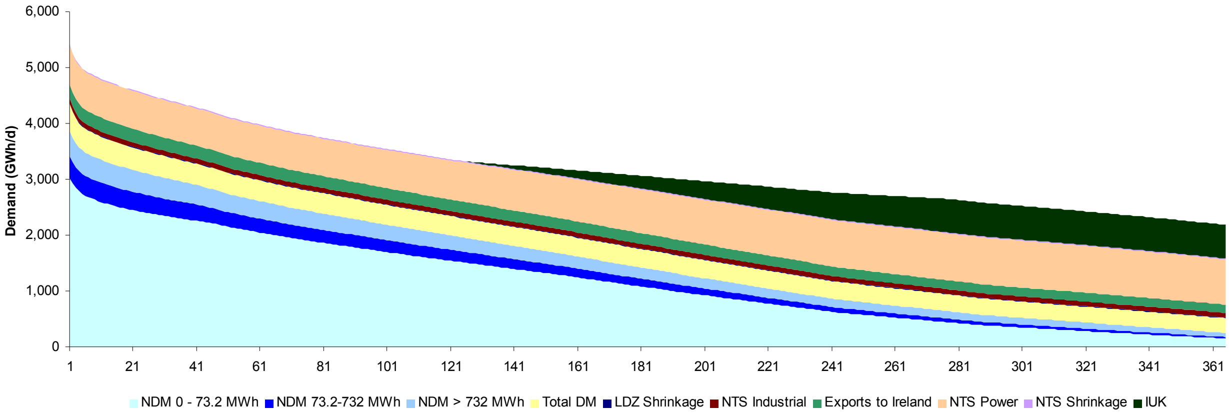


Figure A2.1E - 2011/12 Load Duration Curve – Slow Progression



Notes for figures A2.1E and A2.1F

- *Severe 1 in 50 Load Duration Curve, as defined in the Glossary*
- *Average and Gone Green Load Duration Curves, include Belgian Interconnector*
- *The average load duration curve is based on the EP2 weather basis as described in section 3.8, with the area under the curve being consistent with the annual demands shown in table A2.1.1*
- *These load duration curves take into account the move to 'universal firm' demand post 2011.*

A2.2 Supply Scenarios

Figure 2.2 A - Gone Green Annual Supplies

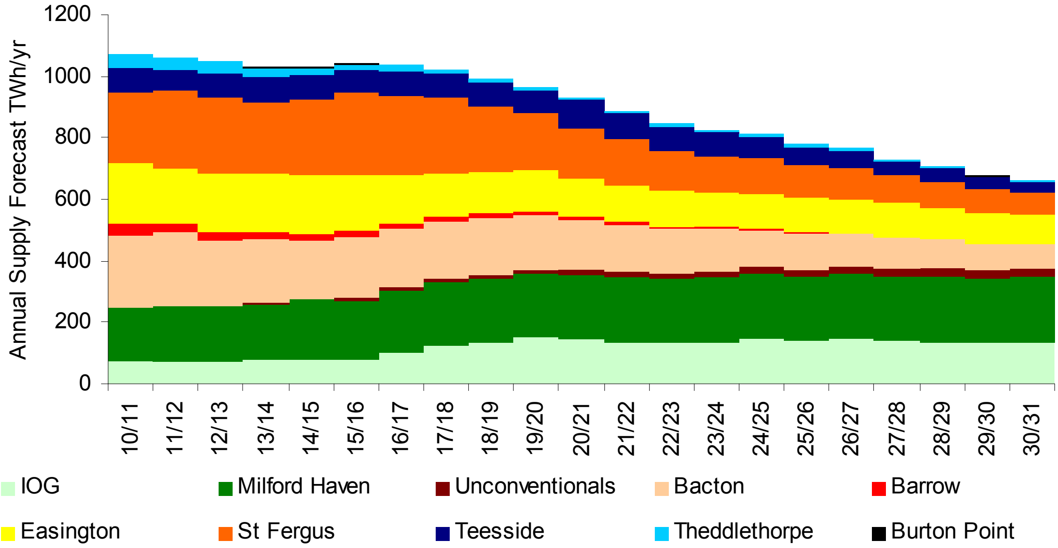
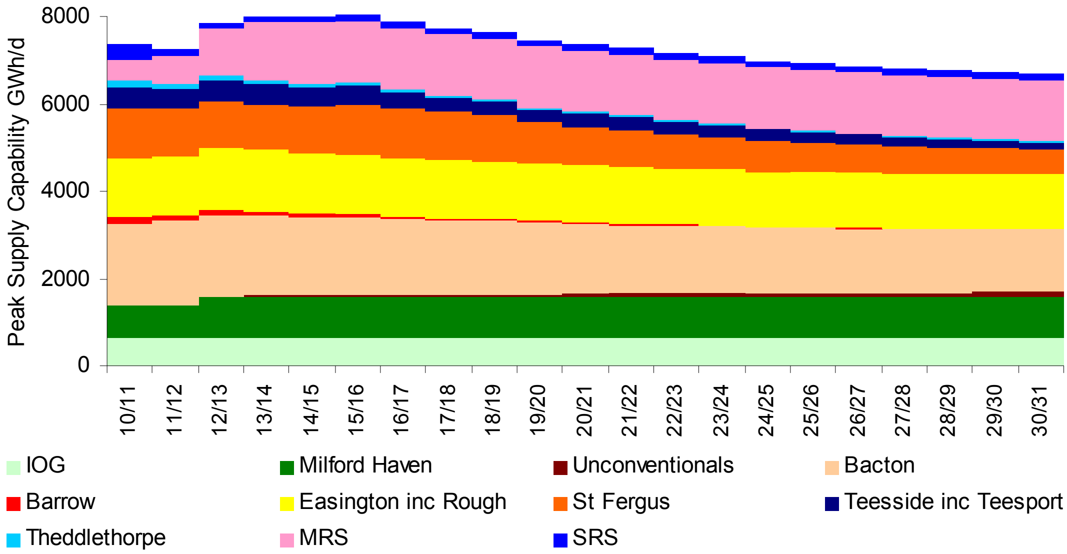


TABLE A2.2.1 - Gone Green Annual Supplies (TWh)

	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Bacton	232	241	216	210	189	201	190	185	186	176	163	151	143	136	122	115
Barrow	41	31	27	23	20	18	18	15	14	13	12	12	10	8	6	5
Easington	198	181	188	189	194	182	160	143	138	133	123	122	116	115	112	112
St Fergus	229	249	248	232	242	266	260	247	209	186	161	146	132	117	117	106
Teesside inc Teesport	76	68	81	81	81	73	79	75	79	75	93	84	77	75	69	61
Theddlethorpe	46	40	34	31	26	21	22	14	12	9	7	9	9	9	7	7
Unconventionals	0	0	1	3	5	7	10	12	13	13	16	17	19	20	22	23
Burton Point [31A]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IOG	73	74	74	76	80	80	102	126	135	149	148	137	134	137	147	140
Milford Haven	175	177	177	183	192	191	201	206	207	209	208	208	207	209	211	208
Total [31A]	1071	1059	1046	1029	1029	1040	1040	1021	992	963	930	887	845	826	811	777

Figure 2.2 B - Gone Green Peak Supplies



[31A] Data differs from scenario published in Transporting Britain's Energy 2011 publication. Data updated 13th December 2011.

TABLE A2.2.2 - Gone Green Peak Supplies (GWh/d)

	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Bacton	1863	1924	1863	1847	1778	1789	1733	1691	1679	1639	1597	1575	1548	1530	1493	1480
Barrow	151	113	100	85	72	64	61	50	48	43	39	38	31	25	18	15
Easington inc Rough	1351	1354	1406	1391	1389	1360	1343	1326	1323	1314	1301	1293	1290	1289	1278	1278
St Fergus	1142	1108	1108	1049	1069	1149	1135	1121	1049	967	879	819	770	715	713	676
Teesside inc Teesport	458	426	470	469	462	436	369	320	318	273	325	320	303	288	251	237
Theddlethorpe	154	132	113	99	81	67	68	42	37	28	22	28	27	29	20	21
Unconventionals	0	0	2	9	16	22	28	35	37	40	46	51	55	60	64	69
Burton Point [31A]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IOG	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650
Milford Haven [31A]	750	750	950	950	950	950	950	950	950	950	950	950	950	950	950	950
MRS	504	640	1044	1325	1405	1405	1405	1405	1405	1405	1405	1405	1405	1405	1405	1405
SRS	354	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
Total [31A]	7377	7240	7849	8017	8015	8035	7885	7733	7639	7452	7357	7272	7172	7084	6985	6924

Figure 2.2 C - Slow Progression Annual Supplies (TWh)

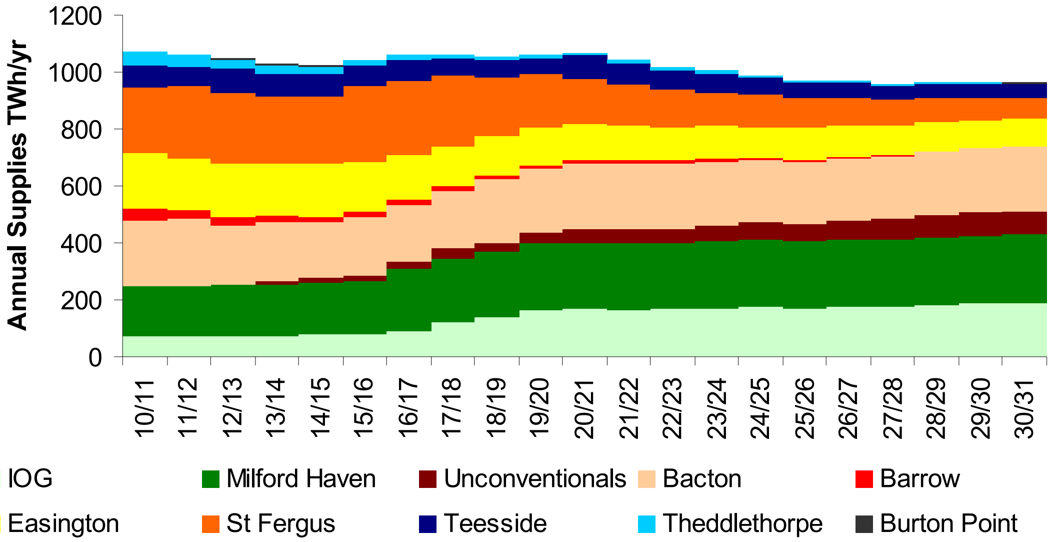


TABLE A2.2.3 - Slow Progression Annual Supplies (TWh)

	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Bacton	229	235	209	207	195	205	204	204	220	227	234	232	228	227	220	220
Barrow	41	31	28	24	20	18	17	14	14	13	12	12	10	8	6	5
Easington	199	182	190	186	186	178	158	142	138	132	124	123	117	115	112	113
St Fergus	230	250	249	232	239	264	258	245	209	185	162	146	132	117	116	107
Teesside inc Teesport	76	68	82	82	80	73	72	61	62	58	80	75	71	70	60	51
Theddlethorpe	47	40	35	31	25	21	22	14	12	9	7	9	9	9	7	7
Unconventionals	0	0	2	8	14	20	26	32	34	37	43	47	51	55	60	64
Burton Point [31A]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IOG	73	74	74	76	77	78	90	122	140	166	170	167	167	171	174	169
Milford Haven	175	178	178	181	185	187	216	226	228	232	233	233	233	235	236	235
Total [31A]	1071	1058	1045	1026	1021	1044	1063	1060	1056	1058	1065	1042	1017	1006	990	969

[31A] Data differs from scenario published in Transporting Britain's Energy 2011 publication. Data updated 13th December 2011.

Figure 2.2 D - Slow Progression Peak Supplies (GWh/d)

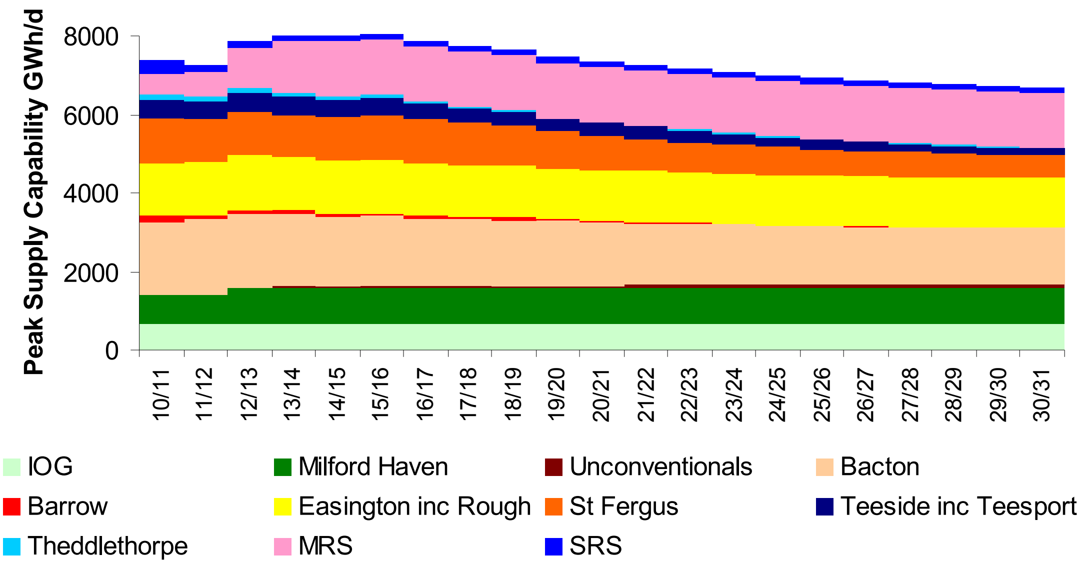


TABLE A2.2.4 Slow Progression Peak Supplies (GWh/d)

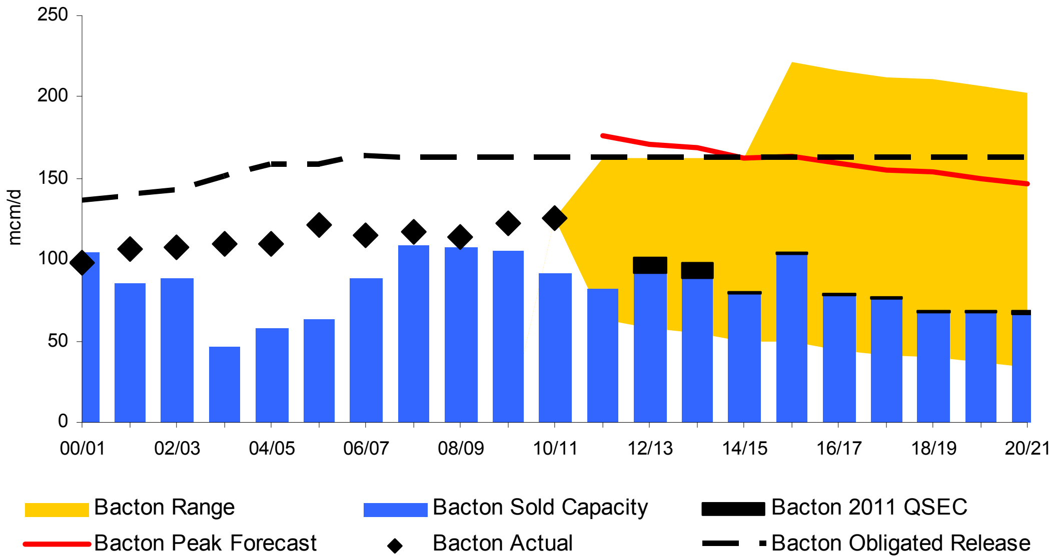
	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Bacton	1863	1924	1863	1847	1778	1789	1733	1691	1679	1639	1597	1575	1548	1530	1493	1480
Barrow	151	113	100	85	72	64	61	50	48	43	39	38	31	25	18	15
Easington inc Rough	1351	1354	1406	1391	1389	1360	1343	1326	1323	1314	1301	1293	1290	1289	1278	1278
St Fergus	1142	1108	1108	1049	1069	1149	1135	1121	1049	967	879	819	770	715	713	676
Teeside inc Teesport	458	426	470	469	462	436	369	320	318	273	325	320	303	288	251	237
Theddlethorpe	154	132	113	99	81	67	68	42	37	28	22	28	27	29	20	21
Unconventionals	0	0	2	9	16	22	28	35	37	40	46	51	55	60	64	69
Burton Point[31A]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IOG	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650
Milford Haven[31A]	750	750	950	950	950	950	950	950	950	950	950	950	950	950	950	950
MRS	504	640	1044	1325	1405	1405	1405	1405	1405	1405	1405	1405	1405	1405	1405	1405
SRS	354	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
Total[31A]	7377	7240	7849	8017	8015	8035	7885	7733	7639	7452	7357	7272	7172	7084	6985	6924

[31A] Data differs from scenario published in Transporting Britain's Energy 2011 publication. Data updated 13th December 2011.

Key

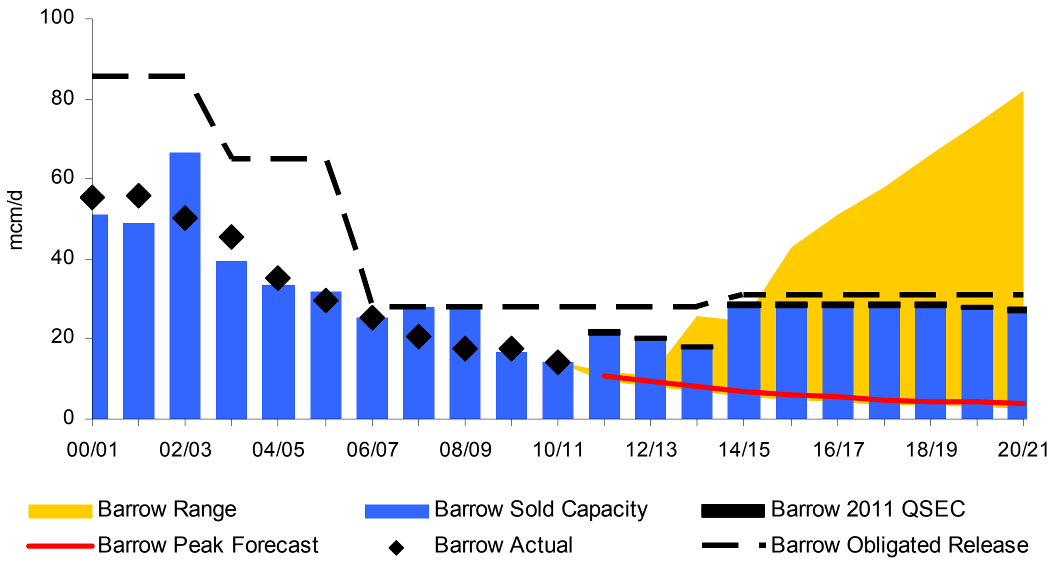
- Range — Range of flows based on assessment. Reflect high and low flow possibilities for imports, storage and UKCS flows
- 2011 QSEC — Long term capacity sold in 2011
- Sold Capacity — Long term capacity sold prior to 2011
- Release Obligation — Published QSEC release obligations
- Peak Forecast — Highest terminal flow day in each year.

Figure 2.2 E - Peak Bacton Forecasts (mcm/d)



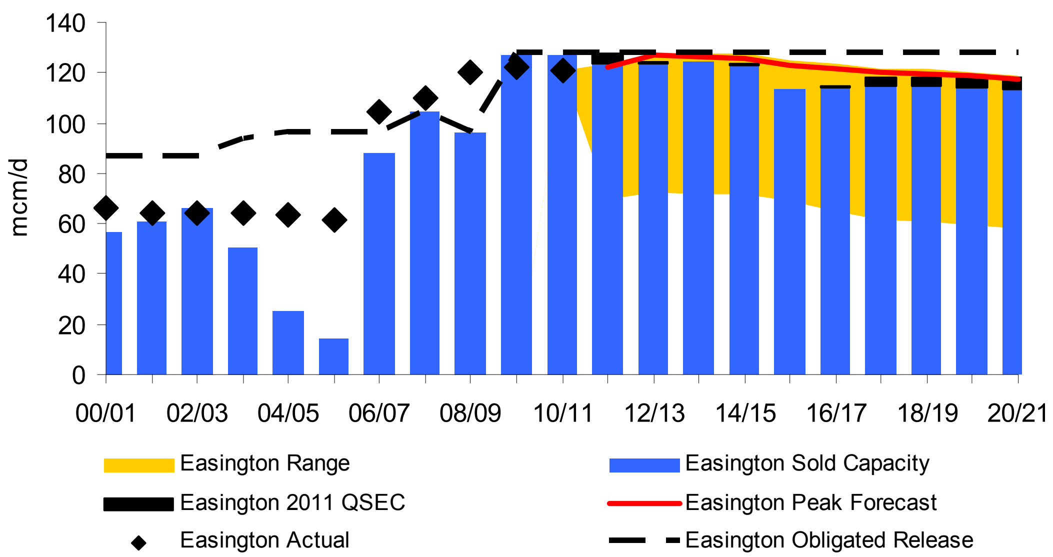
The Bacton range reflects the possibility of high or low flows through IUK and BBL. It also reflects the possibility of an offshore storage project later in the forecast

Figure 2.2 F - Peak Barrow Forecasts (mcm/d)



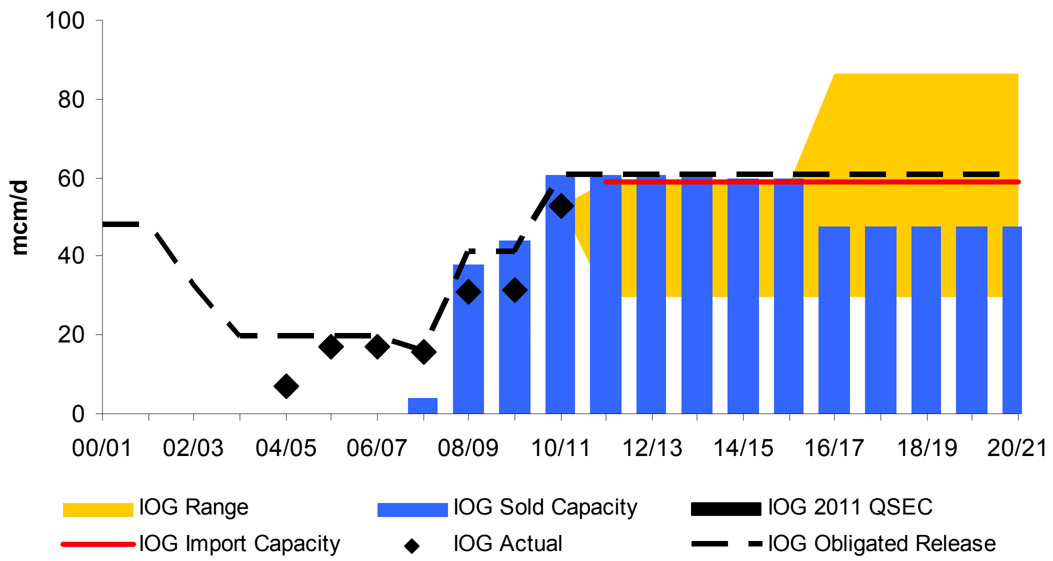
The Barrow range reflects the possibility of an offshore LNG import project and an offshore storage project materialising later on in the forecast period

Figure 2.2 G - Peak Easington Forecasts (mcm/d)



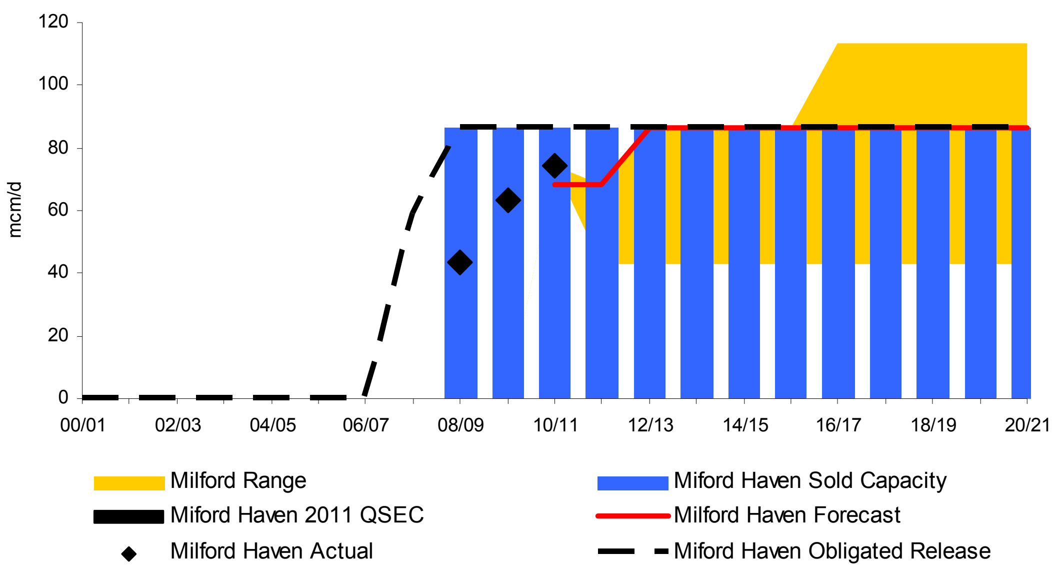
The Easington peak range highlights significant flow possibilities due to Langeled and Rough

Figure 2.2 H - Peak Grain LNG Forecasts (mcm/d)



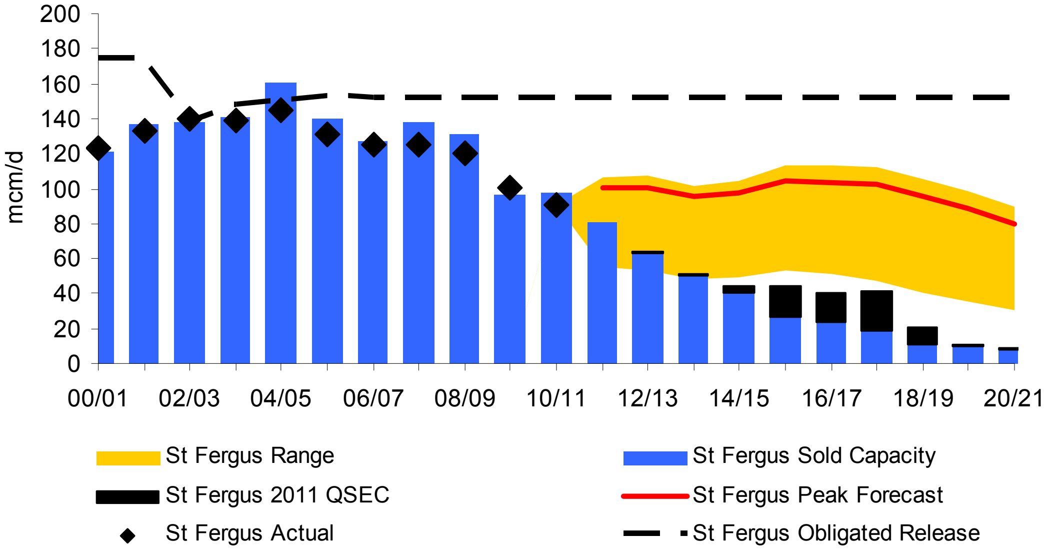
The Grain range highlights the possibility of further capacity expansions but also the wide flow possibilities through LNG importation facilities

Figure 2.2 I - Peak Milford Haven Forecasts (mcm/d)



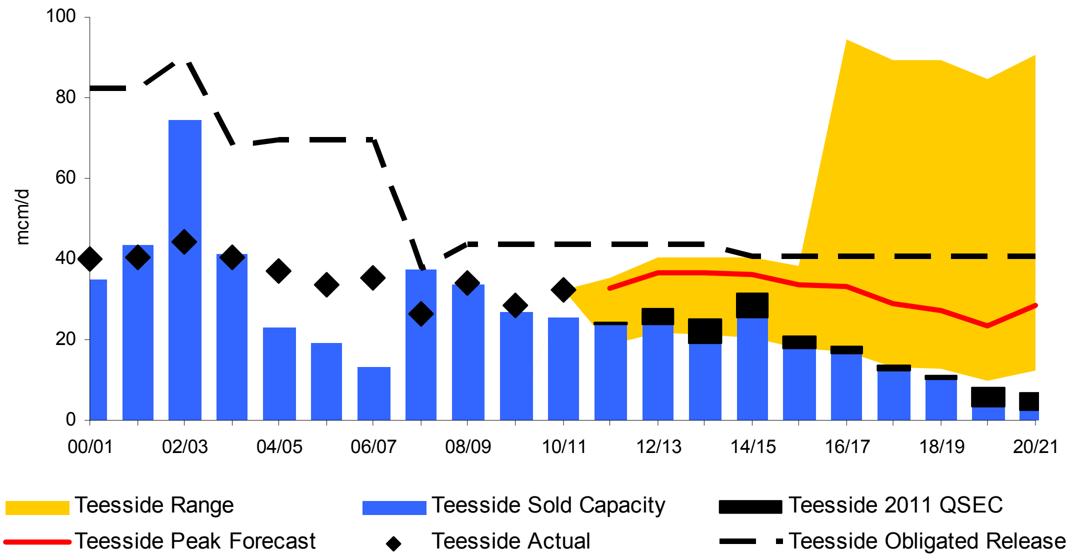
The Milford range highlights the possibility of further capacity expansions through either Dragon LNG or South Hook LNG and emphasizes the wide flow possibilities through LNG importation facilities

Figure 2.2 J - Peak St Fergus Forecasts (mcm/d)



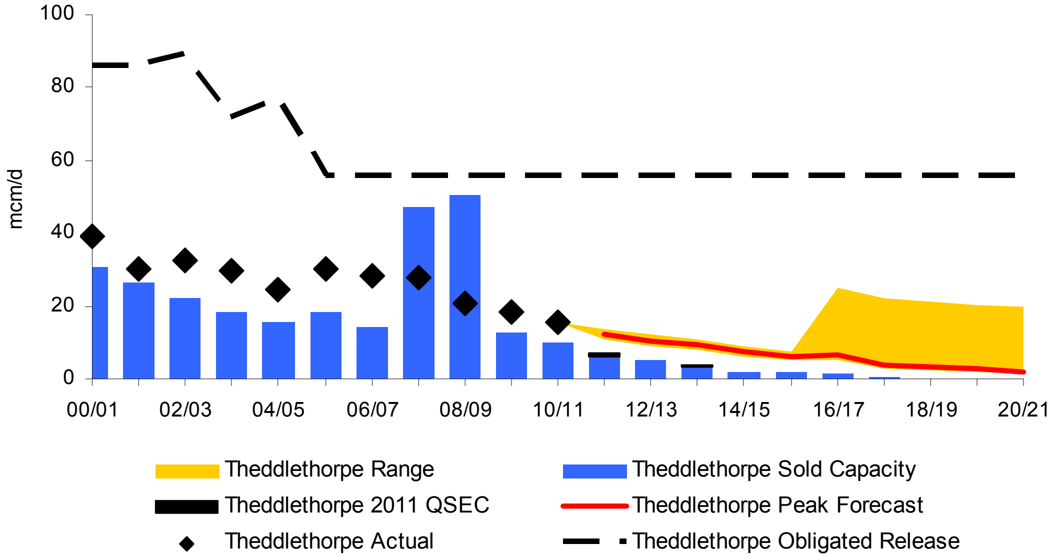
The St Fergus range emphasizes the possibility of flow variation through Norwegian infrastructure, and planned West of Shetlands production from ~2014

Figure 2.2 K - Peak Teesside Forecasts (mcm/d)



The Teesside range emphasizes the flow possibilities due to Teesport LNG, and the possibility of an additional LNG project around the end of the decade

Figure 2.2 L - Peak Theddlethorpe Forecasts (mcm/d)



The Theddlethorpe range highlights the possibility of a new onshore storage project from ~2015

Appendix Three

Actual Flows 2011

This Appendix describes annual and peak flows during the calendar year 2011. Where relevant, more up-to-date data has been included to give gas supply year 2010/11 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.

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 2010 calendar year with the forecasts presented in the 2010 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 2010 (TWh) – LDZ / NTS Split

TWh	Actual Demand	Weather Corrected Demand	2010 TYS Forecast Demand
0-73 MWh	401	352	348
73-732 MWh	54	48	48
>732 MWh Firm	123	116	118
Interruptible	72	71	74
LDZ Consumption	650	587	588
NTS Industrial	32	32	31
NTS Power Gen.	309	309	335
Exports[32]	171	171	131
Total	512	512	497
Total Consumption	1,162	1,099	1,085
Shrinkage	14	14	14
Total System Demand	**1,176**	**1,113**	**1,099**

Notes

- *Figures may not sum exactly due to rounding*

Table A3.1 indicates that our 1 year ahead forecast for 2010 was accurate to 0.2% at an LDZ level. The combined forecasts of the NTS Industrial, NTS Power Generation and Exports were accurate to 3.0%. Total system demand was accurate to 1.3%.

[32] Physical Exports

A3.2 Peak & Minimum Flows

A3.2.1 System Entry – Maximum Day Flows

For Winter 2010/11, the day of highest supply to the NTS was also the day of highest demand. This was 20th December 2010, when 476 mcm of supply fed a demand of 465 mcm. This 1mcm less than the highest ever demand day which occurred on 8th January 2010.

The day of minimum demand in 2010/11 was 10th September 2011, when NTS demand was 155 mcm. This was also the day of minimum supply, when 162 mcm of gas was supplied to the NTS.

TABLE A3.2A – Actual NTS Entry Flows on the Maximum Supply Day of Gas Year 2009/10 (mcm/d)

Terminal	**Max Day 20th December 2010**	**2010/11 TYS Peak Forecast**	**Highest Daily (per terminal) 2010/11**
Bacton inc IUK & BBL	125	159	125
Barrow	10	15	14
Easington inc Rough & Langeled	115	126	121
Isle of Grain (incl. LDZ inputs)	32	56	53
Milford Haven	64	68	75
Point of Ayr	0	0	3
St Fergus	76	111	90
Teesside	21	25	32
Theddlethorpe	15	16	15
Sub Total	458	576	528
MRS & LNG Storage	18	90	58
Total	**476**	**666**	**586**

Notes

- *The maximum supply day for 2010/11 refers to flows on 20th December 2010. 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 2010 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*

A3.2.2 System Entry – Minimum Day Flows

TABLE A3.2B – Actual NTS Entry Flows on the Minimum Supply Day of Gas Year 2010/11 (mcm)

Terminal	**Minimum Day** 10th September 2011
Bacton inc IUK & BBL	50
Barrow	9
Easington inc Rough & Langeled	22
Isle of Grain (incl. LDZ inputs)	3
Milford Haven	22
Point of Ayr	0
St Fergus	44
Teesside	0
Theddlethorpe	12
Sub Total	162
MRS & LNG Storage	0
Total	**162**

Notes

- *The minimum supply day for 2010/11 refers to flows on 10th September 2011. 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 difference between total demand and total supply on the day;*
- *Figures may not sum exactly due to rounding.*

A3.2.3 System Exit – Maximum and Peak Day Flows

Table A3.2C shows actual flows out of the NTS on the maximum demand day of gas year 2009/10 compared to the forecast peak flows.

TABLE A3.2C – Actual NTS Exit Flows on Maximum Demand Day of Gas Year 2010/11 (mcm)

LDZ	**Maximum Day** 20th December 2010	**1 in 20 Undiversified Peak for 2010/11 (Gone Green)**
Eastern	29	33
East Midlands	40	41
North East	22	24
Northern	19	23
North Thames	34	42
North West	44	46
Scotland	28	31
South East	35	45
Southern	26	32
South West	20	23
West Midlands	32	35
Wales (North and South)	21	24
LDZ Total	352	400
NTS Loads	113	203
Total	**465**	603

Notes

- *The maximum day for gas year 2010/11 refers to 20th December 2010. 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 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 2010 Ten Year Statement;*
- *Figures may not sum exactly due to rounding.*

A3.2.4 System Exit – Minimum Day Flows

TABLE A3.2D – Actual NTS Exit Flows on the Minimum Demand Day of Gas Year 2010/11 (mcm/d)

LDZ	**Minimum Day** 10th September 2011
Eastern	4
East Midlands	7
North East	4
Northern	4
North Thames	6
North West	8
Scotland	7
South East	4
Southern	4
South West	3
West Midlands	4
Wales (North and South)	4
LDZ Total	59
NTS Loads	96
Total	**155**

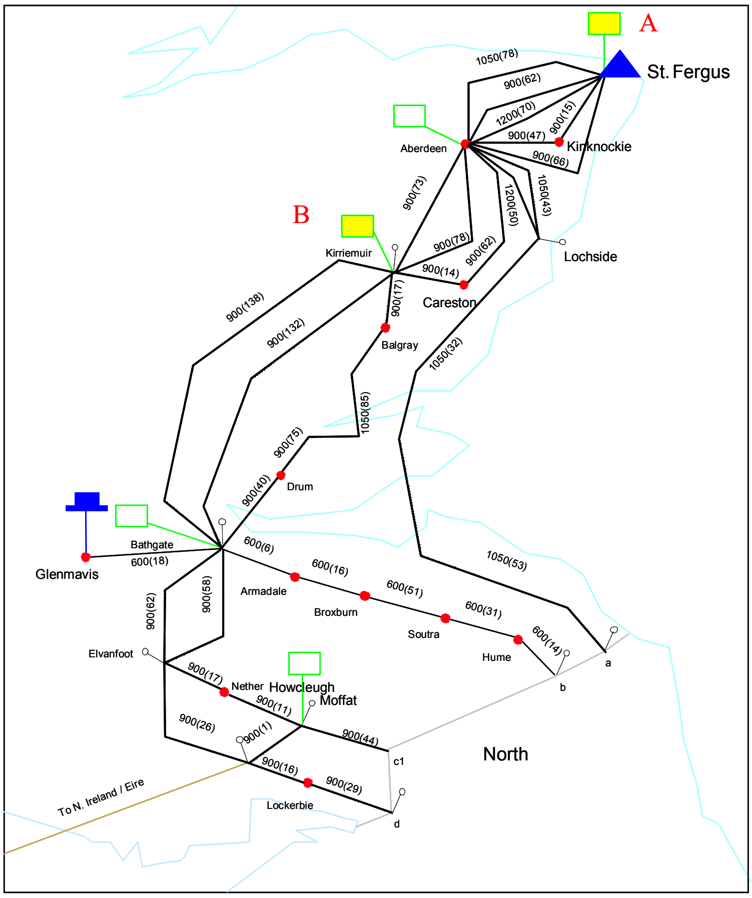
Notes

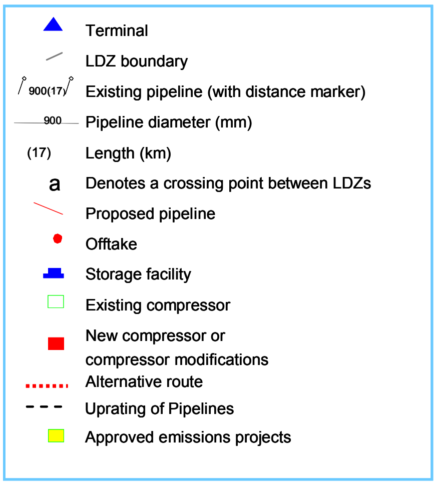
- *The minimum day for gas year 2010/11 refers to 10th September 2011. This was the overall lowest demand day, but individual LDZs may have seen lower demands on other days;*
- *NTS actual loads include interconnector demand;*
- *Due to linepack changes, there may be a small difference between total demand and total supply on the day;*
- *Figures may not sum exactly due to rounding.*

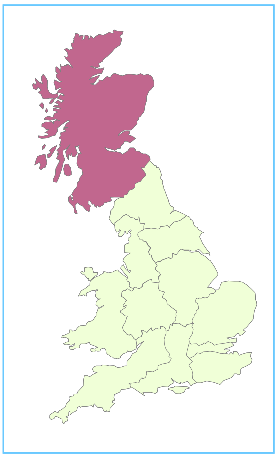
Appendix Four

The Gas Transportation System

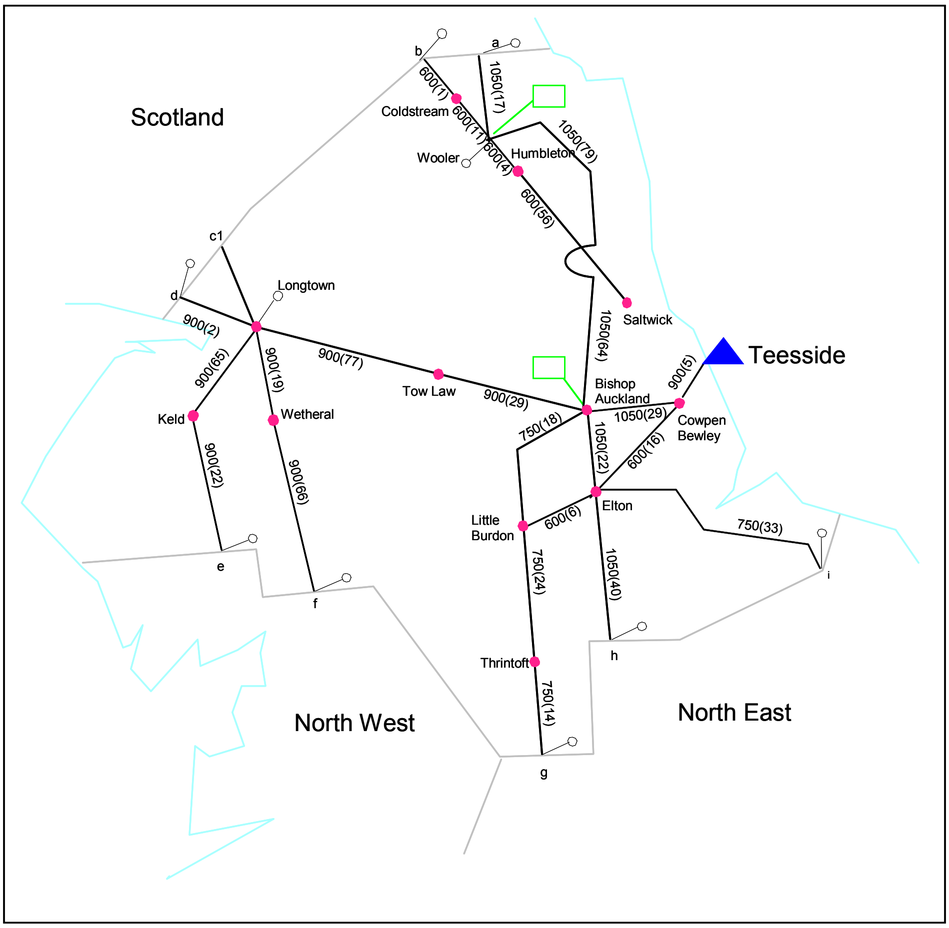
Scotland (SC) – NTS







North (NO) – NTS


Scotland
North West
North East
Teesside
Coldstream
Wooler
Humbleton
Saltwick
Longtown
Keld
Wetheral
Tow Law
Bishop Auckland
Cowpen Bewley
Elton
Little Burdon
Thrintoft
a
b
c1
d
e
f
g
h
i
600(1)
1050(17)
600(11)
600(4)
1050(79)
600(56)
1050(64)
900(2)
900(65)
900(19)
900(77)
900(29)
900(5)
1050(29)
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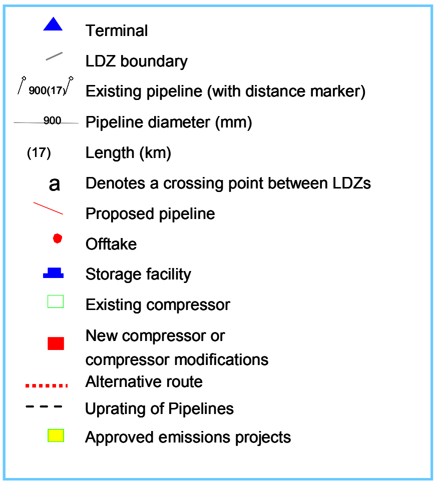
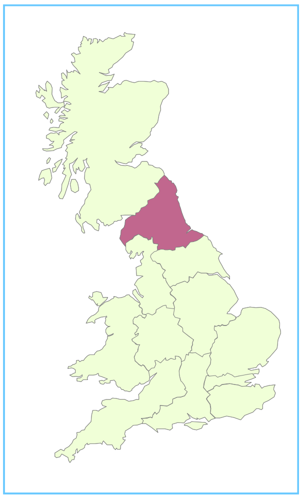
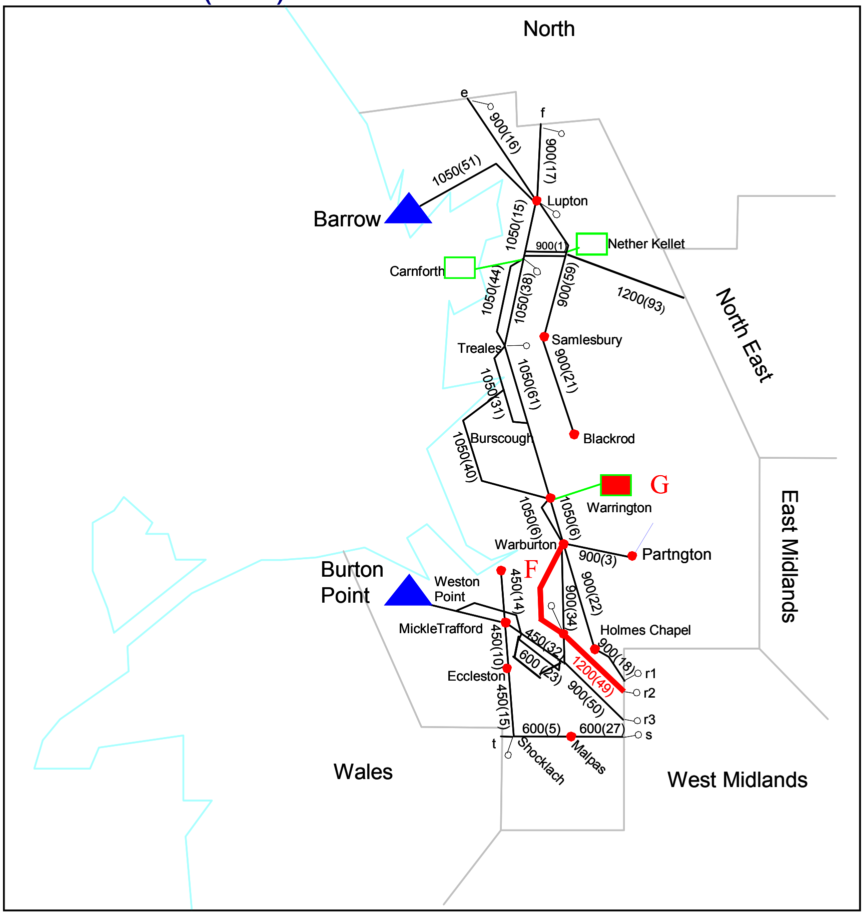
1050(40)
750(14)

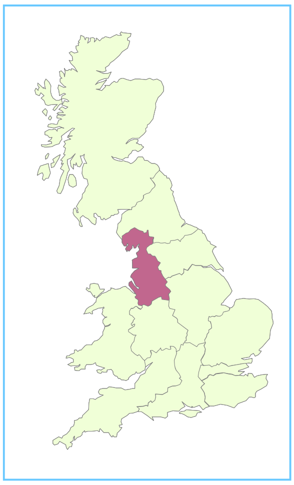

Terminal
LDZ boundary
900(17) Existing pipeline (with distance marker)
900 Pipeline diameter (mm)
(17) Length (km)
a Denotes a crossing point between LDZs
Proposed pipeline
Offtake
Storage facility
Existing compressor
New compressor or compressor modifications
Alternative route
Uprating of Pipelines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



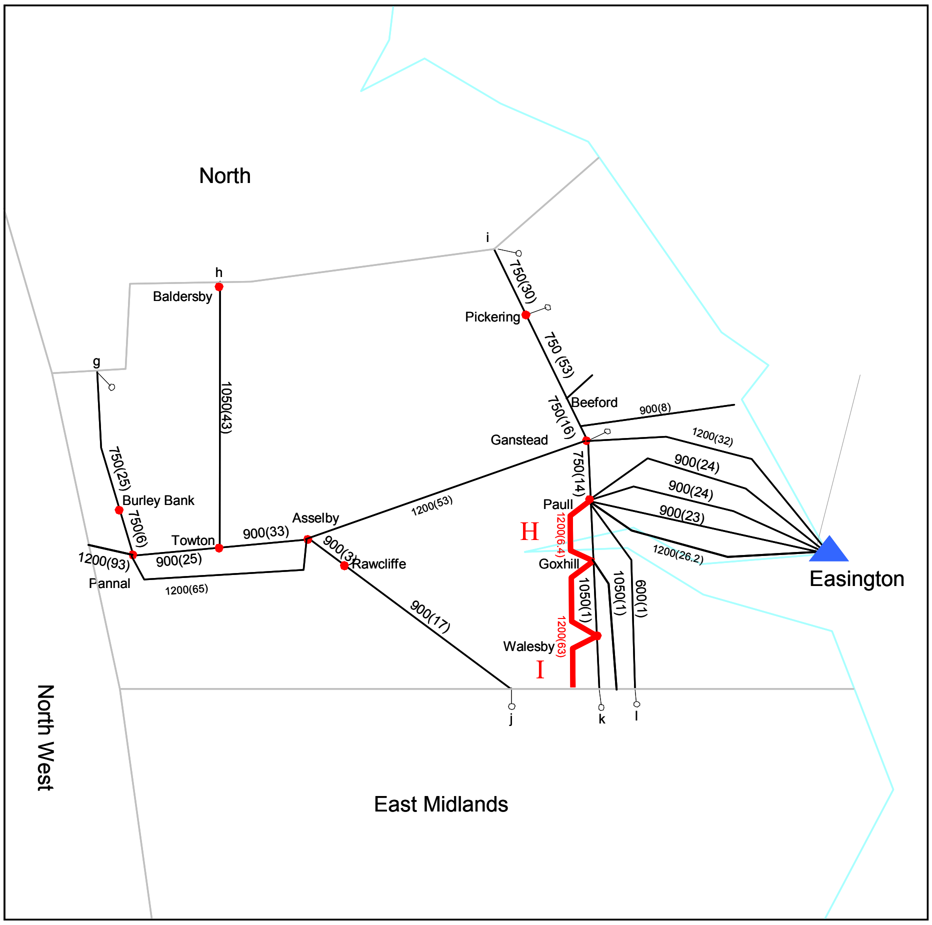
North West (NW) – NTS

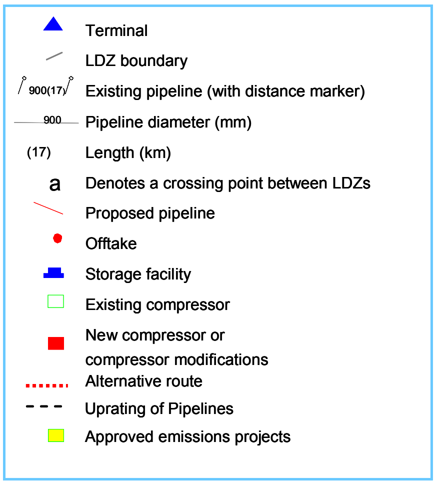


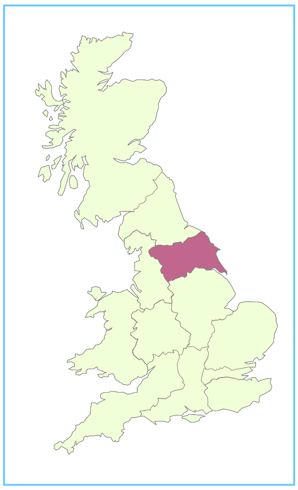
Terminal
LDZ boundary
900(17) Existing pipeline (with distance marker)
900 Pipeline diameter (mm)
(17) Length (km)
a Denotes a crossing point between LDZs
Proposed pipeline
Offtake
Storage facility
Existing compressor
New compressor or compressor modifications
Alternative route
Uprating of Pipelines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



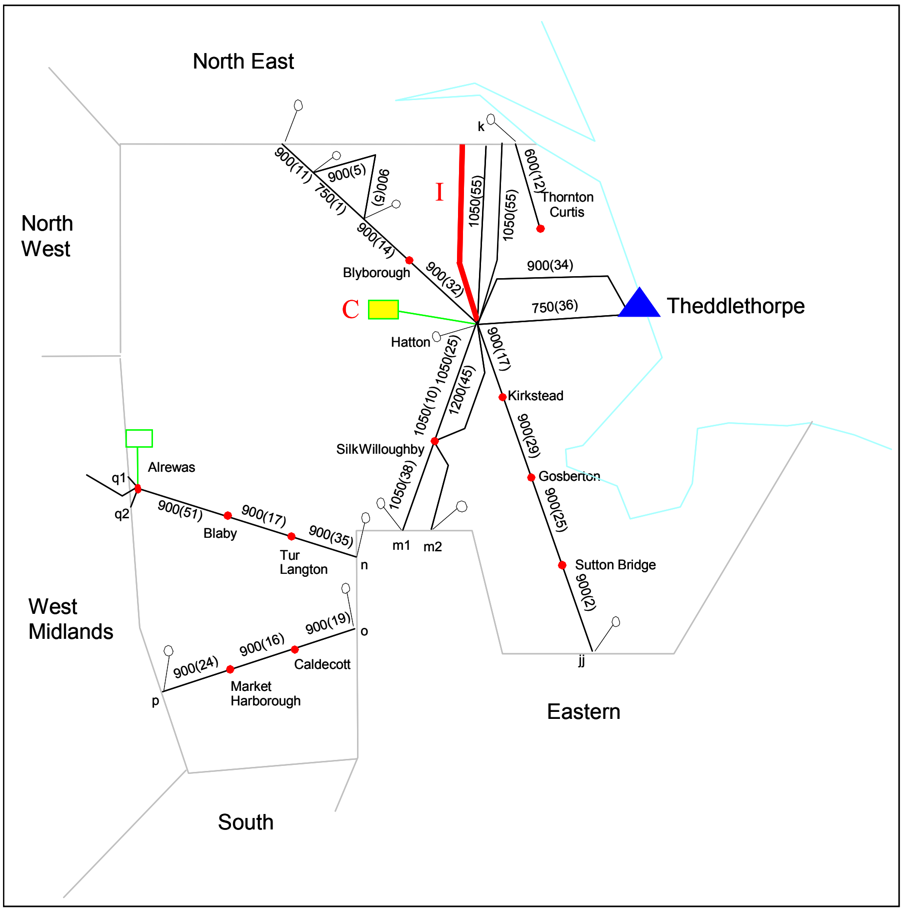
North East (NE) – NTS

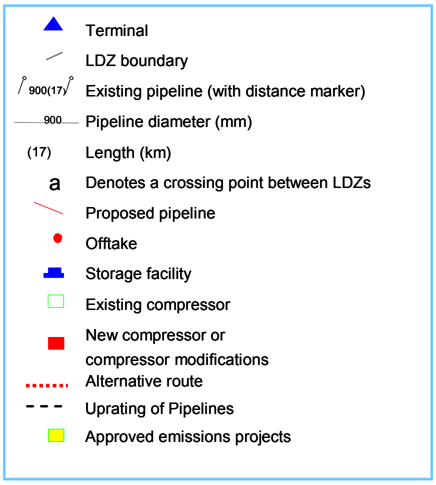


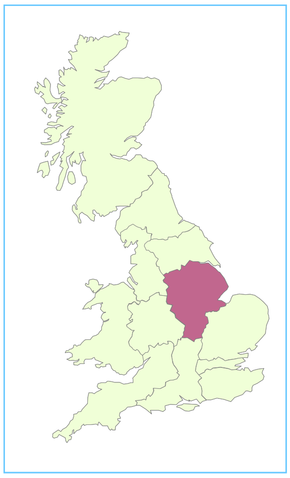




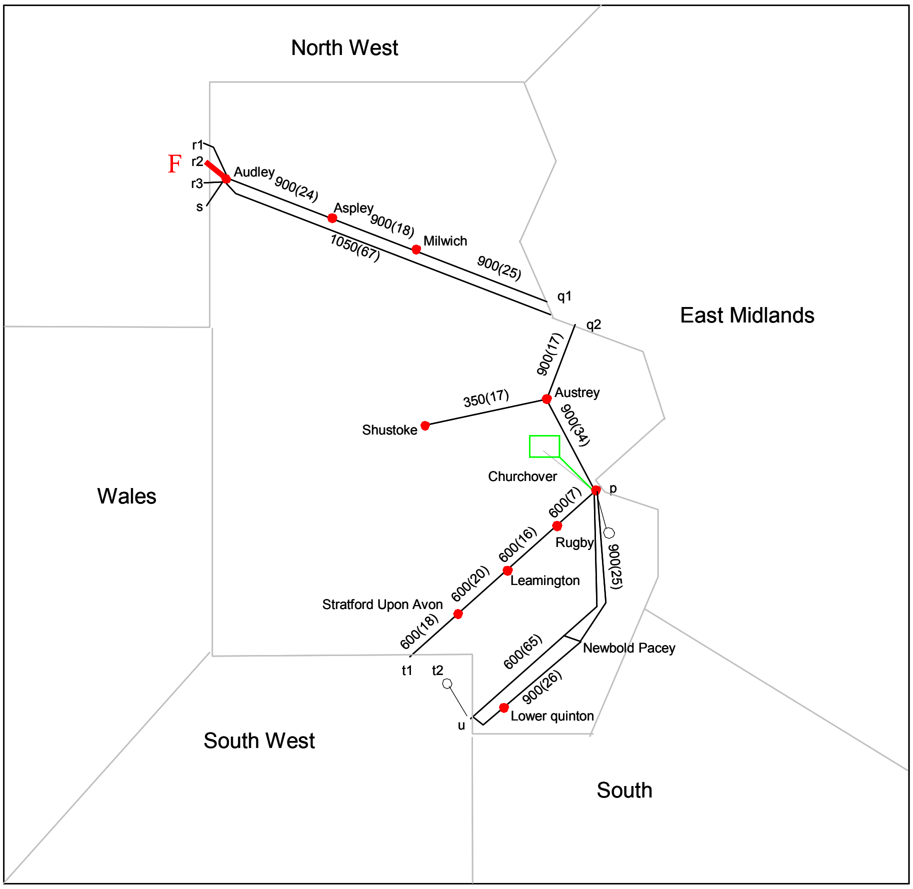
East Midlands (EM) – NTS

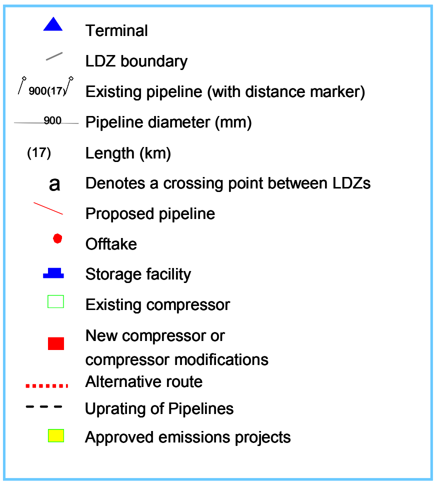


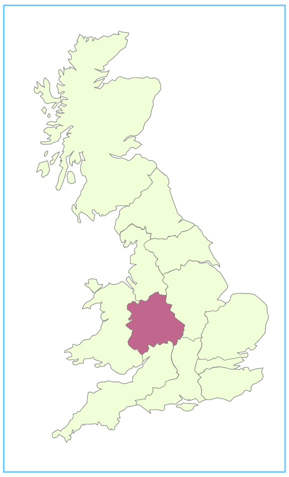




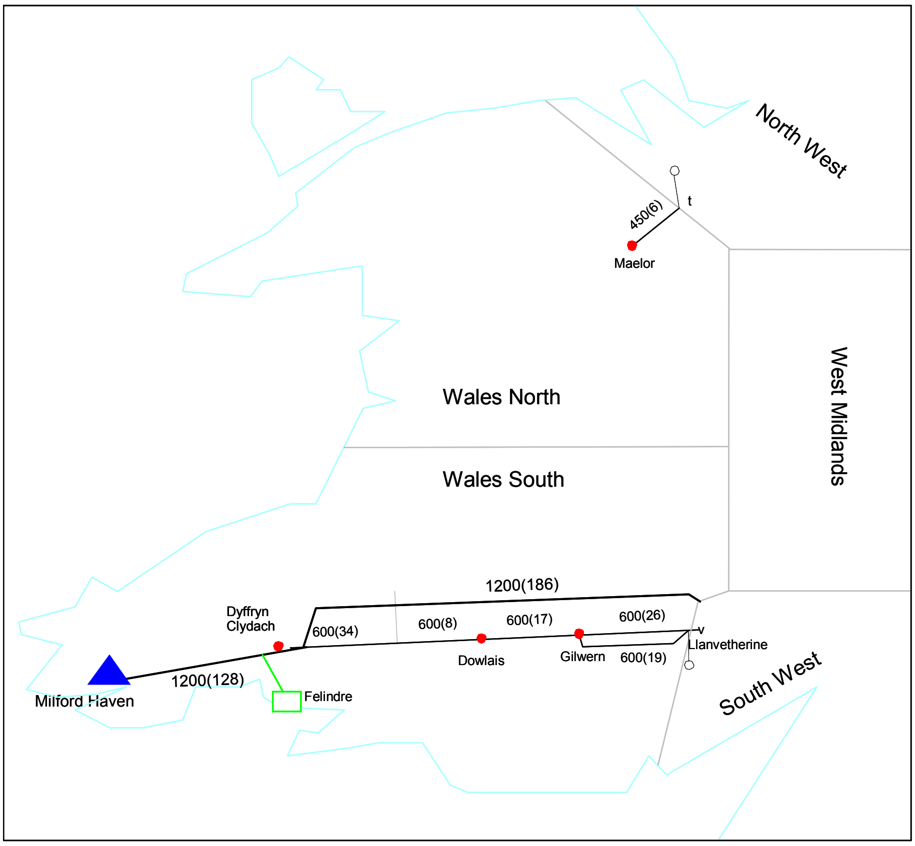
West Midlands (WM) – NTS

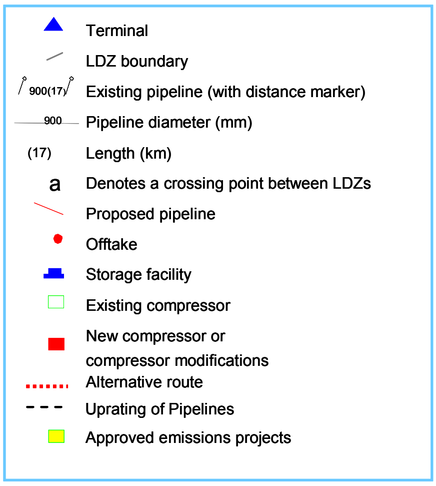


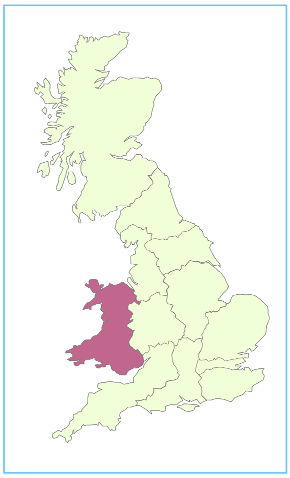




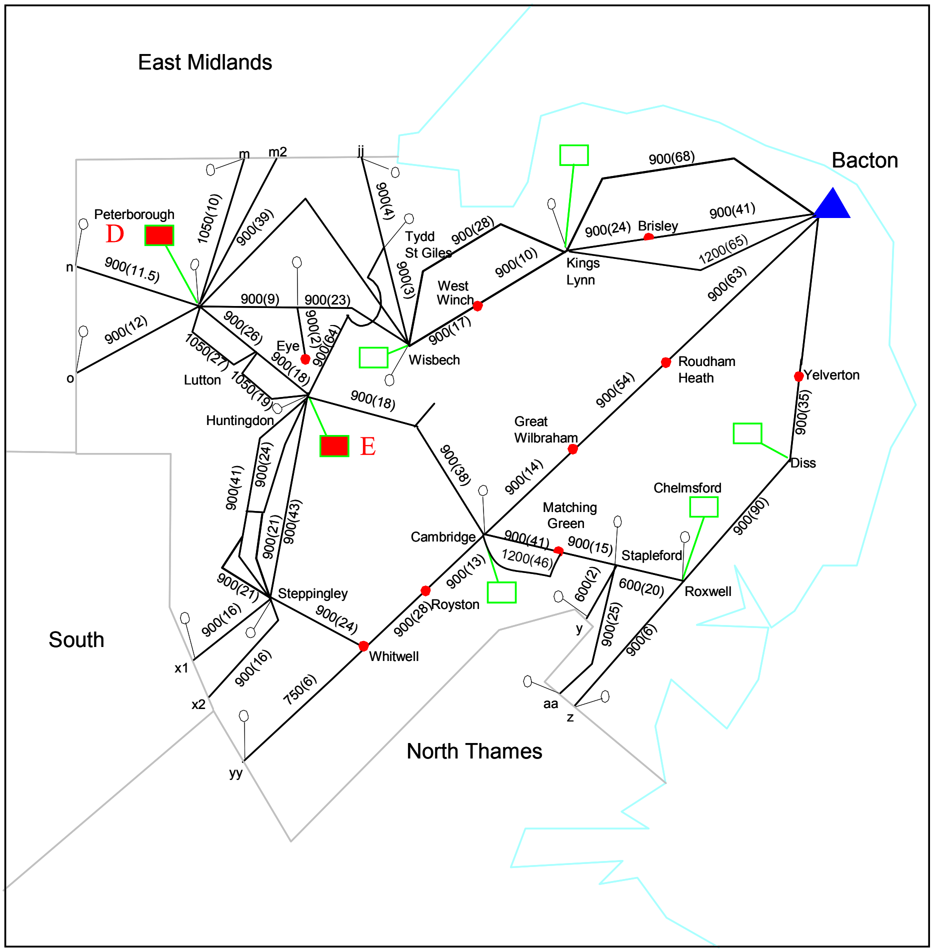
Wales (WN & WS) – NTS

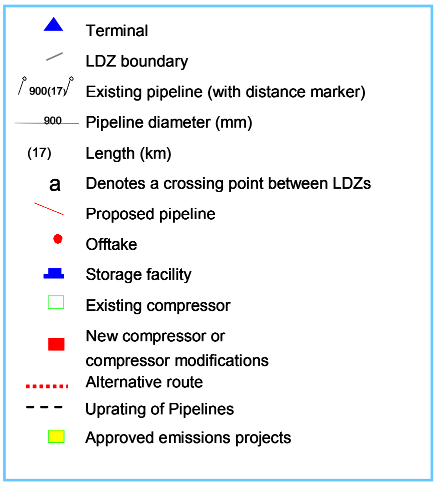


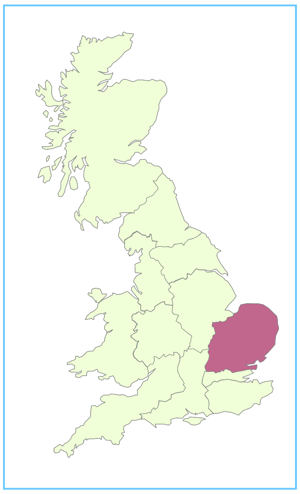




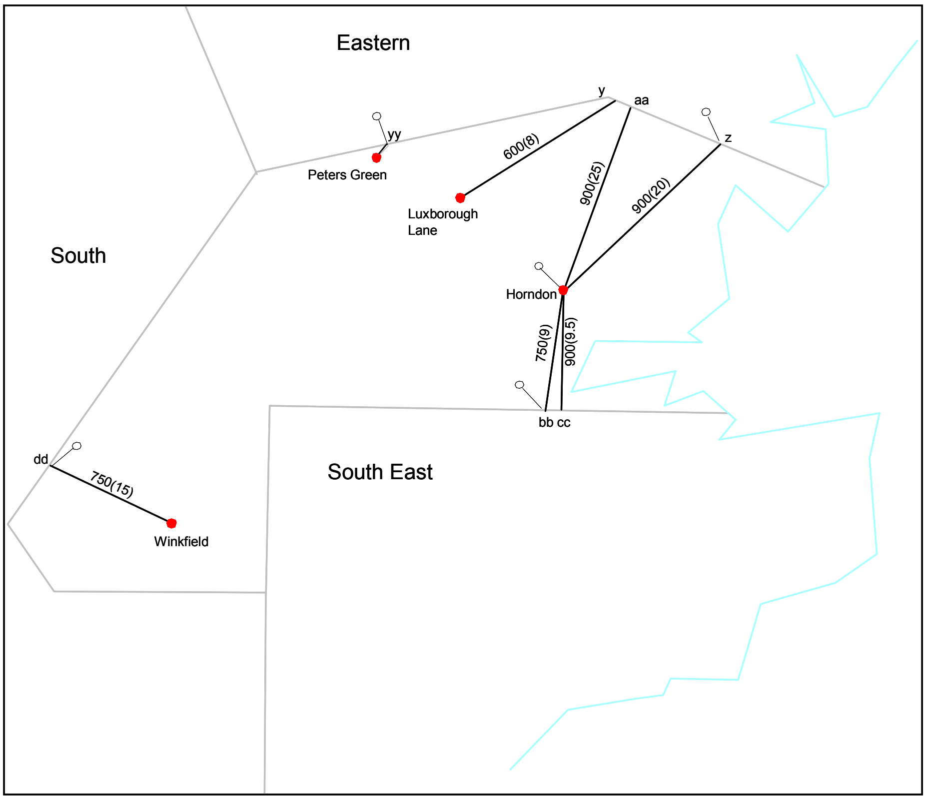
Eastern (EA) – NTS

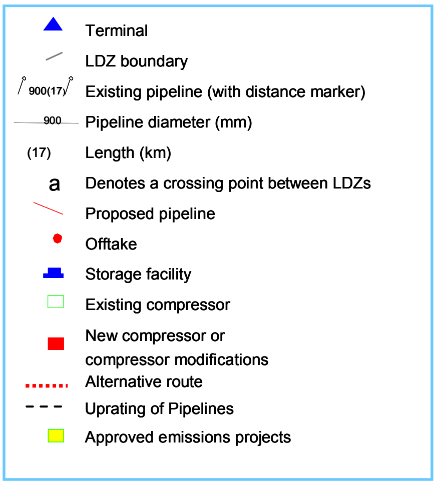


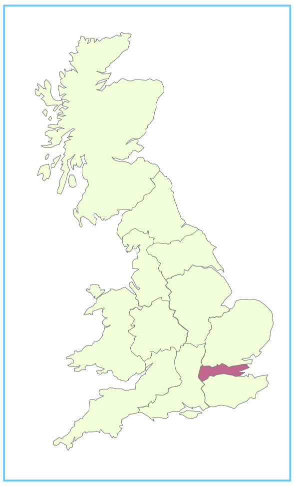




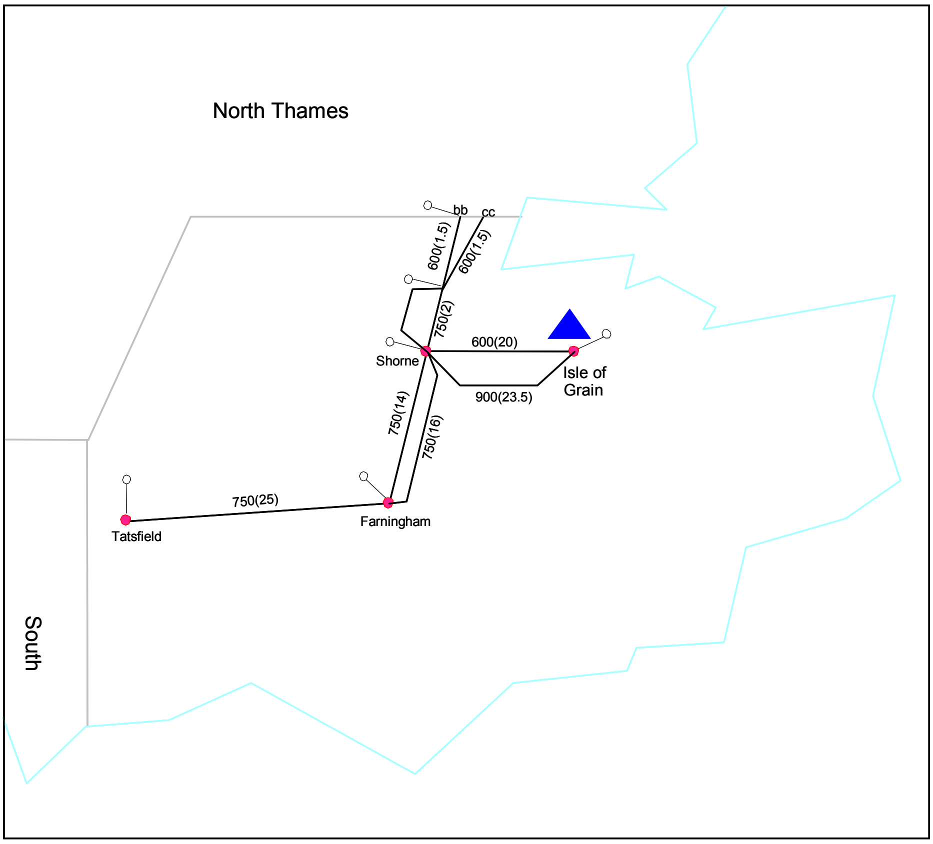
North Thames (NT) – NTS

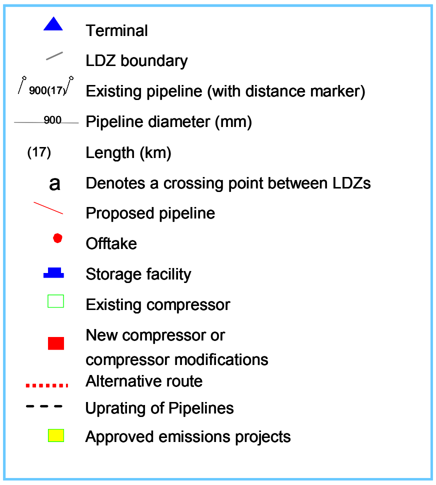


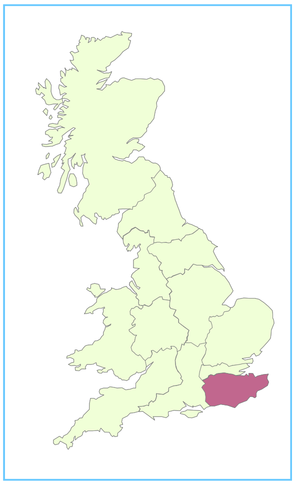




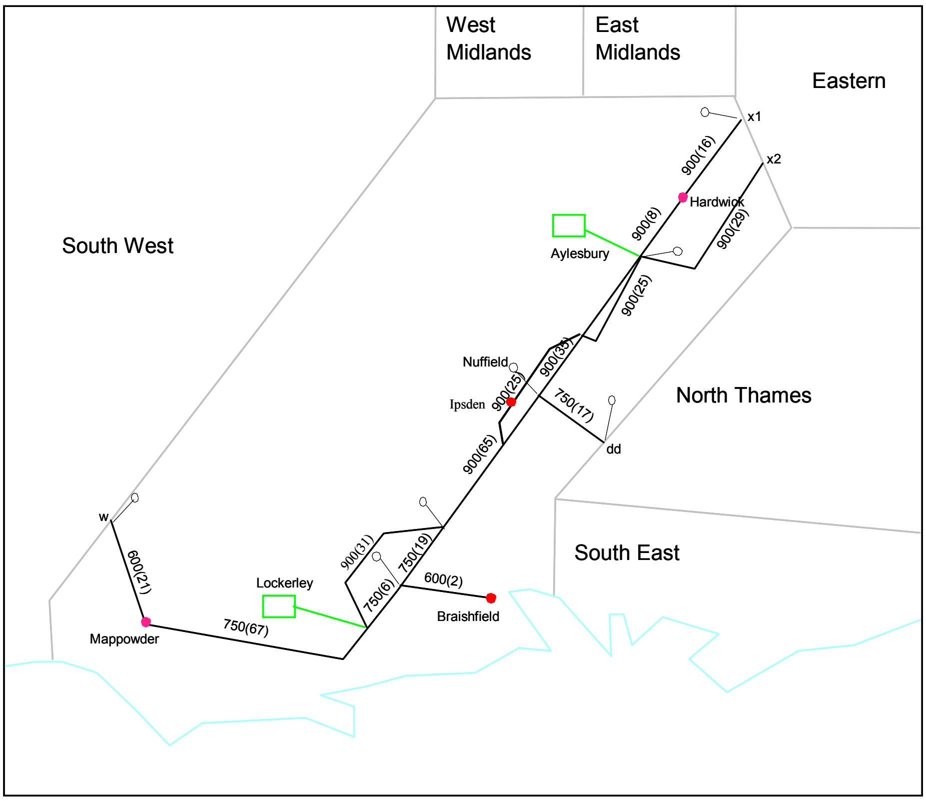
South East (SE) – NTS

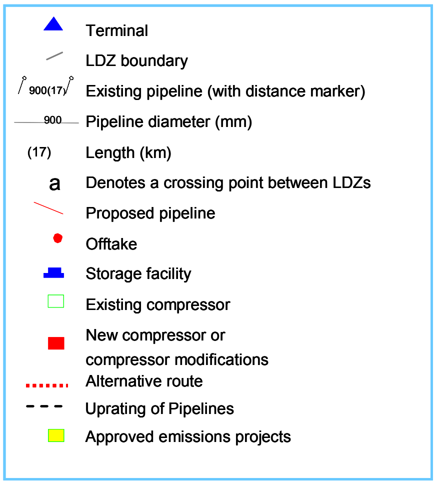






South (SO) – NTS


West Midlands
East Midlands
Eastern
South West
North Thames
South East
x1
x2
900(16)
Hardwick
900(8)
900(29)
Aylesbury
900(25)
Nuffield
900(35)
Ipsden
900(25)
750(17)
dd
900(65)
w
600(21)
900(31)
750(19)
Lockerley
750(6)
600(2)
Braishfield
750(67)
Mappowder


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
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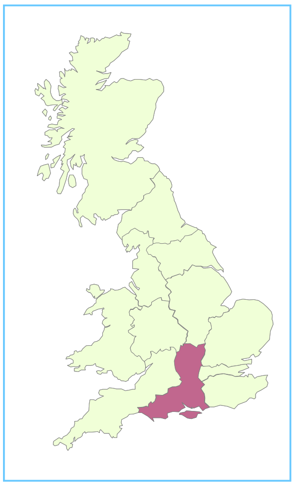
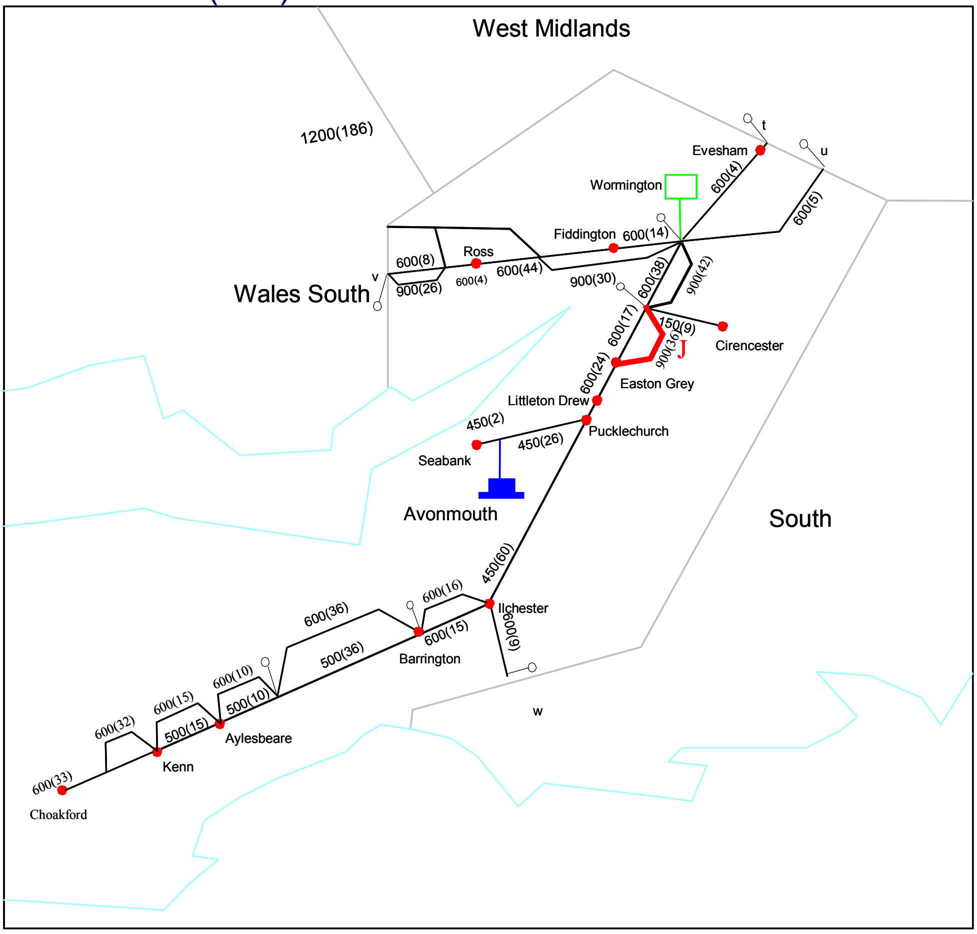
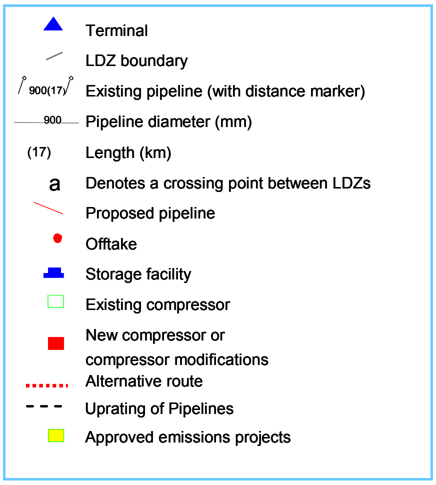
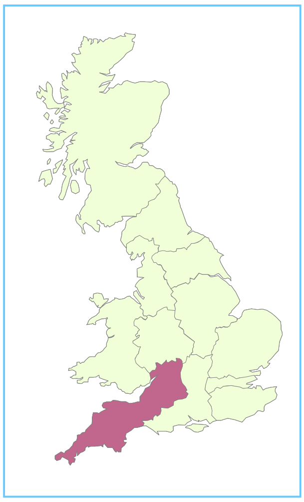
Approved emissions projects



South West (SW) – NTS







Appendix Five

Connections to the National Transmission System (NTS)[33]

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

[33] The current connections process as of December 2011. This is liable to change if UNC modification 373 is approved. (See Section 6.11)

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.

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. Carbon Dioxide
    - Not more than 2.5% (molar)
11. 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

12. Organo Halides
    - Not more than 1.5 mg/m^3
13. Radioactivity
    - Not more than 5 Becquerels/g
14. 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
15. 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.
16. 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 M/400, under which CEN was invited to draw up standards for natural gas quality that were the broadest possible within reasonable costs.

Mandate M/400 envisaged two phases of work – the first being focused on the wobbe index via a testing programme to assess the performance of domestic appliances using different gas qualities and the second being to consider the non-combustion parameters and the drafting of European Standard(s) for natural gas quality. A final report on the phase 1 work is expected by the end of 2011 and phase 2 is already underway with an expected completion in 2014. In addition, mandate M/400 required a cost-benefit analysis of gas quality harmonisation on the whole European gas supply chain to be conducted and the EC's consultants GL Noble Denton and Poyry produced a preliminary report for consultation in July 2011. A final report of this work is expected to be produced in early 2012 following further engagement with stakeholders.

National Grid is also aware of, and continues to monitor 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.

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. Therefore, we encourage project developers to approach us as soon as they are in a position to discuss their projects so that we can assess the potential impact on the NTS and help inform their decision-making. In practice, we find that this is best done several years before they need to book capacity through the formal Uniform Network Code processes.

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.

ASEP (Aggregate System Entry Point)

A term used to refer to gas supply terminals.

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.

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.

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 5.

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.

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.

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 Network Operator (DNO)

The operator of a Distribution Network (DN).

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.

ENTSOG

European Network of Transmission System Operators for Gas.

ENA

Energy Networks Association.

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 industry response to a supply demand mismatch

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.

Gone Green (GG)

A National Grid scenario whereby the 2020 renewables target is met.

IEA

International Energy Agency. An intergovernmental organisation that acts as energy policy advisor to 28 member countries.

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.

IUK

Owner and operator of the Belgian interconnector.

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/LDZ offtakes to distribution system low pressure pipelines. 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 System 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..

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.

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 constitutes the Balancing Market for GB and enables anonymous financially cleared on the day trading between market participants.

Operating Margins

Gas used by National Grid Transmission 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 current price control period which ends 31st March 2012 is being extended by one year, and the new RIIO-T1 price control period will run from 1st April 2013 to 31st March 2021.

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

RHI (Renewable Heat Incentive)

An incentive due to commence in June 2011 that pays renewable heat generators for heat that they produce.

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.

Storage Monitors

The Firm Monitor 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 storage stocks reducing below this level.

Safety Monitors in terms of space and deliverability are minimum storage requirements determined to be necessary 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 storage stocks reducing below this level.

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 (Shipper) 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.

Slow Progression (SP)

National Grid’s forecast scenario under current regulatory regime and known government policies.

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 Meter Points 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.

TSO

Transmission System Operator

TYS

Ten Year Statement

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 Transmission and the Distribution Network Operators.

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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