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Gas Ten Year Statement 2014

UK gas transmission

DECEMBER 2014

Welcome to the 2014 edition of the Gas Ten Year Statement (GTYS). This document is the conclusion of our annual planning cycle and describes how the gas transmission network will evolve to meet future needs, driven by our 2014 Future Energy Scenarios (FES)[1].

Richard Smith
Head of Network Strategy

Box.SystemOperator.GTYS@nationalgrid.com

Our Future Energy Scenarios map out the future energy landscape, based on the energy trilemma of security of supply, sustainability and affordability. We then use the scenarios for our network analysis, helping us identify strategic gas and electricity network investment requirements. The Gas Ten Year Statement focuses on the implications of the scenarios for the development of the gas network. The Electricity Ten Year Statement (ETYS) covers the same for the electricity network. Together, the GTYS, the ETYS and the FES form an integrated and important set of documents that together discuss the "future of energy".

Responding to stakeholder feedback, we have further developed this year's GTYS building upon the changes we made last year, making the need case for future capability requirements clearer. Also, to aid our customers' and stakeholders' decision making, we have included more information about the lead time for providing NTS entry and exit capacity across different geographical zones.

During 2014, we asked our customers and stakeholders how we can improve the transparency of our network capability requirements and decision making in response to these requirements, such as investment or commercial solutions. This engagement will be increasingly important as we face considerable uncertainties in the future of energy. We will build on what we have done around the impact of emissions legislation on our compressor fleet, and broaden the discussion around other key topics such as system flexibility and the impact of future legislation. Our ambition is to make our engagement with you an enduring and rolling process that does not stop/start and makes efficient use of your time.

Your input is very important to us and I encourage you to read the Way Forward chapter of this document for further information on our 2015 GTYS consultation process. Please tell us what you think by writing to us at Box.SystemOperator.GTYS@nationalgrid.com, engaging us at future stakeholder events or meeting us at National Grid House.

I hope that you find this an informative and useful document and look forward to receiving your feedback.

[1] http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/

Executive Summary

The Gas Ten Year Statement illustrates the future development of the National Transmission System (NTS) under a range of plausible energy scenarios. It also aims to provide information to help customers identify opportunities to connect to the NTS.

Developing our network is underpinned by understanding how supply and demand on the network could evolve, what is important to our stakeholders, and how our customers want to use our system in the future.

The UK energy sector has the challenge of providing safe, reliable and secure energy as part of a sustainable, decarbonised and affordable future. There is considerable uncertainty when talking about the future, so National Grid has developed four energy scenarios to help us visualise it and plan. The scenarios consider a range of potential drivers that might have an impact on the future of energy and reflect the energy trilemma of sustainability, affordability and security of supply. When planning the gas transmission system, we have to consider the following:

- The diverse range of gas supplies to the UK, giving a total supply capacity considerably higher than the peak demand in any of our scenarios
- Uncertainty in the world gas market makes it difficult to predict the make-up of our gas imports
- An increasingly broad range of credible supply patterns in order to meet demand at any level
- Peak gas demand could remain relatively stable to the end of this decade, even with falling annual demands. We expect it to increase in the next decade as gas-fired power stations replace closing coal plant
- The variability of power generation is expected to increase as renewable generation grows. This means more gas-fired power generation will be needed to provide flexibility to the electricity system, operating with low load factors. This requirement will increase as more renewable generation comes online and other forms of conventional generation, such as coal, are retired.

Customer requirements from the NTS continue to change and evolve. Against a background of reduced distribution network flat capacity requirements, we continue to see an increased need for distribution network flexibility capacity because of the gasholder closure programmes. We also need to take into account the fact that each of the gas distribution networks is different. We must consider the specifics of each one rather than taking a blanket approach for all the transmission and distribution interface points. The transmission and distribution networks must be designed to complement each other, providing integrated design and specific solutions. We have started to discuss with the gas distribution companies how we approach this and will feed back next year on the progress.

However, the pace of development of the NTS, when judged by customer signals for incremental capacity, has slowed in recent years but customers increasingly want system flexibility via higher ramp rates and shorter notice periods. That said, by the time this document goes to print, the results of the first auction run for the Capacity Market under Electricity Market Reform will be published. Over 60GW[2] of generation capacity qualified for the auctions, and approximately half is made up of gas-fired power stations. While the majority of those may be existing units connected to both gas transmission and distribution, their running patterns may differ to what we have seen in the past. Connecting new gas-fired power stations will drive a period of developments, on the system and commercially, providing new operational challenges for us as system operator.

[2] https://www.emrdeliverybody.com/Shared%20Documents/Prequalification%20Results%20Summary.pdf

Executive Summary

We have previously discussed how over recent years the trend of increased within-day variability is leading to greater operational challenges such as:

- Newer sources of supply such as importation terminals. This operates in a different way to traditional UK Continental Shelf supplies, as shippers can wait until later in the gas day to balance their position
- Larger within-day swings in NTS linepack occurring more frequently. This causes challenges in managing NTS pressures, making sure they remain within safety and contractual tolerances.

The changing nature of supply patterns from day to day means ensuring the system is configured to provide maximum capability is important. As the System Operator, our challenge is to anticipate how these uncertainties can be managed to provide the system capability that our customers need and want into the future: economically, efficiently, safely and reliably.

To help us meet this challenge, we are reviewing the future flexibility requirements for the system. We are considering how different events or factors across gas days and within-day might affect the way that the system is managed. We are also looking at possible asset, commercial and operability options that could be progressed to deliver more capability in this area. We have started engaging with you on this work and there will be opportunities to challenge and contribute to our thinking.

Next year we aim to develop an operational framework that discusses these challenges before, and as they start to manifest. We would like to work with you to be sure that our approach to this meets all our needs and that the output adds value. We must be disciplined and make sure that the framework covers all potential opportunities, whether they are asset or commercial. There are many uncertainties that will provide new opportunities for us and our stakeholders. The future will not necessarily be more difficult than today, but it will be different. Working with you we can put the right solutions in place at the right time and this new framework will help us achieve this.

To support this, we must be able to articulate what is driving our need cases and be transparent about how we make our ‘build’ and ‘no build’ decisions. We aim to develop a policy that builds on our engagement approach in 2014 and give stakeholders greater visibility of our process and outputs. We will work with you in 2015 to develop this policy, making sure it has a clear objective with a plan to deliver it.

In response to stakeholder feedback, the 2013 GTYS included information about the lead time for providing entry and exit capacity across different geographical zones. We have updated this information based on changes in the last 12 months and this will continue to help inform our customers, to guide them in deciding where they may be able to site their projects.

Our current business plan is partly driven by the potential for incremental entry or incremental exit capacity signals that we may see in the next ten years. To provide more certainty in this area, we have proposed an amendment to the contractual framework, known as the Planning and Advanced Reservation of Capacity Agreement (PARCA). The PARCA arrangements will enable customer and National Grid timelines to align, with connections and capacity being delivered together. This process aims to provide more certainty to project developers, with transparency of all the process steps and deliverables required from both parties. It sets out a timeline from initial contact through to capacity release, while also allowing the timetable and break-out points to be reviewed, discussed and potentially revised. Subject to Ofgem approval, the PARCA arrangements could be implemented in time for the 2015 Quarterly System Entry Capacity (QSEC) auction. There are more details in Chapter 4.

A decision has been made to close the Avonmouth storage facility because of the significant levels of investment needed to continue operating the site in the long term. It is anticipated that the site will stop operating in 2018[3]. We have been provided with funding to construct two pipelines to mitigate the loss of Operating Margin (OM) and Constrained LNG gas. During this year we have conducted further analysis and based on the preliminarily results we determined that pressing ahead with the construction is not in the best interest of consumers. Our intention is to complete the discussions with the HSE and the Distribution Network and update our 'capacity' risk analysis for the South West. At this point we then plan to engage with stakeholders to agree the most economic and efficient approach to meet the loss of services provided by Avonmouth in light of the current and future network requirements.

Further major components of our business plan are around various programmes of investment where funding is still to be agreed. Examples of these are ensuring that we secure our critical national infrastructure, we manage significant asset health concerns and our compressor fleet remains compliant with European emissions legislation known as the Industrial Emissions Directive (IED)[4]. In spring 2014 we launched our engagement programme[5] on how the legislation would impact upon our compressor fleet, discussing the challenges and opportunities with you. You told us what was important to you, not just around the decisions and options available to us, but also how you wanted us to engage with you. In November we published our consultation where we presented the options available at each site, scored against the criteria you helped us develop. We have continued to consider your feedback and will publish our proposals in February 2015 and submit our final proposals to Ofgem in May 2015.

We will build upon the engagement we have undertaken around our compressor fleet, broadening the discussion to include key topics such as system flexibility and the impact of future legislation. It is important we do this in the right way and co-ordinate where we can with other opportunities across gas transmission.
Our ambition is to make our engagement with you an enduring and rolling process that does not stop/start and, importantly, makes efficient use of your time.

The Gas Ten Year Statement will continue to evolve and each year our stakeholders will be able to shape the development of this document. We welcome any views on the content and scope of this year's document and whether you would like to see any changes made to future versions. We are happy to receive feedback of any kind through the following means and, of course, whenever we meet:

- At customer seminars
- At operational forums
- Through responses to the GTYS email **Box.SystemOperator.GTYS@nationalgrid.com**
- Bilateral stakeholder meetings
- Through our online survey at **http://surveymonkey.com/s/2014GTYS**

[3] At time of print National Grid LNG Storage business started a consultation on closing the facility early in 2016. http://www2.nationalgrid.com/UK/Services/LNG-Storage/consultation/"

[4] http://www.youtube.com/watch?v=xZu05nHaqrU

[5] http://www.talkingnetworkstx.com/IED-welcome.aspx


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Contents

Chapter 1
Introduction

The Gas Ten Year Statement (GTYS) illustrates the potential future development of the National Transmission System (NTS). It also helps existing and future customers to identify connection opportunities on the NTS. Here, we outline the approach we have taken and the scope of the GTYS.

The GTYS is produced for you, our stakeholders, and we want to be sure it continuously develops as a result of what you have told us.

The GTYS forms part of a suite of publications that is underpinned by our 2014 UK Future Energy Scenarios (FES). This issue builds on the improvements made last year and the format has been updated to give a similar look and feel to our 2014 UK Future Energy Scenarios and the Electricity Ten Year Statement (ETYS).

How to use this document

This document presents information in easily digestible sections, with the subject matter clearly defined in colour-coded chapters.

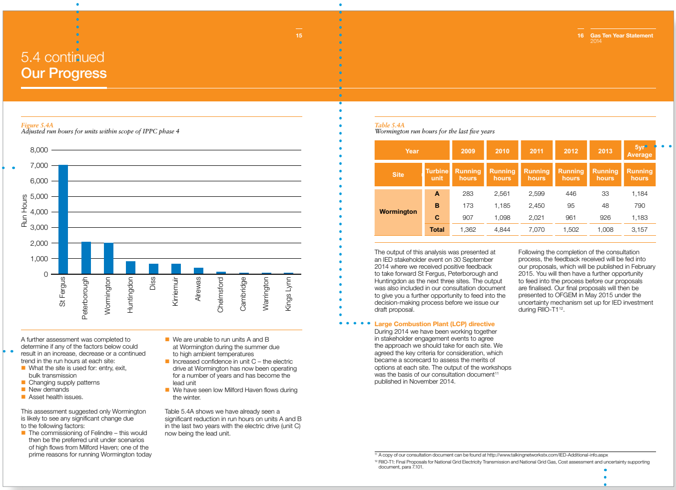
Figure 1.1A
How to use this document

Main heading
Clearly defined headings introduce the main topic dealt with on a particular page.

Subheadings
The main text is divided into sections by easily identifiable headings so that you can locate a particular piece of information.

Table
Provides data to support the analysis and provide key information.

Figure
Provides charts to support the data and analysis, enabling trends to be quickly identified.



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5.4 continued
Our Progress

Figure 5.4A
Adjusted run hours for units within scope of IPPC phase 4

A further assessment was completed to determine if any of the factors below could result in an increase, decrease or a continued trend in the run hours at each site:

- What the site is used for: entry, exit, bulk transmission
- Changing supply patterns
- New demands
- Asset health issues.

This assessment suggested only Wormington is likely to see any significant change due to the following factors:

- The commissioning of Felindre – this would then be the preferred unit under scenarios of high flows from Milford Haven; one of the prime reasons for running Wormington today
- We are unable to run units A and B at Wormington during the summer due to high ambient temperatures
- Increased confidence in unit C – the electric drive at Wormington has now been operating for a number of years and has become the lead unit
- We have seen low Milford Haven flows during the winter.

Table 5.4A shows we have already seen a significant reduction in run hours on units A and B in the last two years with the electric drive (unit C) now being the lead unit.

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Table 5.4A
Wormington run hours for the last five years

Year		2009	2010	2011	2012	2013	5yr Average
Site	Turbine unit	Running hours	Running hours	Running hours	Running hours	Running hours	Running hours
Wormington	A	283	2,561	2,599	446	33	1,184
	B	173	1,185	2,450	95	48	790
	C	907	1,098	2,021	961	926	1,183
	Total	1,362	4,844	7,070	1,502	1,008	3,157

The output of this analysis was presented at an IED stakeholder event on 30 September 2014 where we received positive feedback to take forward St Fergus, Peterborough and Huntingdon as the next three sites. The output was also included in our consultation document to give you a further opportunity to feed into the decision-making process before we issue our draft proposal.

Following the completion of the consultation process, the feedback received will be fed into our proposals, which will be published in February 2015. You will then have a further opportunity to feed into the process before our proposals are finalised. Our final proposals will then be presented to OFGEM in May 2015 under the uncertainty mechanism set up for IED investment during RIIO-T1[12].

Large Combustion Plant (LCP) directive
During 2014 we have been working together in stakeholder engagement events to agree the approach we should take for each site. We agreed the key criteria for consideration, which became a scorecard to assess the merits of options at each site. The output of the workshops was the basis of our consultation document[11] published in November 2014.

[11] A copy of our consultation document can be found at http://www.talkingnetworkstx.com/IED-Additional-info.aspx
[12] RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas, Cost assessment and uncertainty supporting document, para 7.101.

Narrative
Including rich descriptions of the changing requirements of the system and what we are doing in response, as well as relevant breakout boxes and case studies.

Footnotes
Used for citations and further commentary.

1.1 Scope

The GTYS is produced at the end of the planning cycle and provides an update on the challenges we face now, those we may see in the future and what we are doing to meet those challenges as the System Operator (SO).

The pages are structured to explain how the gas network has evolved and what challenges this presents. As you move through the chapters we will explain how these changes could impact you and what we are doing to meet them.

Figure 1.1B
2014 UK Future Energy Scenarios

Affordability More money available

Low Carbon Life is a world of high affordability and low sustainability. More money is available due to higher economic growth and society has more disposable income. There is short-term volatility regarding energy policy and no additional targets are introduced. Government policy is focused on the long term with consensus around decarbonisation, which is delivered through purchasing power and macro policy.

Gone Green is a world of high affordability and high sustainability. The economy is growing, with strong policy and regulation and new environmental targets, all of which are met on time. Sustainability is not restrained by financial limitations as more money is available at both an investment level for energy infrastructure and at a domestic level via disposable income.

Affordability Less money available

No Progression is a world of low affordability and low sustainability. There is slow economic recovery in this scenario, meaning less money is available at both a government and consumer level. There is less emphasis on policy and regulation, which remain the same as today, and no new targets are introduced. Financial pressures result in political volatility, and government policy that is focused on short-term affordability measures.

Slow Progression is a world of low affordability and high sustainability. Less money is available compared to Gone Green, but with similar strong focus on policy and regulation and new targets. Economic recovery is slower, resulting in some uncertainty, and financial constraints lead to difficult political decisions. Although there is political will and market intervention, slower economic recovery delays delivery against environmental targets.

Sustainability Less emphasis

Sustainability More emphasis

Chapter 2 – Gas Supply and Demand Scenarios

We review the key outputs from the 2014 UK Future Energy Scenarios (FES), which triggers the start of a new planning cycle. This year's FES has increased the number of scenarios from two to four, represented by figure 1.1B.

We detail the changes we have seen in supply and demand patterns, how we see these developing under the four scenarios, and what triggers could start the network development process.

Chapter 3 – System Operator

This chapter provides an updated view of the changes we have seen in supply and demand behaviour and shows how these changes could play out in the future.

Chapter 4 – Customer requirements

Here you will find details about entry and exit capacity availability and lead times. We also detail user commitments on capacity on the network from the recent entry capacity auctions and exit commitments.

Chapter 5 – Meeting future capability requirements

We detail what we are doing to understand more about the challenges highlighted in the earlier chapters and provide an update on current projects that have been through the network development process.

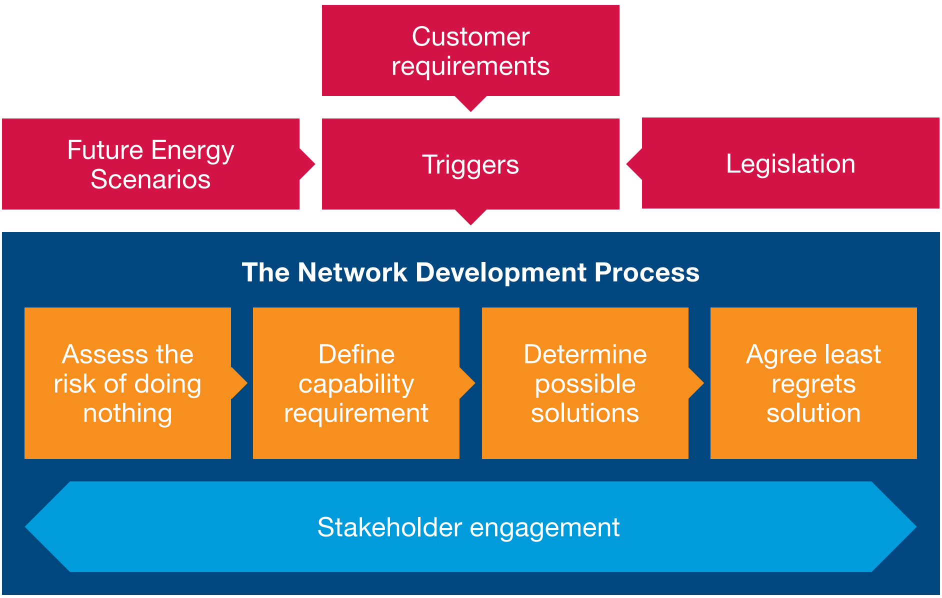
Chapter 6 – Way Forward

We are committed to continuously evolve the GTYS and the Network Development Process and here we share our plans and tell you how you can get involved in shaping this change.

1.2 The Network Development Process

Key to us meeting the challenges that we set out in the Gas Ten Year Statement is the Network Development Process. Figure 1.2A gives an overview of the steps we take during the process.

Figure 1.2A
The Network Development Process



Triggers for the process resulting from changing customer requirements, legislation and FES include:

- Network operability
- Network development policy
- 1-in-20 review
- Incremental capacity
- Constraint risk
- Asset health
- Acceptable risk profile.

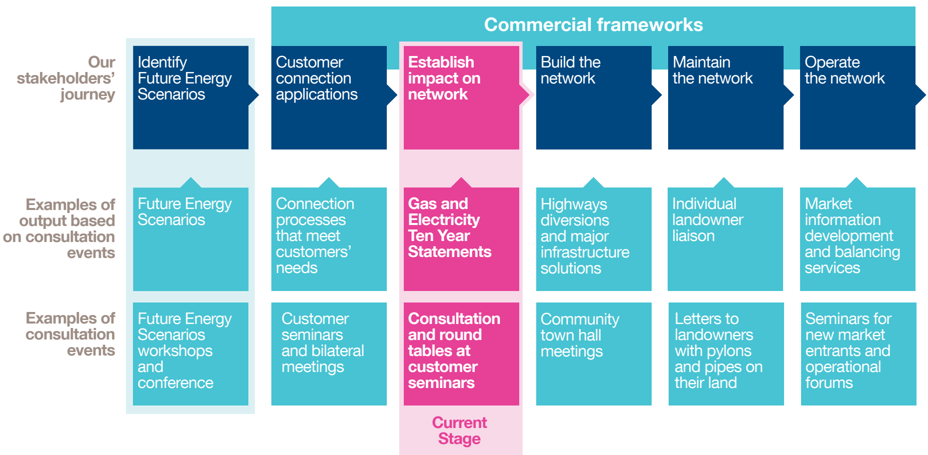
The possible solutions for each trigger are defined as 'rules', 'tools' and 'assets'. These give us the full scope of options available, including making regulatory changes (rules), options for the System Operator (tools) or making changes to or installing new assets.

All of these options are then assessed and prioritised, with support from stakeholder engagement events, to ensure the best solution is taken forward.

More information on the process can be found in the Transmission Planning Code[1]. This describes the way the physical capability of the system is determined to inform parties wishing to connect to and use the NTS, and also the key factors affecting planning and developing the UK gas transmission system.

Figure 1.2A shows how, throughout the end-to-end process, stakeholders are key in the decision-making process. We interact with a diverse range of stakeholders with a wide set of interests, as illustrated in Figure 1.2B:

Figure 1.2B
Business process diagram

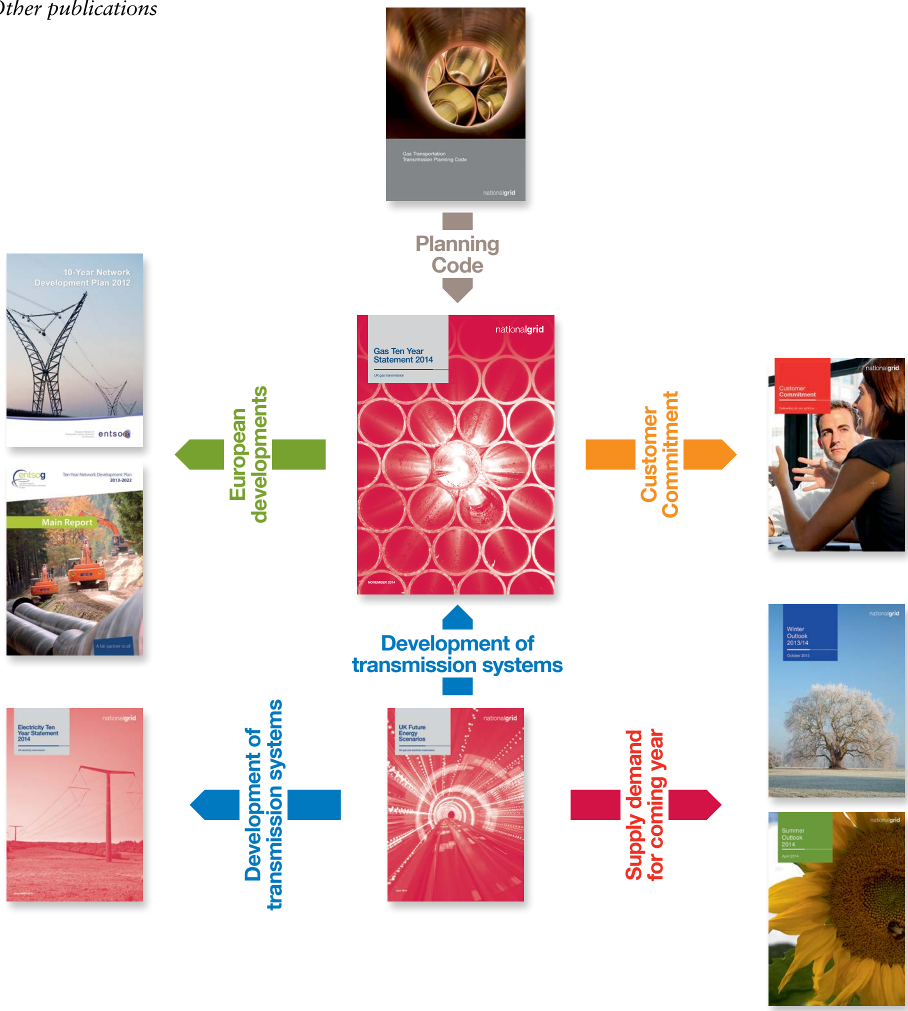


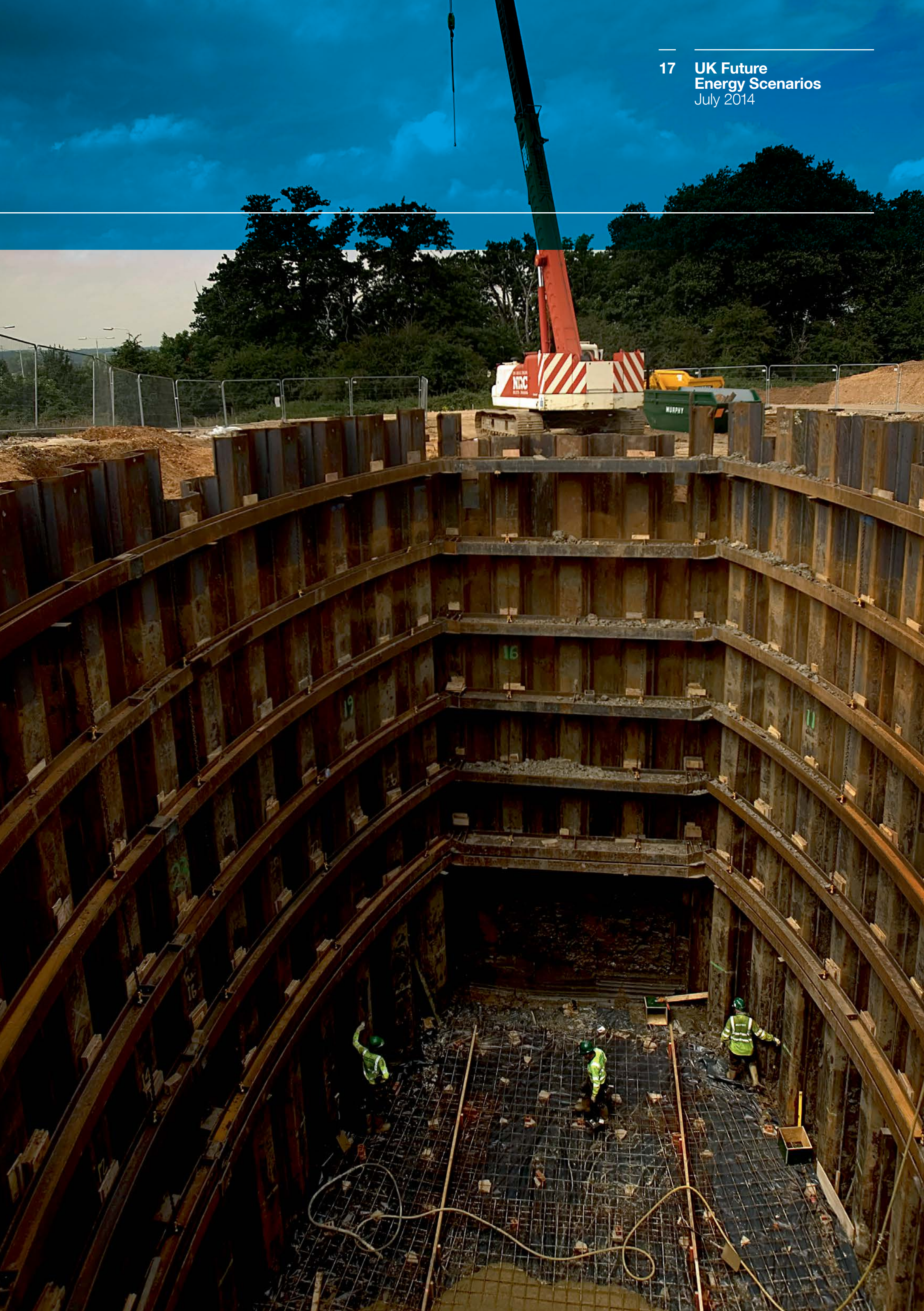
[1] The Transmission Planning Code (TPC) can be found on our website at http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Gas-Ten-Year-Statement/Transmission-Planning-Code/

1.3 Other Publications

The Gas Ten Year Statement is published at the end of the annual planning cycle. Figure 1.3A shows its relationship to some of our other publications.

Figure 1.3A
Other publications

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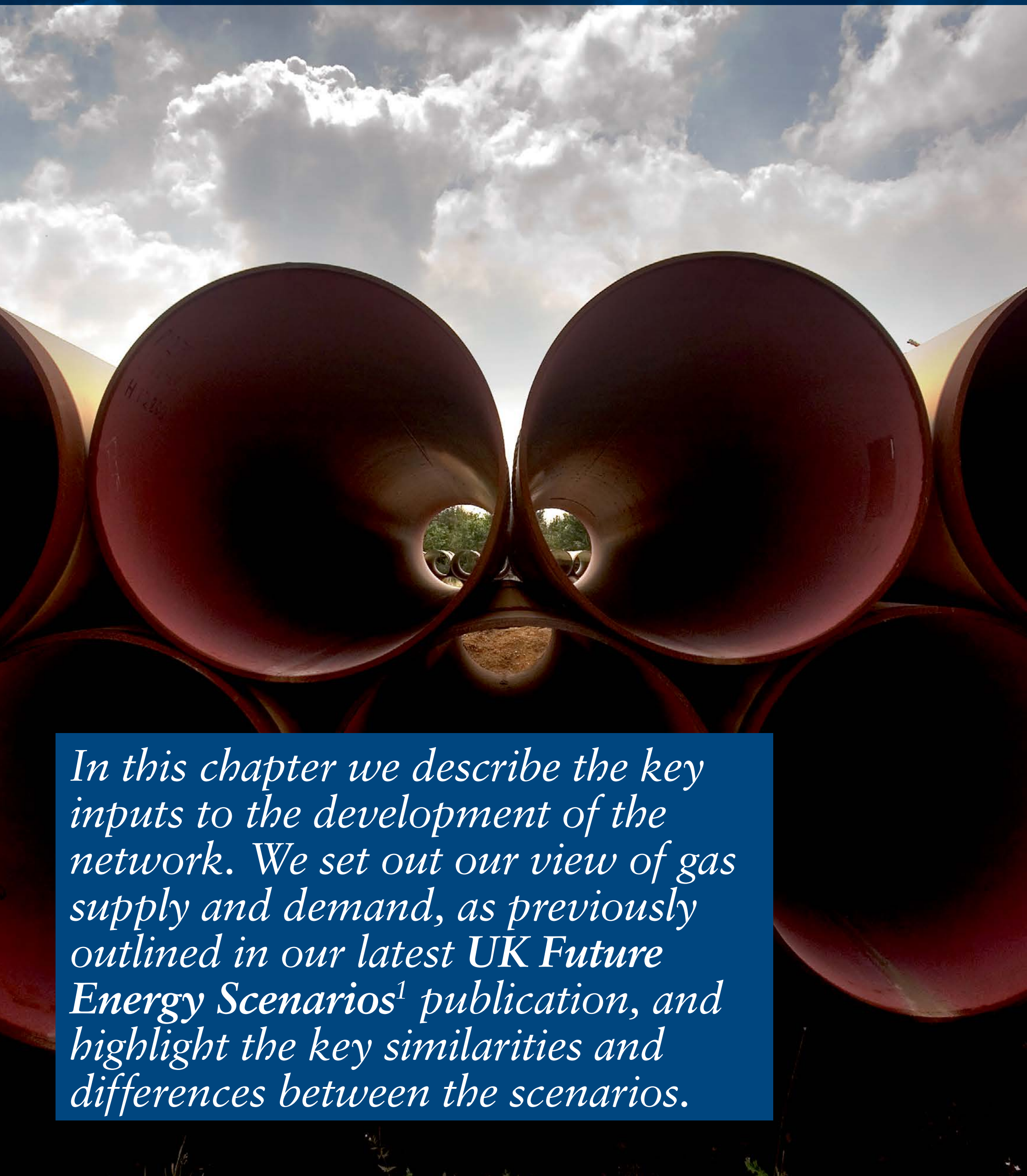
Chapter 2
Gas Supply and Demand Scenarios



In this chapter we describe the key inputs to the development of the network. We set out our view of gas supply and demand, as previously outlined in our latest ***UK Future Energy Scenarios***[1] *publication, and highlight the key similarities and differences between the scenarios.*

2.1
Overview

Key messages in this chapter

Demand

- Peak gas demand will remain relatively stable up to 2019/20. We expect it to increase in 2020/21 as coal generation capacity reduces because of environmental legislation.

- We expect power generation running patterns to vary over time. The growth in renewable generation and the retirement of other forms of conventional generation (such as coal) will increase the requirement for gas-fired power generation to act as a balancing tool, operating with low load factors.

Supply

- There is a very diverse range of gas supplies to the UK, giving a total supply capacity considerably higher than the peak demand in any of our scenarios

- Uncertainty in the world gas market makes it difficult to predict the make-up of our gas imports

- We need to consider an increasingly broad range of credible supply patterns in order to meet demand at any level.

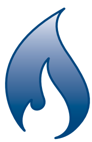
Our 2014 scenarios make extensive use of the axioms[2] that we developed in response to stakeholder feedback[3]. These axioms encompass a wide range of possible developments and have an impact on the level of gas demand in four key sectors: residential, industrial and commercial, exports and gas-fired power generation.

We expect that:
- Total annual gas demand will remain relatively constant in all four scenarios until 2020
- The variability of power generation will increase in line with the growth in renewable generation
- Gas-fired power generation will play an important role in supporting the decarbonisation of electricity, as this type of generation will help to balance variability
- Peak gas demand will increase in 2020/21 as coal generation capacity reduces with the implementation of the Industrial Emissions Directive (IED).

[1] The 2014 UK Future Energy Scenarios can be found on our website at nationalgrid.com/fes

[2] An axiom is a premise or starting point of reasoning.

[3] The stakeholder feedback is detailed on our website at: http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=31269



2020

The total annual gas demand is anticipated to remain relatively constant in all four scenarios until 2020.

2.1 continued
Overview

Appendix 2 of our 2014 UK Future Energy Scenarios publication contains the full set of axioms used in creating our 2014 scenarios. Table 2.1A below shows some of those most relevant to gas supply and demand.

Table 2.1A
Gas supply and demand axioms[4]

	Low Extreme	High Extreme
Renewable energy/ carbon targets	UK 2020 renewable target is missed. Pathway to 2050 falls short of carbon targets set out in the UK carbon budgets[5]. Pressure grows for UK carbon targets to be abandoned.	15% of all energy from renewable sources by 2020; greenhouse gas emissions meeting all existing carbon budgets; and an 80% reduction in greenhouse gas emissions by 2050.
Economic outlook	Low economic growth, benchmarked against external forecasts.	Moderate economic growth, benchmarked against external forecasts.
Energy efficiency including commercial	Lower drive for energy efficiency.	Higher drive for energy efficiency.
Combined Cycle Gas Turbine (CCGT) and Open Cycle Gas Turbine generation (OCGT) (unabated)	Existing fleet closes early. Limited new build for gas plant in the near term.	Limited new build in the near term. Existing fleet remains on for longer than currently anticipated. More aggressive build programme for new fleet.
Carbon Capture and Storage (CCS) generation	CCS is not commercially viable for coal or gas.	Commercial deployment of coal/ gas CCS occurs during the 2020s as part of a mixed low carbon and renewable generation fleet.
Heat	Some conversion of on-gas grid properties. Increased off-gas grid deployment of technology at current rates.	Incentives promote wider uptake of low carbon heating technologies in both on-gas and off-gas grid properties.

Source: National Grid

[4] This list is non-exhaustive; other axioms in our 2014 UK Future Energy Scenarios publication are also relevant to gas supply and demand.

[5] A full description of UK greenhouse gas emission targets and associated UK Carbon Budget process can be found at www.gov.uk/government/policies/

	Low Extreme	High Extreme
Energy user behaviour	High behavioural inertia and little change to energy usage patterns.	Increasing capability and economic incentives reduce behavioural inertia and drive the reduction/ shifting of demand.
Gas supply (UK continental shelf (UKCS))	Fewer discoveries than initially expected. High technical challenges increase the costs of bringing fields to market. Negative investment climate limits exploration.	Discoveries are greater than expected. Fewer technical challenges in recovering reserves. Positive investment climate drives increased exploration activity.
Gas supply (Norway)	Low Norwegian volumes to the UK due to a combination of lower Norwegian production and/or higher flows to the Continent.	High Norwegian volumes to the UK due to a combination of higher Norwegian production and/or lower flows to the Continent.
Gas supply (liquefied natural gas (LNG))	Low LNG imports to the UK due to a combination of low global LNG production and/or high demand in global markets.	High LNG imports to the UK due to a combination of high global LNG production and/or low demand in global markets.
Gas supply (Continent)	Low continental imports to the UK due to limited access to continental markets and/or limited investment in European supply projects.	High continental imports to the UK due to increased access to continental markets and/or significant investment in European supply projects.
UK shale gas, coal bed methane, biomethane	Limited development of UK onshore resources as investment is targeted elsewhere.	High development of UK onshore resources due to a positive investment climate.

Source: National Grid

There are four key drivers for capability in the gas transportation infrastructure:

- The level of 1-in-20 peak day gas demand
- Entry requirements for supplies, including imports and storage
- The range of credible supply and demand patterns, both daily and within-day patterns
- The resilience of the gas transportation infrastructure against credible planned and unplanned events, such as supply loss, outages or the failure of transportation infrastructure.

2.2
Annual Demand

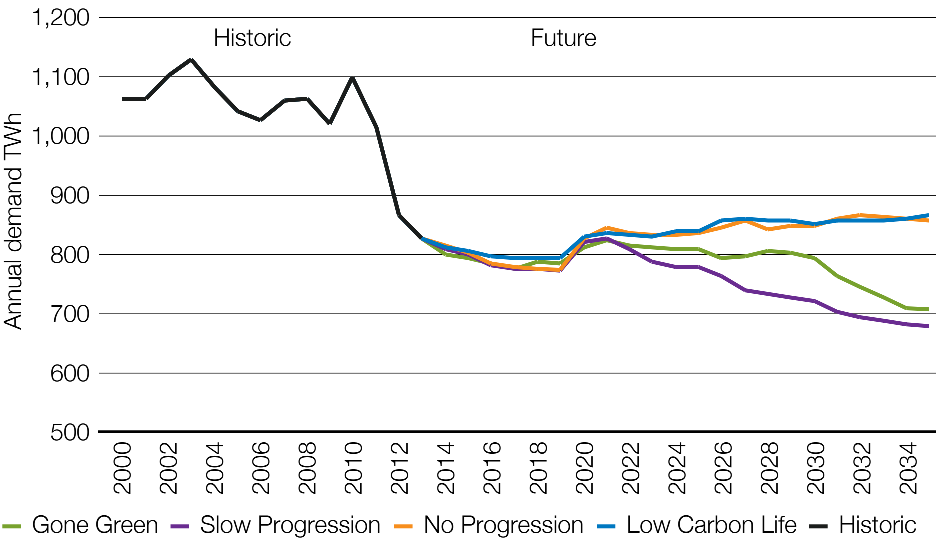
In this section we focus on our assessment of annual gas demand and its key drivers. More information about gas demand is available in our 2014 UK Future Energy Scenarios publication.

The main drivers of gas demand:

- **Fuel prices**
- **Economy**
- **Energy efficiency**
- **Electrification of heat**
- **Sites opening or closing**
- **Extra demand from new houses**
- **Power generation requirements and the associated power generation mix**
- **Gas exports to the Continent and Ireland.**

These factors vary between scenarios due to the axioms that underpin them.

Figure 2.2A
Annual gas demand, TWh



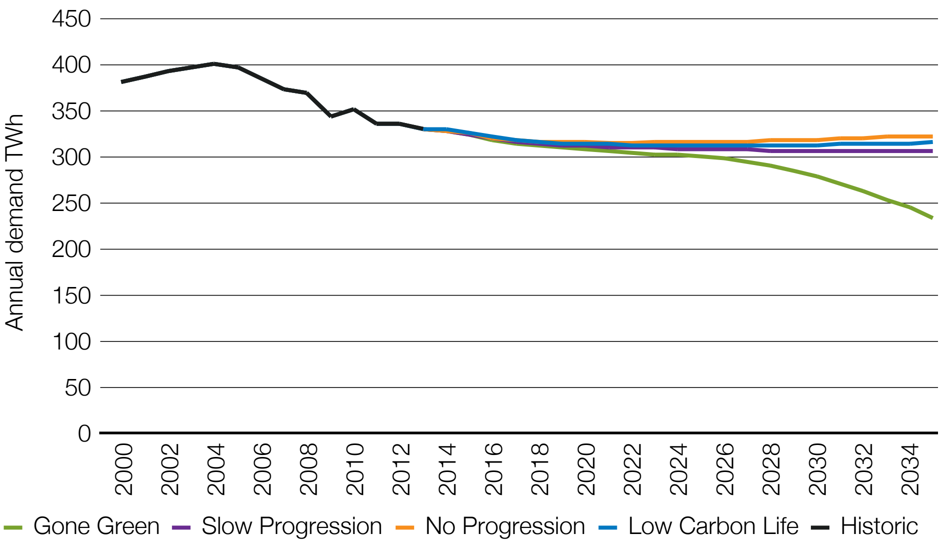
Source: National Grid

UK gas demand has four main categories, outlined below:

Residential

This category accounts for around a third of UK gas demand. It is lowest in our Gone Green scenario because it suggests that the heat pump market will increase, as will solid wall insulation installations (low heat pump and solid wall insulation take-up is assumed in the other three scenarios). These markets start to have a significant downward effect on gas demand from 2025 onwards, by which point heat pump installation reaches 400,000 a year. In the years leading up to 2025, residential gas demand remains relatively flat, falling only slightly in all four scenarios. This is driven by continued replacement of older gas appliances with new efficient appliances and uptake in insulation reducing the demand from existing housing stock; and extra demand from new houses. Internal temperatures increase in our Low Carbon Life scenario up to a capped level (in all other scenarios, internal temperatures are held constant at today's level).

Figure 2.2B
Annual residential gas demand, TWh

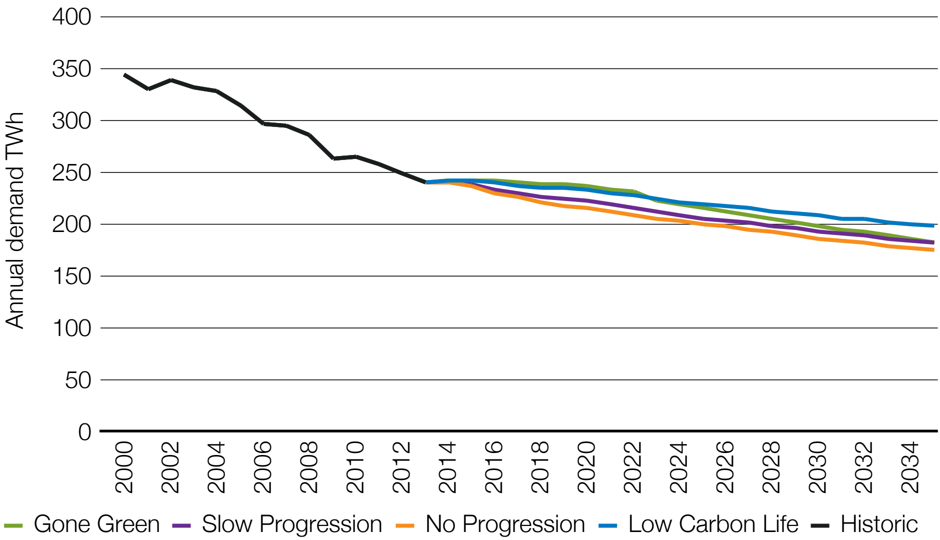


Source: National Grid

2.2 continued
Annual Demand

Industrial and commercial
This category accounts for around a quarter of UK gas demand. All scenarios reflect the underlying demand reductions across the industrial sectors and make provisions for the impact of the Industrial Emission Directive. Commercial sector demand is variable between our scenarios, reflecting the potential for efficiency savings, new developments associated with economic growth, and power and gas prices.

Figure 2.2C
Annual industrial and commercial gas demand, TWh



Source: National Grid

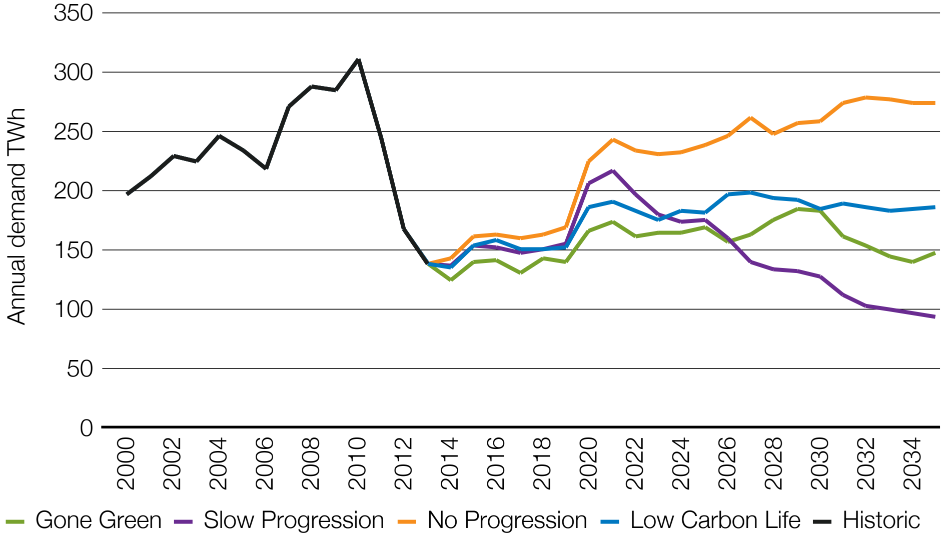
Power generation

Power generation accounts for nearly a quarter of UK gas demand and is dependent upon the demand for electricity, generation plant availability, and prices of coal and gas that influence the position of gas power stations in the generation merit order.

Over the past few years the prices of coal and gas have favoured coal-fired generation and gas demand for power generation fell sharply and continues to serve as marginal power generation. Our scenarios include our assessment of fossil fuel prices and indicate that coal-fired generation remains favoured over the short to medium term with gas remaining as marginal generation within the UK generation merit order.

Accordingly, there is low demand across the scenarios until successive coal plant closures from 2018/19 onwards. There is an increasing requirement for gas-fired power generation to act as a balancing tool for renewable generation in the Slow Progression, Gone Green and Low Carbon Life scenarios, alongside demand from CCS sites in the Gone Green and Low Carbon Life scenarios. The No Progression scenario continues with further gas generation. All four scenarios suggest an increase in installed capacity of gas-fired power generation over the next 10 years in order to act as a balancing tool for renewable generation and in preparation for coal plant closures.

Figure 2.2D
Annual power generation gas demand, TWh



Source: National Grid

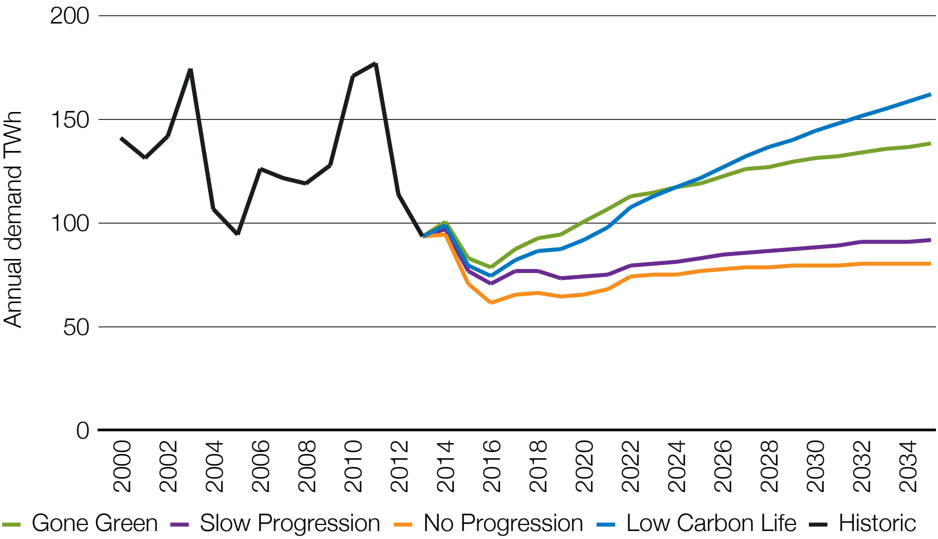
2.2 continued
Annual Demand

Exports

Exports account for around a sixth of UK gas demand. The level of gas exports to Ireland is influenced by indigenous production, with a sharp reduction when the Corrib gas field commences in 2015. After this initial drop, exports to Ireland pick up and our scenarios include a long-term spread in demand due to power generation and economic developments differing by scenario.

Exports to Europe via Interconnector UK (IUK) are highly sensitive to both the overall UK supply/demand balance and continental gas markets, so import and export levels flowing through IUK are subject to uncertainty. This is further described in Section 4.5 of our 2014 UK Future Energy Scenarios publication.

Figure 2.2E
Annual exports gas demand, TWh

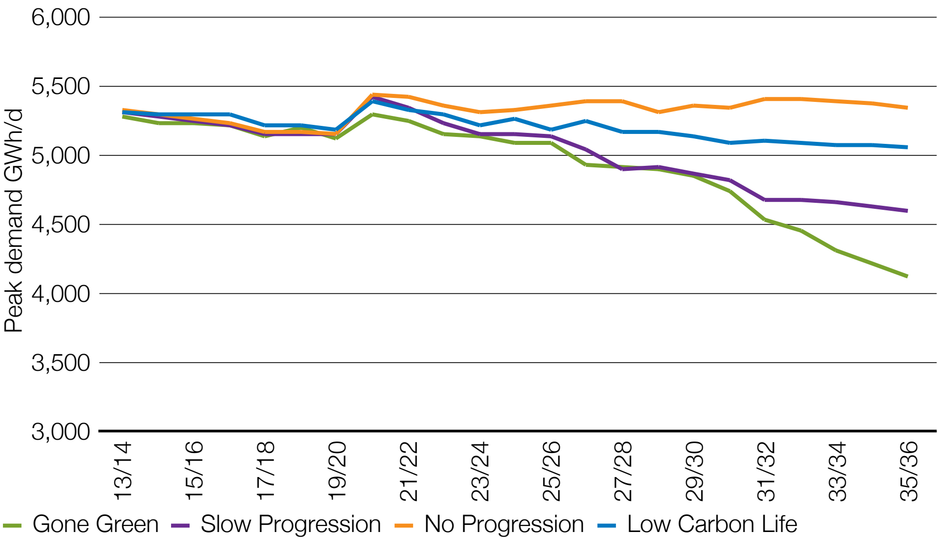


Source: National Grid

2.3
Peak Demand

Peak gas demand is based on the historical relationship between daily demand and weather, combined with the amount of gas-fired power generation expected on a peak day. Figure 2.3A shows our peak demand scenarios, which are aligned to our annual demand scenarios.

Figure 2.3A
Peak gas demand, GWh/d



Source: National Grid

The UK Future Energy Scenarios provide the basis for our assessment of key drivers for capability in the gas transportation infrastructure described in section 2.1. The key figures and tables shown within this document remain consistent with our UK Future Energy Scenarios, however, a range of sensitivities are applied during our capability assessment.

Note that in the Winter Outlook 2014, consideration was given to the short-term risks of nuclear and coal-fired generation plant outages not returning to operation prior to the winter period. In the Winter Outlook 2014 sensitivity we increased gas peak demand for 2014/15 to 5,490GWh/d (499mcm/d) to account for credible short-term risks. This does not influence our annual demand levels or later time periods and for consistency with the UK Future Energy Scenarios has not been reflected in the figures or tables in this document.

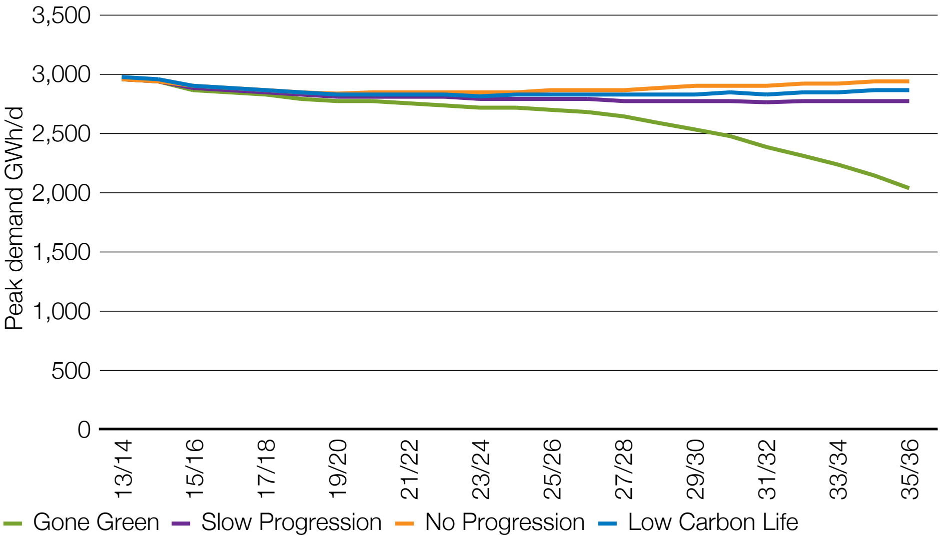
The peaks remain relatively stable up to 2019/20 because of two factors: a balancing of reduced peaks in the residential and commercial sector, driven by efficiency improvements; and increasing peaks in the gas-fired generation sector, due to the increasing requirement for gas-fired power generation to act as a back-up for renewable generation.

2.3 continued
Peak Demand

The reduction in coal generating capacity by 2020/21 drives an upshift in gas power generation both on the associated peak day consistent with annual gas demand levels.

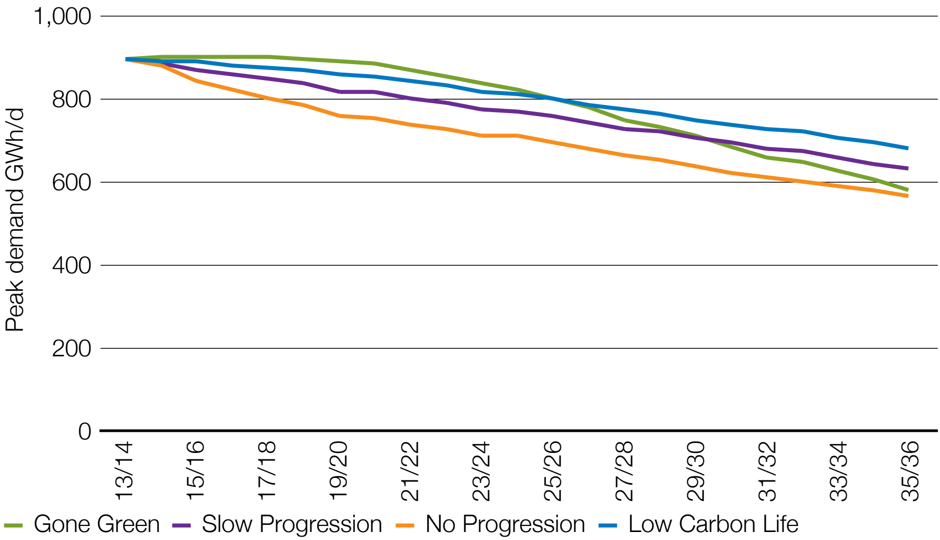
From 2020 the differences in peaks reflect the differences in residential gas demand and gas demand for power generation. The peaks are highest in our No Progression scenario, which shows gas-fired generation as the dominant fuel source contributing more than 40 per cent of electricity output by 2035/36. The lowest peaks are seen under our Gone Green scenario, driven by reductions in the residential and commercial sectors.

Figure 2.3B
Peak residential gas demand, GWh/day



Source: National Grid

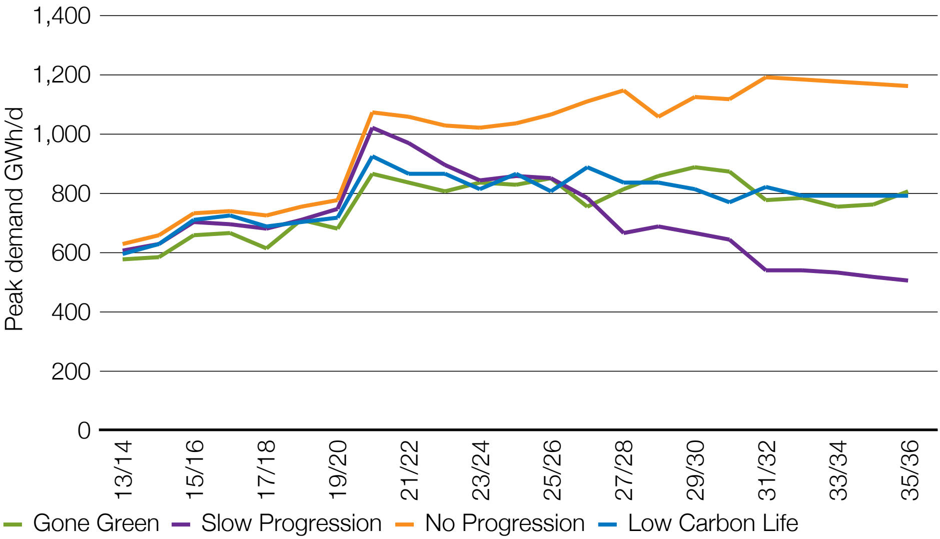
Figure 2.3C
Peak industrial and commercial gas demand, GWh/day



Source: National Grid

2.3 continued
Peak Demand

Figure 2.3D
Peak power generation gas demand, GWh/day



Source: National Grid

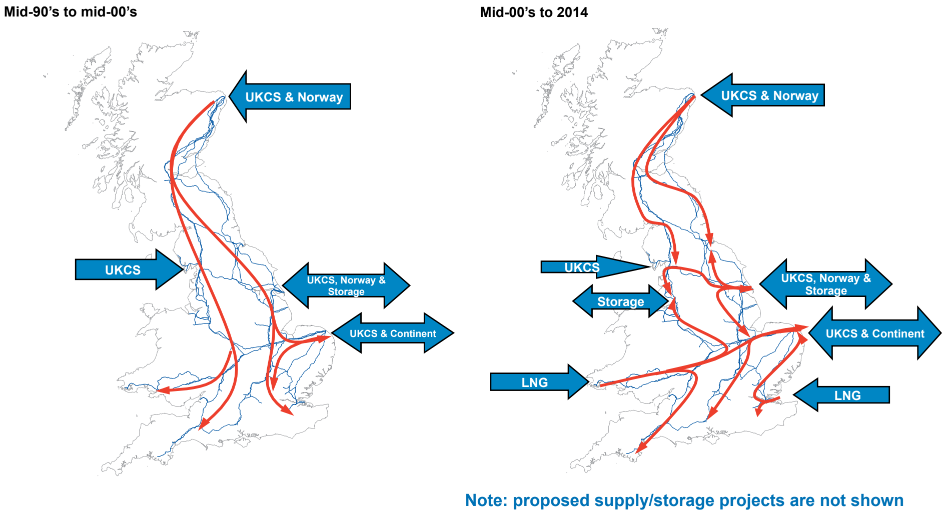
2.4
Gas Supply

Supply overview

Our 2014 UK Future Energy Scenarios publication gives details of annual and peak gas supply for individual components for each of our four different scenarios. The Gas Ten Year Statement expands it by adding locational information.

We have highlighted in recent years how supply patterns on the National Transmission System (NTS) are changing and are anticipated to become more uncertain in the future. Figure 2.4A shows some of the changes we have seen from the mid-1990s to today.

Figure 2.4A
Changing flow patterns on the NTS



2.4 continued
Gas Supply

From the mid-1990s to 2000s, supply patterns were relatively easy to predict because they were dominated by flows from the UKCS, mainly entering at terminals on the east coast and travelling through the system in a general north to south pattern.

The UK became a net importer of gas for the first time in 2004 as production on the UKCS declined.

A positive consequence of this supply transition is that there are more entry points to the NTS and they are more distributed around the UK, so the average distance that gas is transported has reduced. Supply capacity in relation to peak demand has also grown significantly. These factors have helped security of supply and the management of compressor fuel use.

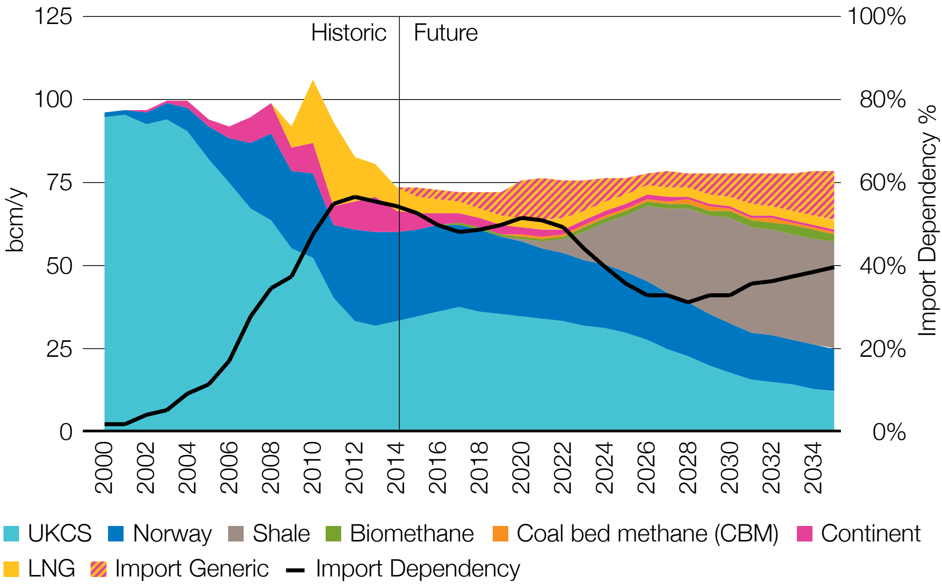
However, the increased supply capacity over peak demand also drives complexity in planning the capability of the gas transmission system. The credible range of supply patterns needed to meet demand is increasing because of factors such as uncertainty in the world gas market and the development of fast cycle storage sites.

This can affect planning – for example, high flows from Milford Haven allow high exit capacity in South Wales, but if Milford Haven flows are lower, exit capacity is limited. A further issue at Milford Haven during 2014 was the uncharacteristically high flow through the summer, significantly higher than during the winter.

2.5
Annual and Peak Gas Supply

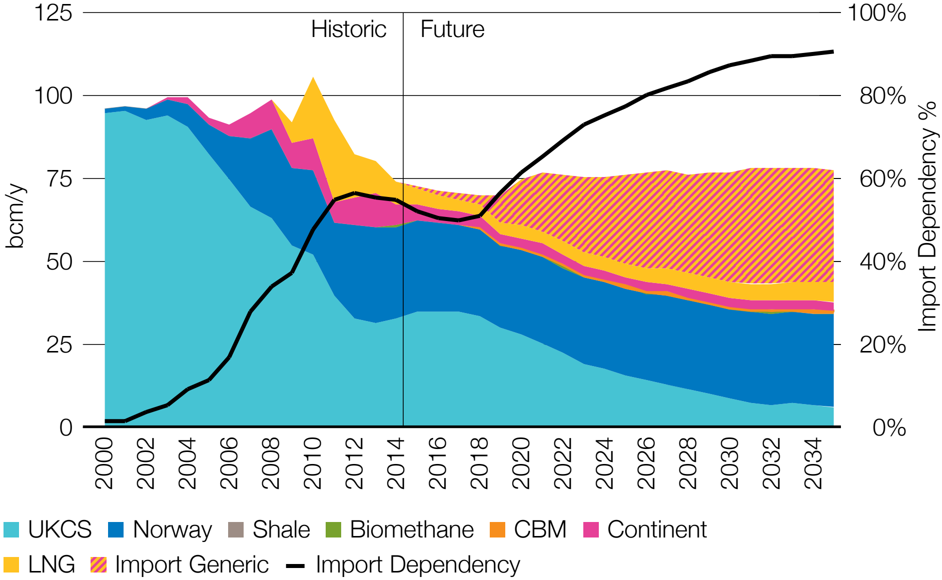
Figures 2.5A and 2.5B, which also appear in our 2014 UK Future Energy Scenarios, show annual gas supplies in two of our scenarios: Low Carbon Life and No Progression. These represent the extreme cases for different elements of the total supply. In Low Carbon Life, supplies from the UK (including UKCS and shale gas) are higher than in any of the other scenarios, leaving less room for imports. In No Progression, UKCS and shale gas are low, leading to a much higher level of imports.

Figure 2.5A
Annual gas supplies for Low Carbon Life



2.5 continued
Annual and Peak Gas Supply

Figure 2.5B
Annual gas supplies for No Progression

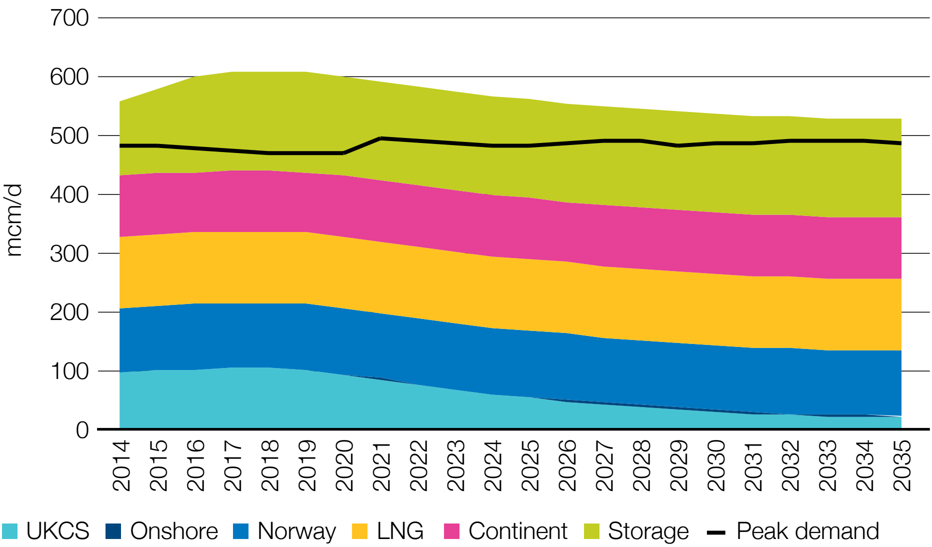


The 'Import Generic' hatched area represents imported gas that could be any mixture of LNG and continental gas. The charts give some indication of the challenge in planning and operating the network. For example, in Low Carbon Life, if the generic import is all continental gas, the total LNG import in 2025 is only 3 bcm; but in No Progression, if the generic import is all LNG, the total LNG import in 2025 is 30 bcm.

Gas supplies for most sources in Gone Green and Slow Progression fall between the extremes of Low Carbon Life and No Progression. The exception is biomethane, which is higher in Gone Green than in the other scenarios. Charts showing annual supplies for all four scenarios are available in our 2014 UK Future Energy Scenarios.

Peak gas supplies were addressed in our 2014 UK Future Energy Scenarios where we showed that the current level of physical supply capacity is more than enough to satisfy peak gas demand in all our scenarios. For example, Figure 2.5C shows the peak demand and supply for the No Progression scenario, which has the highest peak demand but the lowest supply from the UKCS, so represents the most extreme case for analysis of peak supply. The chart shows that in all years the peak demand can be met by the existing supply infrastructure.

Figure 2.5C
Peak demand and supply for No Progression



In order to examine the implications of our gas supply scenarios on the gas network we show annual and peak flows split into supply terminals. To capture the full range there are two cases for each scenario: one where the generic import is all LNG, and one where the generic import is all continental gas. Charts showing the flows by terminal are given in Appendix 2.

2.6 Infrastructure

2.6.1 Infrastructure

The peak supply chart in Figure 2.5C shows that there is no requirement for new infrastructure solely to meet peak demand. However, there may be commercial reasons for new developments – for example, there may be a case for operators to develop storage to make best use of shale gas, which is expected to produce at a constant rate through the year, or to support a power generation market increasingly dominated by intermittent low carbon generation. Similarly, in a scenario with high LNG import, developers may wish to open new capacity to take a share of the market.

2.6.2 Storage

Many new storage sites have been proposed in recent years and there are currently proposals for 7 bcm of space, both for medium-range fast-cycle facilities and for long-range seasonal storage. Two new medium-range sites are expected to start operating in Q1 2015, but the economics (especially the price spread between winter and summer) have limited progress in other projects. Details of existing and proposed storage sites are given in Appendix 2.

2.6.3
Imports

The UK is served through a diverse set of import routes with pipelines from Norway, the Netherlands, Belgium and from other international sources in the form of LNG. There are currently no plans for increased pipeline interconnection. Four new LNG projects are under consideration, but these are at an early stage of development and may not have been helped by the recent limited use of existing LNG capacity. Details of existing and proposed import infrastructure are given in Appendix 2.

Chapter 3
System Operator

Here we look at how evolving UK supply and demand patterns are affecting our operation of the NTS and how these patterns may influence the system's ability to meet future customer requirements.

Key messages

- Within-day demand levels are increasingly variable, driven by the needs of distribution network operators and the requirement for responsive gas generation in electricity markets.
- Supply capacity exceeds peak demand by a third; this provides our customers with significant flexibility in how they meet demand. Our network needs to be able to manage a wide range of potential supply patterns and the uncertainty as to which pattern may occur on a given gas day is increasing.
- Newer sources of supply, such as importation terminals and storage sites, can operate in a more commercially responsive way than traditional UK Continental Shelf (UKCS) supplies. So shippers can wait until much later in the gas day to balance their energy position.
- Large within-day changes in NTS linepack are occurring more frequently. This increases operational challenges, particularly in managing NTS pressures and ensuring they remain within safety and contractual tolerances.

3.1 Overview

Our primary responsibility as system operator is to transport gas from supply points to offtakes by providing a reliable and available network for our customers to use. However, in doing this, we have a number of overriding obligations that affect how we operate the system.

Safety and system resilience:
- Maintaining NTS pressures within safe limits
- Ensuring that the quality of gas transported through the NTS meets the criteria defined within the Gas Safety (Management) Regulations to ensure compliance with UK gas appliances
- Ensuring that capabilities, processes and products are in place to effectively manage or mitigate a network gas supply emergency.

Environment:
- Minimising our environmental impact.

Facilitating efficient market operation:
- Meeting the pressures contractually agreed with our customers
- Providing customers and stakeholders with the information and data they need to allow them to make effective and efficient decisions
- Making NTS entry and exit capacity available in line with our licence obligations and contractual rights
- Taking commercial actions in the event that system capability is lower than contractual rights
- Managing gas quality (calorific value) at a zonal level to ensure consumers are fairly billed for the gas they use
- Optimising the use of NTS infrastructure.

In the following sections we provide an updated view on how evolving supply and demand patterns are driving operational challenges for us and how these may impact on our customers.

How we intend to overcome these future system operator challenges is described in Chapter 5.

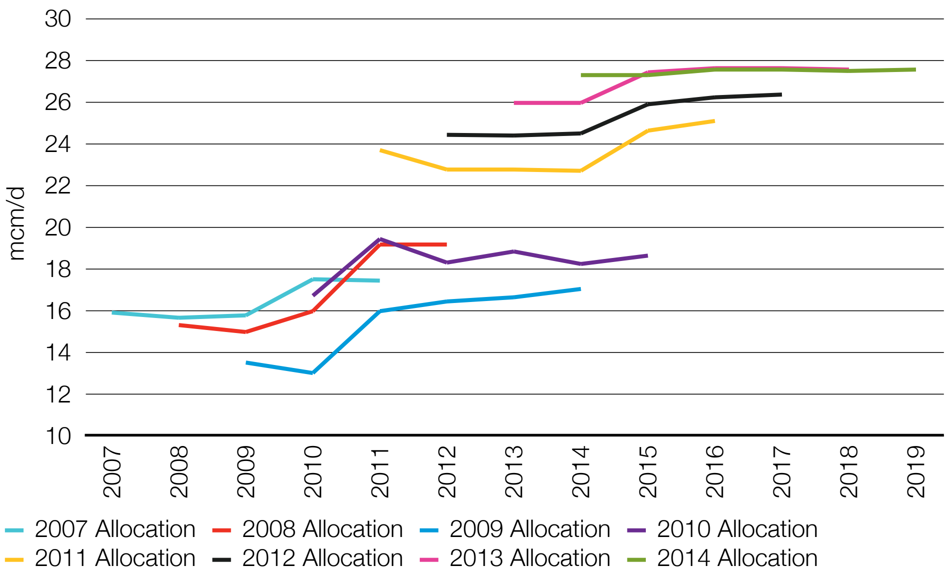
3.2
Evolution of Gas Demand

The changing nature of gas demand in the UK during the last 5 to 10 years, combined with the stakeholder engagement that we undertook for our Future Energy Scenarios, indicates how our customers may want to use our networks in the future.

Annual levels of residential gas demand have fallen steadily over the last 10 years, with 2013/14 being approx 20% lower than 2004/05. We expect this trend to continue, but at a slower rate than previously (see Chapter 2, Figure 2.2B).

As levels of residential demand have fallen, DNOs have reduced the levels of embedded storage in their networks through their gas-holder closure programmes. As a result, they increasingly rely on the use of NTS linepack to meet their required daily storage levels (see section 3.4.2). DNOs signal their requirements for using NTS linepack by booking NTS exit (flexibility) capacity levels – these have seen a steady increase in recent years (see Figure 3.2A).

Figure 3.2A
NTS exit (flexibility) capacity bookings by DNOs



3.2 continued
Evolution of Gas Demand

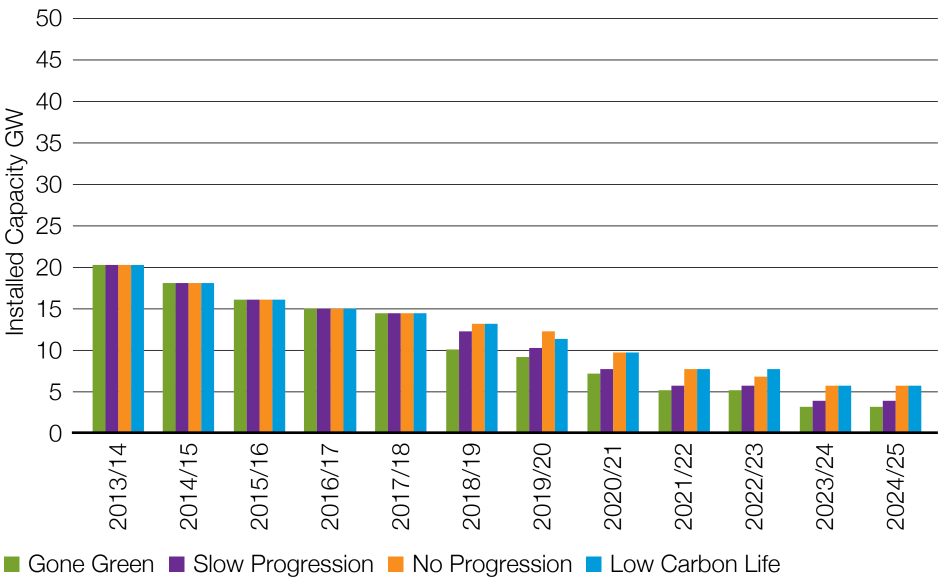
Electricity generation from gas-fuelled plant has become increasingly marginal in recent years, with coal prices falling in relation to gas prices.

The development of unconventional gas sources such as shale in the US has reduced worldwide demand for coal, which has driven the price down. Forms of non-gas generation, such as coal, wind, solar and nuclear, generally have lower operating costs, so these fuels are more likely to generate in preference to gas.

The role of gas-fired power stations (CCGTs) has evolved, and NTS CCGT demand has become increasingly variable, both on a day-to-day and within-day basis. Rather than providing baseload generation, CCGTs now typically provide a portion of the balancing energy to cover variable output from renewable generation on the electricity system. This means that within-day CCGT demand profiles have become more difficult to forecast over both planning and operational timescales.

It is important to note that CCGTs play a role in balancing the electricity system alongside other balancing tools which are available to the electricity system operator (interconnection, storage, other generation and demand-side response). This means that CCGTs do not carry the entire balancing burden by themselves, and volatility in renewable generation does not always lead to volatility in CCGT gas demand.

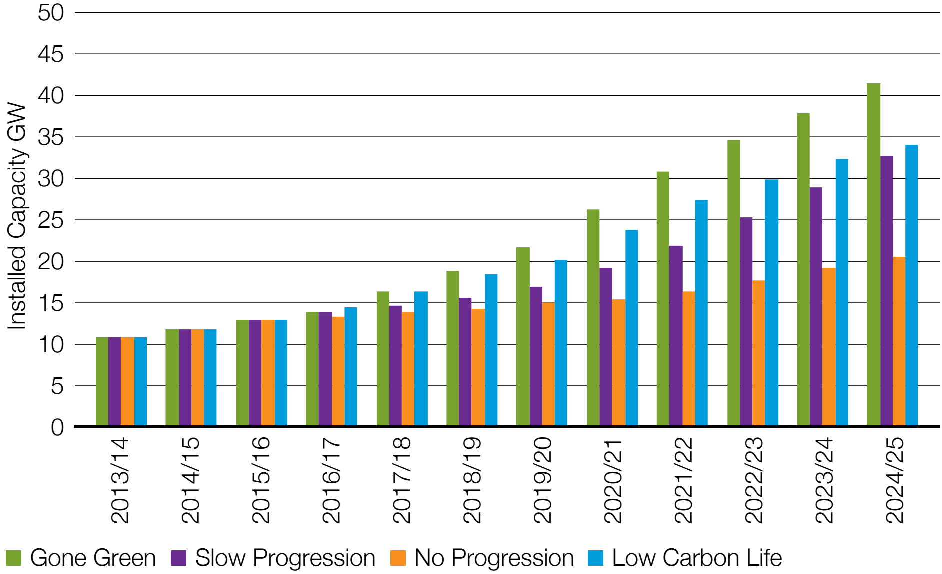
Figure 3.2B
Forecast levels of installed coal capacity



However, as the electricity system operator has a range of balancing tools available, it is difficult to predict when CCGTs will be used, in combination with the other options to maintain a system balance.

With more and more coal power stations being retired as a result of EU environmental directives (see Figure 3.2B) and increasing levels of installed solar and wind capacity connected to onshore and offshore electricity grids (see Figure 3.2C), gas-fuelled generation is likely to become the marginal fuel (i.e. operating with low load factors) on an enduring basis, out to 2020 and beyond. The role of CCGTs' is expected to become even more unpredictable because their requirement to generate will correlate with renewable generation output (e.g. wind, solar etc) and the interaction with other balancing tools.

Figure 3.2C
Forecast levels of installed wind and solar capacity

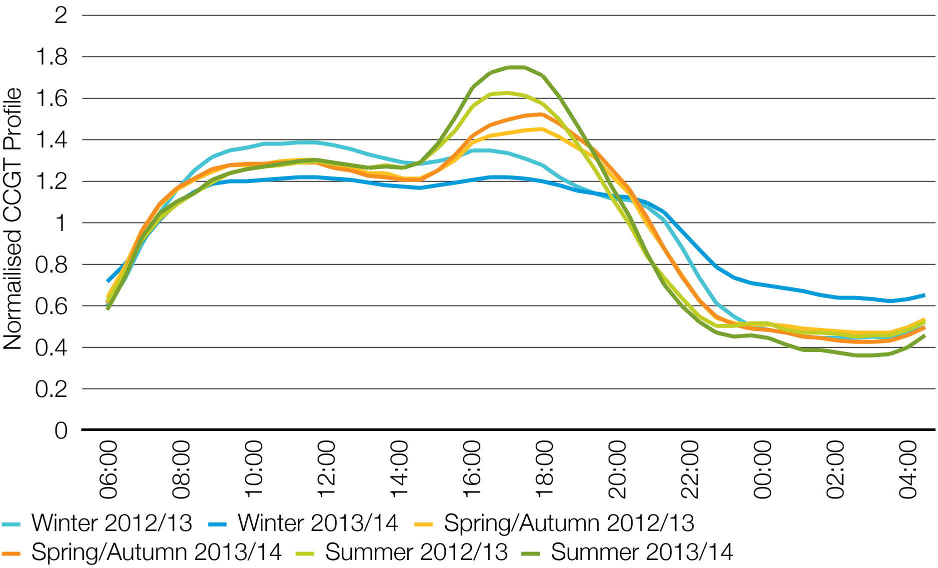


3.2 continued
Evolution of Gas Demand

Figure 3.2D maps how the within-day profiles of CCGTs have changed in the last two years.

The profiles follow expected demand patterns, peaking at 6pm in winter periods.

Figure 3.2D
Normalised CCGT profiles



These changes to how our customers need to use our network have resulted in increasingly variable levels of national and zonal NTS demand, both on a day-to-day and within-day basis.

This presents a number of challenges for us as the system operator (see section 3.4).

3.3 Evolution of Gas Supplies

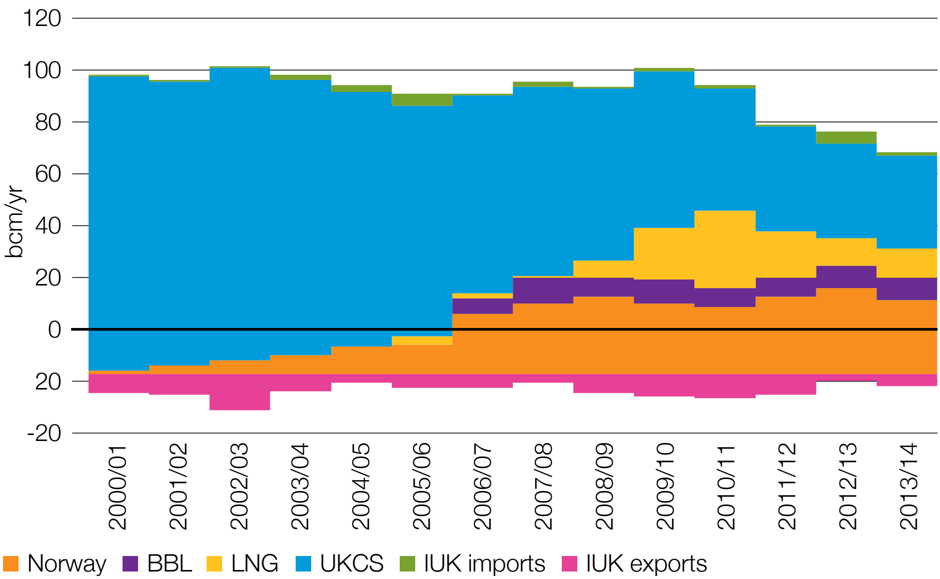
The changing nature of gas supplies to the UK since 2000 provides an indication of how future supply patterns may develop.

The UK was a net exporter of gas until 2003/04. From that point, the level of imports has progressively increased as UK Continental Shelf (UKCS) supplies have declined.

Recent history has also informed our understanding of the potential behaviour of imports and the interaction of international markets and global events, as shown in the following examples:

- The influence of the global LNG market on UK supplies – notably increases in Japanese demand following the 2011 tsunami, and economic growth in China
- The development of unconventional gas sources in the US, such as shale gas, leading to reduced worldwide demand for coal – going forward, the US may become an LNG exporter
- The interaction of Norwegian gas supplies between the Continent and the UK
- The behaviour of the Interconnector (IUK) as a flexible supply source for the UK and Continental markets
- The impact of international events, such as the Russia-Ukraine crisis (European supplies), and US extreme weather events (pricing behaviour and Atlantic LNG).

Figure 3.3A
Historic annual UK gas supplies and IUK exports

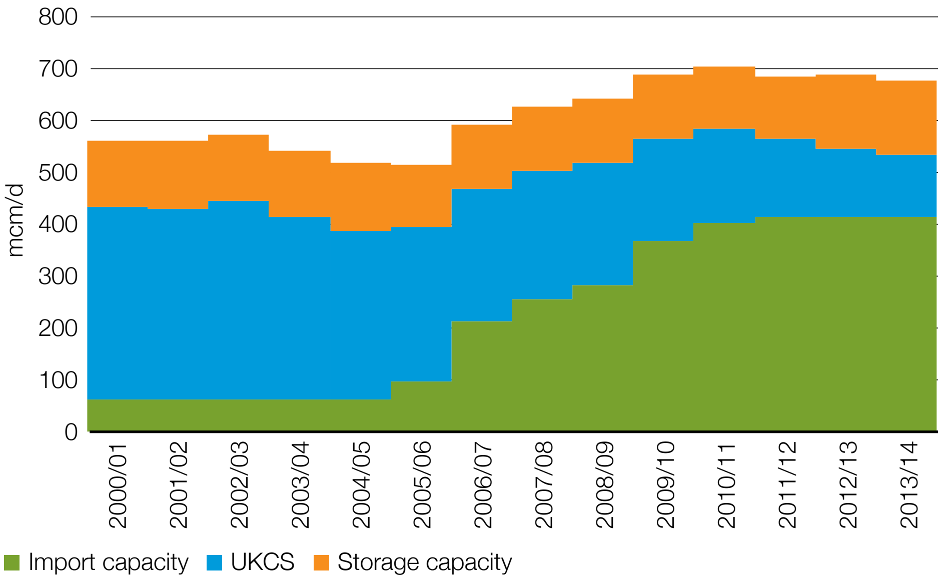


3.3 continued
Evolution of Gas Supplies

Figure 3.3A shows the changing mix of annual gas supplies to the UK[1] since 2000, as well as exports through IUK. It highlights:

- UK self-sufficiency in 2000/01, followed by the decline of UKCS production. UKCS represented 39% of annual inputs in 2012/13 but increased in 2013/14 to 43% – the first annual percentage increase in UKCS supplies for some years
- The increase in Norwegian gas supplies, notably post 2006/07 when Langeled came online
- Imports through Balgzand Bacton Line (BBL) commencing in 2006/07
- Continued exports through the interconnector (IUK) despite increasing import dependency
- LNG imports commencing in 2004/05, peaking in 2010/11 and reducing in recent years because of demand for LNG in Asia.

Figure 3.3B
Actual peak supply



[1] Gas supplied to the NTS

Figure 3.3B highlights how peak supply capacity has increased despite the decline in UKCS production. As the UK has evolved from gas self-sufficiency to an increasing dependence on imports, there has been a considerable shift in how gas supplies are sourced to meet demand.

Historically, demand was met by UKCS supplies and, when needed, storage was used to make up for any supply shortfall. With the onset of import capacity from Norway, the Continent and LNG, the use of supply capacity has changed considerably.

This change is illustrated in Figure 3.3C where each gas supply year since 2000/01 to 2013/14 is shown as three stacked bars – imports, UKCS and storage. The first bar shows the absolute minimum flow experienced during the winter period for each type of supply on a terminal by terminal basis. So for UKCS, the minimum flows from Bacton, Barrow Theddlethorpe, etc are added.

Similarly, minimum LNG and interconnector imports are added, as is the minimum supply from each storage site. The second bar shows the absolute maximum flow across the winter period whilst the third bar shows the volume of sold capacity. Also shown are the highest and lowest days of actual supply/demand for each of the years.

Figure 3.3C
Historic review of peak supplies

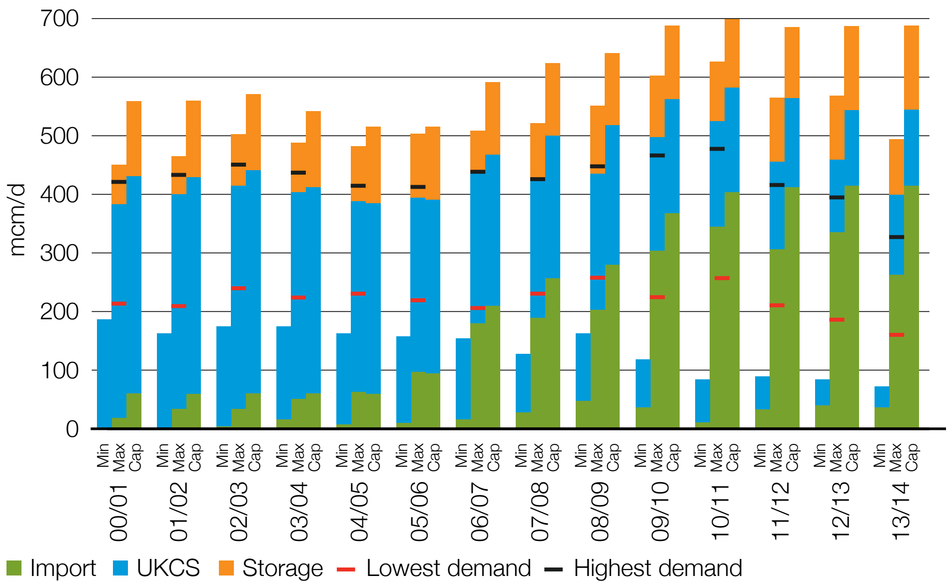


Figure 3.3C highlights many interesting details in how supplies have changed over the past 14 years, with the highest daily demand remaining fairly static at around 400 to 450mcm/d, until 2010/11 when it began to drop.

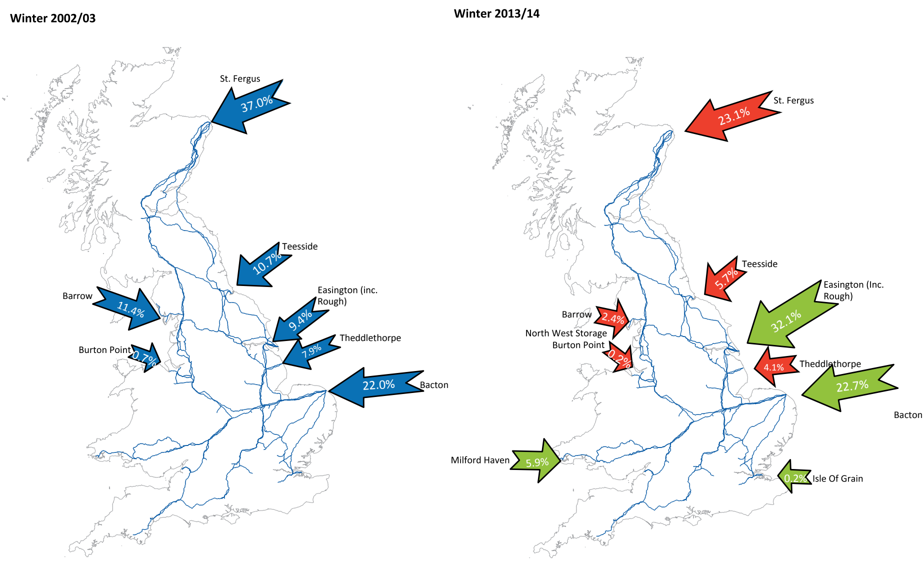
3.3 continued
Evolution of Gas Supplies

Looking ahead, there are some important factors to consider, including the following:

- Post 2005/06 there has been a significant increase in connected import capacity – newer importation terminals can operate in a more commercially responsive way than traditional UKCS supplies. They can respond quickly to small changes in actual and/or anticipated gas price and can change their flow profiles at short notice. So not only can they respond quickly to within-day changes in demand, shippers can also wait until much later in the gas day to balance their energy position (they can quickly re-profile to flow at higher rates during the night, once the end-of-day energy balance position becomes clearer).
- Post 2007/08 there has been an increase in connected storage capacity – like importation terminals, newer fast-cycle storage sites are able to take advantage of short-term changes in commercial conditions and can move between import and export at short notice. Some newer storage sites have large import and export deliverability levels that equate to the forecast peak-day demand for a large local distribution zone (LDZ).
- As more of the UK's supply comes from single-source supply points such as large import facilities and storage sites, the impact of an unexpected within-day loss of supply becomes more severe, especially if such large levels of supply cannot be fully restored until much later in the gas day
- The current total supply capacity (nearly 700mcm/d) is far in excess of the highest demand ever experienced (465mcm/d) and our 2014/15 peak day demand scenario of 499mcm/d. As supply capacity has increased, the way our customers have used this capacity has also changed:
  - Our customers now have greater flexibility over which supplies meet demand
  - This flexibility has increased the maximum and reduced the minimum supply flows across the winter. In 2000/01 the difference between the two was approximately 260mcm/d, but in the past four years this has increased, on average, to about 480mcm/d. To put this into context, the within-winter variation of supply (from minimum to maximum) is now comparable to a 1-in-20 peak-day demand
  - In 2000/01 the difference between the maximum supply flow and the highest demand was about 30mcm/d. For the past four years, this difference has increased to an average of approximately 160mcm/d. Over the same time period, the minimum supply flows have gradually declined. This demonstrates that as customer flexibility around supply patterns has increased, the magnitude of change from one day to the next has also increased.
  - As a result, our network needs the capability to manage a wide range of potential supply patterns and the uncertainty as to which pattern may occur on a given gas day is increasing.

To further illustrate the increasing uncertainty with respect to supply patterns, Figures 3.3D and 3.3E present a snapshot of how winter supply has developed since 2002/03.

Figure 3.3D
Winter supplies, 2002/03 and 2013/14



In Figure 3.3D the red arrows indicate a percentage decline in supplies (the green arrows indicate an increase). The decline in UKCS supplies includes reductions from St Fergus, Teesside, Theddlethorpe and Barrow.

Although the supplies into Bacton have remained relatively consistent, sources of gas into this terminal have evolved. In 2002/03, Bacton was supplied predominately by UKCS gas but by 2013/14 it was mostly Continental European supplies entering the terminal through the IUK and BBL interconnectors.

3.3 continued
Evolution of Gas Supplies

Figure 3.3E
Winter supplies, 2010/11 and 2013/14

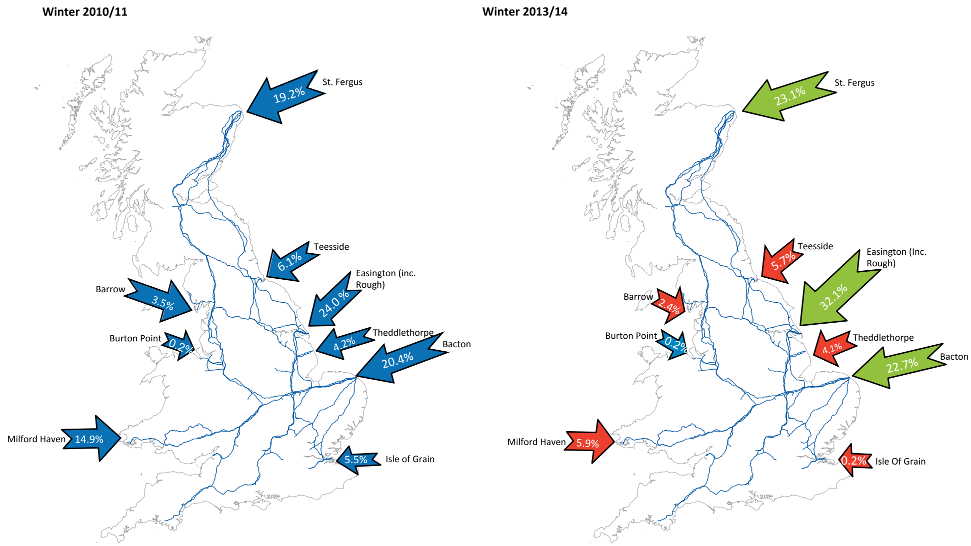
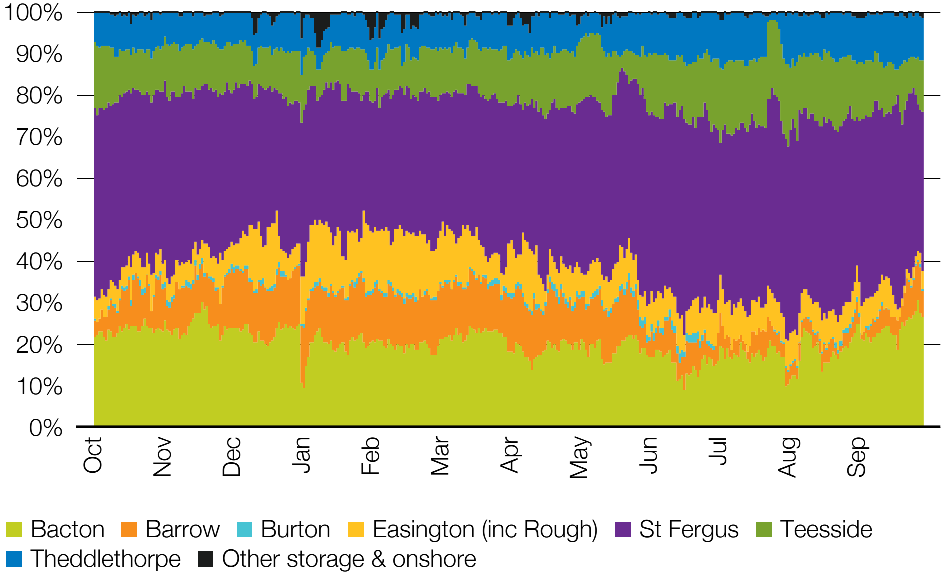


Figure 3.3E shows that winter 2010/11 was dominated by high LNG flows through the Milford Haven and Isle of Grain terminals. In contrast, winter 2013/14 saw higher flows through Bacton from Continental Europe and Easington from Norway, as a result of LNG being diverted to other markets in North East Asia (Japan, China and South Korea).

Winter 2013/14 also saw an increase in St Fergus supplies. Overall UKCS supplies represented 37% of our overall winter supply.

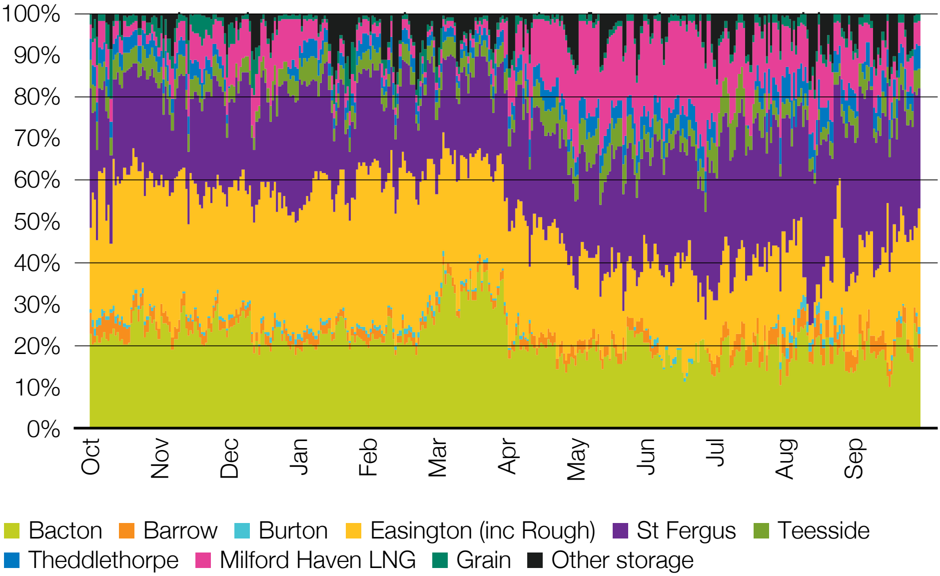
The increased variation in supply pattern from one day to the next can be seen in Figures 3.3F and 3.3G which compare supplies in 2002/03 and 2013/14.

Figure 3.3F
2002/03 Supply variance



3.3 continued
Evolution of Gas Supplies

Figure 3.3G
2013/14 Supply variance



These changes to the ways our customers use our network have resulted in levels of supply from importation terminals and other commercially responsive sites becoming increasingly variable, both on a day-to-day and within-day basis.

This presents a number of challenges for us as the system operator, as described in section 3.4.

3.4
Impact of the Evolution of Within-day Supply and Demand Patterns on the System

3.4.1
System imbalance

Linepack is the volume of gas stored within the NTS. If demand exceeds supply, levels of linepack throughout the network will decrease along with system pressures. The opposite is true when supply exceeds demand.

Throughout a gas day, supply and demand are rarely in balance, so we allow linepack levels to fluctuate. However, in our role as residual balancer of the UK gas market, we need to ensure an end-of-day market balance where total supply equals, or is close to, total demand. We use a metric called Projected Closing Linepack (PCLP) as an indicator of end-of-day market balance.

PCLP is calculated from the physical flow notifications provided by our customers. It is the key data item that we use to determine whether we are required to take an action in the market to improve the end-of-day balance position.

We have seen an increasing trend in underlying market imbalance at the start of the gas day and the time taken for the network to be in balance by the end of the day.

3.4 continued
Impact of the Evolution of Within-day Supply and Demand Patterns on the System

Figure 3.4A
Average projected closing linepack

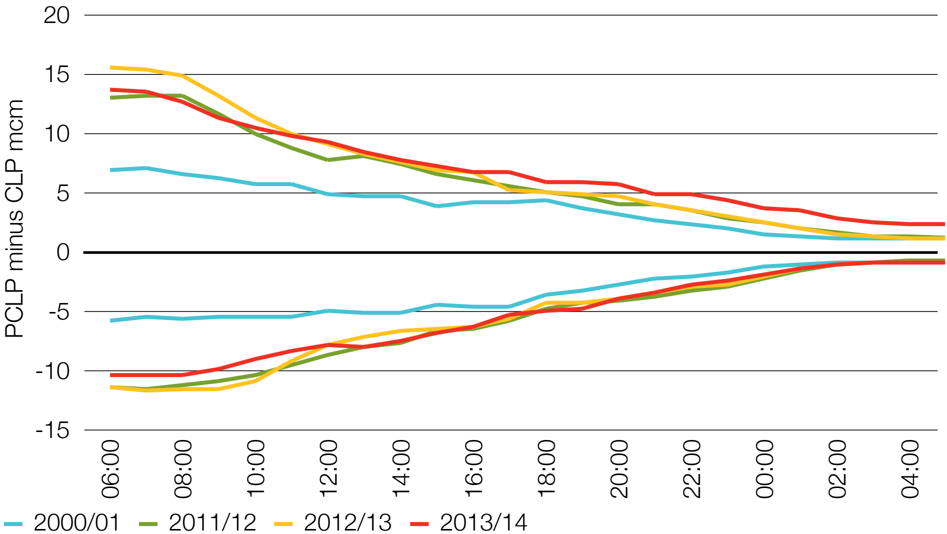


Figure 3.4A shows that average PCLP at the start of the gas days in 2012/13 was approximately twice as much out of balance when compared to 2000/01, although 2013/14 was slightly better than 2012/13.

This reflects how our more commercially responsive customers are changing the way that they want to use our network. This includes a notable trend towards later daily balance reconciliations, along with start-of-day flow notifications that are less reflective of actual outturn flows.

3.4.2
Linepack and system pressures

To ensure that NTS pressures remain within obligated operational and safety tolerances, we manage levels of linepack on a national and zonal level.

The limits within which we can allow linepack – and therefore pressure – to change within a day are determined by the operating envelope, which determines how we manage the network (namely the maximum operating pressures of our assets and the minimum contractual pressures that we have agreed with our customers).

The levels by which linepack will change within-day in a zone of the NTS are driven by the difference between the levels and profiles of local supply and demand, plus the capability of the NTS to transport gas from zone to zone, as required.

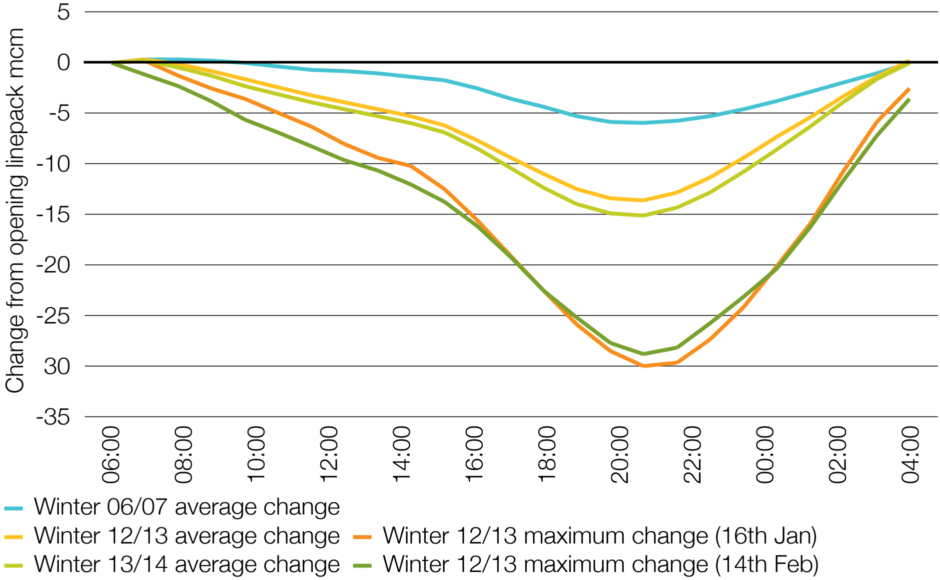
When gas is transported over long distances its pressure can drop significantly, which may mean that we are unable to meet the agreed minimum contractual pressures.

As a result, the evolution of supply patterns and within-day demand variation described in section 3.3 can significantly affect our ability to manage linepack in a controlled way, to allow for the imbalance between supply and demand, while also allowing us to meet our contracted pressures.

Over the last few years we have seen a significant increase in the average change in national linepack across a gas day (see Figure 3.4B).

3.4 continued
Impact of the Evolution of Within-day Supply and Demand Patterns on the System

Figure 3.4B
Average and maximum change in linepack across a gas day



As well as an increase in the average change in linepack across a gas day we have seen an increased frequency of large changes.

Figure 3.4C
Within-day maximum to minimum range of NTS linepack (2002/03 and 13/14)

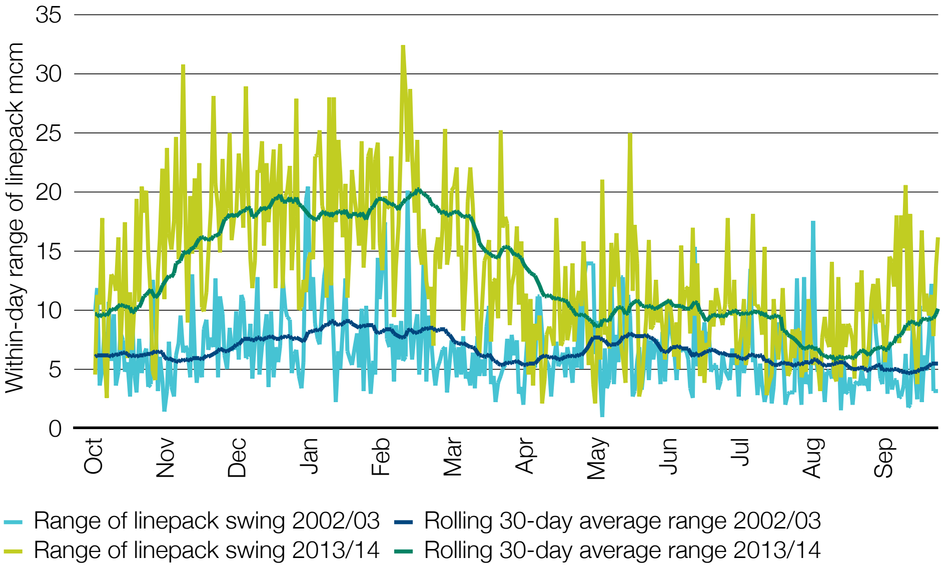


Figure 3.4C compares the within-day linepack changes seen in 2002/03 to those seen in 2013/14. It illustrates that current linepack changes at certain times of the year are up to three times the level seen a decade ago.

This trend of increased linepack volatility is leading to greater operational challenges, particularly in terms of managing NTS pressures and ensuring that they remain within safety and contractual tolerances.

The future is uncertain, with a large range of potential future supply and demand patterns on the NTS. Although most will not lead to operational risks and issues, many have the potential to do so – and a small change to an anticipated supply and demand pattern on a given day can have a significant impact on the NTS and how we operate.

We have provided two examples, both looking ahead to the mid-2020s. They demonstrate how evolving supply and demand may further exacerbate linepack and system pressure volatility, with a resultant impact on how our customers may be able to use the network. The key differences between the two are the wind generation load factors used and the responsiveness of supplies in meeting an unforeseen increase in CCGT demand.

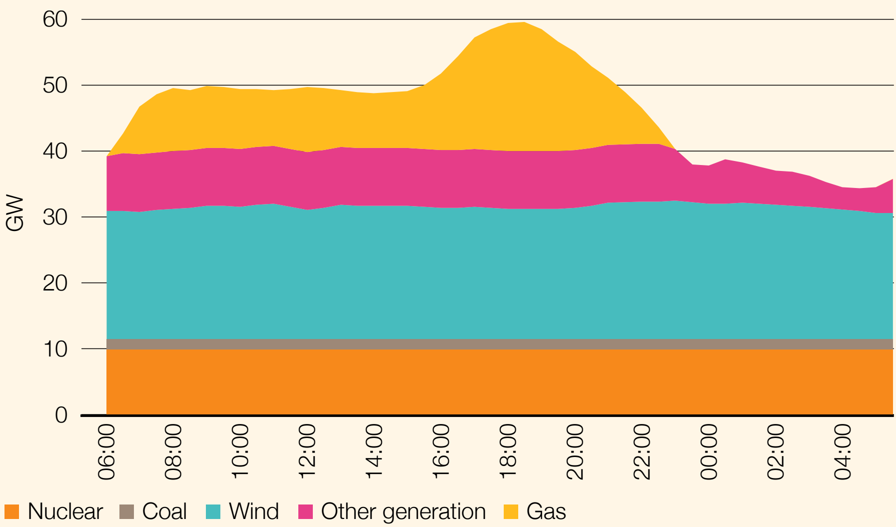
3.4 continued
Impact of the Evolution of Within-day Supply and Demand Patterns on the System

Example 1

By 2025, the electricity generation fuel mix is likely to be significantly different to what we see today.

For our first example, we have assumed a day where electricity demand peaks at approximately 60GW, with the generation merit order as shown in Figure 3.4D below.

Figure 3.4D
Example 1 – Generation merit order

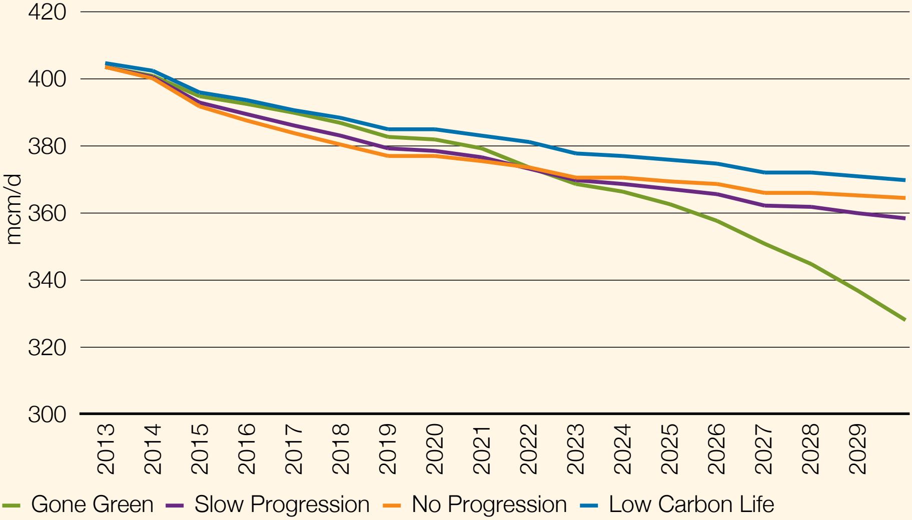


In our 2014 Future Energy Scenarios, the highest forecast level of non-gas baseload generation (nuclear and coal) for 2025 is in the Low Carbon Life scenario and equates to approximately 16GW.

In our other 2014 Future Energy Scenarios, the forecast levels of installed coal and nuclear capacity are lower and, in the case of Gone Green and Slow Progression, just over half that of the Low Carbon Life level. So this example does not represent a worst-case scenario.

We have used an aggregate LDZ demand of approximately 260mcm/d because this represents a typical winter demand equal to approximately 70% of our 1-in-20 Peak Day Undiversified forecast LDZ Demand as shown in Figure 3.4E.

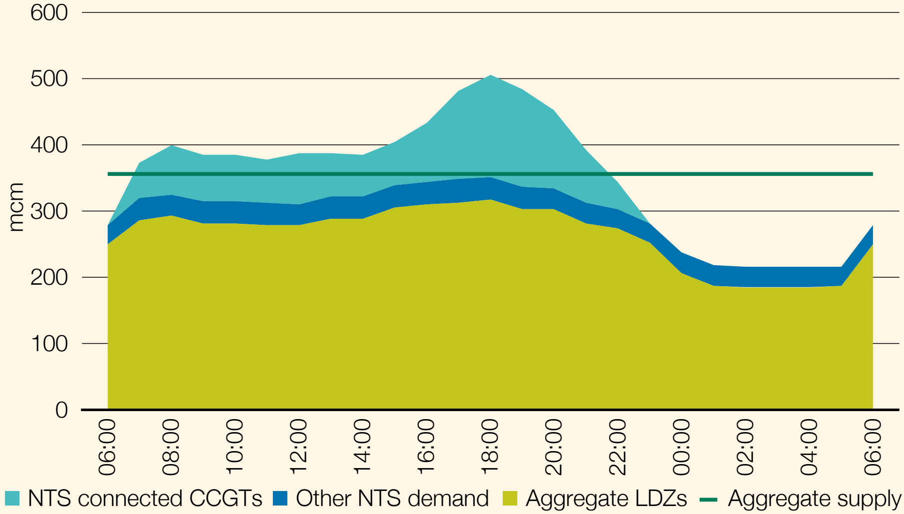
Figure 3.4E
Example 1 – 1-in-20 Peak Day Undiversified forecast LDZ Demand



This example assumes that the total end-of-day NTS demand has been forecast accurately and that, as a result, NTS supplies flow at a flat rate across the day to provide an end-of-day supply and demand balance. The resultant within-day mismatch in supply and demand can be seen in Figure 3.4F.

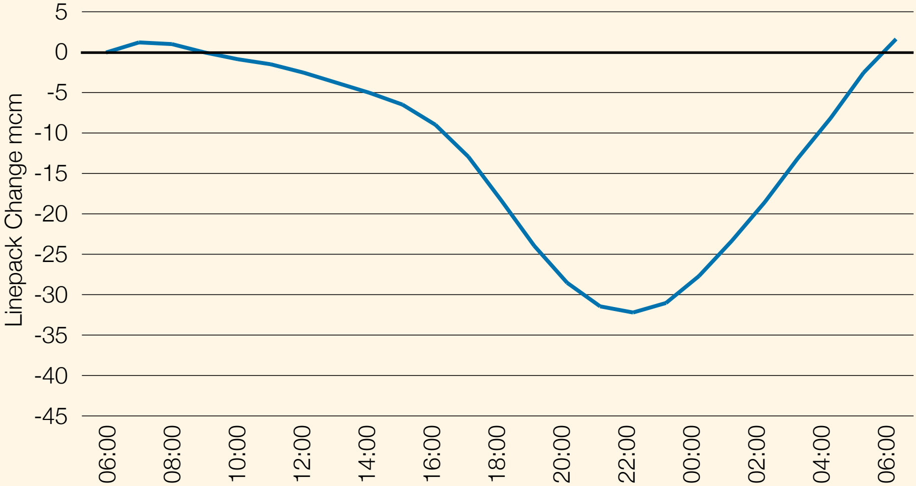
3.4 continued
Impact of the Evolution of Within-day Supply and Demand Patterns on the System

Figure 3.4F
Example 1 – Within-day mismatch in supply and demand



This mismatch will drive levels of NTS linepack to change across the day and will result in a maximum linepack change of 32mcm/d as can be seen in figure 3.4G, which is approximately equal to the largest national linepack change experienced on the NTS.

Figure 3.4G
Example 1 – Forecast change in within-day linepack

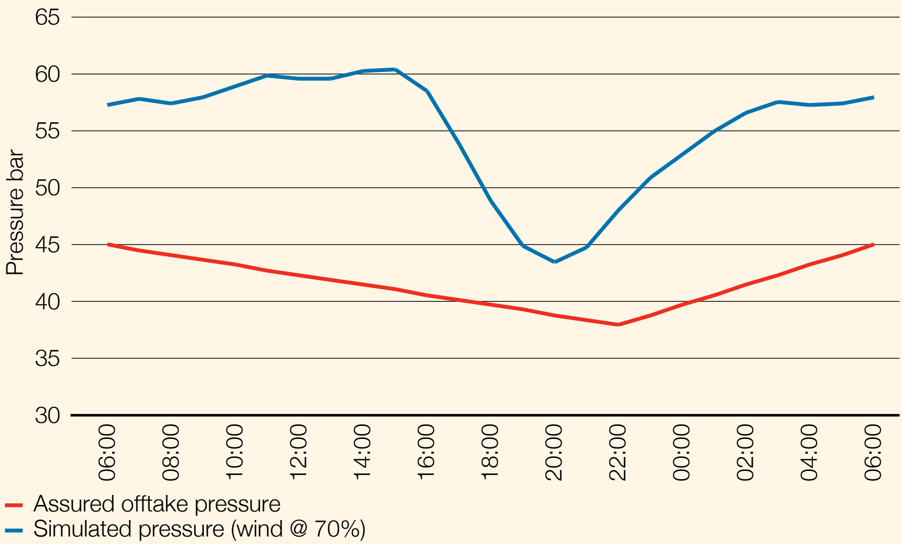


The levels by which linepack volumes will change in particular zones of the NTS is driven by the difference between the levels of local supply and demand plus the capability of the NTS to transport gas from zone to zone. As levels of linepack drop towards a minimum at approximately 22:00, system national and zonal pressures will also fall.

The forecast change in pressure at an extremity point on the NTS is shown in Figure 3.4H.

3.4 continued
Impact of the Evolution of Within-day Supply and Demand Patterns on the System

Figure 3.4H
Example 1 – Forecast change in pressure at an NTS extremity point



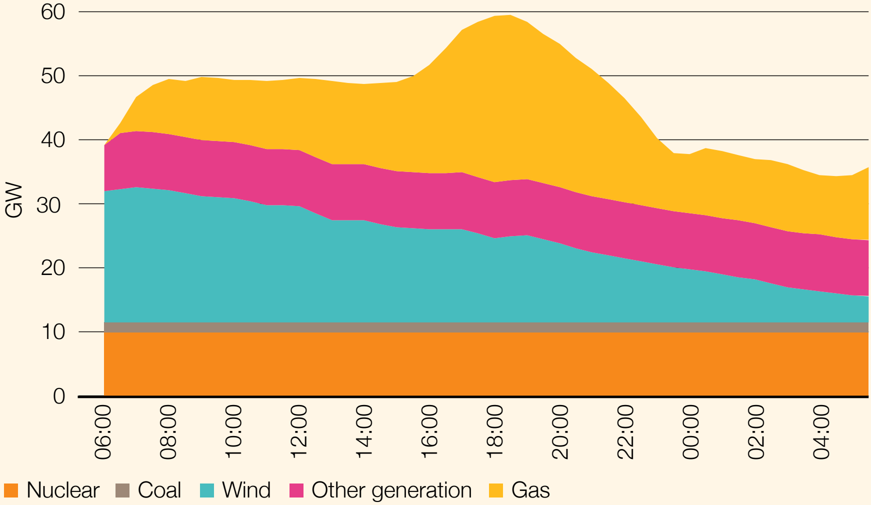
Although the pressure at this point falls close to the Assured Offtake Pressure (the minimum pressure that we have agreed with the DNO to support their downstream network), this minimum pressure level is not breached.

Example 2

Our second example includes a steady, unforeseen decrease in wind generation over the course of the day, from a load factor of 70% to 15%.

This drop in wind generation is met through a considerable increase in CCGT generation. The merit order of electricity generation is shown in Figure 3.4I below.

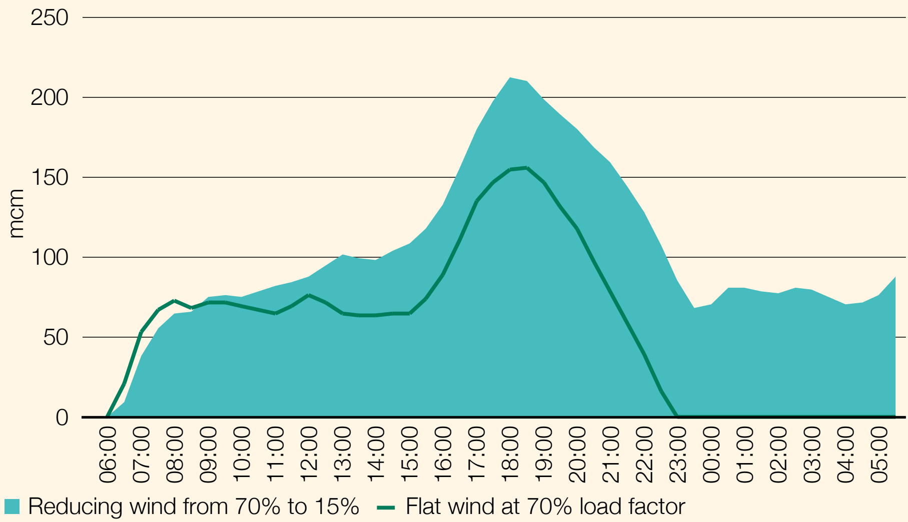
Figure 3.4I
Example 2 – Generation merit order with reducing wind load factor



3.4 continued
Impact of the Evolution of Within-day Supply and Demand Patterns on the System

The drop in wind generation drives considerably higher CCGT demand in the early evening and overnight (see Figure 3.4J).

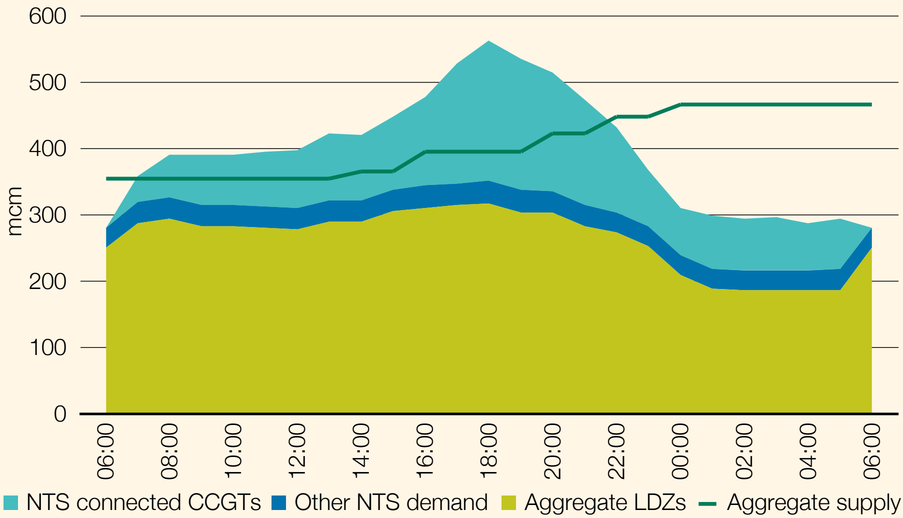
Figure 3.4J
Examples 1 & 2 – Forecast CCGT demand



Our first example was based upon the assumption that the total end-of-day NTS demand had been forecast accurately, and as a result, NTS supplies delivered a flat rate across the day to provide an end-of-day supply and demand balance.

In this example, because the increase in CCGT demand was not forecast, the increase in forecast NTS supplies would lag behind the demand increase. We have used a two to four-hour lag, and have assumed that these increased levels of supply are delivered from more commercially responsive sites (i.e. interconnectors, LNG and storage), with sources of supply spread around the country rather than a single location. The resultant within-day mismatch in supply and demand can be seen in Figure 3.4K.

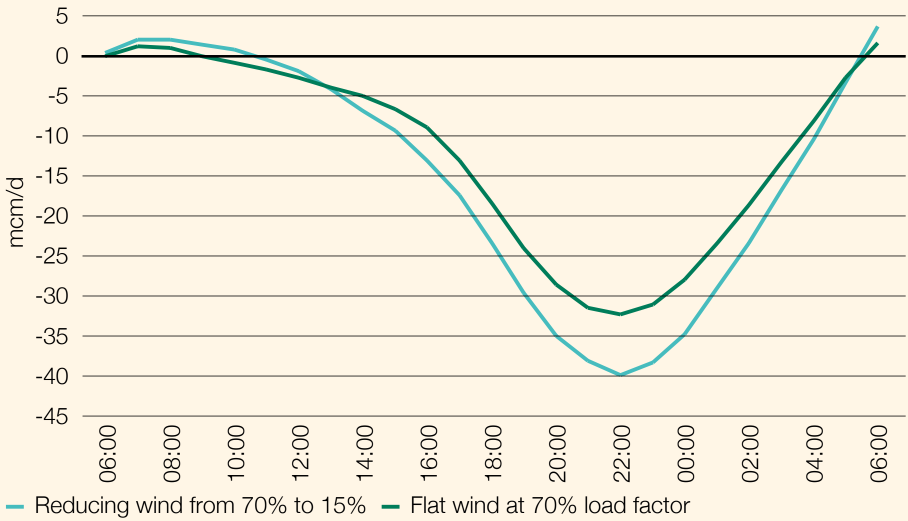
Figure 3.4K
Example 2 – Within-day mismatch in supply and demand



3.4 continued
Impact of the Evolution of Within-day Supply and Demand Patterns on the System

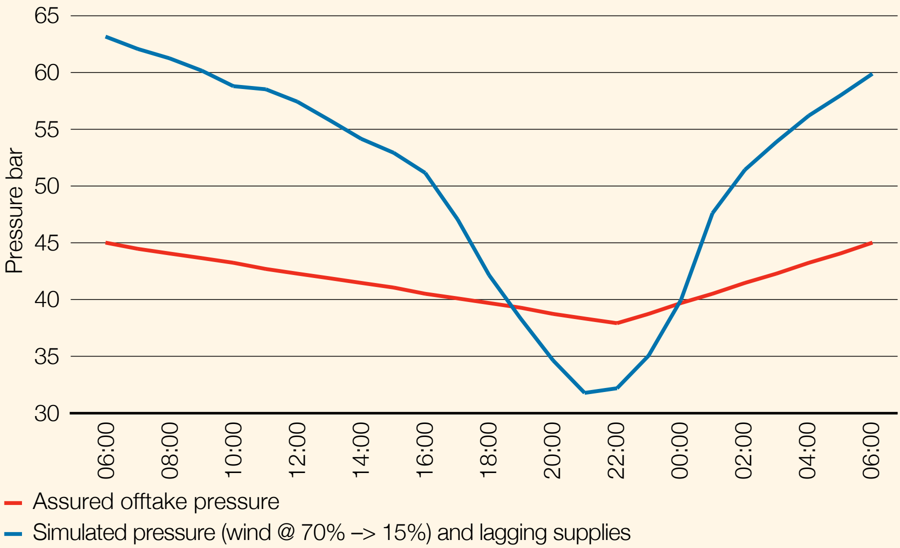
We forecast that the unforeseen CCGT demand increase and subsequent lag in supply response will drive an additional linepack change of approximately 8mcm/d, taking the national swing to approximately 40mcm/d – a 25% increase on the largest national linepack swing experienced on the NTS. (See Figure 3.4L)

Figure 3.4L
Example 2 – Updated forecast change in within-day linepack



Within our control room environment we are developing improved situational awareness tools, including enhanced prediction of within-day system linepack and pressures based upon operational forecasts. If this example were to play out in reality, we would predict that the pressure at the extremity point used in Example 1 would fall to a level such that we would be unable to meet the Assured Offtake Pressure agreed with the DNO as can be seen in Figure 3.4M.

Figure 3.4M
Example 2 – Forecast change in pressure at an NTS extremity point



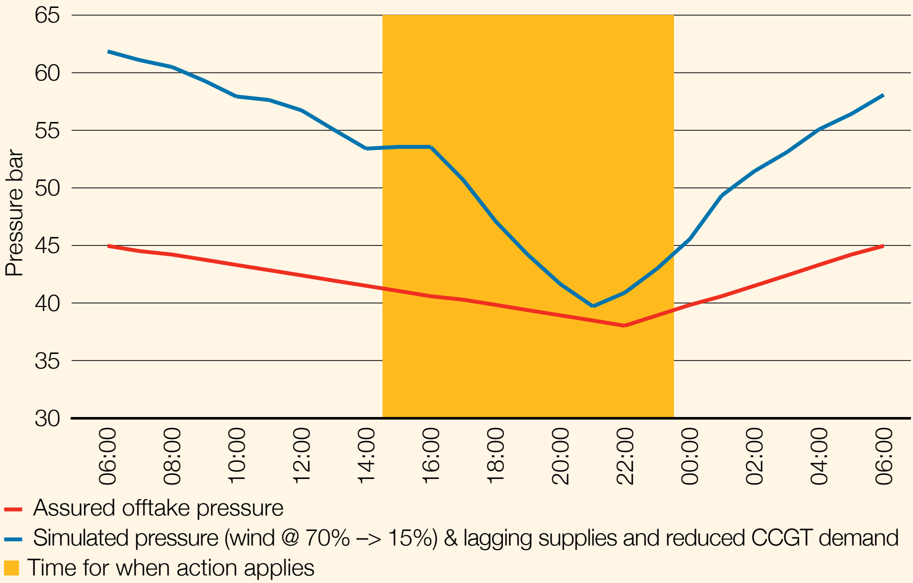
3.4 continued
Impact of the Evolution of Within-day Supply and Demand Patterns on the System

In this instance, our control room would have a number of actions available for managing this low-pressure issue. These could include reconfiguring the network, implementing Uniform Network Code (UNC) rules on the required notice periods for re-profiling demands and/or using commercial actions described in Part C of National Grid's System Management Principles Statement[2].

In Example 2 we have assumed that reconfiguration of the network is not possible, and as a result a commercial action is required.

The control room would take an action during the period highlighted in Figure 3.4N to reduce demand in this zone, either by scaling back off-peak NTS exit capacity or buying back firm NTS exit capacity from a customer who was able (and willing) to surrender their capacity. DNOs are unlikely to be able to offer any capacity for buyback, so demand reduction is likely to occur at a CCGT in the zone.

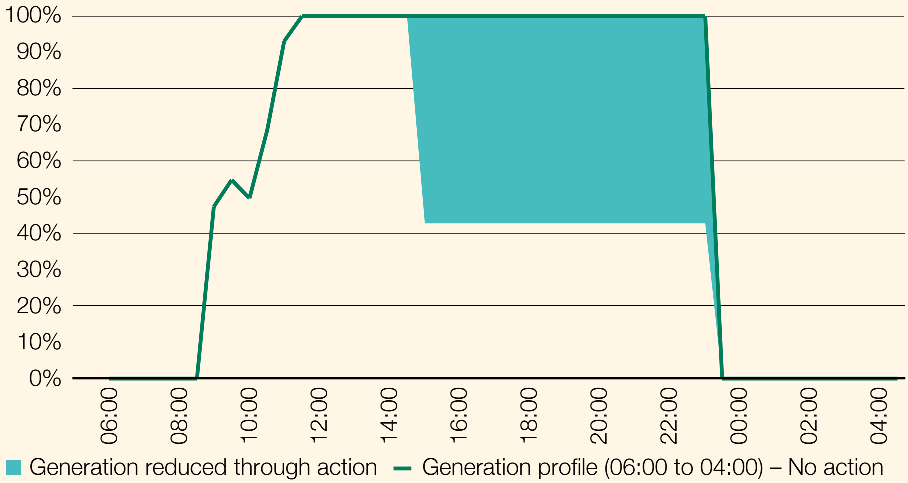
Figure 3.4N
Example 2 – Forecast change in pressure at an NTS extremity point following commercial action



[2] The latest version of National Grid's system management principles statement can be found at http://www2.nationalgrid.com/UK/Industry-information/Business-compliance/Procurement-and-System-Management-Documents-Archive/

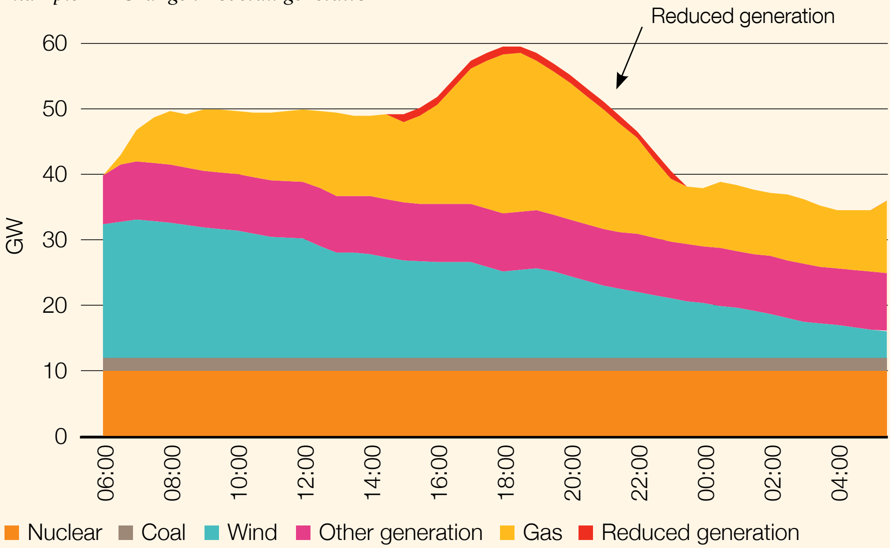
Figure 3.4N also shows the resultant change in pressure profile at the NTS exit point following the reduction in zonal demand between 15:00 and 23:00. Following the action, pressures remain above the Assured Offtake Pressure. The action resulted in a change in generation output at a CGGT (see Figures 3.4O and 3.4P).

Figure 3.4O
Example 2 – Change in generation output profile as a result of the commercial action



3.4 continued
Impact of the Evolution of Within-day Supply and Demand Patterns on the System

Figure 3.4P
Example 2 – Change in overall generation



It is important to note that in Example 2 we have considered the minimum level of demand reduction required to ensure that the Assured Offtake Pressure can be met. We have not made any assumptions regarding how a customer will provide this level of demand reduction (in other words, how many generating units will be affected) or the subsequent impact on other energy markets.

Below are the assumptions used in the above examples:

- Some coal plant is on outage
- In example 1 a flat wind profile of 70% has been used
- All gas generation is from NTS-connected CCGTs
- The dispatch order of CCGTs is based on efficiency
- The Moffat interconnector and industrial sites are set to the forecast levels expected for the set LDZ demand
- Other interconnector and storage sites were not assumed to be NTS demands
- A forecast supply pattern for a day in 2025 with an LDZ demand of 260 mcm/d has been used
- Supplies to balance the forecast industrial, interconnector export and CCGT demand would be delivered by commercially responsive sites (import interconnectors, LNG and storage sites).

These two examples demonstrate how a small change to an anticipated supply and demand pattern on a given day can result in a significantly different impact on the NTS. This in turn can affect how our customers are able to use the network to meet their own business needs.

The unforeseen increase in CCGT demand resulting from a change in wind generation when combined with an associated lag in responsive supply has the potential to significantly affect zonal levels of linepack and pressure across the NTS.

The enhanced situational awareness tools that we are developing in our control room will enable us to determine when a within-day action is required to manage operational issues, such as the low pressures forecast in these examples.

However, as supply and demand patterns continue to evolve, it is possible that the capability of our assets combined with the range of operational rules and tools at our disposal will not be sufficient to meet the challenges described in this section without reducing the flexibility that we can provide to our customers in the use of our network.

How we intend to overcome these anticipated challenges is described in Chapter 5.

Chapter 4
Customer Requirements

This chapter contains exit and entry capacity availability and lead-time information. It also details capacity bookings from the recent entry capacity auctions and exit capacity processes.

Key messages

- While we predict significant change in the period ahead, the pace of development of the NTS, when judged by customer capacity signals, has slowed in recent years; however, customers are increasingly looking to access system flexibility via higher ramp rates and shorter notice periods
- Looking ahead, as the Electricity Market Reform (EMR) processes are implemented, we are seeing indications of renewed development activity
- Customer requirements from the NTS continue to change and evolve. We continue to see a high distribution of network flex capacity requirement against a background of reduced distribution network flat capacity requirements
- In response to stakeholder feedback, our 2013 document included information about the lead time for providing NTS entry and exit capacity across different geographical zones. We have updated this information based on changes in the last 12 months.

4.1
Entry and Exit Capacity

NTS user requirements continue to evolve and both environmental legislation, such as the Industrial Emission Directive (IED), and market reforms, such as Electricity Market Reform (EMR), will impact on future system planning and operation. IED has required us to review the need for a significant proportion of our compressor fleet and may lead us to replace, modify or remove units in line with customer requirements and use of the system.

While we predict significant change ahead, the pace of NTS development, when judged by customer signals for incremental capacity, has slowed in recent years. This trend has continued in the 2014 Quarterly System Entry Capacity (QSEC) auction and the 2014 Exit Capacity window. In contrast the number of connection enquiries we are receiving remains high.

Customer requirements from the NTS continue to change and evolve. We continue to see:

- Increased Distribution Network (DN) exit flexibility capacity requirements (against a background of reduced DN flat capacity requirements)
- Increased requests for higher ramp rates and reduced flow rate change notice periods for gas power generation offtakes
- Our Future Energy Scenarios are highlighting an increased requirement for south-to-north flows as a result of declining St Fergus flows
- Operationally, we are seeing an increased requirement to rapidly switch between ‘west-to-east’ and ‘east-to-west’ flow in the heart of the network.

Through our industry engagement, we have discussed whether these changes (and others) mean we should re-examine the existing design standards and parameters against which we plan the network. With the Transmission Planning Code updated during 2014 in light of the RIIO-T1 outcome, and plans for further review in light of ongoing industry developments, this is an important opportunity to continue the discussion.

Looking ahead, as wider energy market processes come to an end, in particular EMR, and more stringent environmental legislation is introduced, there are strong indications of a period of significant change and renewed development activity.

This makes it even more important that we work together with our stakeholders and customers to make sure that the right operational arrangements (rules), commercial options (tools) and physical investments (assets) are available to us so we can determine the most economic and efficient solutions.

The Planning Act and the NTS capacity process: introduction of Planning and Advanced Reservation of Capacity Agreements

The Planning Act (2008) introduced a new process for planning decisions on Nationally Significant Infrastructure Projects (NSIPs), including gas infrastructure projects. For NSIPs, this new process requires extensive optioneering and consultation with the community before consideration by the Planning Inspectorate and a decision by the Secretary of State. This is likely to increase lead times for complex construction projects up to an estimated 72 to 96 months from the point of a formal capacity signal to delivery of that capacity; however, the default lead times in our Gas Transporter Licence oblige us to deliver incremental entry and exit capacity to 42 and 36-month lead times respectively.

In response to the changes introduced by the Planning Act, we have developed a generic, multi-stage timeline, which has been shared with the industry, to illustrate the planning process stages leading up to a submission to the Planning Inspectorate. This is only a generic timeline; the actual duration of each stage will depend on the nature and complexity of each project.

Table 4.1
Planning process timeline

Planning stage		Activity	Duration
1a	Strategic optioneering	Establish the need case and identify technical options	Up to six months
1b		Develop Strategic Options Report (SOR)	Up to six months
2	Outline routing and siting	Identify preferred route corridor/siting studies	Up to 15 months
3	Detailed routing and siting	Undertake environmental impact assessment (EIA) and detailed design	Up to 24 months
4	Development Consent Order (DCO) application preparation	Formal consultation, finalising project, preparation of application documentation	Up to six months
5	DCO application, hearings and decision	Submission and examination	Up to 15 Months
6		Approval process	

Through our Talking Networks events we highlighted that the Planning Act (2008) meant that the current obligated lead times applicable to incremental entry and exit capacity were not achievable where significant network investment would be required. Releasing incremental entry and exit capacity to these obligated lead times could result in considerable capacity constraint management costs for the industry. Simply increasing these lead times was not thought to be a viable solution, as it would require customers to commit to capacity with lead times that were not consistent with their own project investment decision timescales. Our March 2012 RIIO-T1 business plan submission included a number of proposals that could address this issue while supporting the overarching objective of delivering connections and capacity in the most efficient lead time and in a transparent manner. Together, we and the industry have been working to further develop potential solutions to modifying and aligning the NTS capacity and connections processes more effectively.

4.1 continued
Entry and Exit Capacity

The solution involves introducing a bilateral contract – the Planning and Advanced Reservation of Capacity Agreement (PARCA) for parties wishing to signal incremental capacity.

The PARCA arrangements will enable customer and our timelines to be aligned, with connections and capacity being delivered together. This process aims to provide more certainty to project developers, with transparency around the process steps and deliverables required from both parties. It sets out a timeline from initial contact through to capacity release and allows for review, discussion, and potential revision of that timeline and drop-out points.

The timelines will be developed in conjunction with our customers and will be assessed on a site-by-site/project-by-project basis. As a result, lead times may vary. This would be accompanied by a phased user commitment that would ramp up in line with progression through the process, ending in full user commitment once a formal capacity signal is received, in line with the current UNC and licence principles.

The PARCA approach was developed at the monthly UNC transmission workgroup meetings that lead to UNC modification proposals, the development of the associated changes to our Gas Transporters Licence and Methodology Statements, and the PARCA contract. Each aspect of the solution was discussed at UNC transmission workgroup meetings, allowing the industry to take part in shaping the final solution. The PARCA arrangements are a development of the long-term NTS entry and exit capacity release mechanisms and extend the UNC ad hoc application provisions that allow users to reserve enduring NTS exit (flat) capacity and NTS entry capacity.

The PARCA arrangements are based on and replace the Advanced Reservation of Capacity Agreement (ARCA) for NTS exit capacity and the Planning Consent Agreement (PCA) for both NTS entry and exit capacity.

Incremental capacity that cannot be provided via substitution is only guaranteed for release where a PARCA has been agreed by us and a developer or a user (both DNO and shipper).

Baseline capacity, non-obligated incremental capacity and incremental capacity that can be provided via substitution will be made available through the annual auctions for Quarterly System Entry Capacity (QSEC) and annual enduring annual NTS exit (flat) capacity processes, and can also be reserved through a PARCA by a developer or a user (both DNO and shipper).

Further details on the PARCA arrangements

A PARCA is a multi-phased bilateral contract, between us and a customer, which allows a customer to reserve firm quarterly system entry capacity and/or firm enduring annual NTS exit (flat) capacity while developing the initial phases of their own project.

Any NTS capacity initially reserved through a PARCA will, subject to the case for that capacity being sufficiently demonstrated and any necessary planning permissions received, be allocated exclusively to the PARCA applicant or, where the PARCA applicant is not a UNC party, a NTS user(s) nominated by the PARCA applicant. The PARCA arrangements provide a number of benefits for customers who wish to use them, other customers and us.

Customers who wish to use a PARCA

- A PARCA is designed to help customers approaching us to reserve NTS entry and/or exit capacity early in the development of their own project without fully financially committing to the formal capacity booking, reducing a potential barrier to participation

- Reserved NTS capacity will be exclusive to the PARCA applicant (or their nominated NTS user) and not available to other NTS users though other auction/application mechanisms
- A PARCA provides the customer with greater certainty, earlier in their project timescales, of when we can provide their capacity requirements, should their project progress to completion
- A PARCA enables the customer and us to align project timelines and planning requirements so that projects can progress together, should the customer wish. It would also allow the customer to align the NTS capacity process and connection processes
- The PARCA process is flexible, with logical 'drop-out points' before capacity allocation. Capacity allocation would be closer to the customer's first gas day than under previous arrangements. As a result, the customer would be able to take advantage of these 'drop-out points', should their project become uncertain
- PARCAs are available to both UNC parties and project developers and therefore available to a wider range of customers compared to the existing annual NTS capacity auction and application processes.

Other customers

- Throughout the lifecycle of a PARCA, we will publish increased levels of information, compared to the existing auction/application mechanisms, increasing transparency for other NTS users
- The PARCA entry capacity process includes an ad hoc QSEC auction mechanism to allow other NTS users to compete for unsold quarterly system entry capacity before it is reserved
- The PARCA process also includes a PARCA application window when other NTS users can approach us to sign a PARCA. This provides a focal point for customers considering entering into a PARCA and would allow multiple PARCAs to be considered together. This way, we will make best use of unsold levels of NTS capacity and existing system capability when determining how to meet our customers' requirements, enabling the most economic and efficient investment decisions to be made
- Throughout the lifecycle of a PARCA, the customer should provide us with information about the progression of their project. Should a customer fail to provide the required information in the required timescales, their PARCA may be cancelled and any reserved NTS capacity would either be used for another live PARCA or returned to the market. This should ensure that NTS capacity is not unnecessarily withheld from other NTS users
- A customer will be required to provide financial security under a PARCA as a commitment to the reserved NTS capacity and if that customer cancels their PARCA, a termination amount would be taken from the security provided. This would be credited to other NTS users through the existing charging mechanisms
- The timescales for the release of incremental NTS capacity to the PARCA applicant will be aligned to our timescales for providing increased system capability, including under the Planning Act if required. As a result, the risk of constraint management actions taking place and any costs potentially being shared with end consumers would be reduced.

National Grid

- Throughout the lifecycle of a PARCA, the customer will be required to regularly provide information to us about the progression of their project. This would allow our case for any required investment to be based on clear, demonstrable customer requirements. We would not begin construction on any investment projects until the customer had received full planning permission for their project, enabling economic and efficient NTS investment.

4.2
NTS Exit Capacity Maps and Lead Times

The following section provides shippers, distribution network operators and developers with information about the lead time for providing NTS exit capacity. If unsold NTS exit (flat) capacity is available at an existing exit point then it can be accessed through the July application process for the following winter. If unsold NTS entry capacity is available at an existing ASEP then it can be accessed via the auction processes.

The obligated capacity level, less any already sold, is the amount of capacity that we make available through the application and auction processes. We can increase capacity above the obligated levels when system capability allows, through substitution and via funded reinforcement works.

- In some areas, capacity can be made available without investment, for example by capacity substitution – **lead time <36 months**
- In some areas, capacity can be made available with simple medium-term works – **lead time 36 months**
- In some areas, capacity requires long lead times associated with more significant reinforcement works, including new pipelines and compression – **lead time >>36 months**
- If we receive an application for exit capacity above the obligated capacity level we will first consider whether capacity can be made available without any reinforcement works and without increasing operational risk. This can be the case for exit capacity close to large reliable supplies.

If reinforcement works or increased operational risk is identified, we investigate substituting unsold capacity, which involves moving our obligation to make capacity available from one system point to another, to avoid reinforcement work. An exchange rate is calculated which means more or less than one unit of capacity might be substituted to make a new unit of capacity available elsewhere. Sometimes substitution is not possible due to local constraints.

If substitution is not possible, we will consider reinforcement works and contractual solutions. Works on our existing sites, such as modification of compressors and above-ground installations (AGIs) may not require planning permission, so may have shorter lead times. Significant new pipelines require a Development Consent Order (DCO), as a consequence of The Planning Act (2008). This can result in capacity lead times of 72 to 96 months. Construction of new compressor stations may also require DCOs if a new high- voltage electricity connection is needed and, subject to local planning requirements, may require similar timescales to pipeline projects.

NTS capacity and substitution

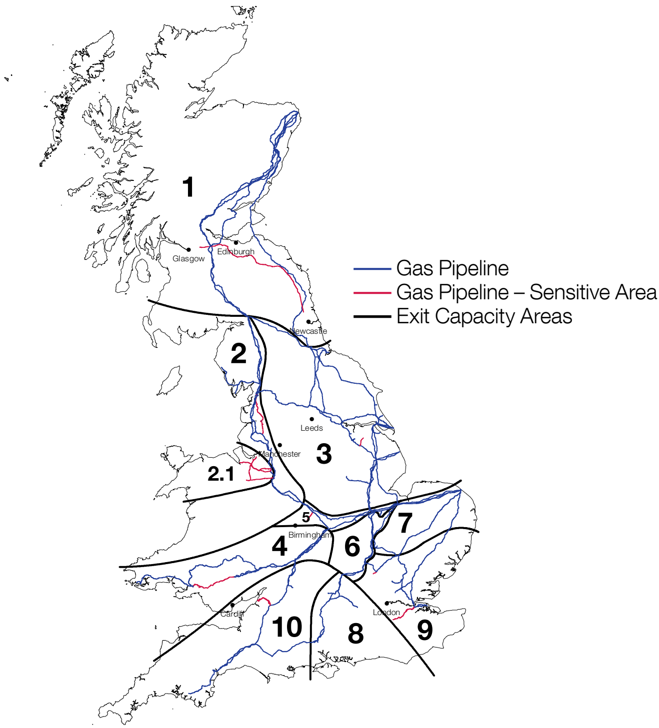
We have an obligation to assess how much entry or exit capacity may be substituted to meet an increased capacity requirement by applying entry and exit capacity substitution methodologies. Capacity substitution is the process of substituting unsold capacity from one or more system points to another, where demand for that capacity exceeds the available capacity quantities for the relevant period, hence avoiding the construction of new assets or material increases in operational risk.

4.2.1
NTS exit capacity map

Figure 4.2A divides the NTS into regions based on key multi-junctions, including compressor stations and multi-junctions that separate sections of the NTS with different pressure ratings. The descriptions explain potential capacity lead times in each region, including areas of sensitivity.

This information is merely an indication and actual capacity availability will depend on the quantity of capacity requested from all customers within a region and interacting regions. This information recognises the impact EMR may have on interest in NTS connections and capacity.

Figure 4.2A
NTS exit capacity map



4.2 continued
NTS Exit Capacity Maps and Lead Times

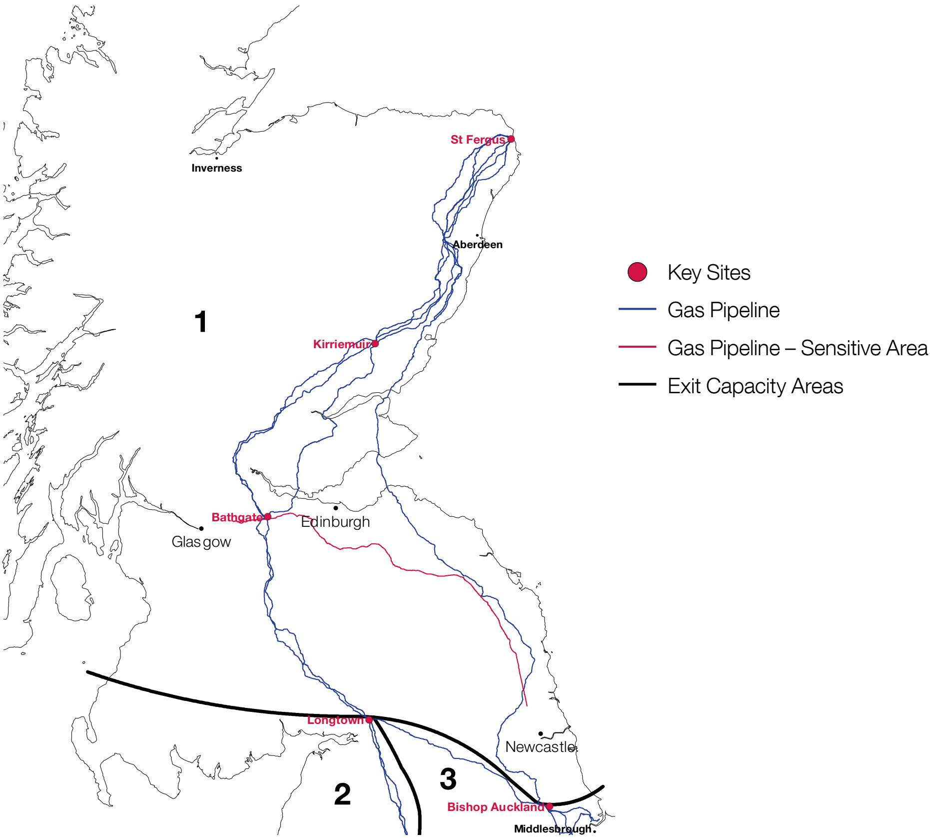
4.2.2
Available (unsold) NTS exit (flat) capacity

Table 4.2A indicates the quantities of unsold NTS exit (flat) capacity in each region that could be used to make capacity available at other sites through exit capacity substitution and how this has changed since the publication of the 2013 Gas Ten Year Statement.

Table 4.2A
Quantities of unsold NTS exit (flat) capacity

Region Number	Region	Obligated (GWh/d)	Unsold (GWh/d)	Unsold % of unsold capacity	Unsold % change from 2013 GTYS
1	Scotland & the North	718	56	8%	+1%
2	North West & West Midlands (North)	1,110	312	28%	+6%
2.1	North Wales & Cheshire	315	204	65%	+7%
3	North East, Yorkshire & Lincolnshire	1,570	460	29%	+10%
4	South Wales & West Midlands (South)	569	48	8%	-1%
5	Central & East Midlands	281	112	40%	+18%
6	Peterborough to Aylesbury	126	29	23%	+3%
7	Norfolk	360	108	30%	+6%
8	Southern	526	208	40%	+3%
9	London, Suffolk & the South East	1,512	334	22%	+1%
10	South West	461	68	15%	+1%

Figure 4.2B
Region 1 – Scotland and the North

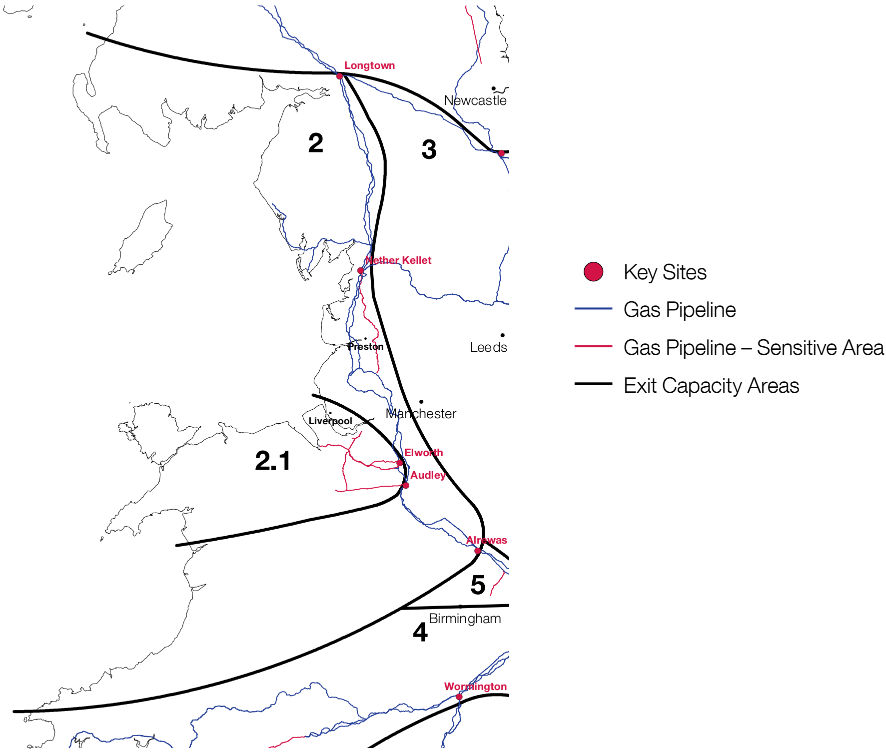


NTS location: North of Longtown and Bishop Auckland
NTS/DN exit zones: SC1, 2, 3, 4, NO1, 2

This region is sensitive to St Fergus flows. High St Fergus flows mean exit capacity will be available. As St Fergus flows reduce, exit capacity will be constrained. There is only a small quantity of substitutable capacity in the area, but compressor flow modifications, including reverse flow capability, can be delivered to provide significant quantities of capacity without requiring Planning Act timescales. Capacity may be more limited in the sensitivity area (feeder 10 Glenmavis to Saltwick) due to smaller diameter pipelines.

4.2 continued
NTS Exit Capacity Maps and Lead Times

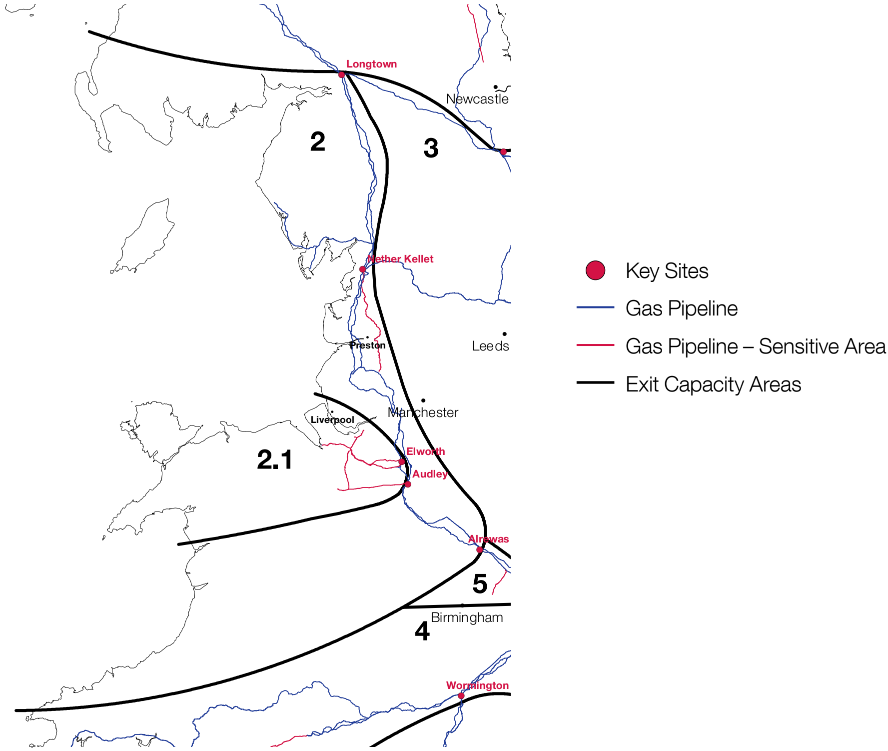
Figure 4.2C(a)
Region 2 – North West and West Midlands (North)



NTS location: South of Longtown, north of Alrewas and east of Elworth
NTS/DN exit zones: NW1, WM1

The amount of unsold capacity in the region indicates that capacity could be made available by exit capacity substitution. Capacity is likely to be available on the main feeder sections between Carnforth and Alrewas. The region is highly sensitive to national supply patterns and use of storage; this area was historically supplied with gas from the north but increasingly receives gas from the south and from the east across the Pennines. Potential non-Planning Act reinforcements could release capacity, but then significant pipeline reinforcement would be required, particularly in the sensitive region around Samlesbury and Blackrod (North Lancashire and Greater Manchester).

Figure 4.2C(b)
Region 2.1 – North Wales and Cheshire

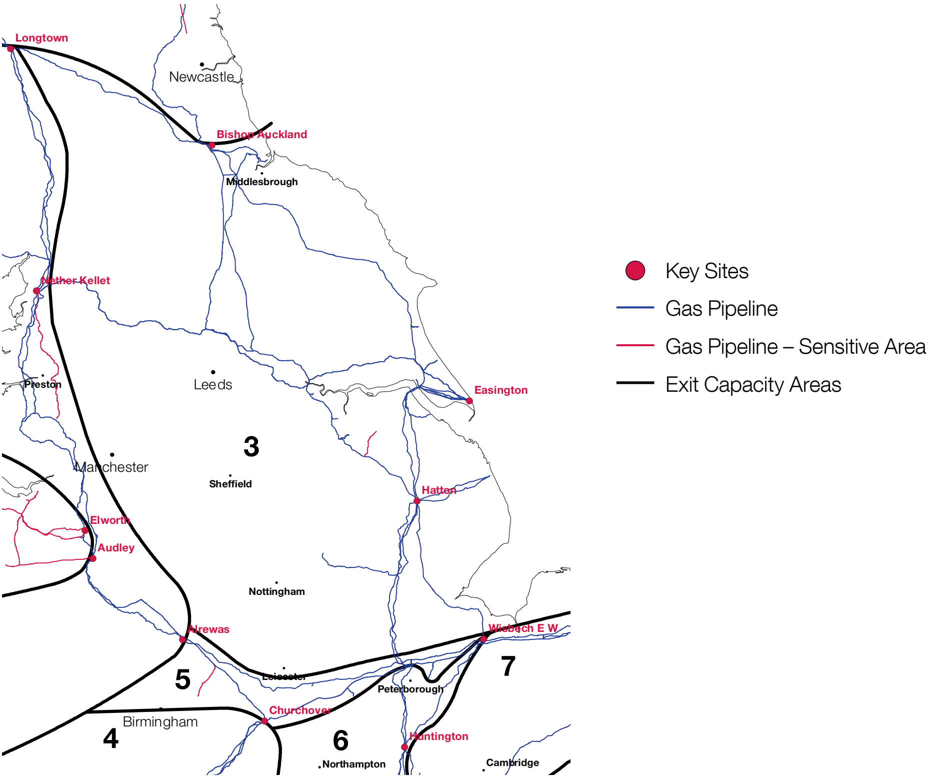


NTS location: West of Elworth and Audley (feeder 4)
NTS/DN exit zones: NW2, WA1

The quantity of unsold capacity within the region indicates a good probability that capacity could be made available via exit capacity substitution, but this is from direct connect offtakes where the capacity could be booked. Potential non-Planning Act reinforcements could release small amounts of additional capacity, but significant pipeline reinforcement would be required, resulting in long (Planning Act) timescales. This is an extremity of the system with limited local supplies (Burton Point) but has a significant number of storage facilities.

4.2 continued
NTS Exit Capacity Maps and Lead Times

Figure 4.2D
Region 3 – North East, Yorkshire and Lincolnshire

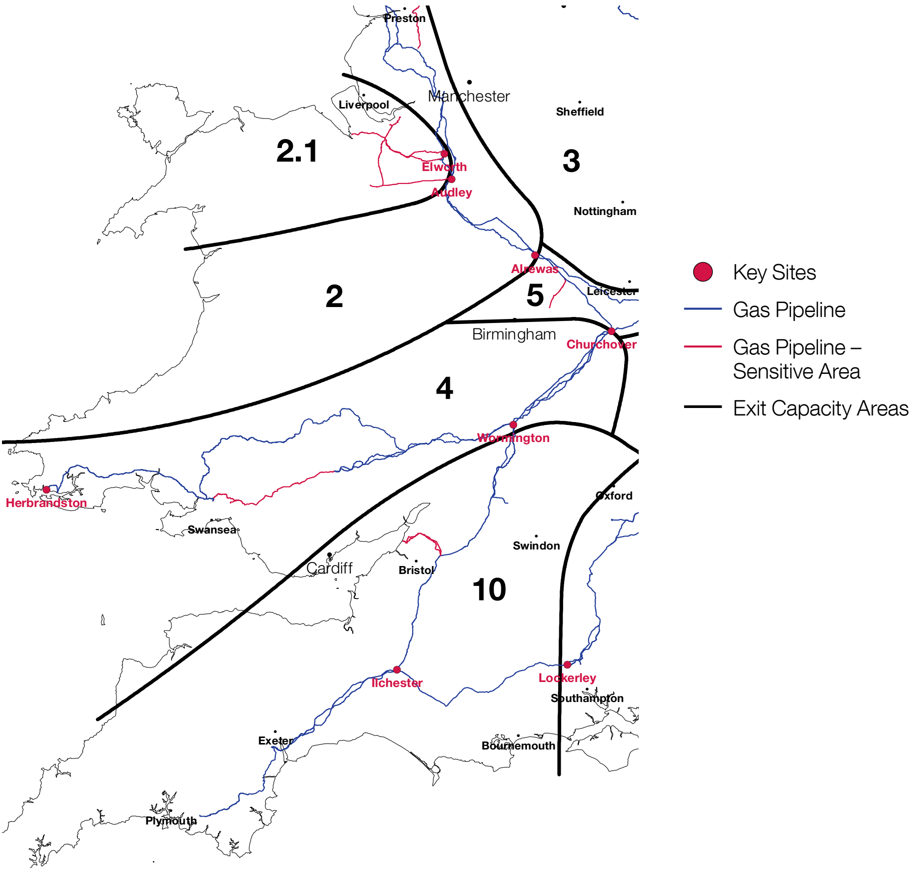


NTS location: South of Bishop Auckland, north of Peterborough and Wisbech and east of Nether Kellet
NTS/DN exit zones: NE1, 2, 3, EM1, 2

The amount of unsold capacity in the region indicates that capacity could be made available through exit capacity substitution. Further capacity should be available without needing reinforcement, assuming stable north-east supplies; however, this may be limited on smaller diameter spurs, including Brigg (shown as a sensitive pipe).

Non-Planning Act reinforcements, including compressor modifications, could be carried out to make additional capacity available. There are a significant number of power stations in this region and this may impact on future ramp rate agreements (the rate at which flows can increase at an offtake, as set out in the Network Exit Agreement – NExA).

Figure 4.2E
Region 4 – South Wales and West Midlands (South)

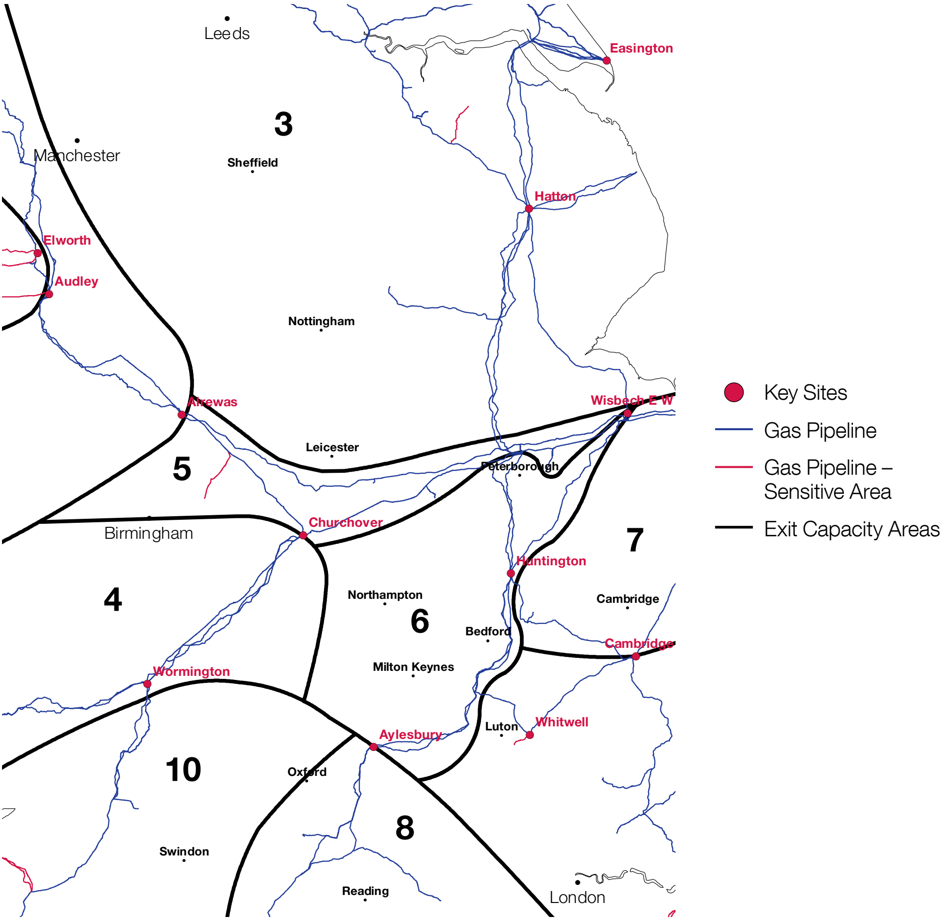


NTS location: West of Churchover
NTS/DN exit zones: WM3, SW1, WA2

The quantity of unsold capacity within the region indicates a limited quantity of capacity could be substituted. Exit capacity availability is highly sensitive to Milford Haven flows. Low Milford Haven flows result in reduced South Wales pressures, which limit capacity. High Milford Haven flows result in reduced pressures in the West Midlands which may limit capacity. Potential non-Planning Act reinforcements could release small quantities of capacity, but significant pipeline reinforcement would be required, since the area south of Cilfrew is a sensitive area (shown in red) due to the different pressure ratings.

4.2 continued
NTS Exit Capacity Maps and Lead Times

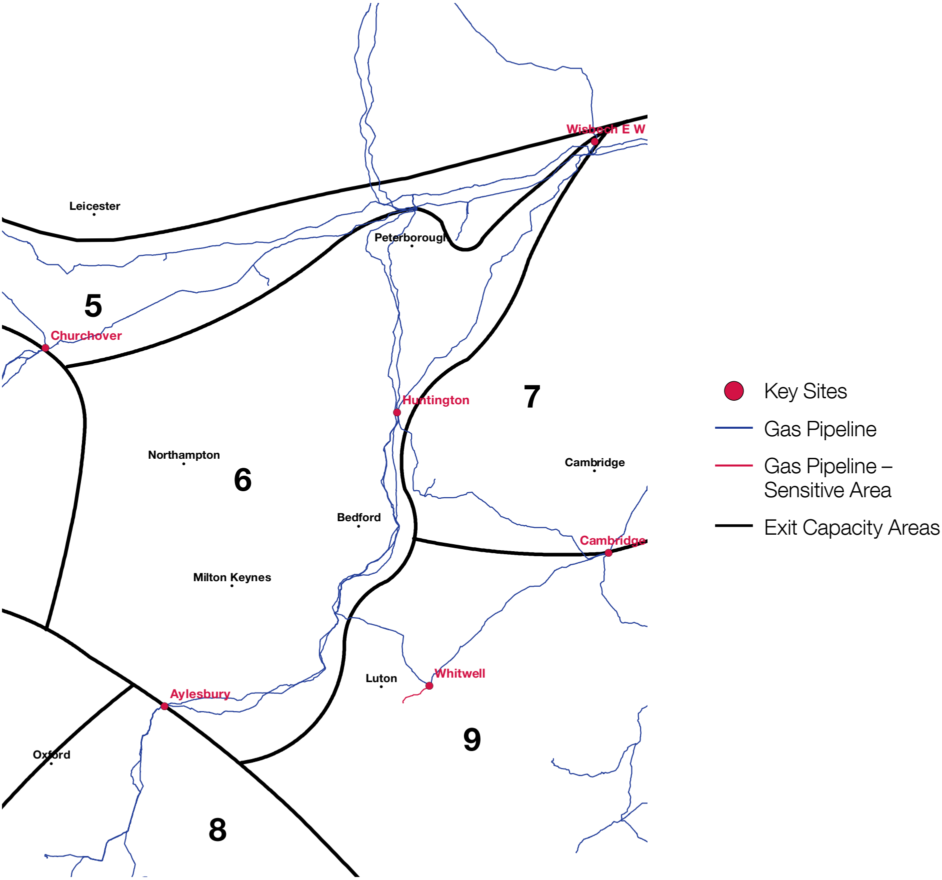
Figure 4.2F
Region 5 – Central and East Midlands



NTS location: South Of Alrewas, north of Churchover, west of Wisbech
NTS/DN exit zones: EM3, 4, WM2

The unsold capacity here indicates a limited scope for substitution. Potential non-Planning Act reinforcements could be carried out to release a small amount of capacity, but significant pipeline reinforcement would be required, in particular for the sensitive area Austrey to Shustoke (shown in red).

Figure 4.2G
Region 6 – Peterborough to Aylesbury

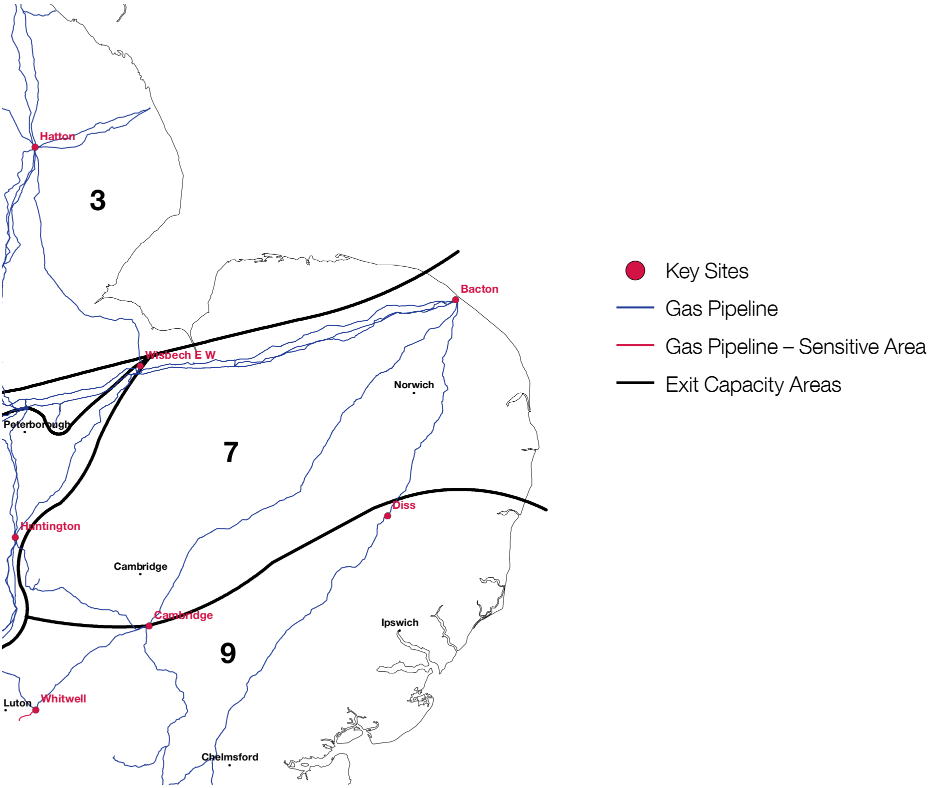


NTS location: North of Aylesbury, south of Peterborough and Wisbech, west of Huntingdon
NTS/DN exit zones: EA6, 7

The quantity of unsold capacity indicates limited scope for exit capacity substitution from the single offtake in the region, but there may be scope for substitution from the southern downstream region. Capacity availability is sensitive to demand increases downstream in region 10, the South West. Potential non-Planning Act reinforcements could be carried out to release capacity.

4.2 continued
NTS Exit Capacity Maps and Lead Times

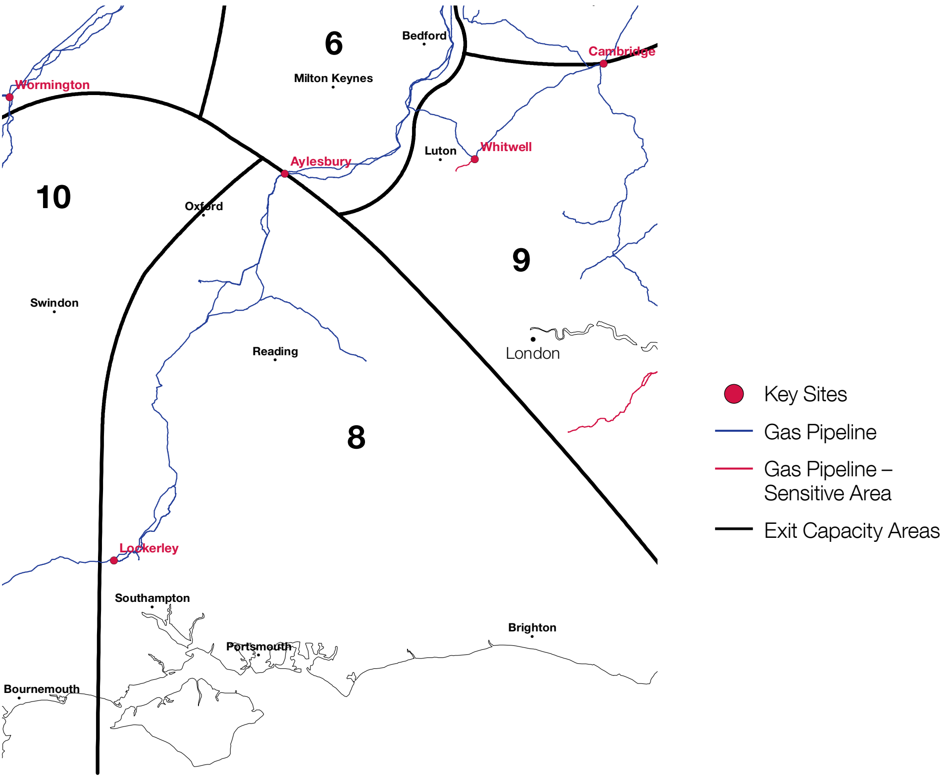
Figure 4.2H
Region 7 – Norfolk



NTS location: North of Diss and Cambridge, east of Wisbech
NTS/DN exit zones: EA1, 2, 3

Unsold capacity here indicates a good probability that capacity could be substituted. Additional capacity could be made available without reinforcement works, assuming stable Bacton supplies. The region is sensitive to South East demand; if demand increases in the South East, capacity may become more constrained.

Figure 4.21
Region 8 – Southern

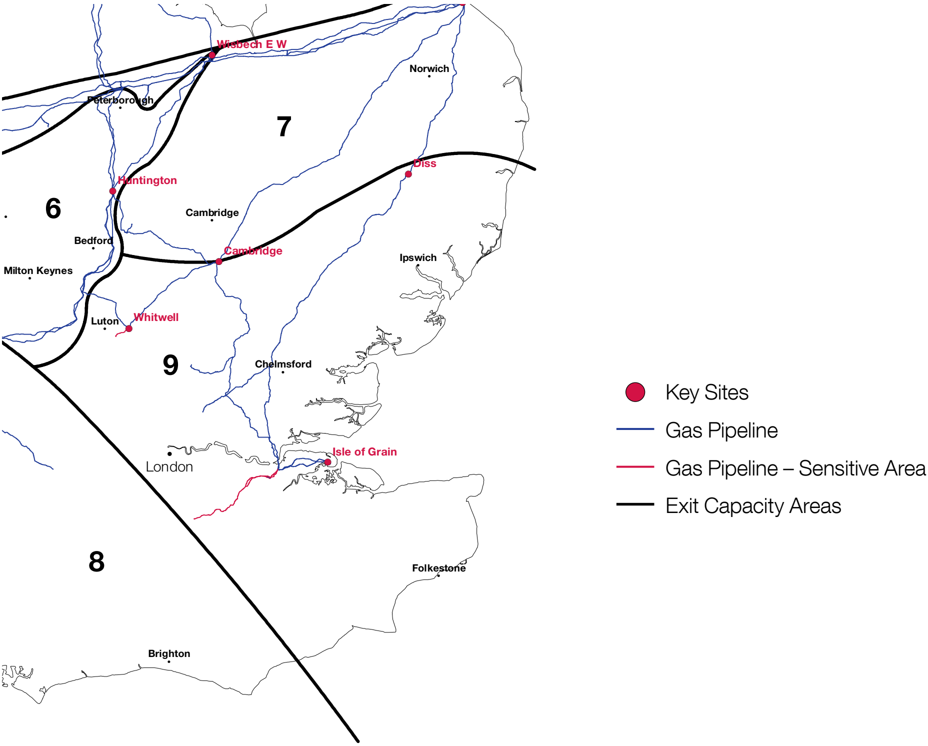


NTS location: South of Aylesbury and north of Lockerley
NTS/DN exit zones: SO1, 2

The amount of unsold capacity indicates a good chance that capacity could be made available via exit capacity substitution. The region is sensitive to demand in the South West; if demand increases, capacity may become more constrained. Potential non-Planning Act reinforcements (compressor station modifications) could release a small amount of capacity.

4.2 continued
NTS Exit Capacity Maps and Lead Times

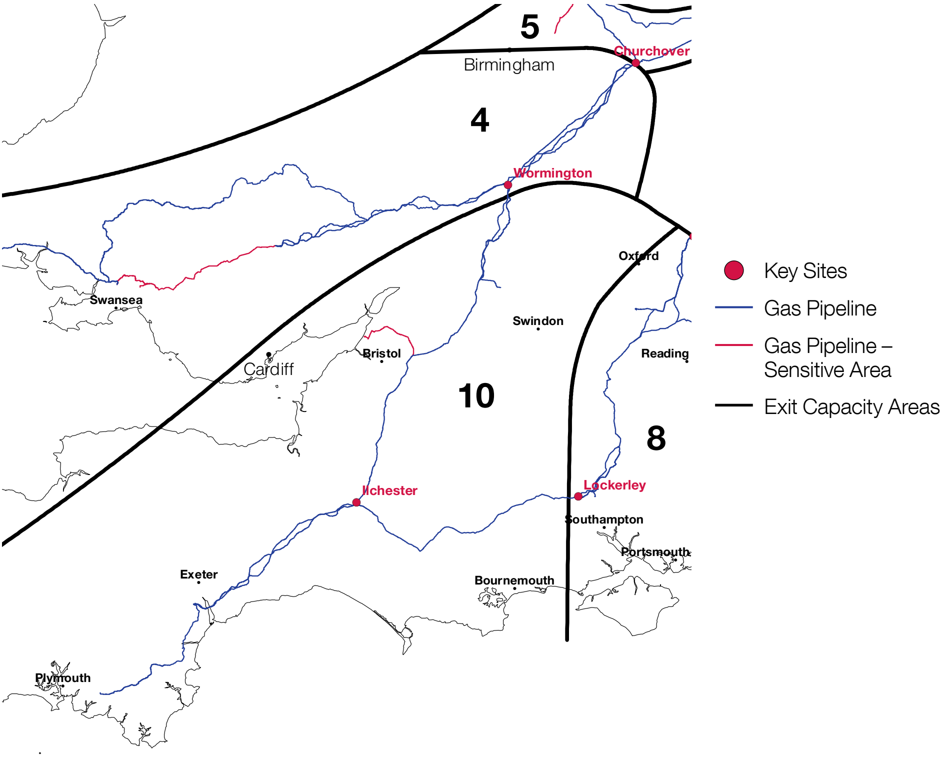
Figure 4.2J
Region 9 – London, Suffolk, and the South East



NTS location: South Diss, Cambridge, east of Whitwell
NTS/DN exit zones: EA4, 5, NT1, 2, 3, SE1, 2

Unsold capacity indicates a good chance that capacity could be made available via exit capacity substitution; however, exchange rates may vary between locations. Potential non-Planning Act reinforcements could be carried out to release small quantities of additional capacity but significant pipeline reinforcement would be needed. The region is sensitive to Isle of Grain flows, with low flows limiting capacity. Capacity may be more limited in the sensitive areas at the extremities of the system shown in red (Tatsfield, Peters Green). The significant number of power stations in the region may impact on future ramp rate agreements (the rate at which flows can increase at an offtake, as set out in the Network Exit Agreement – NExA).

Figure 4.2K
Region 10 – South West



NTS location: South of Wormington and Lockerley
NTS/DN exit zones: SW2, 3

The quantity of unsold capacity in this region indicates limited scope for capacity being made available through exit capacity substitution, and exchange rates may be high due to small diameter pipelines. Potential non-Planning Act reinforcements could release small quantities of additional capacity, but significant pipeline reinforcement would be needed, resulting in long (Planning Act) timescales, particularly in the sensitive area shown in red (west of Pucklechurch on the feeder 14 spur) due to small diameter pipelines. There is some sensitivity to low Milford Haven flows.

4.2 continued
NTS Exit Capacity Maps and Lead Times

4.2.3
NTS/DN exit zones

Table 4.2B
NTS/DN exit zones

Exit Zone	Offtake	Exit Zone	Offtake	Exit Zone	Offtake
EA1	Eye	NO1	Guyzance	SE1	Tatsfield
	West Winch		Cowpen Bewley		Shorne
	Brisley		Coldstream		Farningham
	Bacton Terminal		Corbridge		Isle of Grain (LNG)
EA2	Bacton Terminal		Thrintoft	SE2	Winkfield (SE)
	Great Wilbraham		Saltwick	SO1	North Stoke (Ipsden)
	Roudham Heath		Humbleton	SO2	Mappowder
EA3	Bacton Terminal		Little Burdon		Braishfield 'A'
	Yelverton		Elton		Winkfield (SO)
EA4	Matching Green	NO2	Wetheral	SW1	Fiddington
	Royston		Keld		Evesham
	Whitwell		Tow Law		Ross
EA6	Hardwick	NT1	Winkfield (NIL)	SW2	Littleton Drew
EM1	Thornton Curtis 'A'	NT2	Horndon 'A'		Avonmouth (LNG)
	Walesby	NT3	Peters Green		Easton Grey
EM2	Kirkstead	NW1	Blackrod		Cirencester
	Sutton Bridge		Samlesbury		Ilchester
	Silk Willoughby		Lupton		Pucklechurch
	Gosberton	NW2	Mickle Trafford	SW3	Kenn (South)
	Blyborough		Malpas		Aylesbeare
EM3	Alrewas Compressor		Warburton	WA2	Dyffryn Clydach
	Blaby		Weston Point		Dynevor Arms Tee
	Tur Langton		Holmes Chapel		Gilwern
EM4	Market Harborough		Eccleston		Dowlais
	Caldecott		Audley	WM1	Aspley
NE1	Towton	SC1	Careston		Audley
	Rawcliffe		Balgray		Milwich
	Baldersby		Kinknockie	WM2	Shustoke
	Pannal		Aberdeen		Austrey
	Asselby	SC2	Broxburn		Alrewas Compressor
	Burley Bank		Armadale	WM3	Ross
NE2	Ganstead	SC3	Hume		Rugby
	Hornsea		Soutra		Leamington
	Easington	SC4	Nether Howcleugh		Stratford-Upon-Avon
	Pickering		Lockerbie		
	Paull		Pitcairngreen BV		
			Drum		

Table 4.2B provides the distribution network zones for all the NTS/DN offtakes.

4.3
Exit Capacity – Booking Summary

Aggregate NTS exit (flat) capacity allocations have fallen by approximately three per cent compared to levels previously signalled, and there has been a small increase in aggregate NTS exit (flex) capacity.

Figures 4.3A and 4.3B detail the year-on-year change between exit capacity allocated to DN customers from the 2009 to 2014 Exit Capacity Allocation Processes.

Figure 4.3A
DN exit (flat) capacity bookings

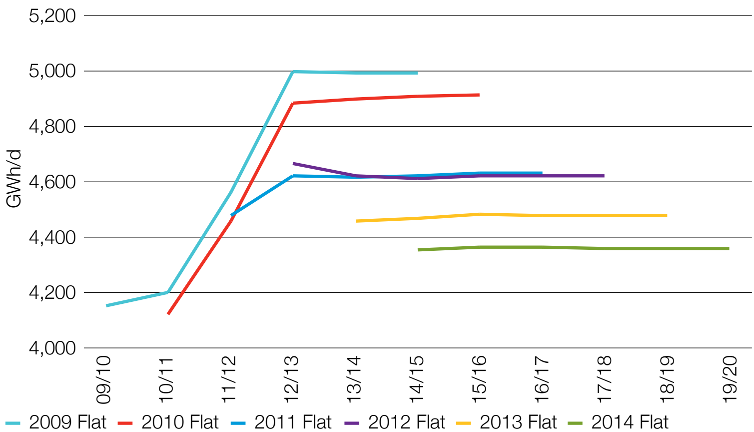
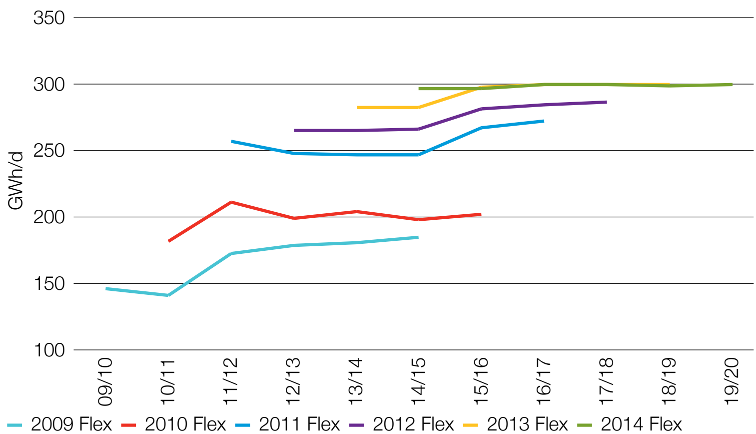


Figure 4.3B
Exit flex capacity bookings



4.3 continued
Exit Capacity – User Commitment Summary

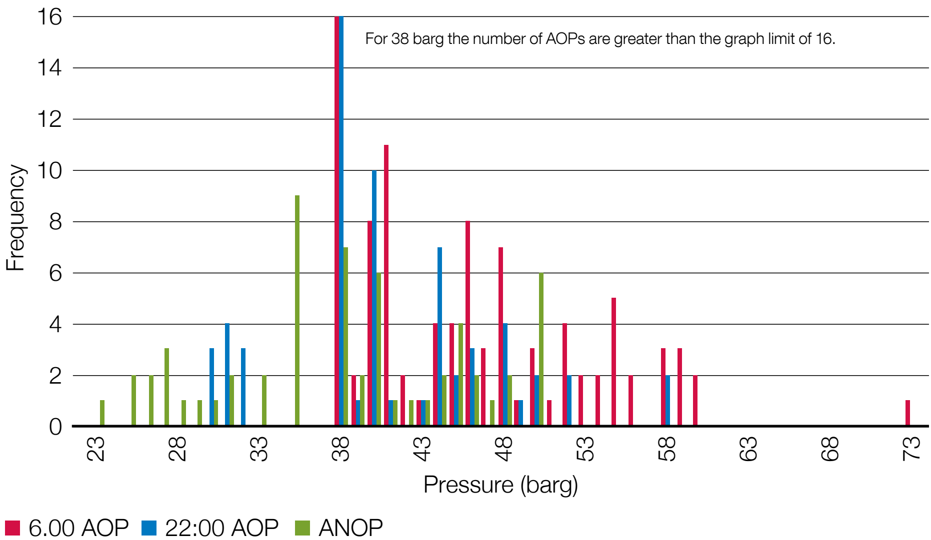
All obligated NTS exit (flat) capacity requests from DNs have been allocated in full. Requested increases in non-obligated NTS exit (flat) capacity and NTS exit (flexibility) capacity were rejected if they could not be accommodated within the capability of the system while maintaining existing entry and exit commitments, or if the release would significantly increase operational costs.

The graphs clearly demonstrate an ongoing trend in flat capacity reductions year-on-year at the same time as significant increases in flex capacity requests. DN NTS exit (flexibility) capacity requirements have nearly doubled over the last five years of bookings.

4.3.1
NTS pressure agreements

Figure 4.3C shows the main exit pressure agreements, both obligated and advisory, that we have in place.

Figure 4.3C
Exit pressure agreements



There are two primary types of pressures on the NTS:

- Assured Offtake Pressures (AOPs) as defined in the UNC. These are a minimum pressure requirement to maintain security of supply to DN customers
- Anticipated Normal Operating Pressures (ANOPs). These are advisory pressures and indicate to directly connected customers the minimum pressure likely to be available on the NTS in their connection area under normal operation.

Assured offtake pressures – All DN offtakes have AOPs covering both 06:00 (start of day) pressures and 22:00 (end of day) pressures and are defined in the UNC. These are pressure obligations, primarily around winter capacity requirements, that we have to maintain to ensure security of supply to DN users. A significant number of these assured pressures (approximately a third of 06:00 and two thirds of 22:00, extending beyond the limits of the graph) are set at 38 barg; the anticipated minimum pressure in most sections of the NTS under normal operating conditions. 06:00 pressures enable DN operators to build linepack within their own systems overnight, potentially reducing their flex capacity requirements. 22:00 pressures are the minimum pressures that must be maintained on the NTS, other than with prior agreement. These pressure agreements, which are in place to maintain supplies to customers within the distribution networks, can lead to transportation and within-day capability restrictions on the NTS.

Anticipated normal operating pressures – The typically lower ANOPs are provided at other NTS exit locations and represent our best view of the minimum pressure likely to be seen at each exit point during normal operations. These are predominantly in place to advise the customer what minimum pressures they could see at their offtake to enable efficient plant design. If NTS capability analysis shows an increasing likelihood that these pressures may not be met under normal operation, the customer will be notified of revised ANOPs with at least 36 months notice.

4.3 continued
Exit Capacity – User Commitment Summary

Impact of Electricity Market Reform (EMR)
EMR is a government policy to incentivise investment in secure, low-carbon electricity, improve the security of Great Britain's electricity supply, and improve affordability for consumers.

The Energy Act 2013 introduced a number of mechanisms. In particular:

- A capacity market, that will help ensure security of electricity supply at the least cost to the consumer
- Contracts for difference, which will provide long-term revenue stabilisation for new low carbon initiatives.

Both are administered by delivery partners of the Department of Energy and Climate Change (DECC). This includes National Grid Electricity Transmission (NGET).

The capacity market has been developed to ensure that there is enough flexible generation available to supply electricity demand for periods with low renewable generation. Both existing and new generation are able to take part in the capacity market, with delivery of the first new capacity expected in 2018. One of the aims of the capacity market is to incentivise new generation to connect. So if new gas-fired generation is successful in the capacity auction, these new gas-fired power stations will require additional gas capacity before 2018 to allow them to meet their EMR capacity market contract.

It is expected that the EMR capacity market will result in a number of new gas-fired power stations being built that have secured capacity contracts. We believe there will be a number of new connection applications following the 2014 EMR capacity market auction process. In addition, existing gas-fired power stations may delay their decommissioning date dependent on successful contracts and may require additional firm capacity.

To better align transmission system developments to the development of projects that would like to connect to the transmission system, we are developing proposals that aim to provide industry parties with additional tools for managing their longer-term capacity arrangements.

The development of the PARCA will introduce arrangements to improve the certainty, flexibility and transparency of the long-term capacity requirements for our customers.

In addition, the EMR capacity market will incentivise generators with a capacity contract to produce electricity at times of forecast scarcity. If they are not producing electricity during these times, it is proposed that they will be subject to a maximum penalty of £17,000/MWh. It is not yet known what impact such an incentive will have on the gas network, or the interaction of the gas and electricity market; however, there is potential for the electricity incentives to feed through into the gas market.

4.4 NTS Entry Capacity Availability and Capacity Lead Times

This section contains information about the lead time for providing NTS entry capacity as a guide for shippers and developers. If unsold NTS entry capacity is available at an existing Aggregate System Entry Point (ASEP) then it can be accessed via the daily, monthly and annual entry capacity auction processes. If unsold capacity is not available through this process, including at new entry points, the lead times may be longer.

The information should inform the likely lead time associated with new entry points; however, new entry points can typically result in significant changes to network flow patterns and we encourage customers to approach our customer service team to discuss specific requirements. This information is just an indication; actual capacity availability will depend on the amount of capacity requested from all customers at an ASEP and interacting ASEPs.

4.4.1 Entry planning scenarios

Chapter 3 discussed the uncertainties in the future supply mix that arise from both existing supplies and potential new developments, which are in aggregate capable of exceeding most peak demand scenarios. These uncertainties are increased by Gas Transporters Licence requirements for us to make obligated capacity available to shippers up to and including the gas flow day. This creates a situation where we are unable to take long-term auctions as the definitive signal from shippers about their intentions to flow gas on any particular day. We are continuing to develop our processes to better manage the risks that arise from such uncertainties.

To help understanding of entry capability, we have used the concept of entry zones which contain groups of ASEPs (figure 4.4A). The entry points in 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 Isle of 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.

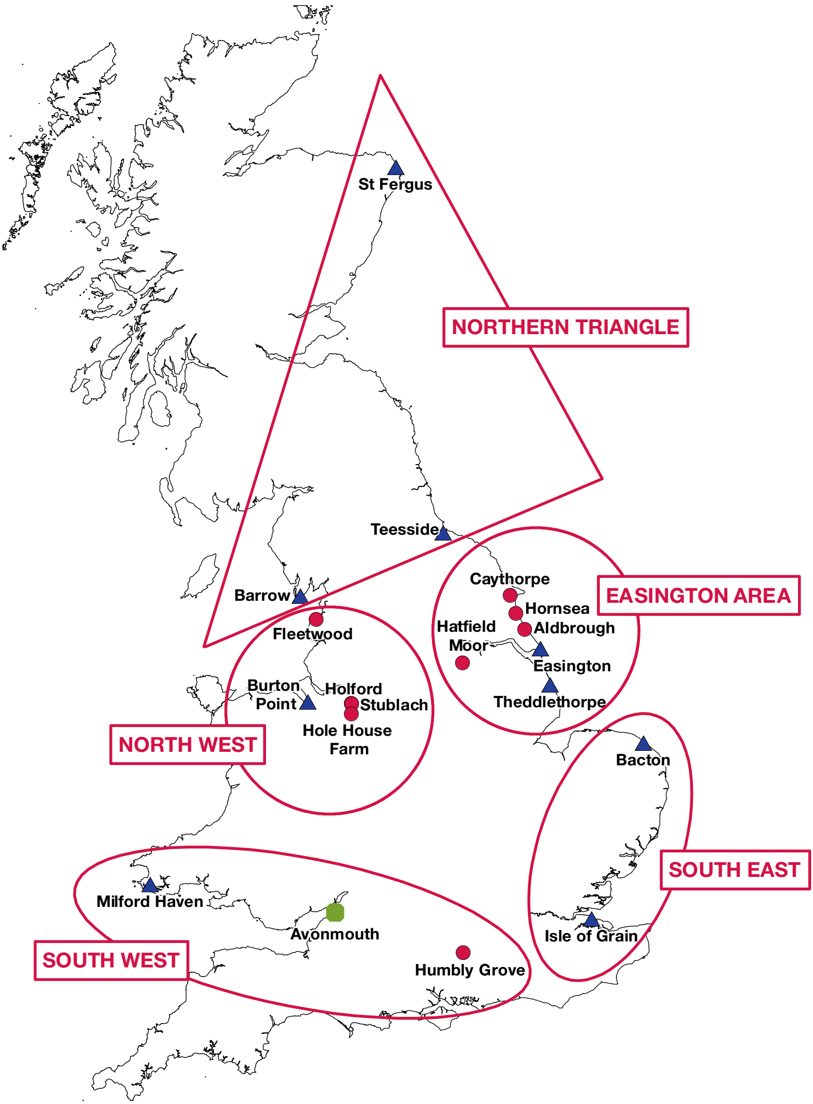
Northern Triangle – includes St Fergus, Teesside and Barrow; all of these northern supplies need to be transported down either the east or west coast of England to reach major demand centres in the midlands and south of the country.

South West – this zone enables sensitivity analysis around potential supplies from Milford Haven.

North West – includes storage at Hole House Farm and Cheshire.

4.4 continued
NTS Entry Capacity Availability and Capacity Lead Times

Figure 4.4A
Zonal grouping of interacting supplies



An example of this approach is that analysis of the South East would consider higher flows from the Bacton and Isle of Grain entry points while reducing other supplies to create a demand balance for the day being considered. Key scenarios examined through the planning process include:

High west to 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, including IUK export.

High south to 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 scenario with a reduction in imported gas balanced by high medium-range storage entry flows to meet winter demand is investigated.

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 customer requirements from the network evolve, it is increasingly necessary to consider the ability of the system to switch between different flow scenarios, explicitly considering changing flows on the network.

If this technique indicates that future requirements from the network are outside of current capability, a range of possible solutions (regulatory, commercial and physical) are investigated where appropriate. This makes sure that broad spectrums of solutions are identified. Where investment in assets is the optimum solution, this would be developed with further optioneering through the planning process.

4.4.2
Available (unsold) NTS entry capacity

The table 4.4A indicates the quantities of obligated and unsold NTS entry capacity at each ASEP within each entry zone. This unsold capacity (obligated less any previously sold) is available at each relevant ASEP and could also be used to make capacity available at other ASEPs through entry capacity substitution. Substitution may also be possible across entry zones.

4.4 continued
NTS Entry Capacity Availability and Capacity Lead Times

Table 4.4A
Entry capacity by zone – see figure 4.4A for the location of entry zones

Entry Zone	ASEP	Obligated Capacity GWh/day	Unsold Capacity 2014/2015 GWh/day	Unsold Capacity 2018/2019 GWh/day	Unsold Capacity 2021/2022 GWh/day
Northern Triangle	Barrow	340.0	30.9	45.7	60.3
	Canonbie	0.0	0.0	0.0	0.0
	Glenmavis	99.0	99.0	99.0	99.0
	St Fergus	1,670.7	1,220.1	1,572.0	1,641.3
	Teesside	476.0	243.7	368.5	442.5
North West	Burton Point	73.5	29.4	65.1	73.5
	Cheshire	542.7	28.6	28.6	28.6
	Fleetwood	650.0	650.0	650.0	650.0
	Hole House Farm	296.6	13.2	13.2	13.2
	Partington	215.0	215.0	215.0	215.0
Easington Area	Caythorpe	90.0	0.0	0.0	0.0
	Easington (incl. Rough)	1,407.2	106.2	106.2	394.0
	Garton	420.0	0.0	0.0	280.0
	Hatfield Moor (onshore)	0.3	0.3	0.3	0.3
	Hornsea	233.1	27.3	27.3	233.1
	Hatfield Moor (storage)	25.0	3.0	3.0	3.0
	Theddlethorpe	610.7	581.9	610.7	610.7
South West	Avonmouth	179.3	179.3	179.3	179.3
	Barton Stacey	172.6	82.6	82.6	172.6
	Dynevor Arms	49.0	49.0	49.0	49.0
	Milford Haven	950.0	0.0	0.0	150.0
	Wytch Farm	3.3	3.3	3.3	3.3
South East	Bacton	1,783.4	886.5	1,034.4	1,181.8
	Isle of Grain	699.7	35.4	35.4	35.4

Table 4.4A contains the ASEP names as defined in the NTS Licence. For clarity, the Garton ASEP contains the Aldborough storage facility, the Barton Stacey ASEP contains the Humbly Grove storage facility, and the Cheshire ASEP contains the Hill Top Farm, Holford and Stublach gas storage facilities. More information on storage facilities can be found in appendix 2 table A2.4.

Appendix 2 figures A2.2 A to H provide further information about the level of booked and obligated entry capacity at each ASEP, excluding those that are purely storage. The figures also provide data points representing historic maximum utilisation and the range of future peak flow scenarios for these ASEPs. While all un-booked capacity can be considered for entry capacity substitution, future bookings may change and the gap between the scenario peak flow data and the obligated capacity level may be a better indication of the capacity available for substitution. Using this indicator, significant capacity for substitution exists at St Fergus and Theddlethorpe.

Entry zone – Northern Triangle

ASEPs: Barrow, Canonbie, Glenmavis, St Fergus, Teesside (and Moffat)

The amount of unsold capacity in this region, combined with the reduced St Fergus forecast flows, indicates a high likelihood that capacity could be made available through entry capacity substitution. Potential non-Planning Act reinforcements, including compressor reverse flow modifications, could release further quantities of additional capacity.

Entry zone – North West

ASEPs: Burton Point, Cheshire, Fleetwood, Hole House Farm, Partington

The unsold capacity in this region indicates that some capacity could be made available via entry capacity substitution; however, entry capability will not necessarily match entry capacity and exchange rates may be greater than one to one. Potential non-Planning Act reinforcements, including compressor reverse flow modifications, could release additional capacity but significant pipeline reinforcement would then be required, resulting in long (Planning Act) timescales.

4.4 continued
NTS Entry Capacity Availability and Capacity Lead Times

Entry zone – Easington area
ASEPs: Caythorpe, Easington (incl. Rough), Garton, Hatfield Moor (onshore), Hornsea, Hatfield Moor (storage), Theddlethorpe

The quantity of unsold capacity in this region indicates a limited scope for additional capacity to be made available via entry capacity substitution. Potential non-Planning Act reinforcements, including compressor reverse flow modifications, could release some additional capacity but significant pipeline reinforcement would be needed, resulting in long (Planning Act) timescales.

Entry zone – South West
ASEPs: Avonmouth, Barton Stacey, Dynevor Arms, Milford Haven, Wytch Farm

The quantity of unsold capacity in this zone is principally at the Avonmouth and Dynevor Arms ASEPs associated with the LNG storage facilities. Due to the short duration of deliverability of these facilities, it is unlikely that the capacity could be made available for entry capacity substitution other than for equivalent facilities. Significant pipeline reinforcement and additional compression would be required to provide incremental capacity resulting in long (Planning Act) timescales.

Entry zone – South East
ASEPs: Bacton, Isle of Grain

While there is a high degree of interaction between the Bacton and Isle of Grain ASEPs, the quantity of unsold capacity in this zone cannot be interpreted as an indication of suitability for entry capacity substitution. This is due to constraints on the network in terms of the ability to transport gas south to north. Potential non-Planning Act reinforcements, including compressor reverse flow modifications, could release some additional capacity, but significant pipeline reinforcement would then be required resulting in long (Planning Act) timescales.

4.5
Entry Capacity – Auction Results Summary

The QSEC auctions opened on Monday 17 March 2014 and closed on Tuesday 18 March 2014. In order for incremental obligated entry capacity to be released, and therefore the obligated entry capacity level to be increased, enough bids for entry capacity must be received during the QSEC auctions to pass an economic test. If insufficient bids are received, capacity in excess of the obligated level can be released on a non-obligated basis, which would mean that the obligated capacity level does not increase for future auctions.

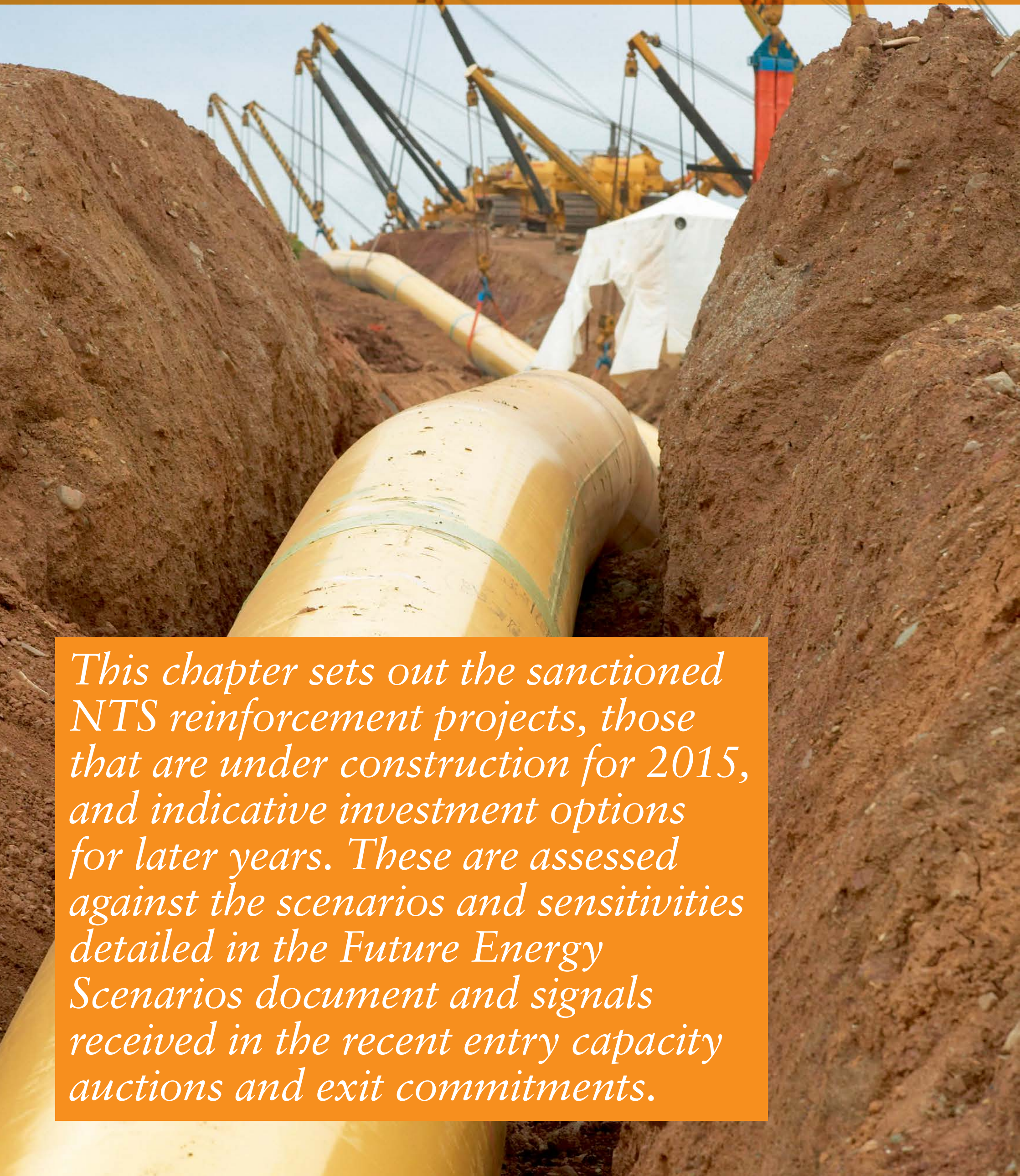
During the March 2014 QSEC auctions, bids were received for incremental entry capacity (for Q1 2016, 2017, 2018, 2019 and 2020) at the Easington Aggregate System Entry Point (ASEP). The bids received were insufficient to pass the economic test for the release of incremental obligated entry capacity; however, following a risk assessment process, non-obligated entry capacity was released to meet all the bids at Easington (for Q1 2016, 2017, 2018, 2019 and 2020).

The incremental risk created by the 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.

4.5.1
Investment implications

No direct investments were identified or triggered, since no incremental obligated entry capacity was released.

Chapter 5
Meeting Future Capability Requirements



This chapter sets out the sanctioned NTS reinforcement projects, those that are under construction for 2015, and indicative investment options for later years. These are assessed against the scenarios and sensitivities detailed in the Future Energy Scenarios document and signals received in the recent entry capacity auctions and exit commitments.

Key messages

- The uncertainty around supply and demand scenarios is making it increasingly complex to plan future capability on the Gas Transmission System.
- Our current business is partly driven by the potential incremental entry or incremental exit capacity signals we may see in the next ten years.
- All our gas-driven compressors that produce emissions above the threshold set by the Industrial Emissions Directive (IED) must be compliant with new limits by 31 December 2023. We recently issued our initial consultation document that was the result of stakeholder engagement conducted during the year. We will be issuing our draft proposal in February 2015 ahead of our May 2015 submission under the RIIO-T1 uncertainty mechanism.
- We are undertaking a project to review future flexibility requirements for the system and considering how different events or factors across gas days, and within-day, might affect the way the system is managed. This work may lead to changes in the planning processes and require asset, commercial and operability solutions to be progressed to deliver more capability in the system.
- Following the announcement that the Liquefied Natural Gas Storage (LNGS) facility at Avonmouth will close in 2018[1], we are working to agree the most economic and efficient approach to meet the current and future network requirements.
- The decline of future St Fergus flows is showing a greater need to move gas south-to-north. However, the system capability to do this is limited. In recent years the expected decline in flows at St Fergus has not been as severe as we've anticipated previously, which gives us time to assess potential solutions against the changes we will see in the network as a result of the Industrial Emissions Directive. We are monitoring the changes in flows and don't envisage any issues in meeting the timescales required to deliver the investment.
- There is a significant amount of interest in shale gas development in the UK. To date, however, no new wells have been drilled. Our 2014 Future Energy Scenarios gives a wide spread of projections for shale gas providing further uncertainty as to future flow patterns we may see on the NTS.

[1] At the time of print National Grid LNG Storage started a consultation on closing the facility early in 2016. http://www2.nationalgrid.com/UK/Services/LNG-Storage/consultation/

5.1 Introduction

There are many different ways the energy market in the UK could develop over the course of the Future Energy Scenarios, some of which we have covered in the earlier chapters. In this section we are looking to explain what we have done over the last 12 months to meet these challenges so we continue to operate a safe, efficient and economic system.

The key areas we have focused on over the past year are:

- Industrial Emissions Directive (IED) – in preparation for the uncertainty mechanism reopener in May 2015
- System flexibility – to further develop our understanding of the potential impacts and the options we have to mitigate them
- Avonmouth – to assess the impact of the site closing and the planned pipeline investment.

We also provide an update on progress made on other key projects from last year's GTYS and set out the currently sanctioned projects, those that are presently under construction for 2015, and indicative investment (and where applicable, commercial) options for later years. All these have been assessed against the scenarios and sensitivities detailed in our 2014 Future Energy Scenarios document, and signals received in the recent entry capacity auctions and exit capacity allocations.

The annual planning process performs a critical role in allowing us to prepare for likely future system capability requirements, while making sure investment decisions that have not yet progressed to construction remain valid in light of the latest supply and demand scenarios. Maps showing the current NTS and future investments are presented in Appendix 4.

5.2 Load-related Investment

Load-related investment is the term given to physical reinforcement projects generated by signals for incremental entry capacity or incremental exit capacity.

A key part of our planning process is understanding any system reinforcements that may be necessary to meet future customer requirements as a result of enquiries we receive for new connections to the network (including expansions at existing customer sites). 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 is likely to result in a requirement for reinforcement. Following positive customer feedback from last year, we are again publishing this information in the form of capacity maps in response to customer requests for more information about where connections to the system would require little or no reinforcement (see sections 4.2 and 4.4).

As described in section 2.3, peak demand to 2020 under all four of our energy scenarios is similar, then shows an upshift due to the reduction in coal generating capacity. Peak demand then either remains flat or goes into decline (varying by scenario) over the FES horizon. Any incremental entry or exit capacity signals received against these backgrounds for at least the next 10 years are likely to trigger similar levels of total investment to enhance network transmission capability (to increase the levels of end-of-day volumes of gas that can be put on to or taken from the system).

We are working with developers who want to connect to the NTS to understand the options for asset and other solutions that enable the release of incremental capacity under the Planning Consent Agreement (PCA) process. These discussions have informed our latest business plan. However, as we have not yet received firm signals for all of the projects, there is significant variability in our investment plans for load-related projects.

Our current business plan is partly driven by potential incremental entry or incremental exit capacity signals we may see in the next ten years. These could arise due to signals for:

- New power station connections in the South West of England
- New power station connections in the South East of England
- New power station and/or storage connections in the North West of England
- New entry connections in the South East of England
- New shale gas connections.

It is important to stress that reinforcement projects in our business plan 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. We will also consider non-asset-based solutions alongside system reinforcement when looking at options for meeting capacity requests from customers. Non-asset-based solutions could be to negotiate bilateral 'turn up' or 'turn down' contracts with other users of the network. These may be more economic if additional capability is only needed over a relatively short timescale. Other options could be to develop optimised investment strategies across the NTS and distribution networks in collaboration with distribution network owners to reduce the need for large scale investment on the NTS.

5.3 Industrial Emissions Directive

The Industrial Emissions Directive[2] (IED) brought together a number of existing pieces of European legislation including the Integrated Pollution Prevention and Control (IPPC) Directive and the Large Combustion Plant (LCP) Directive. IED came into force on 6 January 2013.

The major provisions of the IED, which impact us and our compressor units' are:

1) The use of permits for installations
2) Establishment of BAT reference documents
3) The updating of ELVs for installations above 50MW
4) Limited lifetime derogation
5) Emergency use provision.

This means:

- Under the IPPC part of the legislation we target sites currently operating high NOx or CO emitting compressor units or with high forecast utilisation to achieve the most environmental improvement at the lowest cost
- Under the IED part of the legislation (affecting 17 of our 64 compressor units) we must either:
  i. Ensure captured units comply with the legislation
  ii. Enter units into a limited lifetime derogation
  iii. Enter units into an Emergency Use Provision.

There is also the potential for further legislation with the Medium Combustion Plant (MCP) directive that will apply limits on emissions to air from sites below 50MW thermal input. MCP is likely to come into force by 2020 and could impact compressor units across 10 of our sites.

Permits

IED[3] specifies that all installations must be operated with a permit. These permits will specify the ELVs for polluting substances which are likely to be emitted from the installation concerned. The permit conditions will also determine the environmental risk of that installation and will make sure the principles of BAT have been applied. This mirrors the specifications set out in the IPPC where installations have to comply with the ELVs set out in that permit which are based on BAT. We have agreed to continue the Network Review Process to comply with these requirements.

BAT reference (BREF) documents

The IED also introduces an increased emphasis on the status of the BAT reference (BREF) documents. These BREF documents draw conclusions on what the BAT is for each sector to comply with the requirements of IED. The BAT conclusions drawn as a result of the BREF documents then form the reference for setting the permit conditions mentioned above. The BREF document for large combustion plants is in draft form and should be finalised in 2016. From finalisation there will then be four years for member states to implement it. At this stage it is still uncertain how the BREF documents will be applied and what impact it will have on our compressor units.

Update of ELVs for installations above 50MW

IED states[4] that for installations with a thermal input over 50MW it is mandatory for the following ELVs to be complied with:[5]

- Carbon Monoxide (CO) – 100mg/Nm^3
- Nitrogen Oxide (NO_x) – 75mg/Nm^3 for existing installations and 50mg/Nm^3 for new installations[6].

[2] A copy of the Industrial Emissions Directive can be found at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:334:0017:0119:EN:PDF
[3] Article 4
[4] Article 30
[5] Annex V, Part 1, para 6
[6] An existing installation is one that was granted a permit before 7 January 2013.

In this respect, the IED mirrors the requirements set out in the LCPD. Our compressors that cannot meet the new ELVs for CO and NO_x must stop operating on 31 December 2015 unless the unit receives a derogation.

Limited lifetime derogation

In the IED[7] the requirements needed to receive a limited lifetime derogation are specified. It states that from January 2016 to 31 December 2023 the combustion plant may be exempted from compliance with the ELVs for installations above 50MW provided that certain conditions are fulfilled:

- The operator makes a declaration before 1 January 2014 not to operate the plant for more than 17,500 operating hours starting from 1 January 2016, and ending no later than 31 December 2023
- Each year the operator submits a record of the number of operating hours since 1 January 2016
- The ELVs set out in the permits, as per the requirements of the IPPC Directive, are complied with.

We have already made this 17,500 operating hours declaration referred to and have been allowed to utilise this derogation for our current stations. However, there is still the option to pull out of using this derogation before it starts on 1 January 2016.

Emergency use provision

The IED also makes a provision for using installations for emergency use:

"Gas turbines and gas engines for emergency use that operate less than 500 operating hours per year are not covered by the emission limits values set out in this point. The operator of such plant shall record the used operating hours."[8]

This means that we may still be able to use our affected compressor units that do not comply with the above ELVs if we use them for 500 hours or less. As with the limited lifetime derogation, this would also be applicable from 2016.

Figure 5.3A illustrates how the IPPC and the LCP directives have fed into the IED and resulted in the key features of the IED split by installations below and above 50MW.

[7] Article 33
[8] Annex V, Part 1, para 6

5.3 continued
Industrial Emissions Directive

Figure 5.3A
IED key features

IPCC
Apply for permit which states emissions limits to be achieved using BATs

LCP
Defines emissions limits to be complied with

IED
Industrial Emission Directive

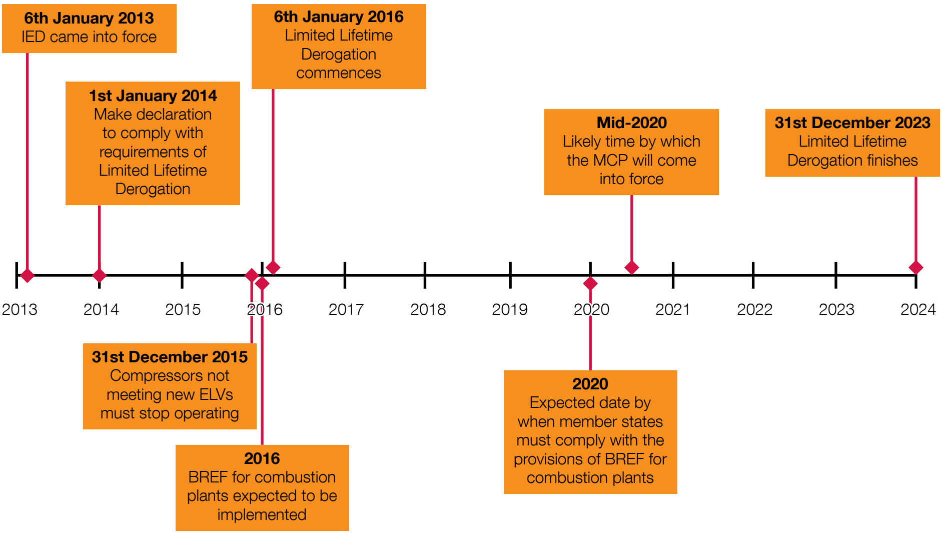
IED Key Features					
Below 50MW	Installations must be operated with a permit	Permits specify the ELVs to be complied with which are based on BAT	BREF documents draw conclusions on what the BAT is for each sector affected by IED	BREF document for combustion plant is likely to be finalised in mid-2016	
Above 50MW	Set new ELV for carbon monoxide 100mg/Nm³ for new and existing plant Set new ELV for nitrogen oxide 50mg/Nm³ new plant; 75mg/Nm³ for existing plant	All our gas-driven compressors that produce emissions above the threshold set by the Industrial Emissions Directive (IED) must be compliant with new limits by 31 December 2023	Compressors not meeting new ELVs have to stop operating by 31st December 2015 unless a Limited Lifetime Derogation is applied for or the unit is entered into emergency use	Through Limited Lifetime Derogation the operator declares not to operate plant for more than 17,500 hours until 31/12/2023	Can use affected compressors that do not comply with ELVs for ‘emergency use’ for less than 500 hours per year

Upcoming legislation: Medium Combustion Plant directive

The Medium Combustion Plant (MCP) directive will apply limits on emissions to air from sites below 50MW thermal input. It is expected that this legislation will introduce ELVs that are differentiated according to the plant's age, capacity and type of installation. It is thought that existing installations would be given a long transition period, up to 2025 for the larger (5–50MW) plants, and up to 2030 for the smaller ones. It is expected that the MCP is likely to come into force by 2020. At this stage the impact of MCP on our compressor units is unclear; however, it could impact units across 10 of our sites.

Figure 5.3B is a timeline of key dates and milestones in the new emission abatement legislation.

Figure 5.3B
Emissions abatement legislation timeline



5.4 Our Progress

5.4.1 Integrated Pollution Prevention and Control (IPPC) directive

A long-term strategy has been developed for the NTS in consultation with Ofgem and the relevant environmental regulators to allow prioritisation of investment across our compressor fleet by dividing investment over phases. This allows us to target sites currently operating high NO_x or CO emitting compressor units, or with high forecast utilisation, and achieves the most environmental improvement at the lowest cost. The priority of sites targeted for investment is reviewed annually through the Network Review process, which documents our investment strategy, together with historical and forecast compressor utilisation.

This approach has proved cost effective, with investment delayed at those sites with higher emissions based on current operation, but with reducing or uncertain utilisation into the future due to changing system flow patterns.

IPPC: Phases 1, 2 and 3

Emissions-related investment is currently progressing at the following sites under Phases 1 and 2 of our IPPC Emissions Reduction Programme. These sites are in the final stages of commissioning and are expected to be operational during early 2015:

- St Fergus (two new electrically-driven compressor units)
- Kirriemuir (one new electrically-driven compressor unit)
- Hatton (one new electrically-driven compressor unit).

Phase 3 of the Emissions Replacement Programme includes investment at Huntingdon and Peterborough to comply with IPPC NO_x and CO emissions limits by 2021. These sites are of an older design and are anticipated to remain high utilisation sites into the future.

The operation of these sites is affected by supply flows (from the terminals to the north, Bacton terminal, and LNG imports from the Milford Haven and Isle of Grain terminals) and demand in the south of the system. Both Peterborough and Huntington are needed to manage network flows in the south and east of the system including at the 1-in-20 peak day demand level described by our Design Standard[9] as defined in our transportation licence. Peterborough and Huntingdon compressors operate together to maintain flows and pressures in the system at high demand levels, and can be used interchangeably at lower demand levels, to provide network resilience (for example, to allow maintenance to be undertaken on one of the sites or to maintain minimum system pressures during unplanned outages).

[9] To plan the system to meet the 1-in-20 peak aggregate daily demand, including but not limited to, within-day gas flow variations on that day.

Peterborough is also a key site for the north–south, east–west and west–east transfer of gas to manage flows from the north, from Milford Haven terminal and to and from Bacton terminal.

We have undertaken extensive analysis of the requirement for operating both sites against our Future Energy Scenarios, under a range of different network flow patterns. We have confirmed through the analysis that both sites are required to manage network flows across a range of supply and demand patterns in the longer term and that future capability requirements are very similar to the current capability provided at these sites so the existing units should be replaced. The Front End Engineering Design (FEED) contract has been awarded and is approaching the end of the Feasibility stage. The tender for the machinery trains has been completed and award of contract is expected before the end of 2014. With the orders placed for the machinery trains, the FEED study will progress to the Conceptual stage in early 2015. Our current view is that these units will need to be replaced by 2021 in order to manage outage requirements on the system and the interaction with investment required as a result of the Industrial Emissions Directive. Given the uncertainty around future supplies and demands, we will be regularly reviewing the requirement for this investment as each stage of the programme of works progresses. A key factor in selection of the machinery train was the flexibility of operation afforded by the design although inevitably, options for significant change are more limited once the machinery trains have been ordered.

5.4.2
Large Combustion Plant (LCP) directive

Phase 1: Aylesbury

Aylesbury is located in the south of the system and is affected by supply flows from the Bacton and Isle of Grain terminals and demand in the south of the system. It is a key site in a series of compressor stations between Hatton in Lincolnshire, to Lockerley in the South West which move flows around the system and support 1-in-20 peak day demand levels in the South West. At lower demand levels than the 1-in-20 peak day demand, this group of compressors can be operated to manage linepack within the system to maintain system resilience to plant failure or unavailability and within day flow variation to the levels we are experiencing on the network today. Under lower demand conditions Aylesbury is also of particular importance as a partial gas-powered backup site to the downstream Lockerley compressor station which only has electrically driven compressor units installed as a consequence of strict local planning constraints.

We have determined that Aylesbury is still required under our Future Energy Scenarios to meet 1-in-20 peak day demand levels in the south of the system. We have also identified that the site could require enhancement to accommodate additional flows (above obligated entry capacity levels) from the Bacton or Isle of Grain terminals or to support system pressures if new CCGTs connect in the South West.

The works at Aylesbury are scheduled for completion by end 2015 in order to minimise constraint costs related to outage requirements and the interaction with Huntingdon and Peterborough IPPC investment (these compressor stations interact and provide resilience for each other).

The existing gas generators at Aylesbury are compliant with current NO_x limits but non-compliant on CO. The preferred solution is based on the installation of a CO oxidation catalyst in the exhaust stack to oxidise excess CO to CO_2. A number of other asset related works are scheduled for delivery at Aylesbury during 2015 as part of an overall upgrade package.

5.4.3
Future phases

During 2014 we have been working to agree the best approach at each site through engagement events. Details of the process we have been through and how we will take this forward are detailed in chapter 6.

IPPC phase 4

In phase 4 it was agreed with the Environmental Agency (EA) and the Scottish Environment Protection Agency (SEPA) that we would target three sites. So that we target the correct sites we extracted data for the current usage at all those sites that have not been BAT-compliant for the last five years. We then adjusted these run hours to take account of the assumed impacts from the previous phases of IPPC:

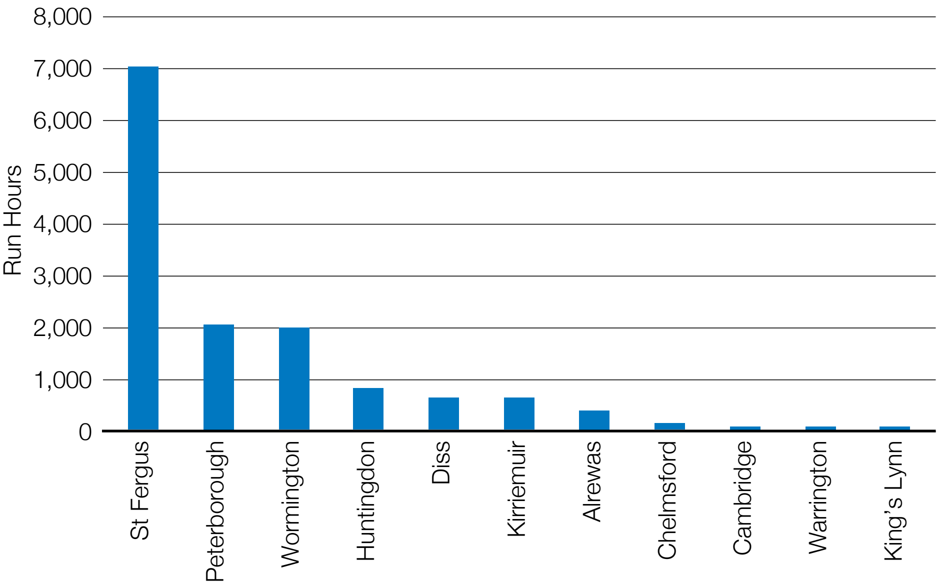
- St Fergus
  - The two electric drives will take most of the duty for the existing 25MW RB211s
  - The RB211s[10] will remain on site with the five Avons that are used for start-up, single operation and back-up
- Kirriemuir
  - The new electric drive will take most of the duty for the 25MW RB211
  - The RB211 remains with the three Avons used for single operation and back-up
- Hatton
  - The new electric drive will take most of the duty for the site
  - The three 25MW RB211s on site fall under the scope of the Industrial Emission Directive
- Peterborough and Huntingdon
  - A new IPPC phase 3 unit should provide most of the duty at each site, but will leave significant operating hours to be covered
  - The six remaining Avons will continue to provide single unit operation and back-up across the two sites and are required to hit other points on the compressor operating envelope.

Based on these changes, the predicted run hours of non-BAT units at each site is shown in figure 5.4A.

[10] The RB211(s) fall under the scope of the LCPD of IED

5.4 continued
Our Progress

Figure 5.4A
Adjusted run hours for units within scope of IPPC phase 4



A further assessment was completed to determine if any of the factors below could result in an increase, decrease or a continued trend in the run hours at each site:

- What the site is used for: entry, exit, bulk transmission
- Changing supply patterns
- New demands
- Asset health issues.

This assessment suggested only Wormington is likely to see any significant change due to the following factors:

- The commissioning of Felindre – this would then be the preferred unit under scenarios of high flows from Milford Haven; one of the prime reasons for running Wormington today
- We are unable to run units A and B at Wormington during the summer due to high ambient temperatures
- Increased confidence in unit C – the electric drive at Wormington has now been operating for a number of years and has become the lead unit
- We have seen low Milford Haven flows during the winter.

Table 5.4A shows we have already seen a significant reduction in run hours on units A and B in the last two years with the electric drive (unit C) now being the lead unit.

Table 5.4A
Wormington run hours for the last five years

Year		2009	2010	2011	2012	2013	5yr Average
Site	**Turbine unit**	**Running hours**	**Running hours**	**Running hours**	**Running hours**	**Running hours**	**Running hours**
Wormington	**A**	283	2,561	2,599	446	33	1,184
	B	173	1,185	2,450	95	48	790
	C	907	1,098	2,021	961	926	1,183
	Total	1,362	4,844	7,070	1,502	1,008	3,157

The output of this analysis was presented at an IED stakeholder event on 30 September 2014 where we received positive feedback to take forward St Fergus, Peterborough and Huntingdon as the next three sites. The output was also included in our consultation document to give you a further opportunity to feed into the decision-making process before we issue our draft proposal.

Large Combustion Plant (LCP) directive

During 2014 we have been working together in stakeholder engagement events to agree the approach we should take for each site. We agreed the key criteria for consideration, which became a scorecard to assess the merits of options at each site. The output of the workshops was the basis of our consultation document[11] published in November 2014.

Following the completion of the consultation process, the feedback received will be fed into our proposals, which will be published in February 2015. You will then have a further opportunity to feed into the process before our proposals are finalised. Our final proposals will then be presented to Ofgem in May 2015 under the uncertainty mechanism set up for IED investment during RIIO-T1[12].

[11] A copy of our consultation document can be found at http://www.talkingnetworkstx.com/IED-Additional-info.aspx

[12] RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas, Cost assessment and uncertainty supporting document, para 7.101.

5.5 Avonmouth

The Liquefied Natural Gas Storage (LNGS) facility at Avonmouth was built in the 1970s and provides both commercial and regulated gas storage services. As well as providing commercial storage services to shippers, it also provides regulated services to the NTS to maintain operational security in the form of Operating Margins (OM) (both for locational and national requirements); and to meet the 1-in-20 demand element of the NTS Security Standard in the form of Transmission Support Services (TSS) through the provision of Constrained LNG (CLNG) services in the south west extremities of the National Transmission System (NTS). It also provides a service for Scotland Gas Networks (SGN) for supplying LNG through tankers to four towns in Scotland (known as the Scottish Independent Undertakings (SIUs)), which are not connected to the gas distribution networks. A decision has been made to close the storage facility because of the significant levels of investment needed to continue operating the site in the long term. It is anticipated that the site will stop operating in 2018[13].

We also procure OM and Transmission Support Services (TSS) from other providers in the South West, and review these requirements and contracts annually. As the current level of contractual cover provided by these other service providers does not fully replace the services offered by the Avonmouth LNGS facility, there is a need to understand the impact of the removal of Avonmouth as a service provider to the NTS in the longer term. Within our RIIO-T1 submissions, it was identified that there was an enduring need for the capability provided by the Operating Margins (OM) gas and constrained LNG services in the south west of the gas network. Based on the enduring need for services, and an assessment of possible alternative options, (Invest in Avonmouth (re-life), alternative provision of services, pipeline solution), funding was provided for construction of a pipeline solution as the most efficient and economic option. Before starting external engagement on the build of any pipelines, we revisited the case for investment. The analysis looked at both the key services Avonmouth provides, locational OM and constrained LNG services, and the relevant high level results are described below:

Operating margins – what has changed since we put forward our RIIO-T1 submission

We purchase operating margins (OM) on an annual basis in line with both the requirements of the UNC, and obligations as described in the National Grid Gas Safety Case in respect of the NTS (the 'Safety Case'). The Safety Case obliges us to maintain OM at certain levels and locations determined throughout the year.

The OM service is used to maintain system pressures in the period before other system management services become effective (e.g. national or locational balancing actions). Primarily, OM will be used in the immediate period after any of the following have taken place and all the other system operator actions are insufficient:

- Supply loss: terminal, sub-terminal, interconnector, LNG importation terminal
- Pipe break (including loss of infrastructure that renders pipe unusable)
- Compressor failure
- Demand forecast error.

A further quantity of OM is also procured to manage the orderly run-down of the system in the event of a Network Gas Supply Emergency (NGSE), while firm load shedding takes place.

[13] At time of print National Grid LNG Storage business started a consultation on closing the facility early in 2016. http://www2.nationalgrid.com/UK/Services/LNG-Storage/consultation/

The Avonmouth LNG storage facility presently provides operating margins (OM) services for certain pipe breaks and compressor failures in the South West and for supply losses on a national basis. The national requirement for OM will need to be met by other providers across the network.

We have undertaken a fundamental review of the reasons and needs for procuring locational OM services from Avonmouth, which is a driver for pipeline investment in the South West.

The locational OM requirement is principally driven by the need to mitigate the effects of a pipeline failure. It should be noted that the risk of pipe failure as a result of third party interference has been quantified as one leak in 2,527 years operating at 75 barg pressure. This puts the risk at a very low likelihood for a very high impact event. In terms of defects in the pipeline material that could lead to failure (e.g. corrosion), as routine inspections are made on NTS pipelines during periods of lower demand, the risk of a defect being found under high-demand conditions is reduced. Cathodic protection systems are maintained on NTS pipelines to further reduce the incidence of corrosion. Based on this level of risk, we have engaged with the HSE and the Distribution Network to consider the appropriateness of building new pipelines to meet this requirement.

We have also carried out an external risk assessment to assess the risks arising from any requirement to manage a pipeline failure without pipeline investment, in line with the risk assessment methodologies accepted by the HSE.

Constrained LNG – what has changed since we put forward our RIIO-T1 submission

In addition to the OM requirement in the South West, there is also a need for Transmission Support Services (TSS) which are defined in our Safety Case as a substitute for pipeline capacity at high demands to support a 1-in-20 peak day. We currently have two different forms of TSS available to us; contracts under the Long Run Contracting Incentive and Constrained LNG (CLNG).

Contracts funded under the Long Run Contracting Incentive are required in order to deliver obligated baseline capacity at five specifically named sites in the South West that were classed as interruptible prior to the introduction of the exit reform arrangements in October 2012.

The Constrained LNG (CLNG) service is a regulated service that gives us access to instruct withdrawals from the Avonmouth LNG facility at high demands. This service has been used historically in the South West of the system to defer pipeline investment, for example because of uncertain demand levels, and to provide flexibility to ensure we comply with our NTS Security Standard while managing the risk of uncertainty in future supply and demand patterns particularly at investment lead times.

We have seen a significant decline in the level of 1-in-20 peak day demand within our FES. As a result, we've undertaken further analysis to review the 'capacity' need case for pipeline investment following the closure of the Avonmouth LNG facility, and further considered the least cost options to meet the network capability requirements and to mitigate the network risk.

5.5 continued
Avonmouth

Our updated analysis shows that CLNG is not required under the current FES for the gas year 2018/19, although sensitivities beyond FES, but within capacity obligations, show a shortfall in capability. This has been driven by the general decline in demand levels projected by the 2013 and 2014 FES processes in comparison to the 2012 process.

The current best view based on the information available at this time is that:

- SW quadrant capability is sufficient to meet existing DN and power station customer requirements without investment
- We cannot meet baseline obligations without contracting for services in the South West and there is a risk that future DN exit capacity requirements could increase beyond current levels, particularly if power stations connect within the DN
- If local power station demand increases within obligated levels the capability of the network in the area could be exceeded.

The recommendations from this analysis were to:

- Continue to monitor exit capacity risks
- Defer pipeline investment for CLNG
- Further consider CLNG requirements following the outcome of DN and HSE discussions on OM requirements; and
- Continue to review the network capability requirement as long-term supply and demand patterns change.

Based on the analysis undertaken and the preliminary results, we determined that pressing ahead with the construction of the two pipelines is not in the best interest of consumers. Our intention is to complete the discussions with the HSE and the Distribution Network and update our ‘capacity’ risk analysis for the South West. At this point we then plan to engage with stakeholders to agree the most economic and efficient approach to meet the loss of services provided by Avonmouth in light of the current and future network requirements.

5.6
System Flexibility

We have previously highlighted system flexibility requirements, arising from the changing use of the NTS, as a driver for gas network development. This is an issue that the current regime might not address as it is not necessarily signalled via the release of incremental entry or exit capacity.

There is significant change in customer requirements from the NTS, resulting in very different gas flow patterns than those for which the network was originally designed. The current regime is based on the concept of user commitment to support the provision of incremental capacity. However, there is no existing mechanism to trigger the enhancement of the system capability required specifically in response to changing and /or reducing flows of gas in the network, i.e. the net impact of a number of different customers changing their use of the NTS.

Our discussions, via customer seminars and engagement events, have highlighted that system flexibility is important to them, and that our analysis and plans in this area do not provide enough information. In particular we understand that we need to better describe what we mean by system flexibility and what could happen.

We have been told that customers and stakeholders would also like more information on the asset and non-asset options to address greater calls on system flexibility.

We are reviewing the future flexibility requirements for the system and considering how different events or factors across gas days and within-day might affect the way that the system is managed. This work may lead to changes in the planning processes and may require asset, commercial and operability solutions to be progressed to deliver more capability in this area.

The categories we are considering include supply-side behaviour (e.g. supply shocks, supply profiling in response to market behaviour), demand-side behaviour (e.g. the impact of wind intermittency on CCGT use, demand profiling, ramp rates and notice periods, pressure commitments) and network flow direction changes (e.g. changes from east–west to west–east flow patterns over a short timescale, storage and interconnector behaviour). In parallel, we are also considering how our design and security standard is applied in our planning and operational processes and whether these are appropriate for supply and demand patterns we may see in the future.

5.6 continued
System Flexibility

5.6.1
What is system flexibility?

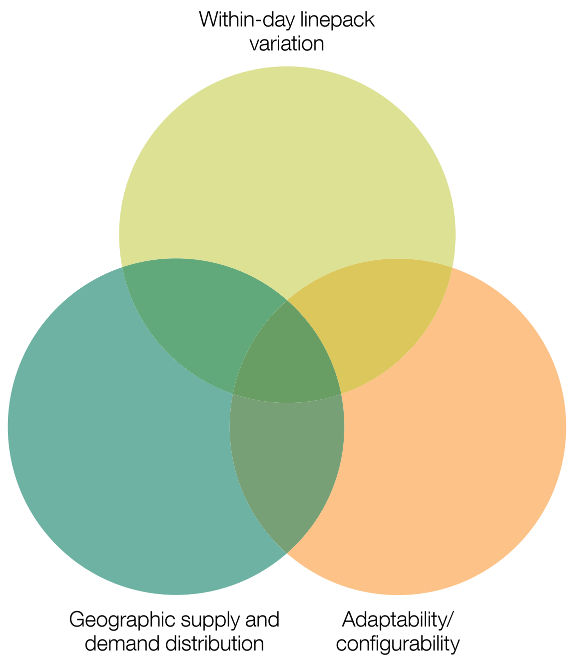
Through the RIIO negotiations we reached a definition of system flexibility as being: "a requirement for additional operational capability driven by changing user behaviour (as detailed in Chapter 3) and explicitly not the provision of incremental entry or exit capacity".

System flexibility can be thought of as:

- The ability of the network to cater for varying daily supply and demand profiles and imbalances through variations in system linepack and consequentially through variations in system pressures. Linepack is the volume of gas stored within a network, network section, or individual pipe and can be calculated from the pipe volumes, pressures and gas characteristics. Potential diurnal storage is the difference between maximum linepack (which is limited by maximum system pressures) and minimum linepack (which is limited by minimum system pressures).
- The ability of the network to cater for supply and demand levels which occur away from the 1-in-20 peak demand level but result in network flows in some parts of the network that are higher than would occur at the 1-in-20 demand level. This might therefore trigger investment e.g. storage or IUK exit flows at high demand levels.
- The ability of the network to cater for the rate of change in the geographic distribution of supply and demand levels, which result in changes in the direction and level of gas flow through pipes, compressors and multi-junctions, and which may require rapid changes to the flow direction in which compressors and multi-junctions operate.

Figure 5.6A
System flexibility can be thought of as the capability of the system (assets and operational tools) to deal with…

"Within-day linepack variation"	"Geographic supply and demand distribution"	"Adaptability/ configurability"
…varying daily supply and demand profiles and imbalances through variations in system linepack and pressures.	…supply and demand scenarios which occur away from the 1-in-20 peak demand and maximum supply levels.	…changes in the geographic distribution of supply and demand which result in changes in the direction of gas flow.



5.6 continued
System Flexibility

5.6.2
What might stakeholders want in terms of flexibility?

Shippers tell us that once they have procured their entry and exit capacity, they want to use that capacity to supply customers and achieve a supply and demand balance (taking into account gas trades and imbalance cost risk) with the minimum of other restrictions.

Directly connected (DC) offtakes have restrictions in terms of ramp rates and notice periods. Typically a ramp rate (the rate at which the offtake of gas can be increased at the offtake) of 50 MW/minute is offered but increasingly higher ramp rates are being requested and agreed where they can be facilitated. Notice periods are written into the Network Exit Agreements and typically are defined as the number of hours' notice for increases of up to 25%, up to 50% and greater than 50% of maximum offtake rate.

DNOs offtake gas from the NTS to meet their consumers' gas requirements. DNOs tell us that they book NTS exit 'flat' (end-of-day quantity) and flex (profile) capacity, in part, to comply with their 1-in-20 NTS Security Standard. The quantity of flex booked by a DNO is calculated as a top-up to their own diurnal storage availability (linepack and other diurnal storage devices) to ensure that they can meet their 1-in-20 diurnal storage requirements and other operational requirements. On low demand days, defined as being when the first LDZ demand forecast on the preceding gas day is less than 50% of the 1-in-20 peak day forecast, we have the right under the UNC to require that the aggregate LDZ NTS Exit (Flexibility) capacity utilised is not greater than zero.

DNO flexibility at an LDZ (aggregate offtake rate) level is limited by the two-hour 5% rule. This limits the change in offtake rate for any hour bar to a 5% change with two hours notice given. This rule is more onerous at lower demands as a lower demand change would represent a 5% increase. This rule has been subject to a recent UNC modification proposal which, while initially seeking to remove the rule, was approved on the basis that the rule would only be applied when required and hence was effectively 'off by default'.

Directly Connected consumers will simply offtake the quantity of gas they wish to consume, subject to offtake rules and market prices.

Flows at bi-directional system points (storage and interconnectors) and other system entry points will be influenced by shipper behaviour in terms of balancing their portfolios taking into account their expected end-of-day demand and supply allocations at all their exit and entry points.

As demand changes within-day, Shippers may not immediately make supply re-nominations to balance their portfolios as they may utilise gas trades first; hence utilising NTS within-day flexibility to manage within-day imbalances. Within-day imbalances may also occur due to supply losses and, again, these may not be addressed immediately as gas trades may be carried out first.

5.6.3 Factors that affect within-day flexibility

NTS exit (flexibility) capacity

Flex usage is the cumulative effect of taking gas with a profile, measured at 22:00. It is calculated as the quantity of gas offtaken between 06:00 and 22:00 less two thirds (16/24) of the daily quantity offtaken i.e. the additional gas actually offtaken over and above a flat profile.

The volume of flex taken is the linepack reducing effect. The underlying assumption is that, in a daily balancing regime, a quantity of gas will be supplied to match the daily demand quantity offtaken and it will be delivered, ignoring entry profiles, at a flat (1/24th) rate. The flex is therefore measuring how much gas is offtaken over and above this flat entry flow and therefore how much gas is taken out of linepack. The measurement is made at 22:00 as this is typically when the profiled demand for both DN and power generation offtakes drops below the average daily rate.

In DN planning terms, the volume of flex is the volume of diurnal storage used and the DNOs book NTS Exit (Flexibility) Capacity to meet their diurnal storage requirements. The DNOs can agree assured pressures and pressure can be an alternative to flex. The reason for this is that the DNOs can use higher pressures to store more gas in their own systems in the form of linepack and they can then use more of their own linepack to meet their diurnal storage requirements i.e. offset the difference between the flows from the NTS and the profiles of their customers.

DC profiling

Shippers at Directly Connected (DC) offtakes are not required to book NTS Exit (Flexibility) Capacity; however, the impact of their gas offtake profiles is broadly the same as for DN offtakes. There are a number of key differences between DC offtakes and DN offtakes. While DNOs can trade off flex and pressure, additional pressure at a DN offtake has no impact on the required offtake (flex) profile. DNOs book flex capacity to meet the 1-in-20 NTS security standard and this provides a key input to the NTS planning process. DC profiling is not limited by flex bookings but power generation offtakes are effectively limited by the electricity supply profile and hence further 'booked' capacity may not be of value.

Forecast error

Within-day changes in demand with a delayed supply response are met through system linepack and consequently require system flexibility. Within-day demand changes will result in either increase in flow rate at relevant supply points, once the demand change has been identified, as a result of shipper/market behaviour and/or balancing actions.

This behaviour is replicated when market behaviour in total results in supply flows starting the day at a rate that is less than the daily demand. The difference in flow rate and the period over which the imbalance persists will create a within-day imbalance volume and hence a draw on system linepack and flexibility.

Adherence to offtake rate change notice periods reduces the impact of within-day demand changes, and hence within-day imbalances. Notice of rate changes are required through Network Exit Agreements and as a result of the DN two-hour 5% rule.

Supply losses

Supply losses may occur due to offshore or delivery facility technical problems or failures. Supply losses will result in either an increase in flow rate at the relevant point once the problem has been rectified, or an increase in flow rate at an alternative point (as a result of shipper/market behaviour and/or balancing actions) if the problem cannot be rectified. There can be a delay between a supply loss and the market response.

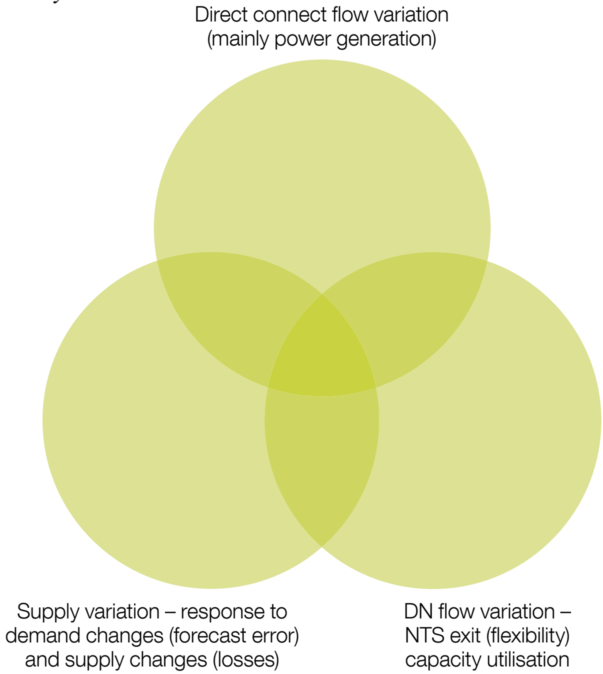
5.6 continued
System Flexibility

5.6.4
Quantifying within-day flexibility

We are working on a project to quantify the requirements for the three main areas of within-day flexibility; DN diurnal support, power generation profiling, supply variation. This project should provide more robust planning information to ensure that we have the right mix of assets, operational measures and services to manage within-day variability.

Within-day linepack variation is managed through adherence to contractual rules (flow change notice periods) when required. Enforcing the rules (rejection of offtake profile notices) has occurred, and may be more frequent in the future. We recognise that customers value freedom to exceed limits but we may find it more difficult to enable this in the future.

Figure 5.6B
Within-day flexibility areas



5.6.5
How will we plan for system flexibility?

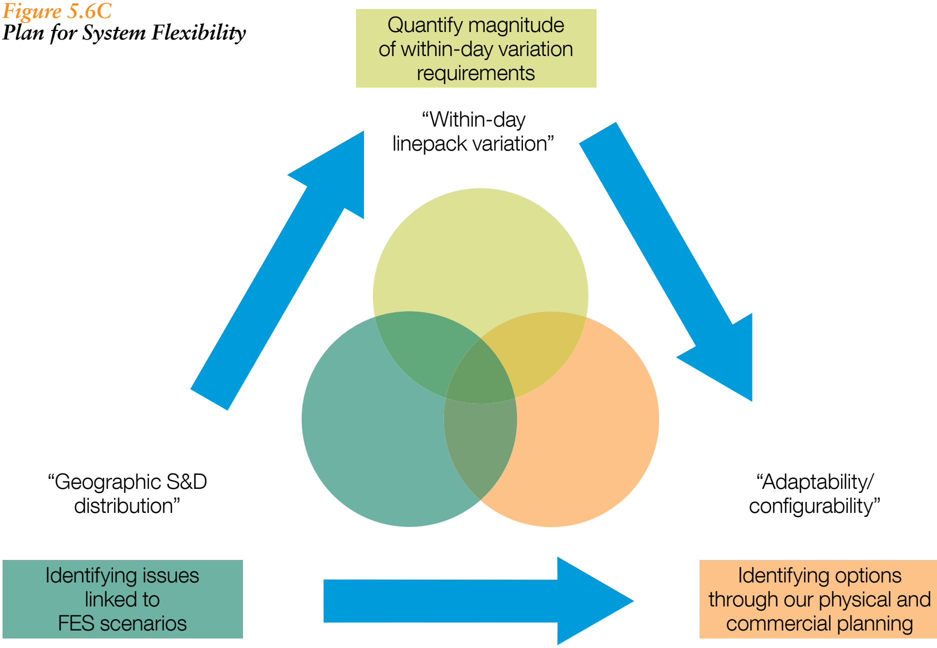
We plan for within-day flexibility by explicitly modelling the profiling of demand. We manage supply profiling by the reservation of operational linepack via the application of a design margin and via the procurement of operating margins services. DN flex bookings give us a good indication of likely DN offtake profiling and we are looking to improve our modelling of gas power generation offtake profiling through the flexibility project work we are doing. Supply profiling comes mainly from market response to demand changes and supply losses and we aim to agree the appropriate market behaviour and supply reliability to factor into our planning processes models.

We plan for geographic distribution of supply and demand by identifying the appropriate scenarios through the Future Energy Scenarios (FES) process and by applying sensitivities to those scenarios. We will seek to agree the appropriate sensitivities, such as minimum supply levels at times of high demand, to include within the planning process.

We plan for the adaptability of the system by considering the FES supply and demand data to inform what configurations might be required. We also consider profiling and rates of change to identify the plant and equipment we might need at our compressor stations and other key multi-junctions, and the operational tools we might need to manage extreme events. Through our Industrial Emissions Directive (IED) stakeholder engagement activities, we have given the example of replacing larger non-IED compliant units with multiple smaller IED-compliant units (rather than a single unit) as an example of how we might maintain or even increase system flexibility.

5.6 continued
System Flexibility

Figure 5.6C
Plan for System Flexibility



5.6.6
Outlook for 2015 and beyond

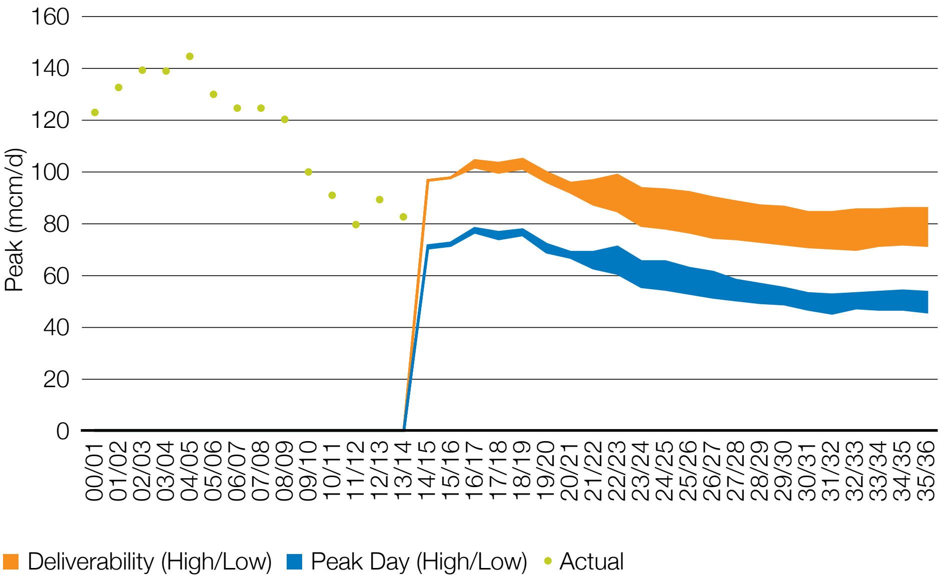
We are engaging with stakeholders as part of the work we are carrying out on compressors captured by the Industrial Emissions Directive (IED) limits. If there are material issues with regard to system flexibility, there will be an opportunity with the 2016 RIIO-T1 mid-period review to propose funding for asset or operational solutions, combined with other commercial changes. Some of the flexibility issues could be reviewed and addressed via our proposed solutions for the IED compressor strategy.

5.7
Scotland 1-in-20

Figure 5.7A shows the forecast gas supplies at St Fergus, as informed by our industry consultative processes. It shows that supplies are continuing to decline at the St Fergus terminal with expected peak day (Day 0) supply volumes some 30 to 50 mcm/d lower than the terminal's full deliverability.

Against this backdrop of falling supplies, demand in Scotland (including the Moffat offtake to Ireland) has risen, reaching the point where on some days this demand is already marginally greater than the supplies from St Fergus. The rate of flow decline from the St Fergus terminal has reduced across our scenarios. However, those scenarios still strongly indicate this situation will worsen over the coming years as existing UKCS supplies through St Fergus continue to decline and become more uncertain. The uncertainty at St Fergus is mainly driven by uncertainty in Norwegian supplies, which can go to European markets via the offshore pipeline system, or arrive in the UK via the Easington importation terminal. The reduction in supply at St Fergus has been compensated for by additional supplies at Southern ASEPs. This means that to maintain supplies in Scotland it will be increasingly necessary to route gas south-to-north within the network. Actual peak flows, and future slow decline in peak forecasts, imply south-to-north flows are likely to become the norm.

Figure 5.7A
Forecast flows from the St Fergus ASEP 2014
Source: National Grid



5.7 continued
Scotland 1-in-20

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, 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 and regulatory 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 has been no clear trigger mechanism to identify these projects and provide funding for a solution (be it commercial, operational or asset based). We have identified modifications to the network, designed to enhance the network capability to maintain Scottish pressures and enhance south-to-north flows. In response to feedback received during our RIIO Talking Networks Stakeholder Consultation process, we requested funding for these projects in our final RIIO-T1 submission and categorised the funding as 1-in-20 Licence Obligation.

In our Ten Year Statement last year we outlined how we are progressing some of these projects through our internal governance processes towards approval for construction so that we continue to meet our obligations. Since the publication of last year's statement we have begun consulting on a holistic network-wide strategy for managing the implications of IED across all affected sites. The outcome of this work will affect the optimum locations to undertake the Scottish 1-in-20 works, both through the availability/suitability of individual sites (for example Moffat compressor station), but also through the potential to alter prevailing flow configurations through the network. The analysis is running in parallel with the IED consultation and we will be looking to finalise the location of the works during 2015.

We still expect to be able to deliver the necessary works by the end of 2020. Regardless of the ultimate optimum location, the physical works required are most likely to be modifications on (and within the current boundary of) existing operational sites, and as such will not trigger the need for major planning applications. Aside from planning, the factors that are expected to most influence our ability to deliver these works quickly are availability of long lead items and network access. We are monitoring both of these factors and do not currently envisage any issues.

5.8 Projects Under Construction

The tables 5.8A and B indicate the status of existing construction projects.

Final commissioning of the four new electrically-driven compressors with variable speed drives (VSD) at Hatton, Kirriemuir and St Fergus is currently underway as part of our ongoing programme of works for reducing emissions. These projects will then be tested under operational conditions during winter 2014/15.

Table 5.8A
Projects under construction

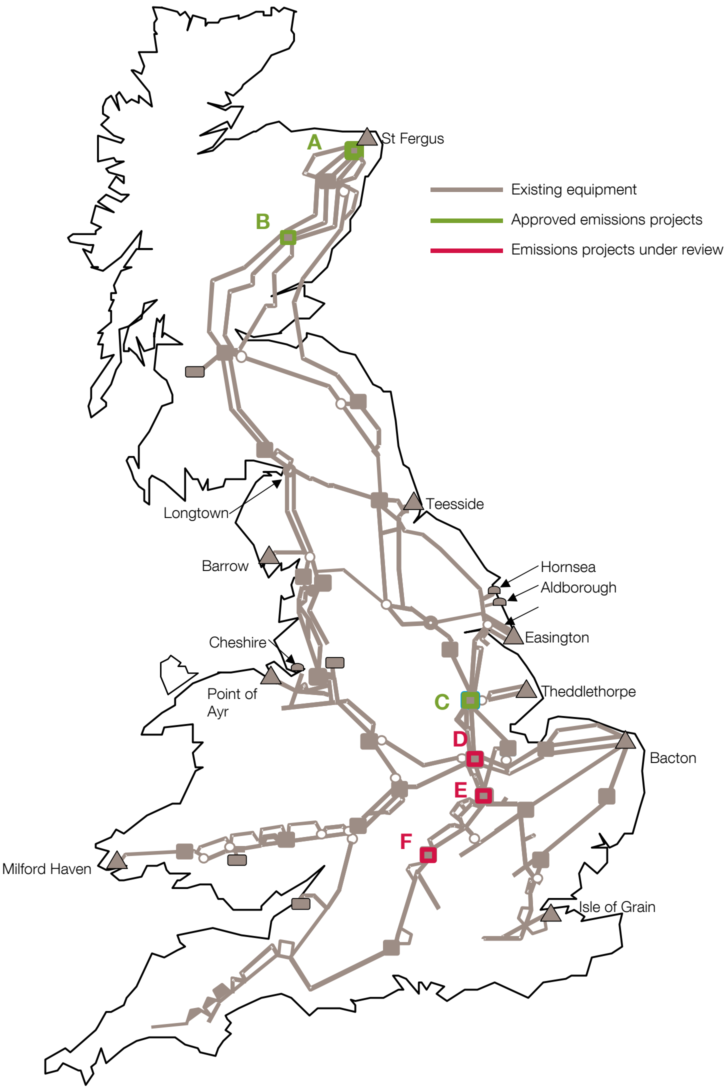
Map ref.	Project	Scope	Driver
A	St Fergus compressor station	2 new VSD units	Emission reduction
B	Kirriemuir compressor station	1 new VSD unit	Emission reduction
C	Hatton compressor station	1 new VSD unit	Emission reduction

Table 5.8B
Projects under review (please note locations are indicative and subject to change as we progress through the planning process)

Map ref.	Project	Scope	Driver
D	Peterborough compressor station	New unit	Emission reduction
E	Huntingdon compressor station	New unit	Emission reduction
F	Aylesbury compressor station	Modifications to existing units	Emission reduction

5.8 continued
Projects Under Construction

Figure 5.8A
NTS projects, completed, approved and under review



Chapter 6
Way Forward

Here, we outline our plans for developing GTYS, our stakeholder engagement process since the 2013 edition, and how we intend to engage with the industry in the coming year.

6.1
Continuous Development of GTYS

Our Gas Ten Year Statement (GTYS) is an opportunity for us to outline our plans for developing the National Transmission System (NTS) to meet the future needs of our customers. We want to continue to use GTYS and develop it so that it remains valuable for our stakeholders. We also want to continue developing other ways to engage with the industry and beyond to keep you fully informed of our plans and involved in the decision-making process.

We welcome your feedback and comments on this document. Please take part in our 2015 stakeholder engagement programme so we can better understand and respond to your needs. Feedback on all aspects of the 2014 GTYS can be made by email to **Box.systemoperator.gtys@nationalgrid.com** or complete our online survey at: **http://surveymonkey.com/s/2014GTYS**

To make sure the GTYS continues to add value we will:
- Seek to identify and understand the views and opinions of all our stakeholders
- Provide opportunities for engagement to enable constructive debate
- Create open, two-way communication with our stakeholders around assumptions, drivers and outputs
- Provide feedback on how stakeholder views have been considered and the outcomes of any engagement process.

The GTYS is reviewed every year, facilitated by National Grid, and involving all stakeholders who use the publication. The purpose of the review is to make sure the GTYS evolves along with the industry. Some of the areas considered are:

- Does the GTYS:
  – illustrate the future development of the transmission system in a co-ordinated and efficient way?
  – provide information to help customers identify opportunities to connect to the transmission network?
- Are there any areas where the GTYS can be improved to meet these aims?

We are happy to receive engagement of any kind through channels including:
- At consultation events as part of the customer seminars
- At Operational Forums
- Through responses to the GTYS email **Box.systemoperator.gtys@nationalgrid.com**
- Through organised bilateral stakeholder meetings.

6.2
2014 Stakeholder Engagement

This year, we have started an extensive stakeholder engagement programme to discuss the implications of the Industrial Emissions Directive for the NTS.

Building on our RIIO stakeholder engagement, we began by asking you your preferred method of engagement. The engagement process has, and continues to be, driven by your feedback and we have held a number of interactive workshops. In response to feedback from these workshops, we have changed our engagement process and made improvements to GTYS.

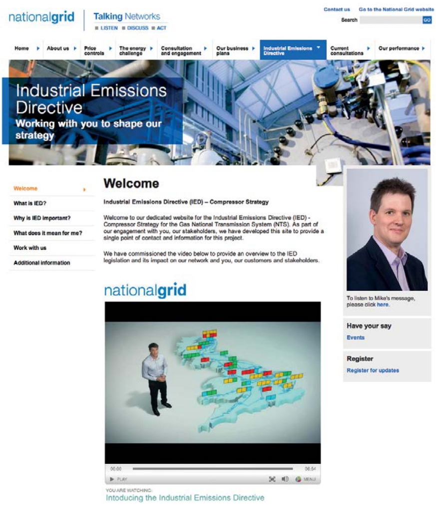
Provide more information on the IED legislation

You told us:

> **National Grid needs to provide more focus on the actual legislation around the compressor replacement programme, including timelines and technical impacts.**

Our response:
We have developed a project-specific website within the Talking Networks umbrella that can be accessed from different parts of the National Grid website. Here you will find further background information on the legislation, as well as the initial engagement questionnaire, material from stakeholder workshops and an opportunity to register for updates.

Also on Talking Networks is a short film[1], and clear information about the IED and what it means for the future of the NTS. Please continue to contribute and work with us to determine the most effective and efficient strategy for our compressor fleet.



Our initial consultation in preparation for our final proposals to Ofgem in May 2015 contains further background on the legislation and the range of options available at each site, including the costs and impact on the network. The consultation is available at the following link and we value your feedback on our proposals:

http://talkingnetworkstx.com/IED-welcome.aspx

We have also used GTYS to summarise the current direction of IED, which can be found in Chapter 5.

[1] The short film can be viewed at http://www.youtube.com/watch?v=xZu05nHaqrU

IED interaction with system flexibility

You told us:

IED cannot be considered in isolation to system flexibility

Our response:
The range of options at our compressor stations developed in response to the IED legislation, as outlined in our initial consultation document, have considered the impact on system flexibility on a site-by-site basis. We have taken on board that stakeholders have identified future flexibility of the NTS as a key priority when developing network solutions.

In parallel to the IED project, we are assessing the scenarios we use to plan the network, specifically in relation to the within-day variation of supply and demand, and we will use these scenarios to make sure the solutions progressed for IED are fit for purpose into the future. Further details of the system flexibility project and how it is progressing can be found in Chapter 5.

Understanding system constraints

You told us:

It is useful to understand system constraints brought about by choices under certain scenarios

Our response:
In last year's GTYS we provided more information about the scenarios that might cause system constraints in the future. This year we have gone further and outlined two examples of specific scenarios that could cause system constraints at the extremities of the NTS due to unexpected changes in demand from connected gas-fired power stations caused by changes in wind generation on the electricity network. These examples are outlined in chapter 3.

6.3
Future Engagement

Next year, we plan to develop an operational framework that brings together and discusses future challenges to the network. We would like to work with you to make sure that how we do this meets both your needs and our needs.

The future will not necessarily be more difficult than it is today, but we know it will be different. By working with you we can make sure that the right solutions are in place at the right time, and this new framework will give us the vehicle to achieve this.

To support this, we must be able to be clear on what is driving our needs and be transparent about how we make our ‘build’ and ‘no-build’ decisions. The plan is to develop a policy that builds on our 2014 engagement approach and gives stakeholders greater visibility of our process and actions. We will work with you in 2015 to develop this policy, give it a clear objective and a plan to deliver it.

Appendix 1
Process Methodology

A1.1
Transmission Planning Code

Under Special Condition 7B of our Gas Transporters' Licence, we must prepare and maintain a Transmission Planning Code (TPC) that describes the methodology used to determine the physical capability of the system. The code is for everyone who wants to connect to and use the NTS and tells them about the key factors affecting the planning and development of the system.

We do annual investment planning, looking ten years ahead. The investment plan is developed using long-term supply and demand scenarios based on information gathered through the commercial processes to reserve capacity on the system.

We start our annual planning cycle after the initial data has been gathered through the Future Energy Scenarios consultation process and we will use this data to compile long-term supply and demand scenarios. The planning process will consider investments that may be needed to respond to potential entry and exit capacity signals from the market. We use detailed network models of the NTS under different supply and demand scenarios to understand how the system might 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 from these commercial processes will be used to decide the final investments that are needed to develop the system.

Long-term signals received for additional capacity will be considered by us within the same annual planning process. This means capacity above the prevailing obligated/contracted capacity levels and long-term capacity bookings/reservations within obligated/contracted capacity levels.

We will also consider commercial options to avoid or defer investment and to determine the most economic and efficient outcome. Commercial arrangements can include (but are not limited to) booking constrained services at LNG storage sites, supply turn-up contracts, buy-back contracts and interruption contracts.

The TPC was reviewed in 2014 in light of industry and regulatory developments, and stakeholder feedback, prior to a consultation being carried out. Changes were made to provide more detail about the derivation of the '1-in-20' Security Standard and how National Grid NTS meets elements of it, for example, by using DN booking data and profiling power generation, operational measures (in particular the use of operating margins gas), and compressor standby. The TPC review also incorporated the 'Determination of the Technical Capacity of the NTS' to comply with EU Regulation EC715/2009.

We proposed consulting on separate PARCA (Planning and Advanced Reservation of Capacity Agreement) and non-PARCA versions of the TPC, acknowledging that an Ofgem decision was anticipated on UNC Modifications 0452V and 0465V.

As no Ofgem decision on Modifications 0452V and 0465V had been made, and no formal consultation on associated licence drafting issued, we proposed to submit, for consultation, only the non-PARCA version of the TPC. We also proposed that if a decision is made to implement either 0452V or 0465V we would consult on a revised (as required) PARCA version of the TPC. The non-PARCA version of the TPC was approved by the authority and implemented on 1 October 2014.

Appendix 1 continued
Process Methodology

A1.2
Investment procedures and project management

All investment projects must comply with our Transmission Investment Management Procedure, which sets out the broad principles that should be followed when evaluating high value investment or divestment projects.

The investment guidelines define the methodology to be followed when undertaking individual investments to ensure consistency in delivery. They are used to encourage and prioritise the right investments, ensuring strategic alignment and maximising cost efficiency while enhancing investor confidence. The guidelines make sure that stakeholders are treated fairly throughout the process.

To determine whether an investment is required, a clear 'needs case' must be established to substantiate a scope of work. Once the needs case is confirmed, approval of the investment is sought from the appropriate governing routes.

Successfully managing and delivering our investment projects helps us remain aligned with our business outputs defined under RIIO. Our project management strategy typically involves:

- Determining the level of financial commitment and appropriate method of funding for a project
- Undertaking preliminary studies to make sure that 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
- Reviewing the project and investment to be sure of compliance and to capture lessons learned.

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 specific experience relevant to the project may support the team.

Tenders are received and evaluated against previously agreed technical, quality, safety, financial and programme criteria. Tenders 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 day-to-day work and manage the project funding by careful cost control. A post-completion review provides feedback to management on project performance and helps improve future decision-making processes. Our management of major investment projects is designed to make sure that they are delivered on time, to the appropriate quality standards, at minimum cost. The project management process uses professional consultants and specialist contractors 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, and lessons learned are recorded.

Appendix 2
Gas Demand and Supply Volume Scenarios

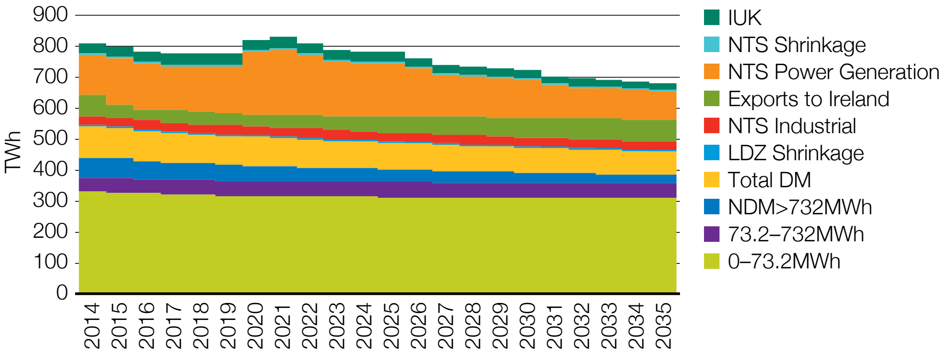
A2.1
Demand

Table A2.1A
Slow Progression: Annual demand – Split by load categories (TWh)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
0–73.2 MWh	329	326	321	318	316	314	313	312	311	311	310	310	309	309	308	308	308	307	307	307	307	307
73.2–732 MWh	45	46	47	48	49	49	49	49	49	49	49	49	49	49	49	48	48	48	47	47	47	46
NDM > 732 MWh	65	62	58	55	53	51	49	48	46	44	43	41	39	38	36	35	33	32	31	30	28	27
Total NDM	**439**	**434**	**426**	**422**	**418**	**414**	**412**	**409**	**406**	**404**	**402**	**400**	**398**	**396**	**393**	**391**	**389**	**387**	**385**	**383**	**382**	**380**
Total DM	101	100	98	96	95	94	93	92	91	88	86	85	84	83	83	82	81	80	80	79	78	78
LDZ Shrinkage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2
Total LDZ	**542**	**537**	**527**	**521**	**515**	**511**	**507**	**503**	**500**	**495**	**491**	**488**	**485**	**482**	**479**	**475**	**473**	**470**	**467**	**464**	**462**	**460**
NTS Industrial	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Exports to Ireland	65	43	34	38	39	37	38	41	46	48	50	53	55	57	59	61	63	65	67	68	69	71
NTS Power Generation	133	150	149	144	146	152	203	213	193	175	171	171	156	135	130	129	124	108	100	97	94	90
NTS Consumption	229	223	213	213	215	219	271	284	269	254	251	254	242	223	219	219	217	202	196	195	193	191
NTS Shrinkage	5	4	4	4	4	4	4	4	4	4	4	4	4	4	3	3	3	3	3	3	3	3
Total excluding IUK	776	764	745	738	735	734	783	791	773	752	746	746	730	708	702	698	693	676	667	662	658	654
IUK	31	33	35	37	39	38	36	36	35	34	33	32	31	30	29	28	27	26	25	24	23	22
Total including IUK	**806**	**797**	**780**	**775**	**773**	**772**	**819**	**827**	**807**	**786**	**778**	**777**	**760**	**738**	**730**	**726**	**720**	**701**	**692**	**686**	**681**	**675**

Figures may not sum exactly due to rounding.

Figure A2.1A
Slow Progression: Annual demand



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Table A2.1B
Gone Green: Annual demand – Split by load categories (TWh)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
0–73.2 MWh	329	325	320	316	314	311	309	307	306	304	303	301	299	296	292	285	279	271	263	254	244	234
73.2–732 MWh	45	47	49	50	51	52	52	53	52	52	52	51	49	48	46	45	43	41	40	38	36	35
NDM > 732 MWh	65	63	61	59	58	56	54	52	50	49	47	45	44	42	41	39	38	36	35	34	32	31
Total NDM	**439**	**435**	**429**	**425**	**422**	**419**	**416**	**412**	**408**	**405**	**401**	**397**	**392**	**385**	**378**	**369**	**359**	**349**	**338**	**326**	**313**	**300**
Total DM	101	101	100	99	98	98	97	96	95	89	88	87	86	85	85	84	84	83	82	82	81	81
LDZ Shrinkage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2
Total LDZ	**543**	**539**	**533**	**528**	**524**	**520**	**516**	**511**	**507**	**497**	**492**	**486**	**481**	**473**	**466**	**455**	**445**	**434**	**422**	**410**	**397**	**383**
NTS Industrial	31	31	32	32	32	32	32	33	33	33	33	33	33	34	34	34	34	34	35	35	35	35
Exports to Ireland	66	45	36	41	42	41	42	45	49	52	54	57	60	63	65	66	68	70	72	73	74	76
NTS Power Generation	121	136	138	127	139	136	162	169	157	161	161	165	152	159	172	181	179	157	150	140	136	145
NTS Consumption	219	213	206	200	212	209	237	247	239	246	248	255	246	255	271	281	281	261	256	248	245	256
NTS Shrinkage	5	4	4	4	4	4	4	4	4	4	4	4	4	4	3	3	3	3	3	3	3	3
Total excluding IUK	767	756	742	732	740	733	757	762	750	747	744	745	730	732	740	740	730	699	682	661	645	642
IUK	31	35	39	43	47	51	55	59	63	63	63	63	63	63	63	63	63	63	63	63	63	63
Total including IUK	**798**	**791**	**782**	**775**	**787**	**784**	**812**	**821**	**813**	**809**	**806**	**808**	**793**	**795**	**803**	**803**	**793**	**762**	**745**	**724**	**708**	**705**

Figures may not sum exactly due to rounding.

Figure A2.1B
Gone Green: Annual demand

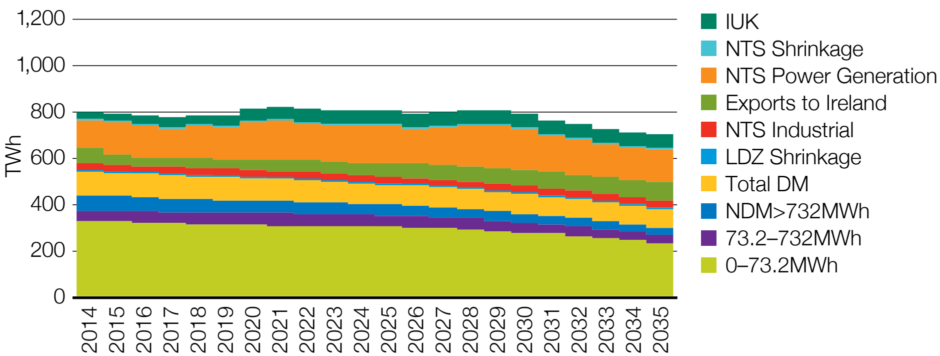
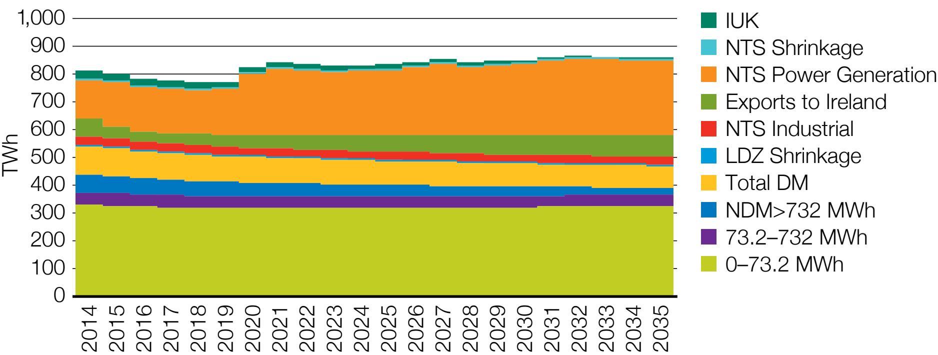


Table A2.1C
No Progression: Annual demand – Split by load categories (TWh)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
0–73.2 MWh	329	326	322	320	318	317	317	316	316	317	317	317	318	318	319	319	320	321	322	323	323	324
73.2–732 MWh	45	45	44	43	43	43	43	42	42	42	43	43	43	42	42	41	41	41	40	40	40	39
NDM > 732 MWh	65	62	58	55	53	51	49	47	46	44	42	40	39	37	35	34	33	31	30	29	28	26
Total NDM	**439**	**433**	**424**	**419**	**414**	**411**	**408**	**406**	**404**	**403**	**402**	**400**	**399**	**397**	**396**	**395**	**394**	**393**	**392**	**392**	**391**	**390**
Total DM	101	100	98	96	95	93	93	92	90	89	88	86	86	85	84	83	82	81	81	80	79	79
LDZ Shrinkage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2
Total LDZ	**542**	**536**	**525**	**518**	**512**	**507**	**504**	**500**	**497**	**494**	**492**	**490**	**487**	**485**	**483**	**480**	**478**	**477**	**475**	**474**	**472**	**471**
NTS Industrial	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Exports to Ireland	65	44	35	40	42	42	45	48	55	57	60	62	65	66	68	70	72	73	75	76	77	79
NTS Power Generation	141	158	160	156	159	164	221	239	229	227	228	234	242	257	243	252	253	269	274	272	270	269
NTS Consumption	236	232	225	227	231	237	296	318	314	315	318	326	337	353	341	352	355	372	379	378	378	378
NTS Shrinkage	5	4	4	4	4	4	4	4	4	4	4	4	4	4	3	3	3	3	3	3	3	3
Total excluding IUK	783	772	754	749	747	748	803	822	816	813	814	819	828	841	827	836	837	852	858	855	853	853
IUK	31	29	28	27	25	24	22	21	20	19	17	16	15	13	12	11	9	8	7	5	4	3
Total including IUK	**814**	**801**	**782**	**776**	**772**	**772**	**826**	**844**	**836**	**832**	**831**	**835**	**842**	**855**	**839**	**846**	**846**	**860**	**864**	**861**	**857**	**855**

Figures may not sum exactly due to rounding.

Figure A2.1C
No Progression: Annual demand



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Table A2.1D
Low Carbon Life: Annual demand – Split by load categories (TWh)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
0–73.2 MWh	331	327	323	320	318	316	315	315	314	314	314	314	314	314	314	314	314	315	315	315	316	317
73.2–732 MWh	45	46	47	47	48	49	49	50	50	50	50	50	50	50	50	50	49	49	49	48	48	48
NDM > 732 MWh	65	63	61	59	57	56	54	52	50	48	46	44	43	41	40	38	37	35	34	33	32	30
Total NDM	**441**	**436**	**430**	**426**	**423**	**421**	**418**	**416**	**414**	**412**	**410**	**408**	**407**	**405**	**403**	**402**	**400**	**399**	**398**	**396**	**396**	**395**
Total DM	101	101	100	99	98	98	97	96	95	93	92	91	90	90	89	88	88	87	87	86	86	85
LDZ Shrinkage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2
Total LDZ	**545**	**540**	**534**	**529**	**525**	**521**	**518**	**515**	**512**	**508**	**505**	**502**	**500**	**497**	**495**	**492**	**490**	**488**	**487**	**485**	**484**	**482**
NTS Industrial	31	31	32	32	32	32	32	33	33	33	33	33	33	34	34	34	34	34	34	35	35	35
Exports to Ireland	67	46	38	44	46	45	48	52	59	62	64	67	70	74	76	77	79	81	83	84	86	88
NTS Power Generation	132	150	154	147	147	149	183	187	179	172	179	178	193	194	189	188	180	185	183	180	182	183
NTS Consumption	230	228	224	223	224	226	263	271	270	267	276	278	297	302	299	300	294	301	300	299	303	306
NTS Shrinkage	5	4	4	4	4	4	4	4	4	4	4	4	4	4	3	3	3	3	3	3	3	3
Total excluding IUK	780	773	762	756	753	752	785	790	786	778	785	784	800	802	797	796	788	792	790	787	790	792
IUK	31	33	35	37	39	41	43	45	47	49	51	54	56	57	60	61	63	64	67	69	71	73
Total including IUK	**810**	**806**	**797**	**793**	**792**	**792**	**828**	**835**	**833**	**828**	**837**	**838**	**855**	**859**	**857**	**856**	**851**	**857**	**857**	**856**	**860**	**864**

Figures may not sum exactly due to rounding.

Figure A2.1D
Low Carbon Life: Annual demand

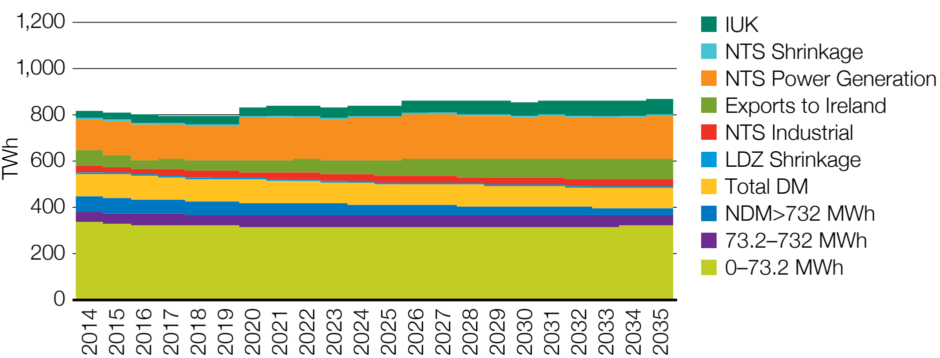
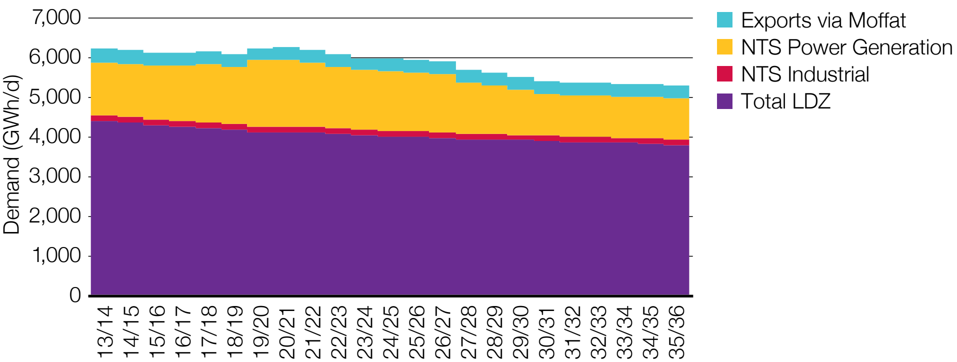


Table A2.1E
Slow Progression: 1-in-20 peak day undiversified demand (GWh/day)

National	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Scotland	335	331	325	321	318	315	312	310	308	306	304	302	301	300	297	295	294	292	290	289	287	286
Northern	237	236	231	229	227	224	222	221	219	218	216	215	214	213	211	210	209	208	206	206	205	204
North West	518	512	502	496	490	485	479	477	474	471	466	464	462	460	456	454	451	449	445	444	442	440
North East	266	263	258	256	253	251	248	247	245	244	241	241	239	238	236	235	234	233	230	230	229	228
East Midlands	431	427	418	415	411	407	402	401	399	397	393	392	389	387	383	382	380	377	374	373	372	370
West Midlands	380	375	367	363	359	355	350	348	346	342	338	336	334	332	328	326	324	321	318	317	315	313
Wales North	49	48	47	47	46	46	45	45	45	44	44	44	43	43	43	42	42	42	41	41	41	41
Wales South	198	198	195	193	191	189	191	191	187	184	181	179	177	176	173	173	172	172	171	171	170	170
Eastern	364	361	355	352	350	348	345	345	346	333	331	331	330	329	327	327	326	325	323	323	322	322
North Thames	471	466	458	454	451	448	443	442	440	438	435	434	432	431	427	427	425	423	419	419	417	416
South East	488	490	482	479	477	475	472	473	473	472	469	469	469	468	464	465	464	462	455	455	454	454
Southern	360	358	351	349	347	344	341	340	339	338	334	331	330	329	327	327	326	325	323	323	323	322
South West	275	273	268	267	265	263	261	260	259	258	257	256	256	255	254	255	254	253	251	252	251	251
Total LDZ	**4,370**	**4,338**	**4,257**	**4,220**	**4,183**	**4,148**	**4,109**	**4,101**	**4,080**	**4,045**	**4,008**	**3,995**	**3,978**	**3,960**	**3,925**	**3,918**	**3,900**	**3,882**	**3,847**	**3,842**	**3,828**	**3,816**
NTS Industrial	145	145	144	144	144	144	144	144	144	144	144	138	138	138	138	138	138	138	138	138	138	138
NTS Power Generation	1,347	1,347	1,392	1,426	1,481	1,466	1,655	1,674	1,635	1,547	1,511	1,498	1,478	1,471	1,280	1,231	1,135	1,041	1,041	1,041	1,041	1,041
Exports via Moffat	361	329	318	318	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**1,853**	**1,821**	**1,854**	**1,888**	**1,939**	**1,924**	**2,113**	**2,132**	**2,092**	**2,004**	**1,968**	**1,949**	**1,929**	**1,922**	**1,731**	**1,682**	**1,587**	**1,492**	**1,492**	**1,492**	**1,492**	**1,492**
Total	**6,223**	**6,159**	**6,111**	**6,108**	**6,122**	**6,072**	**6,222**	**6,234**	**6,173**	**6,049**	**5,976**	**5,944**	**5,907**	**5,883**	**5,656**	**5,600**	**5,487**	**5,374**	**5,339**	**5,334**	**5,321**	**5,308**

Figures may not sum exactly due to rounding.

Figure A2.1E
Slow Progression: 1-in-20 peak day undiversified demand



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Table A2.1F
Gone Green: 1-in-20 peak day undiversified demand (GWh/day)

National	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Scotland	335	332	327	324	322	319	316	314	311	308	304	302	299	295	289	283	276	269	261	253	245	236
Northern	236	234	231	229	227	225	223	222	220	218	216	214	212	210	206	203	199	194	189	184	179	173
North West	519	513	505	501	496	491	485	483	479	474	468	464	460	454	446	437	427	416	404	393	380	365
North East	266	264	260	259	256	254	251	250	248	246	243	242	239	236	232	228	222	217	210	205	198	191
East Midlands	431	428	421	419	415	411	407	405	402	399	394	391	387	382	374	367	358	349	338	329	318	306
West Midlands	380	376	370	367	363	360	355	353	349	345	340	337	333	327	320	314	305	296	286	277	267	256
Wales North	49	48	48	47	47	46	46	46	45	45	44	44	43	43	42	41	40	39	38	37	36	35
Wales South	198	197	195	193	192	190	190	190	188	184	179	178	177	174	172	170	167	164	160	157	153	149
Eastern	364	361	356	355	353	351	348	348	350	325	323	321	318	313	308	302	295	287	278	270	261	251
North Thames	471	467	461	459	456	453	448	447	444	440	435	432	428	421	413	405	395	384	372	361	348	334
South East	488	490	484	481	479	477	473	474	473	467	461	460	456	451	442	435	425	414	402	391	378	364
Southern	360	358	353	352	349	347	344	343	341	339	334	329	326	322	317	311	304	297	288	281	272	263
South West	275	273	269	268	266	265	262	261	259	257	254	253	251	247	242	238	232	226	218	212	205	196
Total LDZ	**4,371**	**4,343**	**4,278**	**4,252**	**4,222**	**4,189**	**4,147**	**4,136**	**4,110**	**4,047**	**3,994**	**3,967**	**3,929**	**3,874**	**3,800**	**3,734**	**3,646**	**3,553**	**3,444**	**3,349**	**3,238**	**3,117**
NTS Industrial	145	145	144	144	144	144	144	144	144	144	144	138	138	138	138	138	138	138	138	138	138	138
NTS Power Generation	1,383	1,383	1,428	1,426	1,509	1,488	1,543	1,668	1,650	1,576	1,439	1,499	1,485	1,392	1,392	1,468	1,447	1,447	1,345	1,345	1,307	1,421
Exports via Moffat	361	329	318	318	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**1,889**	**1,857**	**1,890**	**1,888**	**1,967**	**1,945**	**2,000**	**2,125**	**2,107**	**2,034**	**1,897**	**1,951**	**1,936**	**1,843**	**1,843**	**1,920**	**1,899**	**1,899**	**1,797**	**1,797**	**1,759**	**1,873**
Total	**6,260**	**6,200**	**6,168**	**6,140**	**6,188**	**6,135**	**6,147**	**6,261**	**6,217**	**6,081**	**5,891**	**5,918**	**5,866**	**5,718**	**5,644**	**5,654**	**5,545**	**5,452**	**5,241**	**5,147**	**4,997**	**4,990**

Figures may not sum exactly due to rounding.

Figure A2.1F
Gone Green: 1-in-20 peak day undiversified demand

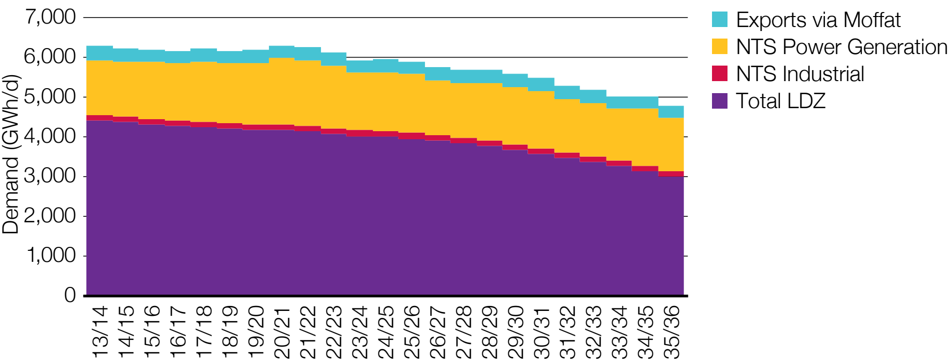
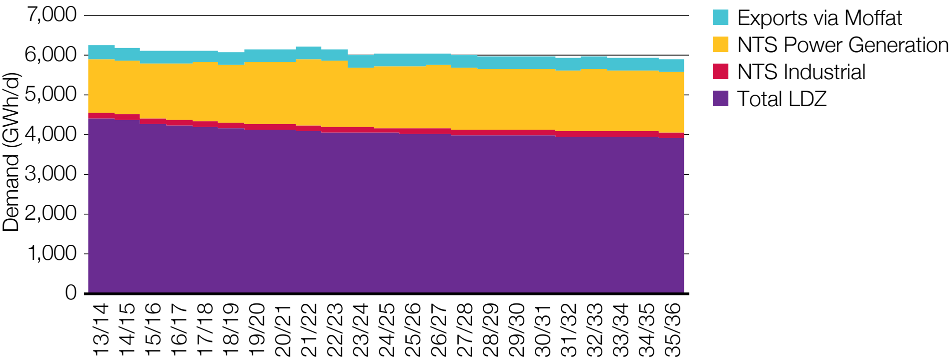


Table A2.1G
No Progression: 1-in-20 peak day undiversified demand (GWh/day)

National	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Scotland	335	331	324	319	316	313	309	308	306	305	303	303	302	301	299	298	297	296	295	295	294	294
Northern	237	235	230	228	225	223	221	220	219	218	216	215	215	214	212	212	211	211	209	209	209	208
North West	518	512	500	493	487	481	475	474	472	469	465	464	463	461	458	457	455	454	452	452	451	449
North East	266	263	257	254	251	249	246	245	244	243	241	241	240	239	237	236	235	235	233	234	233	232
East Midlands	431	427	417	413	408	404	400	399	397	396	393	392	391	389	386	385	384	382	380	380	380	379
West Midlands	380	375	366	361	356	352	347	346	344	341	337	336	334	332	329	328	326	324	322	322	320	319
Wales North	49	48	47	46	46	45	45	45	44	44	44	44	43	43	43	43	42	42	42	42	42	42
Wales South	198	198	195	193	191	189	192	196	192	186	182	182	181	180	178	178	177	177	176	177	177	176
Eastern	364	361	354	351	349	346	344	344	344	343	341	342	342	341	340	340	340	341	340	341	342	342
North Thames	471	466	456	451	447	443	439	438	437	435	433	433	432	431	428	429	428	427	425	426	426	425
South East	488	489	480	477	474	472	470	472	472	472	470	472	472	472	470	471	472	471	470	472	472	473
Southern	360	357	350	347	344	342	339	339	338	337	334	332	331	330	329	329	328	328	327	328	328	327
South West	275	273	267	265	263	261	259	259	259	258	257	258	258	258	257	259	259	259	258	260	260	260
Total LDZ	**4,371**	**4,335**	**4,243**	**4,198**	**4,156**	**4,119**	**4,084**	**4,084**	**4,066**	**4,045**	**4,015**	**4,013**	**4,004**	**3,992**	**3,963**	**3,964**	**3,955**	**3,947**	**3,929**	**3,937**	**3,932**	**3,925**
NTS Industrial	145	145	144	144	144	144	144	144	144	144	144	138	138	138	138	138	138	138	138	138	138	138
NTS Power Generation	1,347	1,347	1,392	1,426	1,481	1,466	1,572	1,559	1,655	1,630	1,515	1,541	1,545	1,583	1,570	1,535	1,535	1,535	1,535	1,535	1,514	1,514
Exports via Moffat	361	329	318	318	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**1,853**	**1,821**	**1,854**	**1,888**	**1,939**	**1,924**	**2,029**	**2,017**	**2,113**	**2,088**	**1,972**	**1,993**	**1,997**	**2,035**	**2,022**	**1,987**	**1,987**	**1,987**	**1,987**	**1,987**	**1,966**	**1,966**
Total	**6,224**	**6,156**	**6,097**	**6,086**	**6,095**	**6,043**	**6,113**	**6,101**	**6,179**	**6,133**	**5,987**	**6,006**	**6,001**	**6,027**	**5,985**	**5,951**	**5,942**	**5,933**	**5,915**	**5,924**	**5,898**	**5,891**

Figures may not sum exactly due to rounding.

Figure A2.1G
No Progression: 1-in-20 peak day undiversified demand



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Table A2.1H
Low Carbon Life: 1-in-20 peak day undiversified demand (GWh/day)

National	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Scotland	336	333	328	325	323	320	318	316	315	313	311	310	309	308	306	305	303	302	301	301	300	299
Northern	237	235	231	230	228	226	224	223	222	220	218	218	217	216	214	214	213	212	211	210	210	209
North West	520	515	506	501	496	492	486	485	482	479	474	473	471	470	466	464	462	461	458	457	456	454
North East	267	265	261	259	257	255	252	252	250	249	247	247	245	244	242	242	240	240	238	238	237	237
East Midlands	433	429	422	420	416	413	409	409	407	405	401	400	398	397	393	392	390	389	386	386	385	384
West Midlands	381	378	371	367	364	360	356	355	352	349	345	343	341	339	335	334	332	329	327	326	325	323
Wales North	49	48	48	47	47	47	46	46	46	45	45	45	45	44	44	44	43	43	43	43	43	43
Wales South	198	198	196	195	192	190	192	192	188	186	184	182	181	181	180	179	178	178	177	177	177	177
Eastern	365	363	357	356	355	353	351	352	352	349	347	347	347	346	344	345	345	345	343	345	345	345
North Thames	473	469	462	459	457	454	451	450	449	447	444	444	443	441	438	439	437	436	434	434	433	433
South East	490	492	485	483	481	479	477	479	480	479	476	477	477	477	474	475	475	474	473	474	470	470
Southern	362	360	354	353	351	349	346	346	345	344	340	338	337	336	335	335	334	334	332	333	333	333
South West	276	274	270	269	268	267	265	265	264	263	262	262	262	262	261	262	262	262	261	262	262	263
Total LDZ	**4,386**	**4,360**	**4,290**	**4,264**	**4,234**	**4,206**	**4,172**	**4,169**	**4,151**	**4,129**	**4,094**	**4,086**	**4,074**	**4,060**	**4,031**	**4,030**	**4,016**	**4,004**	**3,982**	**3,986**	**3,976**	**3,971**
NTS Industrial	145	145	144	144	144	144	144	144	144	144	144	138	138	138	138	138	138	138	138	138	138	138
NTS Power Generation	1,347	1,347	1,392	1,428	1,468	1,480	1,530	1,699	1,645	1,740	1,636	1,633	1,492	1,492	1,439	1,344	1,294	1,281	1,281	1,243	1,243	1,243
Exports via Moffat	361	329	318	318	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**1,853**	**1,821**	**1,854**	**1,890**	**1,926**	**1,938**	**1,988**	**2,157**	**2,103**	**2,198**	**2,094**	**2,085**	**1,944**	**1,944**	**1,891**	**1,796**	**1,746**	**1,733**	**1,733**	**1,695**	**1,695**	**1,695**
Total	**6,239**	**6,181**	**6,145**	**6,154**	**6,160**	**6,144**	**6,160**	**6,326**	**6,254**	**6,326**	**6,188**	**6,171**	**6,017**	**6,004**	**5,922**	**5,826**	**5,762**	**5,737**	**5,715**	**5,681**	**5,671**	**5,666**

Figures may not sum exactly due to rounding.

Figure A2.1H
Low Carbon Life: 1-in-20 peak day undiversified demand

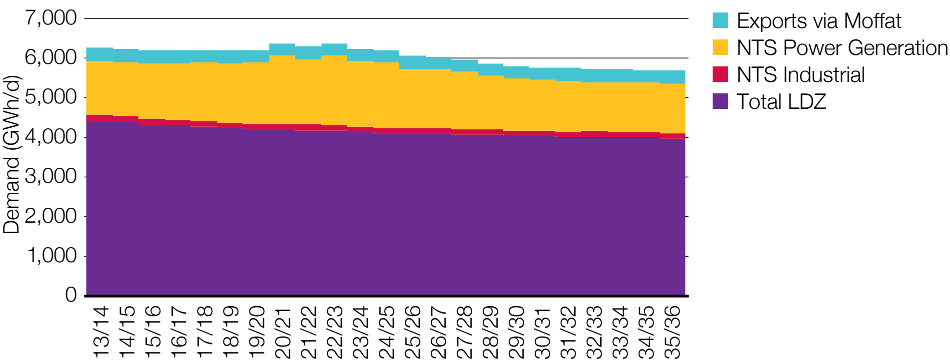
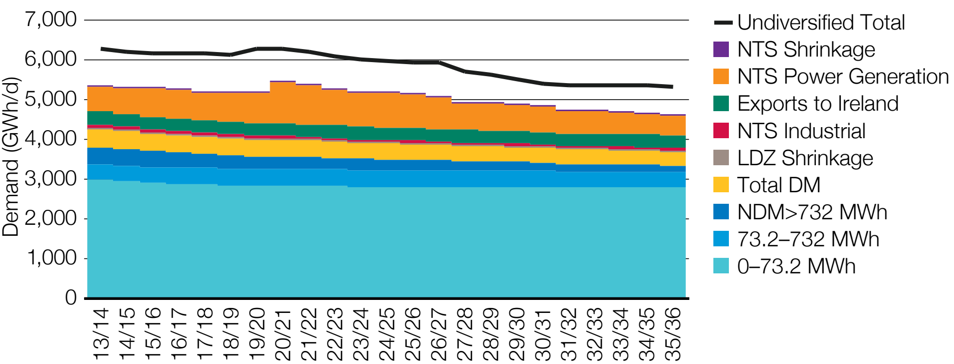


Table A2.1I
Slow Progression: 1-in-20 peak day diversified demand (GWh/d)

Diversified Peak	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
0–73.2 MWh	2,967	2,941	2,887	2,871	2,851	2,833	2,811	2,810	2,809	2,807	2,792	2,796	2,795	2,796	2,783	2,785	2,785	2,782	2,768	2,774	2,777	2,780	2,770
73.2–732 MWh	379	385	393	402	407	411	408	413	410	409	409	412	412	410	405	407	402	398	394	394	389	384	378
NDM > 732 MWh	431	417	392	373	356	342	325	318	306	295	282	272	261	249	238	231	221	212	203	195	186	178	170
Total NDM	3,777	3,742	3,672	3,646	3,614	3,586	3,545	3,540	3,525	3,511	3,484	3,480	3,467	3,455	3,426	3,422	3,408	3,392	3,364	3,363	3,353	3,342	3,318
Total DM	448	451	443	436	430	424	424	423	419	400	393	384	380	377	371	369	365	362	355	353	351	348	343
LDZ Shrinkage	9	9	9	9	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7	7	6	6	6
Total LDZ	**4,233**	**4,202**	**4,124**	**4,091**	**4,053**	**4,018**	**3,976**	**3,972**	**3,952**	**3,920**	**3,884**	**3,871**	**3,855**	**3,839**	**3,804**	**3,798**	**3,780**	**3,761**	**3,726**	**3,723**	**3,710**	**3,697**	**3,667**
NTS Industrial	87	88	87	87	88	88	87	87	87	87	87	87	87	87	87	87	87	87	86	86	86	86	86
Exports to Ireland	361	329	318	318	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
NTS Power Generation	604	631	705	700	682	714	746	1022	971	895	843	860	854	783	669	689	667	641	538	540	532	520	506
NTS Consumption	1,052	1,048	1,110	1,105	1,083	1,115	1,147	1,423	1,372	1,297	1,244	1,261	1,255	1,184	1,069	1,089	1,068	1,041	938	940	932	920	906
NTS Shrinkage	13	12	12	12	12	11	11	11	11	11	11	10	10	10	10	9	9	9	9	9	9	9	9
Total excluding IUK	5,298	5,262	5,246	5,208	5,147	5,145	5,135	5,406	5,335	5,227	5,139	5,143	5,121	5,033	4,884	4,897	4,857	4,812	4,673	4,672	4,651	4,626	4,582
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**5,298**	**5,262**	**5,246**	**5,208**	**5,147**	**5,145**	**5,135**	**5,406**	**5,335**	**5,227**	**5,139**	**5,143**	**5,121**	**5,033**	**4,884**	**4,897**	**4,857**	**4,812**	**4,673**	**4,672**	**4,651**	**4,626**	**4,582**

Figures may not sum exactly due to rounding.

Figure A2.1I
Slow Progression: 1-in-20 peak day diversified demand



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Table A2.1J
Gone Green: 1-in-20 peak day diversified demand (GWh/d)

Diversified Peak	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
0–73.2 MWh	2,966	2,936	2,873	2,855	2,829	2,804	2,771	2,770	2,758	2,748	2,724	2,720	2,708	2,680	2,643	2,597	2,540	2,475	2,397	2,324	2,241	2,146	2,041
73.2–732 MWh	379	389	405	417	426	434	438	444	442	439	434	429	418	406	389	380	365	351	334	326	313	298	283
NDM > 732 MWh	433	423	410	398	386	375	361	350	337	325	313	302	291	280	267	260	249	240	231	224	215	207	199
Total NDM	3,779	3,748	3,689	3,670	3,641	3,613	3,571	3,563	3,537	3,512	3,471	3,450	3,416	3,367	3,300	3,237	3,154	3,065	2,962	2,874	2,769	2,652	2,523
Total DM	447	451	448	445	442	438	436	437	438	405	395	389	386	383	379	378	375	373	370	370	368	367	363
LDZ Shrinkage	9	9	9	9	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7	7	6	6	6
Total LDZ	**4,235**	**4,208**	**4,145**	**4,123**	**4,091**	**4,059**	**4,015**	**4,008**	**3,983**	**3,925**	**3,874**	**3,847**	**3,810**	**3,757**	**3,686**	**3,622**	**3,536**	**3,445**	**3,339**	**3,250**	**3,143**	**3,025**	**2,892**
NTS Industrial	89	91	91	91	92	93	93	94	94	95	95	95	96	97	97	97	98	98	99	100	100	101	101
Exports to Ireland	361	329	318	318	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
NTS Power Generation	574	585	656	664	615	712	680	864	836	804	830	818	843	745	804	846	877	866	764	772	742	753	797
NTS Consumption	1,024	1,004	1,065	1,073	1,021	1,118	1,087	1,271	1,245	1,213	1,239	1,228	1,253	1,155	1,215	1,257	1,289	1,279	1,177	1,186	1,156	1,167	1,211
NTS Shrinkage	13	12	12	12	12	11	11	11	11	11	11	10	10	10	10	9	9	9	9	9	9	9	9
Total excluding IUK	5,272	5,224	5,222	5,208	5,124	5,189	5,114	5,291	5,239	5,148	5,123	5,085	5,073	4,922	4,910	4,888	4,835	4,733	4,525	4,445	4,309	4,201	4,112
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**5,272**	**5,224**	**5,222**	**5,208**	**5,124**	**5,189**	**5,114**	**5,291**	**5,239**	**5,148**	**5,123**	**5,085**	**5,073**	**4,922**	**4,910**	**4,888**	**4,835**	**4,733**	**4,525**	**4,445**	**4,309**	**4,201**	**4,112**

Figures may not sum exactly due to rounding.

Figure A2.1J
Gone Green: 1-in-20 peak day diversified demand

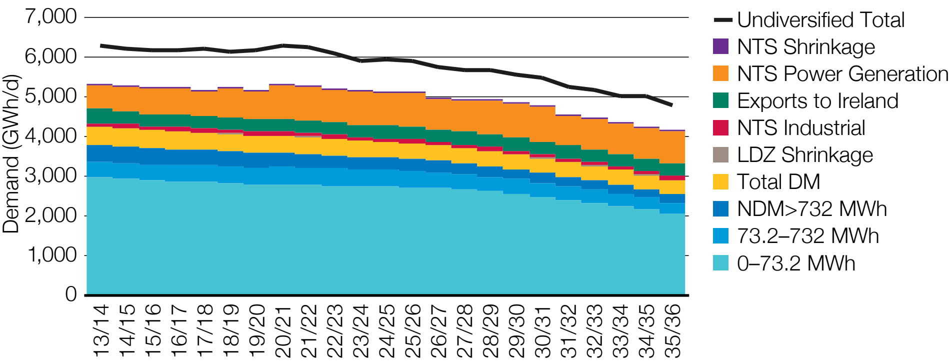
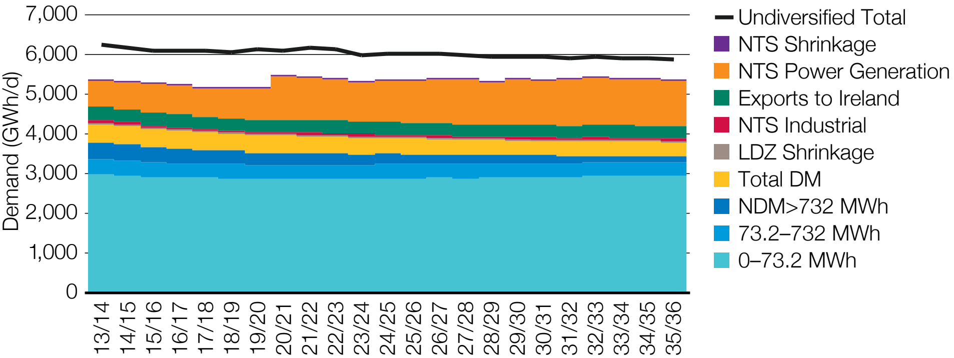


Table A2.1K
No Progression: 1-in-20 peak day diversified demand (GWh/d)

Diversified Peak	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
0–73.2 MWh	2,968	2,945	2,900	2,885	2,872	2,859	2,841	2,844	2,854	2,858	2,852	2,861	2,869	2,876	2,872	2,888	2,899	2,909	2,904	2,925	2,934	2,943	2,936
73.2–732 MWh	379	377	368	367	362	360	354	356	351	353	352	358	356	353	348	345	339	333	331	330	327	322	319
NDM > 732 MWh	431	417	390	372	354	339	323	315	301	289	275	266	255	244	233	223	213	202	195	187	179	170	163
Total NDM	3,778	3,739	3,658	3,624	3,588	3,558	3,518	3,515	3,506	3,500	3,480	3,485	3,480	3,473	3,452	3,456	3,450	3,445	3,430	3,442	3,440	3,436	3,417
Total DM	448	451	443	436	430	424	424	427	421	410	401	393	389	386	379	377	373	369	366	364	361	359	353
LDZ Shrinkage	9	9	9	9	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7	7	6	6	6
Total LDZ	**4,235**	**4,199**	**4,110**	**4,069**	**4,026**	**3,990**	**3,950**	**3,950**	**3,934**	**3,918**	**3,889**	**3,886**	**3,877**	**3,866**	**3,838**	**3,840**	**3,830**	**3,821**	**3,802**	**3,813**	**3,807**	**3,800**	**3,776**
NTS Industrial	87	88	87	87	88	88	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87
Exports to Ireland	361	329	318	318	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
NTS Power Generation	627	658	735	740	726	753	781	1,074	1,058	1,026	1,008	1,025	1,054	1,103	1,137	1,046	1,116	1,106	1,178	1,175	1,169	1,158	1,151
NTS Consumption	1,075	1,075	1,140	1,145	1,128	1,154	1,183	1,475	1,460	1,428	1,409	1,426	1,455	1,505	1,538	1,448	1,17	1,508	1,579	1,576	1,570	1,559	1,552
NTS Shrinkage	13	12	12	12	12	11	11	11	11	11	11	10	10	10	10	9	9	9	9	9	9	9	9
Total excluding IUK	5,322	5,286	5,262	5,226	5,166	5,155	5,144	5,436	5,405	5,356	5,309	5,323	5,342	5,380	5,386	5,297	5,357	5,338	5,391	5,398	5,386	5,369	5,338
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**5,322**	**5,286**	**5,262**	**5,226**	**5,166**	**5,155**	**5,144**	**5,436**	**5,405**	**5,356**	**5,309**	**5,323**	**5,342**	**5,380**	**5,386**	**5,297**	**5,357**	**5,338**	**5,391**	**5,398**	**5,386**	**5,69**	**5,338**

Figures may not sum exactly due to rounding.

Figure A2.1K
No Progression: 1-in-20 peak day diversified demand



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Table A2.1L
Low Carbon Life: 1-in-20 peak day diversified demand (GWh/d)

Diversified Peak	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
0–73.2 MWh	2,981	2,958	2,899	2,889	2,870	2,852	2,828	2,833	2,832	2,832	2,818	2,829	2,830	2,835	2,825	2,836	2,841	2,843	2,836	2,849	2,859	2,866	2,863
73.2–732 MWh	379	384	391	395	401	407	410	416	419	420	420	421	422	420	417	417	412	409	404	407	402	399	392
NDM > 732 MWh	433	422	410	395	383	371	357	346	334	320	308	296	285	272	261	253	243	233	224	217	207	199	191
Total NDM	3,793	3,764	3,700	3,680	3,654	3,630	3,595	3,596	3,584	3,573	3,546	3,546	3,538	3,528	3,504	3,505	3,495	3,485	3,465	3,473	3,469	3,465	3,446
Total DM	447	451	448	445	440	436	436	435	430	422	414	406	403	400	396	394	390	388	385	384	377	376	370
LDZ Shrinkage	9	9	9	9	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7	7	6	6	6
Total LDZ	**4,249**	**4,224**	**4,157**	**4,134**	**4,102**	**4,075**	**4,038**	**4,039**	**4,022**	**4,003**	**3,968**	**3,960**	**3,948**	**3,936**	**3,907**	**3,907**	**3,893**	**3,879**	**3,857**	**3,864**	**3,853**	**3,847**	**3,823**
NTS Industrial	89	91	91	91	92	93	93	94	94	95	95	95	96	97	97	97	98	99	99	99	100	101	101
Exports to Ireland	361	329	318	318	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
NTS Power Generation	596	627	708	723	687	706	721	924	869	863	813	870	806	889	838	837	818	773	821	792	791	795	794
NTS Consumption	1,046	1,046	1,117	1,133	1,093	1,113	1,128	1,332	1,277	1,272	1,222	1,279	1,216	1,300	1,249	1,248	1,230	1,186	1,234	1,205	1,205	1,210	1,208
NTS Shrinkage	13	12	12	12	12	11	11	11	11	11	11	10	10	10	10	9	9	9	9	9	9	9	9
Total excluding IUK	5,307	5,283	5,285	5,278	5,207	5,199	5,178	5,382	5,311	5,286	5,200	5,249	5,174	5,245	5,166	5,165	5,132	5,074	5,100	5,078	5,067	5,066	5,040
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**5,307**	**5,283**	**5,285**	**5,278**	**5,207**	**5,199**	**5,178**	**5,382**	**5,311**	**5,286**	**5,200**	**5,249**	**5,174**	**5,245**	**5,166**	**5,165**	**5,132**	**5,074**	**5,100**	**5,078**	**5,067**	**5,066**	**5,040**

Figures may not sum exactly due to rounding.

Figure A2.1L
Low Carbon Life: 1-in-20 peak day diversified demand

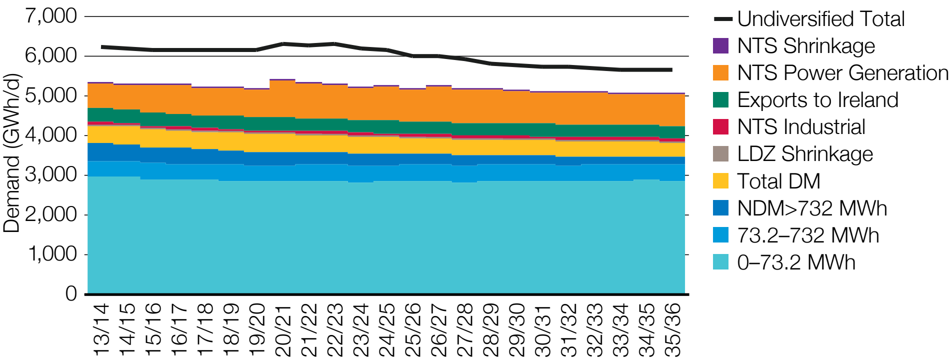


Figure A2.1M
2014/15 Load curve – Slow Progression

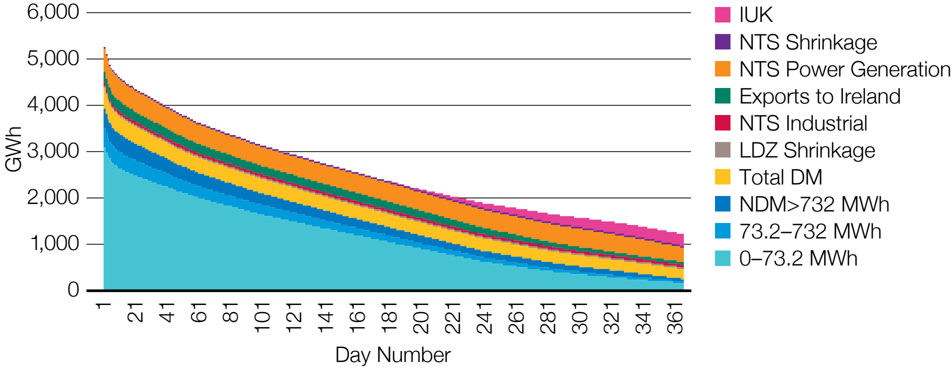
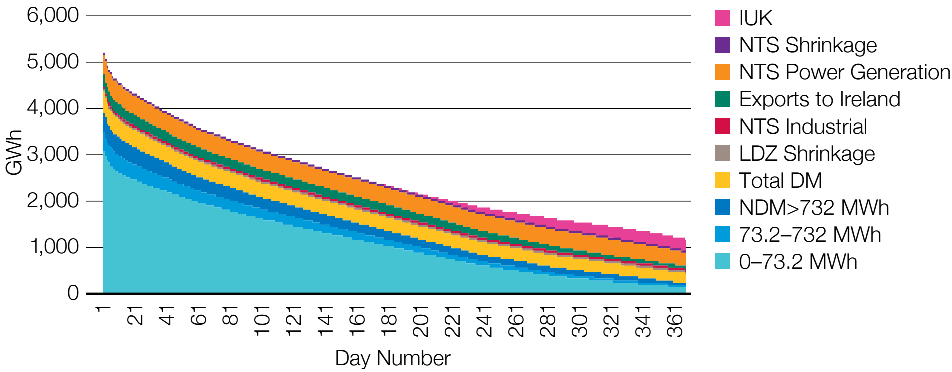


Figure A2.1N
2014/15 Load curve – Gone Green



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Figure A2.1O
2014/15 Load curve – No Progression

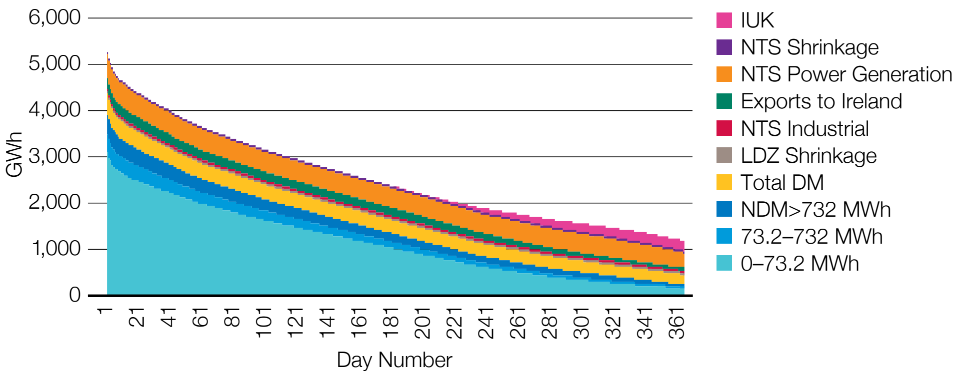


Figure A2.1P
2014/15 Load curve – Low Carbon Life

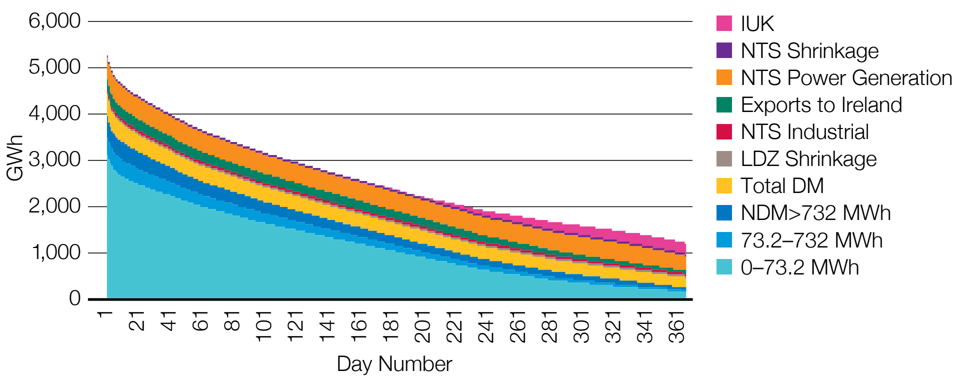


Figure A2.1Q
2025/26 Load curve – Slow Progression

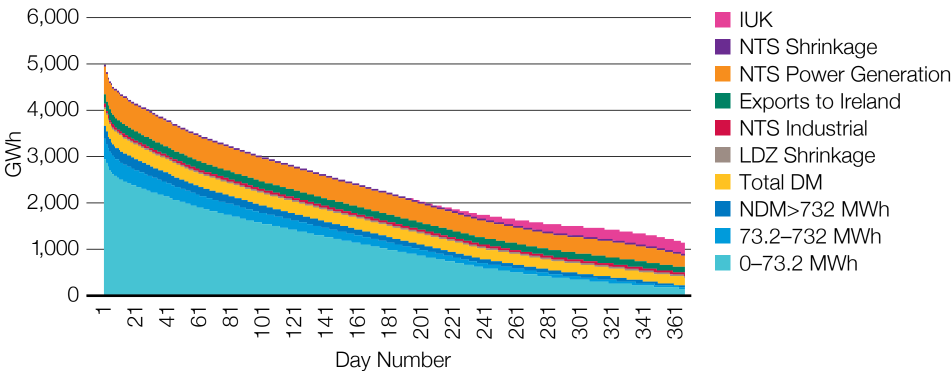
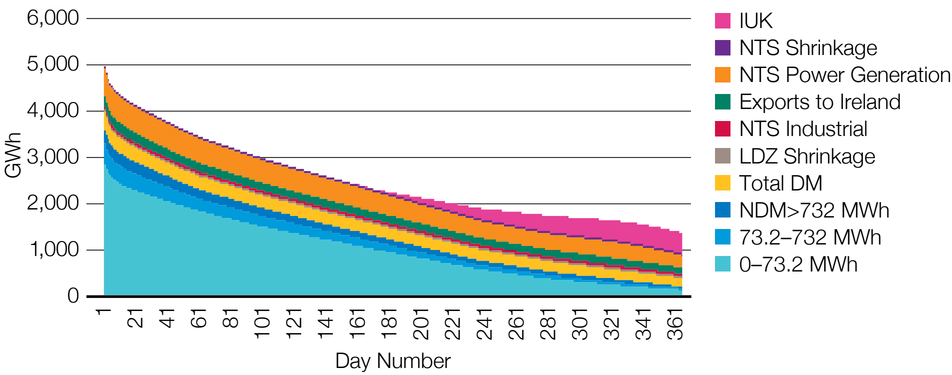


Figure A2.1R
2025/26 Load curve – Gone Green



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Figure A2.1S
2025/26 Load curve – No Progression

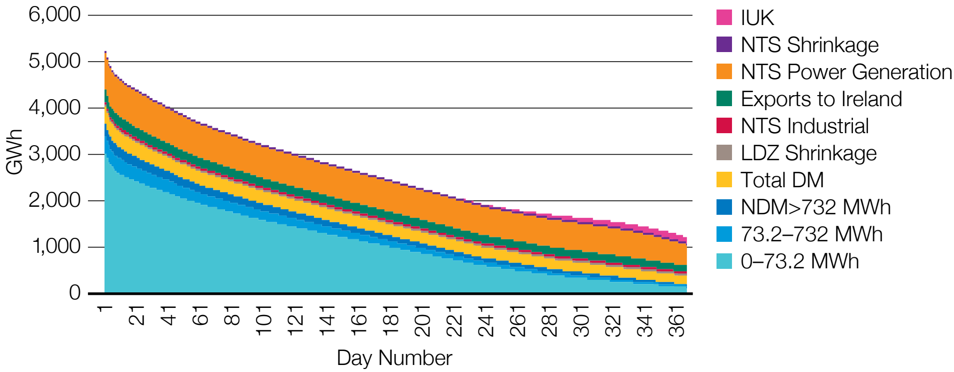


Figure A2.1T
2025/26 Load curve – Low Carbon Life

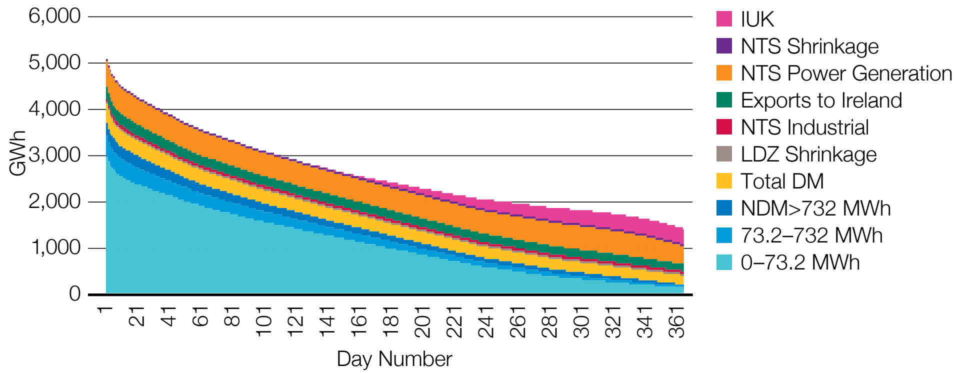


Figure A2.1U
2030/31 Load curve – Slow Progression

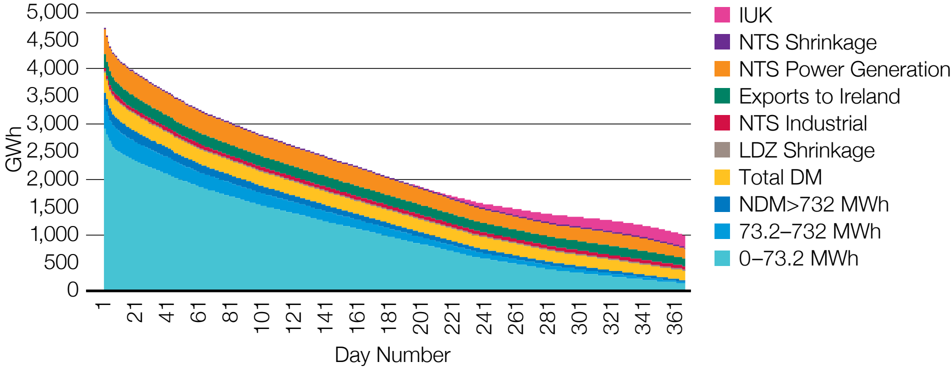
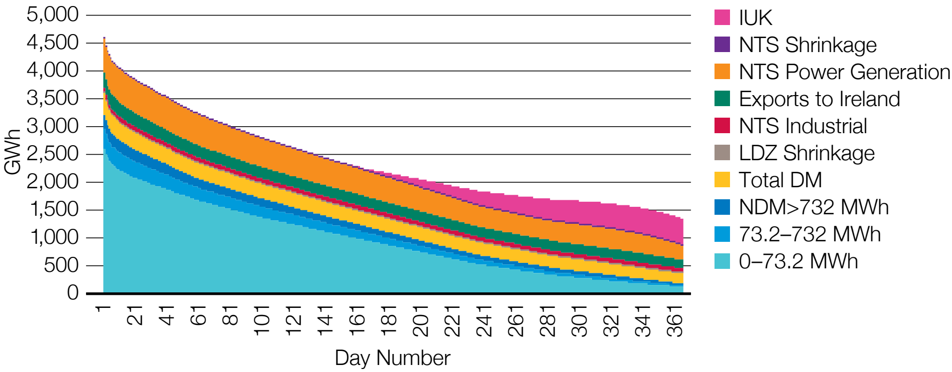


Figure A2.1V
2030/31 Load curve – Gone Green



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Figure A2.1W
2030/31 Load curve – No Progression

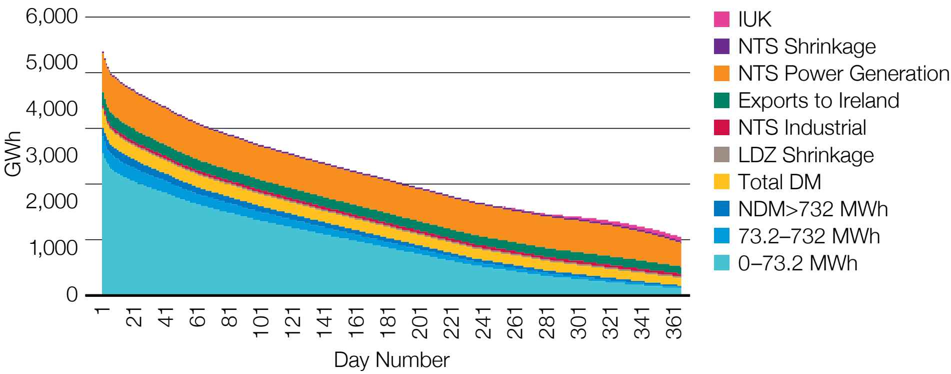
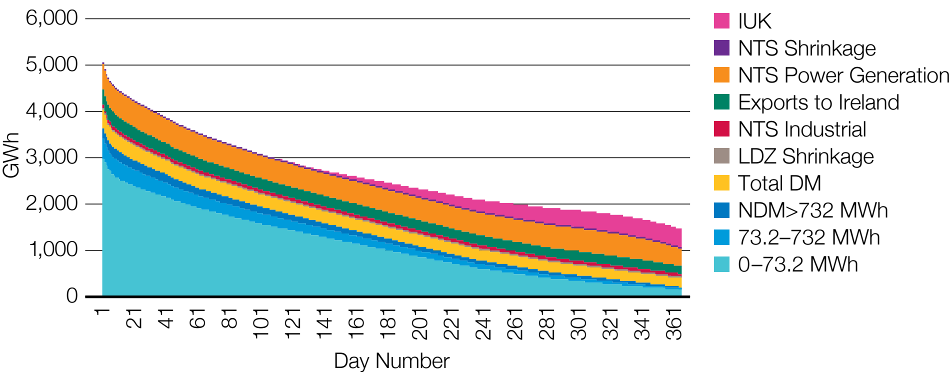


Figure A2.1X
2030/31 Load curve – Low Carbon Life



A2.2
Supply

Figure A2.2A
Peak Bacton scenarios (mcm/d)

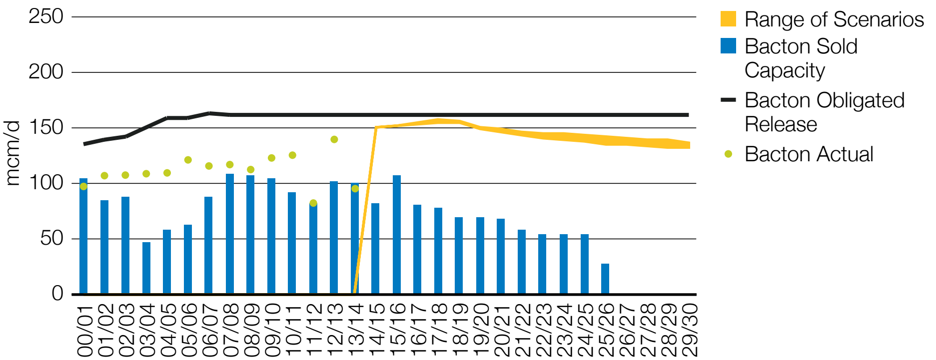
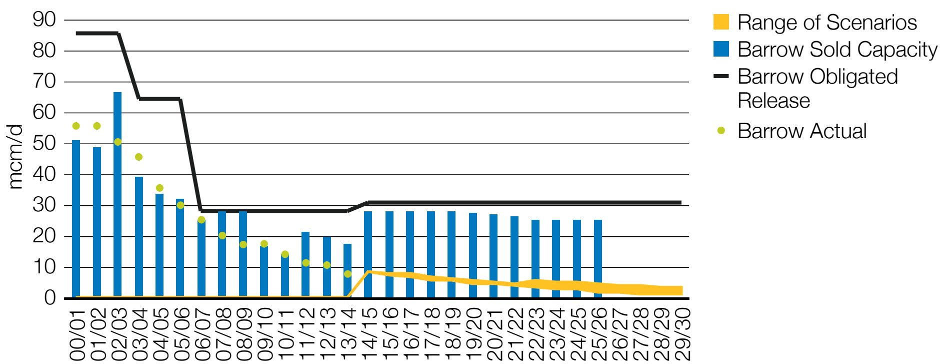


Figure A2.2B
Peak Barrow scenarios (mcm/d)



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Figure A2.2C
Peak Easington scenarios (mcm/d)

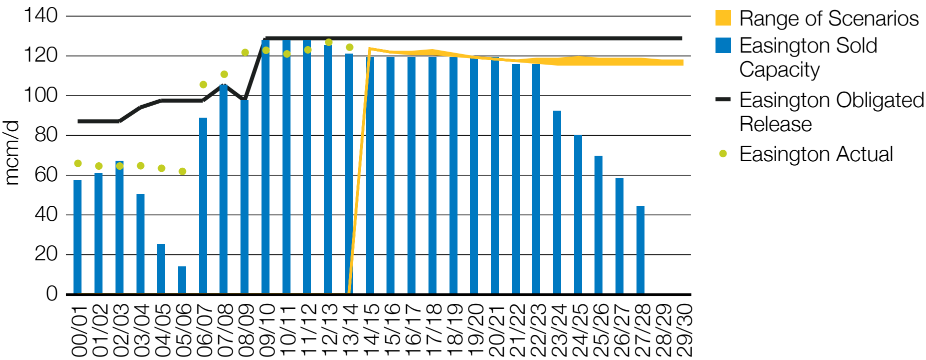


Figure A2.2D
Peak St. Fergus scenarios (mcm/d)

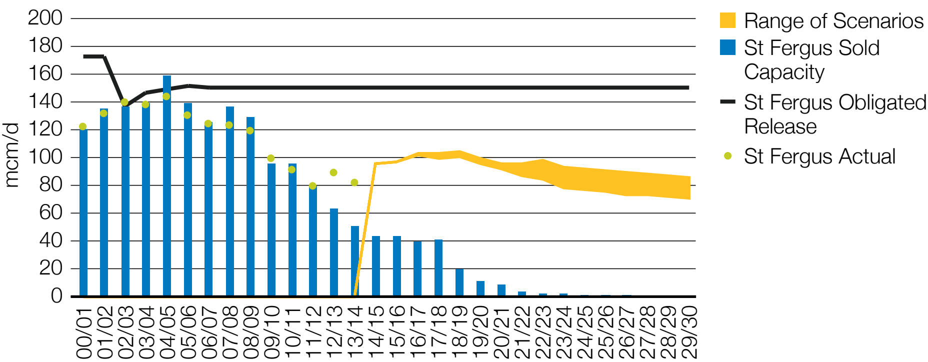


Figure A2.2E
Peak Teesside scenarios (mcm/d)

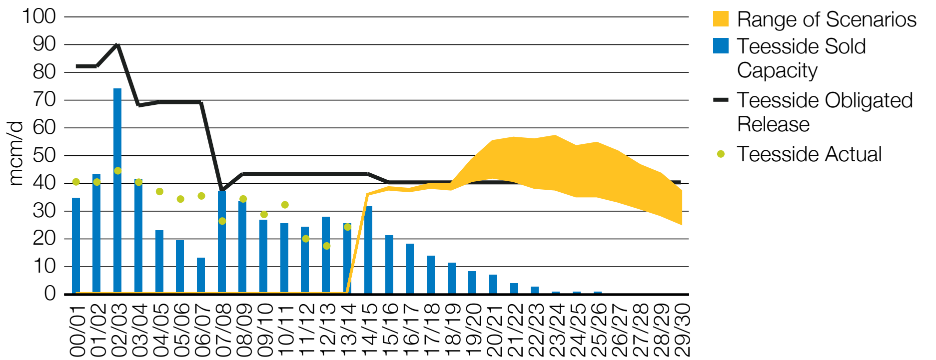
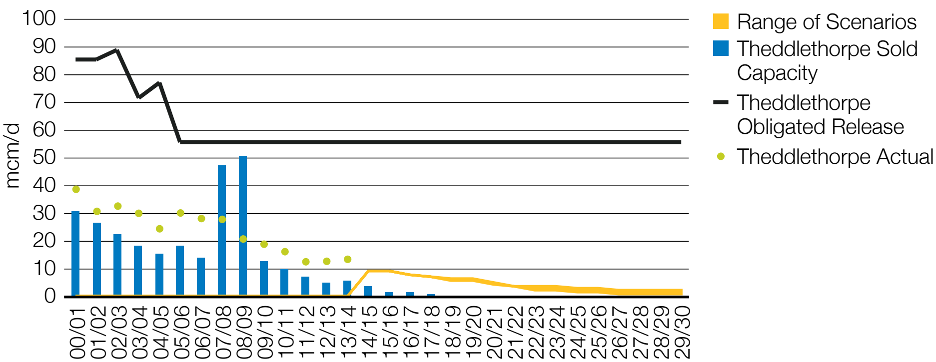


Figure A2.2F
Peak Theddlethorpe scenarios (mcm/d)



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Figure A2.2G
Peak Isle of Grain LNG scenarios (mcm/d)

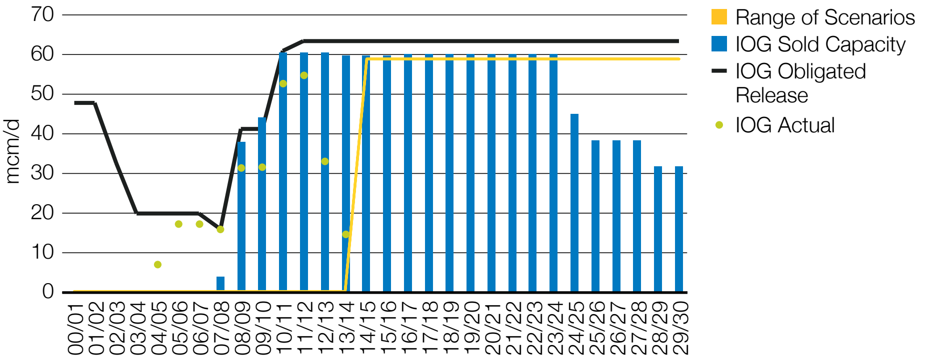


Figure A2.2H
Peak Milford Haven scenarios (mcm/d)

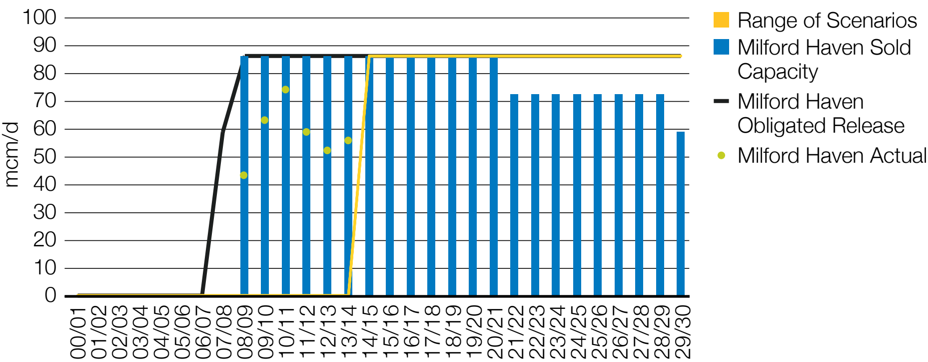


Figure A2.2I
Gone Green: Annual supply by terminal – high continent/low LNG case

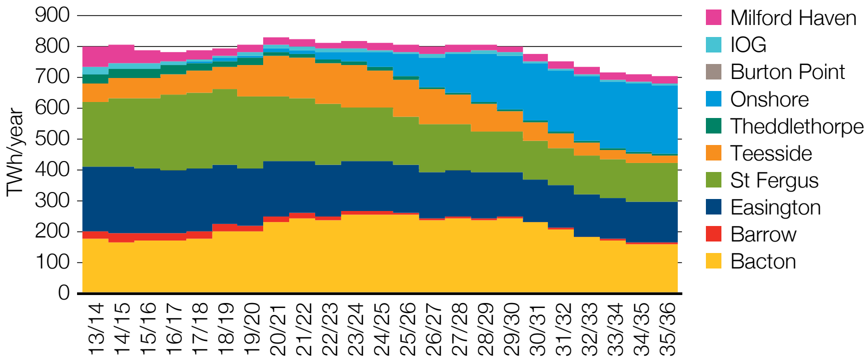
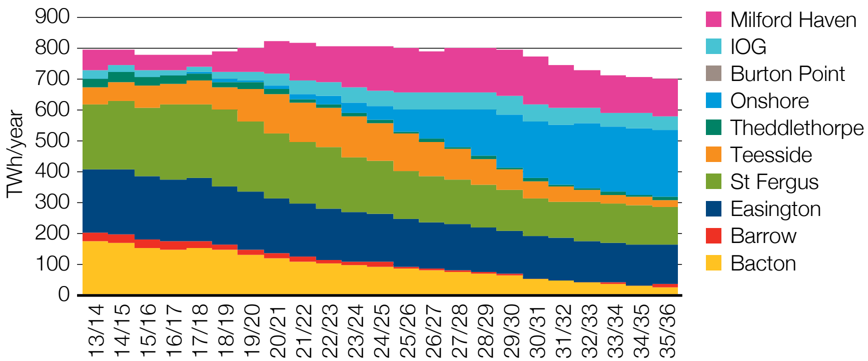


Figure A2.2J
Gone Green: Annual supply by terminal – low continent/high LNG case



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Figure A2.2K
Gone Green: Peak supply by terminal

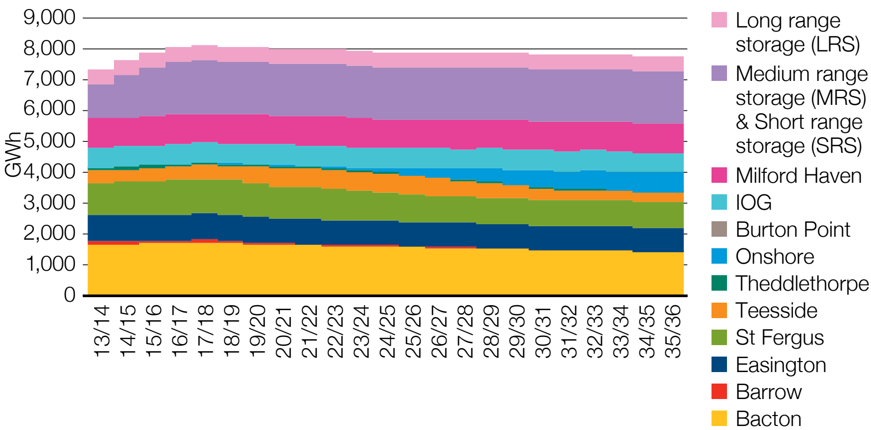


Figure A2.2L
Slow Progression: Annual supply by terminal – high continent/low LNG case

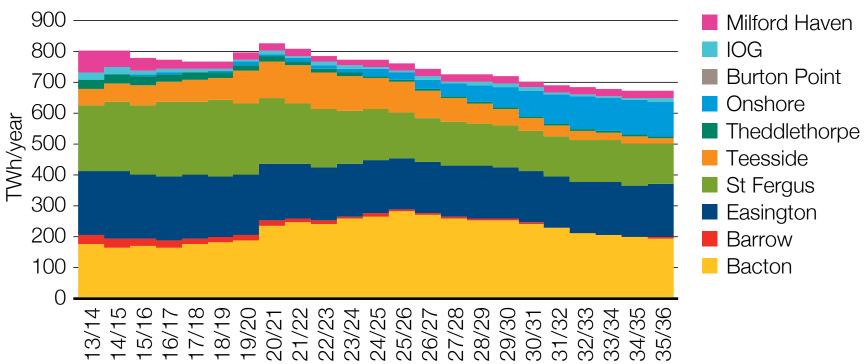


Figure A2.2M
Slow Progression: Annual supply by terminal – low continent/high LNG case

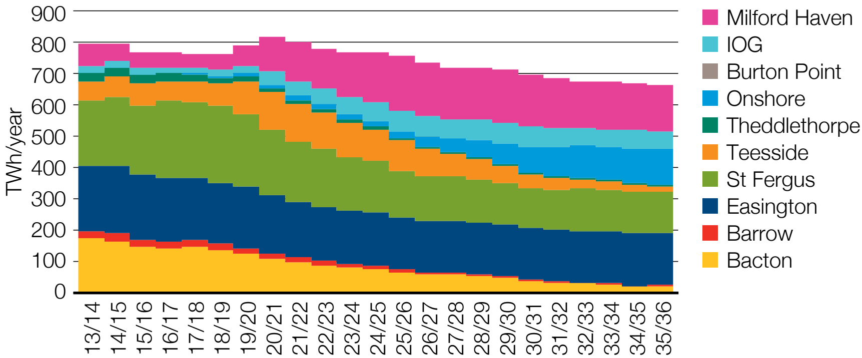
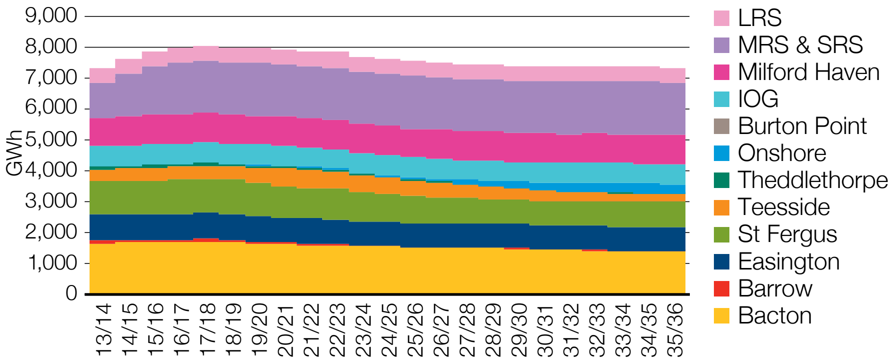


Figure A2.2N
Slow Progression: Peak supply by terminal



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Figure A2.2O
No Progression: Annual supply by terminal – high continent/low LNG case

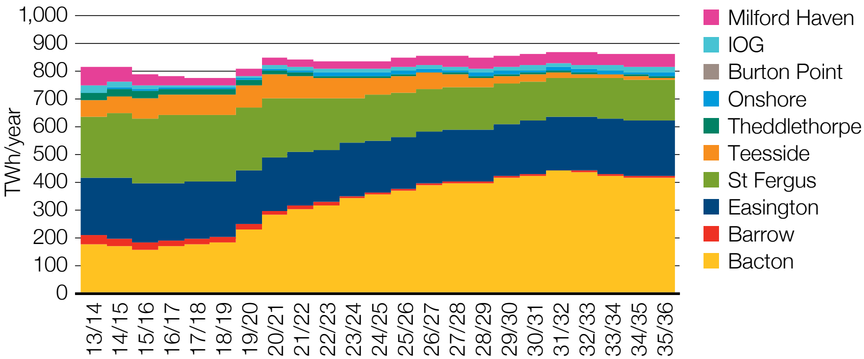


Figure A2.2P
No Progression: Annual supply by terminal – low continent/high LNG case

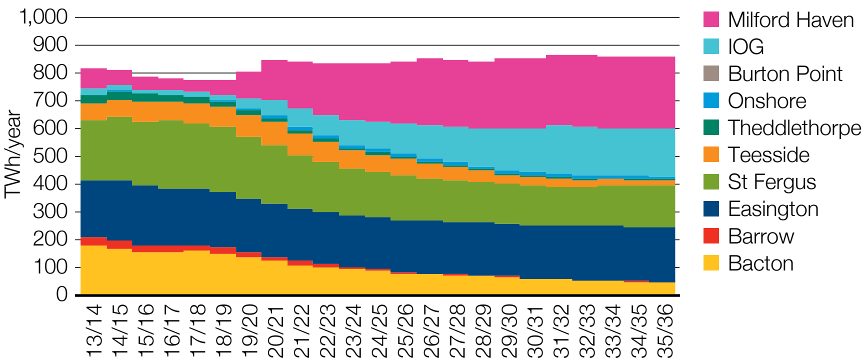


Figure A2.2Q
No Progression: Peak supply by terminal

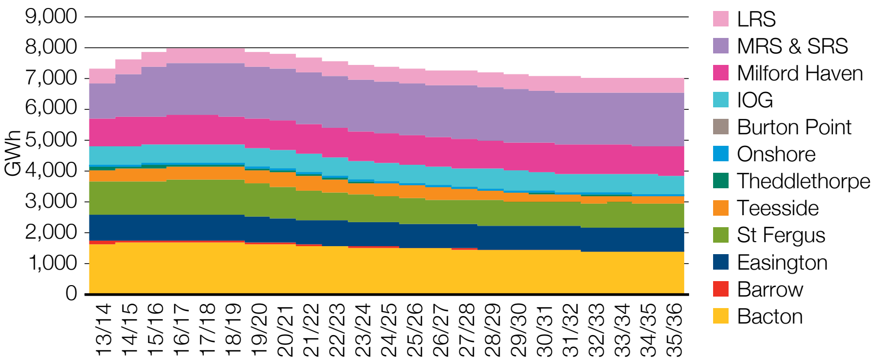
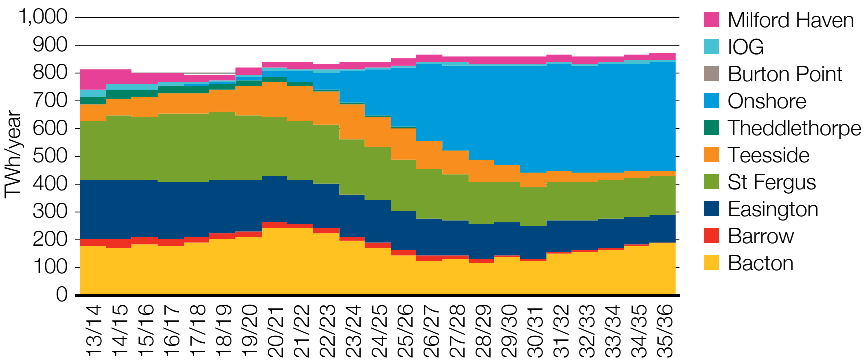


Figure A2.2R
Low Carbon Life: Annual supply by terminal – high continent/low LNG case



Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Figure A2.2S
Low Carbon Life: Annual supply by terminal – low continent/high LNG case

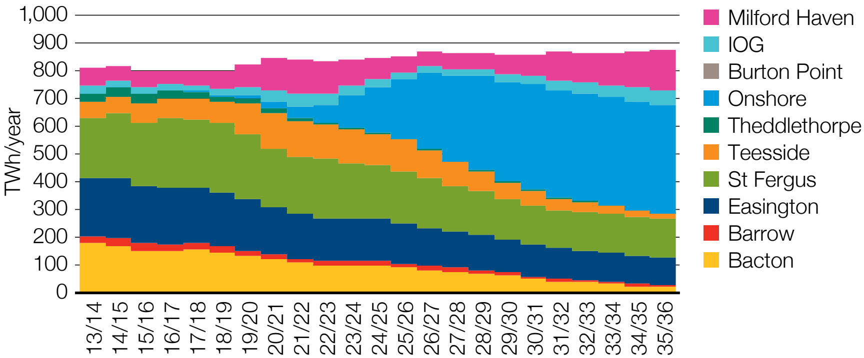
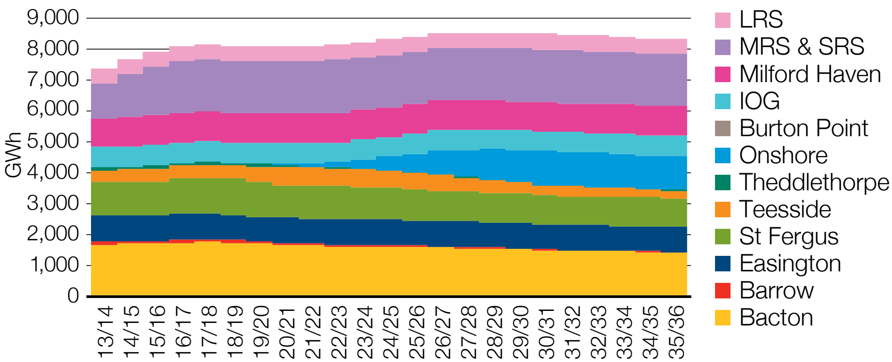


Figure A2.2T
Low Carbon Life: Peak supply by terminal



A2.3
UK Importation Projects

While there are proposals for further import projects, currently no importation projects are under construction. The UK's import capacity is currently around 156 bcm/y, this is split into three near equal sources: the Continent (46 bcm/y), Norway (56[1] bcm/y) and LNG (53 bcm/y). The UK is served through a diverse set of import routes from Norway, Holland, Belgium and from other international sources through the LNG importation terminals.

Table 2.3A shows existing UK import infrastructure and Table 2.3B shows proposals for further import projects.

Table 2.3A
Existing UK import infrastructure

Project	Operator / Developer	Type	Location	Capacity (bcm/y)
Interconnector	IUK	Pipeline	Bacton	26.9[2]
BBL Pipeline	BBL Company	Pipeline	Bacton	19.5[3]
Isle of Grain 1–3	National Grid	LNG	Kent	20.4
GasPort	Excelerate Energy	LNG	Teesside	4.1
South Hook 1–2	Qatar Petroleum and ExxonMobil	LNG	Milford Haven	21
Dragon 1	BG Group / Petronas	LNG	Milford Haven	7.6
Langeled	Gassco	Pipeline	Easington	26.3
Vesterled	Gassco	Pipeline	St Fergus	14.2
Tampen	Gassco	Pipeline	St Fergus	9.8
Gjøa	Gassco	Pipeline	St Fergus	6.2
			Total	**156**

Source: National Grid

[1] Norwegian import capacity through Tampen and Gjøa is limited by available capacity in the UK FLAGS pipeline.
[2] Adjusted for UK standard conditions. Value reported on interconnector.com is 25.5bcm/y at normal conditions.
[3] Adjusted for UK CV and standard conditions; bblcompany.com report 20.6GWh/h at CV of 35.17MJ/m^3 (normal).

Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Table 2.3B
Proposed UK import projects[4]

Project	Operator / Developer	Type	Location	Start- up	Capacity (bcm/y)	Status
Isle of Grain 4	National Grid	LNG	Kent	-	-	Open Season
Norsea LNG	ConocoPhillips	LNG	Teesside	-	-	Planning granted, no FID. Currently on hold
Port Meridian	Port Meridian Energy	LNG	Barrow, Cumbria	2016+	5	Open Season
Amlwch	Halite Energy	LNG	Anglesey	-	~30	Approved Onshore
				Total	30+	

Source: National Grid

Please note Tables 2.3A and 2.3B represent the latest information available to National Grid at time of going to press. Developers are welcome to contact us to add or revise this data.

[4] This list is in no way exhaustive; other import projects have at times been detailed in the press.

A2.4
UK Storage Projects

In the last 12 months no proposals have attained a Final Investment Decision for subsequent construction.

The following tables detail UK storage in terms of existing storage sites, those under construction and proposed sites.

Table 2.4A
Existing UK storage

Project	Operator	Location	Space (bcm)	Approximate maximum delivery (mcm/d)
Rough	Centrica Storage	Southern North Sea	3.3	41
Aldbrough	SSE / Statoil	East Yorkshire	0.3	40[5]
Hatfield Moor	Scottish Power	South Yorkshire	0.07	2
Holehouse Farm	EDF Trading	Cheshire	0.05	11
Holford	E.ON	Cheshire	0.2	22
Hornsea	SSE	East Yorkshire	0.3	18
Humbly Grove	Humbly Grove Energy	Hampshire	0.3	7
Avonmouth	National Grid LNGS	Avon and Somerset	0.08	13[6]
		Total	**4.6**	**154**

Source: National Grid

Note, due to operational considerations, the space and deliverability may not be fully consistent with that used for operational planning as reported in our 2014/15 Winter Outlook Report.

[5] Represents nameplate capacity
[6] Represents maximum capability

Appendix 2 continued
Gas Demand and Supply Volume Scenarios

Table 2.4B
Storage commissioning

Project	Operator	Location	Space (bcm)	Deliverability (mcm/d)	Planned Start-up
Hill Top Farm[7]	EDF Energy	Cheshire	0.1	15	2014/15
Stublach[8]	Storengy UK	Cheshire	0.2	15	2014/15
		Total	0.3	30	

Source: National Grid

Over the last 1–2 years, a number of projects have been put on hold or cancelled. These include Aldbrough 2, Baird, Caythorpe, Gateway and Portland.

Table 2.4C shows other storage site proposals.

Table 2.4C
Proposed storage[9]

Project	Operator	Location	Space (bcm)	Status
Deborah	eni	Offshore Bacton	4.6	Planning granted, no FID
Islandmagee	InfraStrata	County Antrim, Northern Ireland	0.5	Planning granted, no FID
King Street	King Street Energy	Cheshire	0.3	Planning granted, no FID
Preesall	Halite Energy	Lancashire	0.6	Planning not yet granted
Saltfleetby	Wingaz	Lincolnshire	0.8	Planning granted, no FID
Stublach[10]	Storengy UK	Cheshire	0.2	Planning granted, no FID
Whitehill	E.ON	East Yorkshire	0.5	Planning granted, no FID
		Total	**7.5**	

Source: National Grid

Please note Tables 2.4A–2.4C represent the latest information available to National Grid at time of going to press. Developers are welcome to contact us to add or revise this data.

7 Represents completed space (fully available from 2017).
8 Data represents phase 1 which is currently under construction.
9 This list is in no way exhaustive; other storage projects at times have been detailed in the press.
10 Represents second phase which is currently undecided.

Appendix 3
Actual Flows 2013/14

Introduction
This appendix describes annual and peak flows during the calendar year 2013 and gas year 2013/14.

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 reallocation of demand between 0–73.2MWh/y and >73MWh/y 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 A3.1A provides a comparison of actual and weather-corrected demands during the 2013 calendar year with the forecasts presented in the 2013 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.

Appendix 3 continued
Actual Flows 2013/14

Table A3.1A
Annual demand for 2013 (TWh) – LDZ / NTS split

	Actual Demand (TWh)	Weather-Corrected Demand (TWh)	GTYS (2013) GG Demand
0–73.2 MWh	365	332	333
73.2–732 MWh	49	45	44
>732 MWh Firm	173	168	177
Total LDZ Consumption	**587**	**545**	**553**
NTS Industrial	28	28	30
NTS Power Gen.	162	162	155
Exports	91	91	104
Total NTS Consumption	**281**	**281**	**290**
Total Consumption	**868**	**826**	**843**
Shrinkage	8	8	8
Total System Demand	**876**	**834**	**851**

Figures may not sum exactly due to rounding.

Table A3.1A indicates that our 1-year ahead forecast for 2013 was accurate to 1.5% 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 2.0%.

A3.2
Peak and minimum flows

A3.2.1 System entry – maximum day flows
For winter 2013/14, the day of highest supply to the NTS was also the day of highest demand. This was 30 January 2014, when 327mcm fed a demand of 327mcm. This is lower than the highest demand day in the 2012/13 gas year, in which 392mcm of gas was supplied for a demand of 393mcm.

The day of minimum demand in 2013/14 was 14 September 2014, when NTS demand was 137.6mcm. The day of lowest supply to the NTS was on 13 September 2014, in which 135mcm of gas was supplied for a demand of 138mcm.

Table A3.2A
IGMS M+15 physical NTS entry flows: 30 January 2014 (mcm/d)

Terminal	Max Day 30 January 2014	GTYS (2013) Gone Green Supply Capability	Highest Daily (per terminal)
Bacton inc. IUK and BBL	55	158	96
Barrow	5	7	8
Easington inc. Rough & Langaled	123	122	124
Isle of Grain (excl. LDZ inputs)	0	59	12
Milford Haven	8	86	56
Point of Ayr (Burton Point)	3	0	4
St Fergus	57	95	82
Teesside	20	38	24
Theddlethorpe	12	12	14
Sub-total	283	578	420
MRS & LNG Storage	43	124	51
Total	**327**	**702**	**471**

Notes
– The maximum supply day for 2013/14 refers to NTS flows on 30 January 2014.
– This was the overall highest supply day, but individual terminals may have supplied higher deliveries on other days.
– Supply Capability refers to that published in the 2013 Gas Ten Year Statement. Conversions to mcm have been made using a CV of 39.6MJ/m^3.
– 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.

Appendix 3 continued
Actual Flows 2013/14

A3.2.2 System entry – minimum day flows

Table A3.2B
IGMS M+15 physical NTS entry flows: 13 September 2014 (mcm/d)

Terminal	Min Day 13 September 2014
Bacton inc. IUK and BBL	25
Barrow	0
Easington inc. Rough & Langaled	27
Isle of Grain (excl. LDZ inputs)	0
Milford Haven	22
Point of Ayr (Burton Point)	0
St Fergus	41
Teesside	16
Theddlethorpe	0
Sub-total	131
MRS & LNG Storage	4
Total	**135**

Notes
– The minimum supply day for 2013/14 refers to NTS flows on 13 September 2014. 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 2013/14 compared to the forecast peak flows.

Table A3.2C
IGMS D+5 physical LDZ demand flows: 30 January 2014

LDZ	Maximum Day 30 January 2014	GTYS (2013) 1 in 20 Undiversified Gone Green Peak
Eastern	19	32
East Midlands	27	40
North East	16	25
Northern	13	21
North Thames	23	42
North West	31	50
Scotland	20	31
South East	22	45
Southern	19	32
South West	14	25
West Midlands	22	35
Wales [North & South]	14	23
LDZ Total	**242**	**402**
NTS Loads	**84**	**171**
Compressor Fuel Usage (CFU)	**1**	
Total	**327**	**572**

Notes
– The maximum day for gas year 2013/14 refers to 30 January 2014. 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.
– The Gone Green 1-in-20 Peak Day Firm Demand forecast was published in the 2013 Gas Ten Year Statement. Conversions to mcm have been made using a CV of 39.6MJ/m^3.
– Figures may not sum exactly due to rounding.

Appendix 3 continued
Actual Flows 2013/14

A3.2.4 System exit – minimum day flows

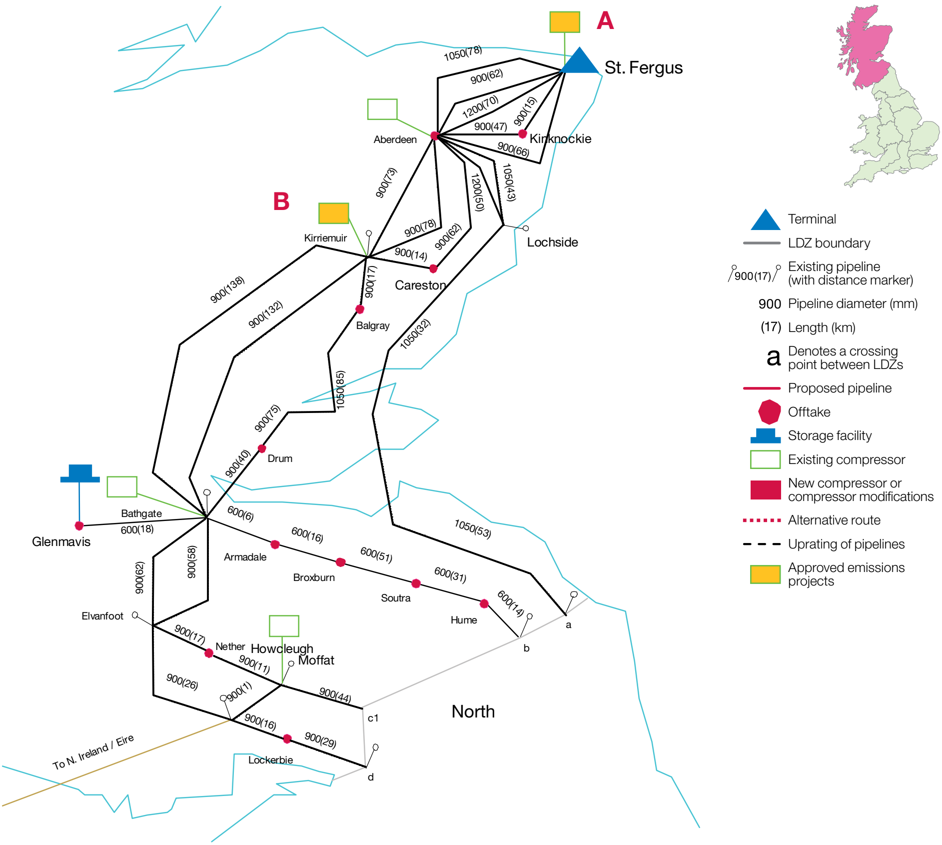
Table A3.2D
IGMS D+5 physical LDZ demand flows: 14 September 2014

LDZ	Minimum Day 14 September 2014
Eastern	5
East Midlands	7
North East	6
Northern	5
North Thames	5
North West	9
Scotland	7
South East	3
Southern	4
South West	3
West Midlands	5
Wales [North & South]	4
LDZ Total	**62**
NTS Loads	**67**
Compressor Fuel Usage (CFU)	**0**
Total	**129**

Notes
– The minimum day for gas year 2013/14 refers to 14 September 2014. 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 4
The Gas Transportation System

Figure A4.1
Scotland (SC) – NTS



Appendix 4 continued
The Gas Transportation System

Figure A4.2
North (NO) – NTS

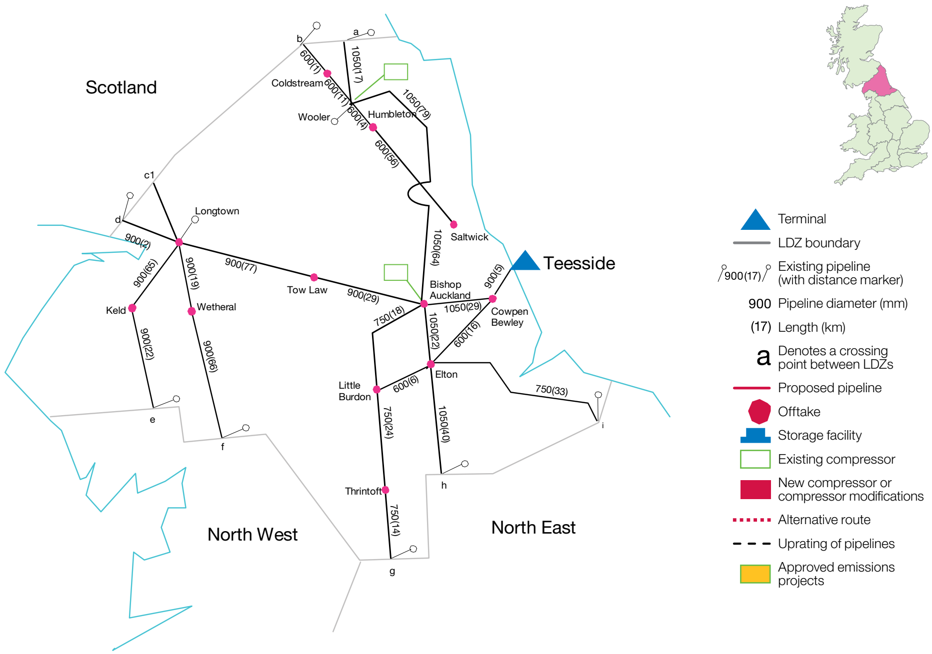
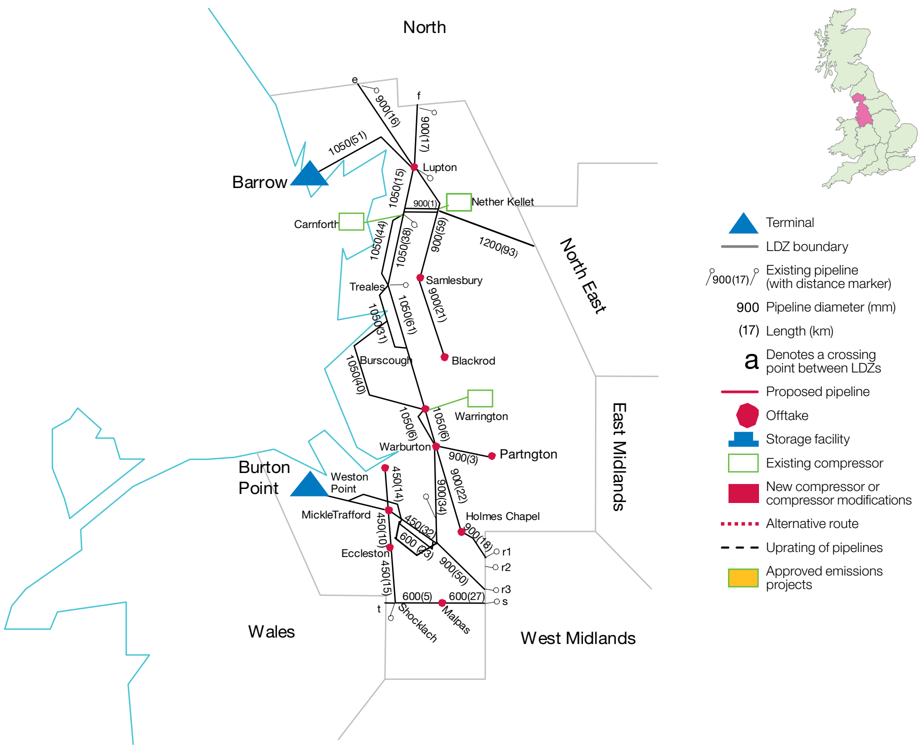


Figure A4.3
North West (NW) – NTS



Appendix 4 continued
The Gas Transportation System

Figure A4.4
North East (NE) – NTS

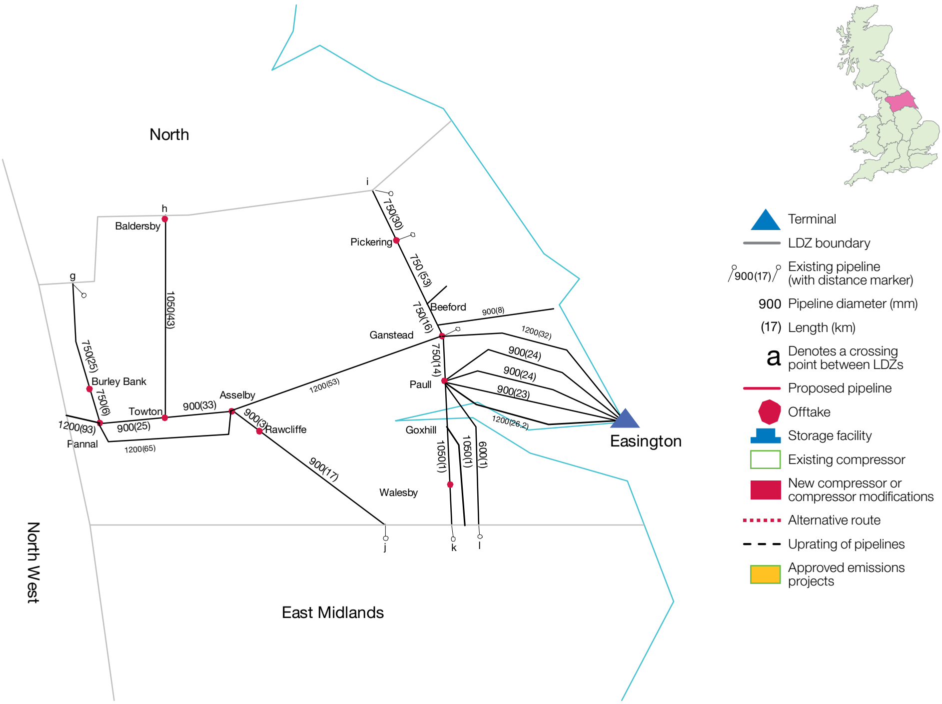
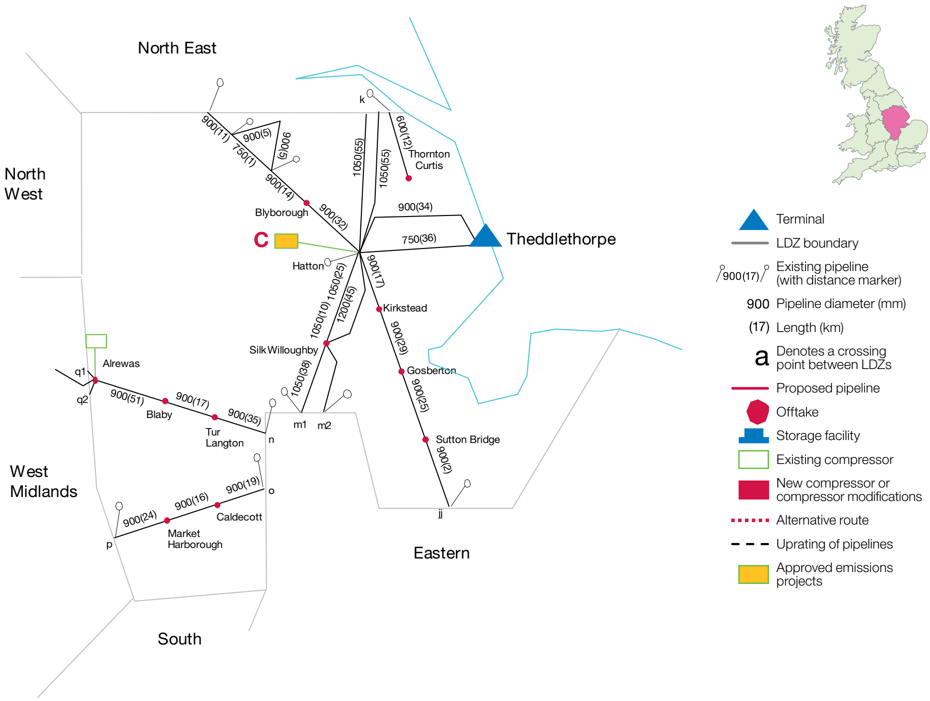


Figure A4.5
East Midlands (EM) – NTS



Appendix 4 continued
The Gas Transportation System

Figure A4.6
West Midland (WM) – NTS

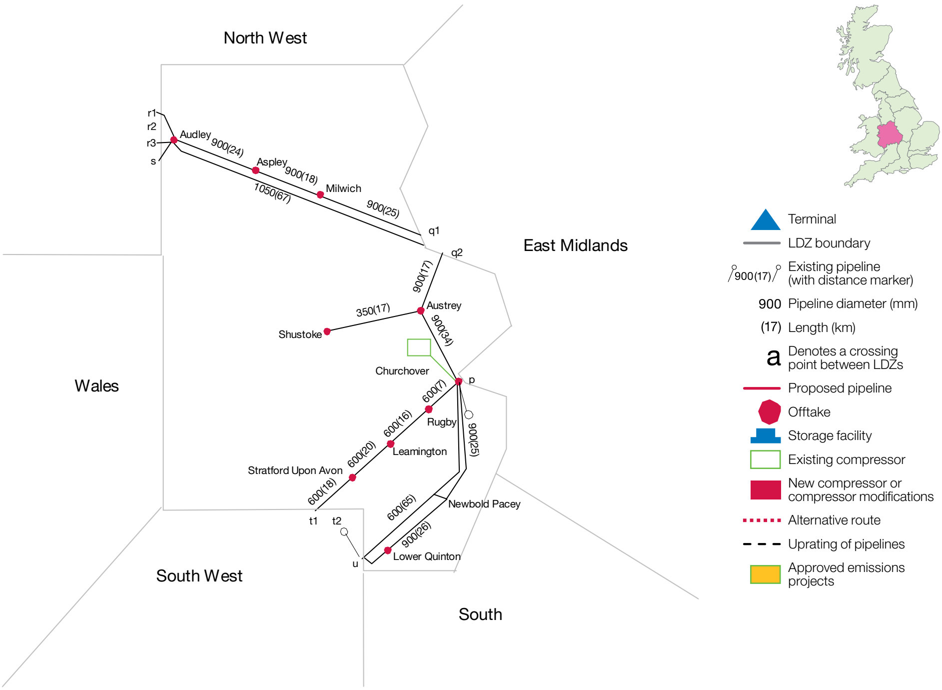
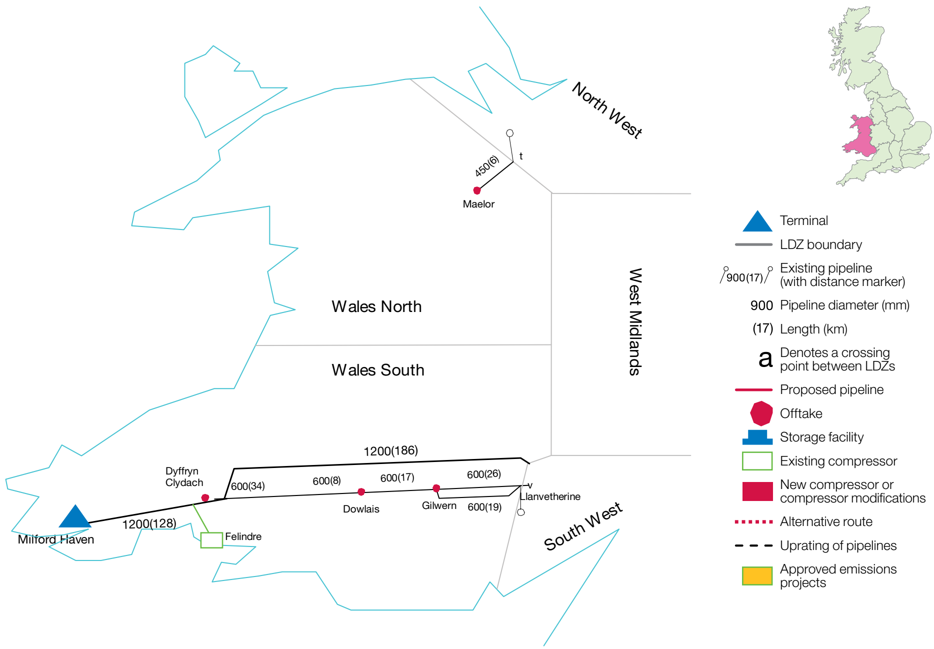


Figure A4.7
Wales (WN & WS) – NTS



Appendix 4 continued
The Gas Transportation System

Figure A4.8
Eastern (EA) – NTS

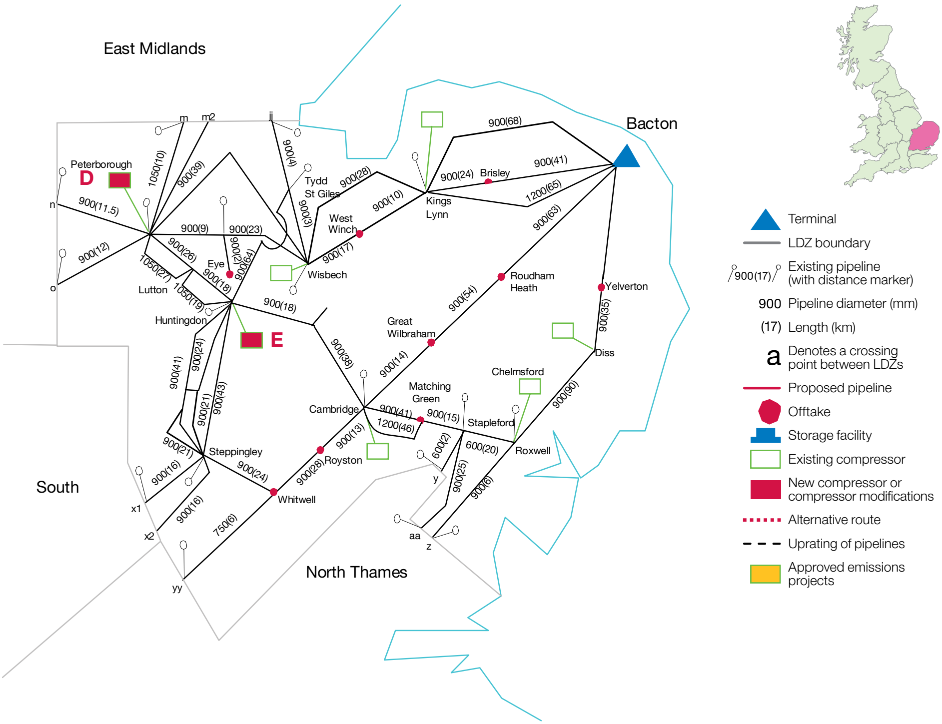


Figure A4.9
North Thames (NT) – NTS

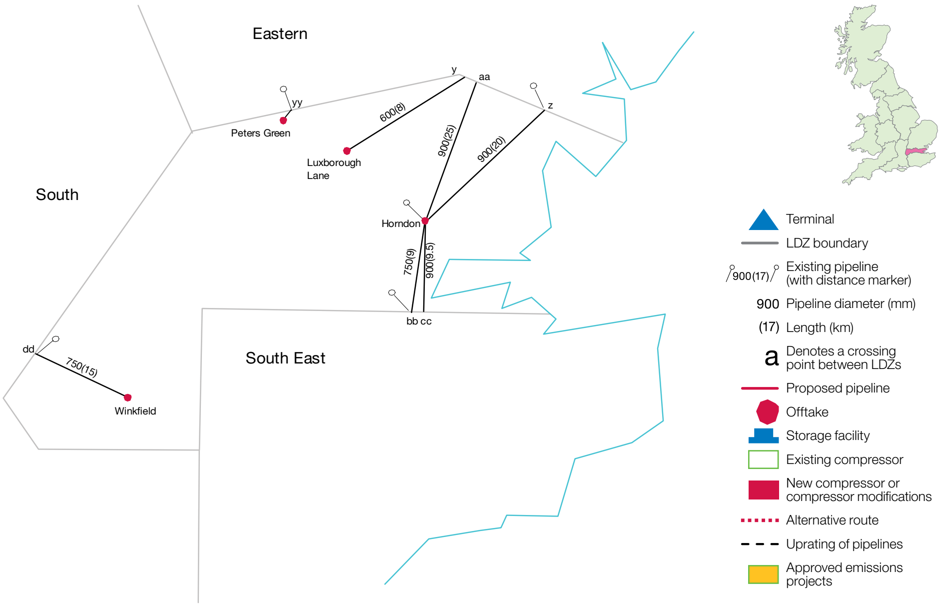


Figure A4.10
South East (SE) – NTS

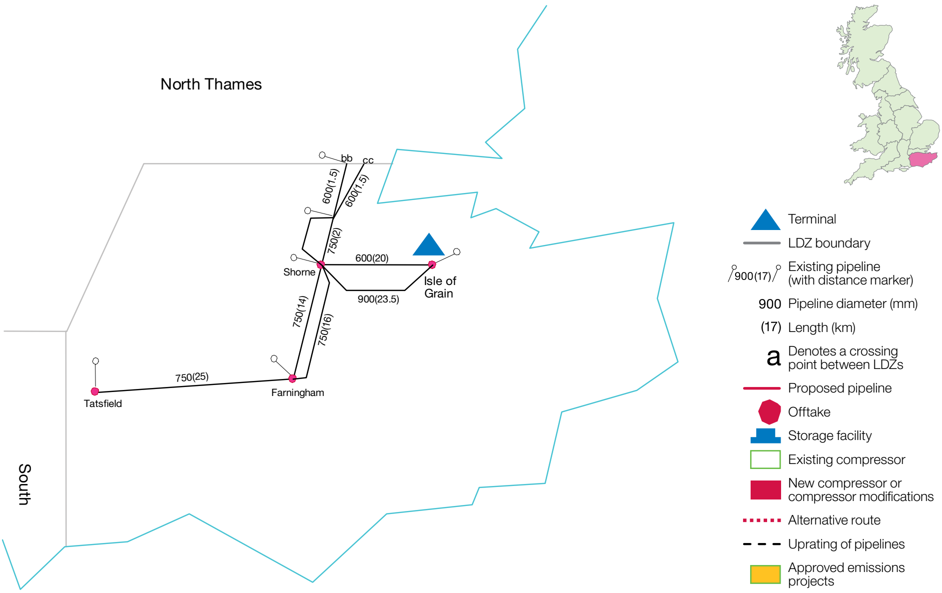
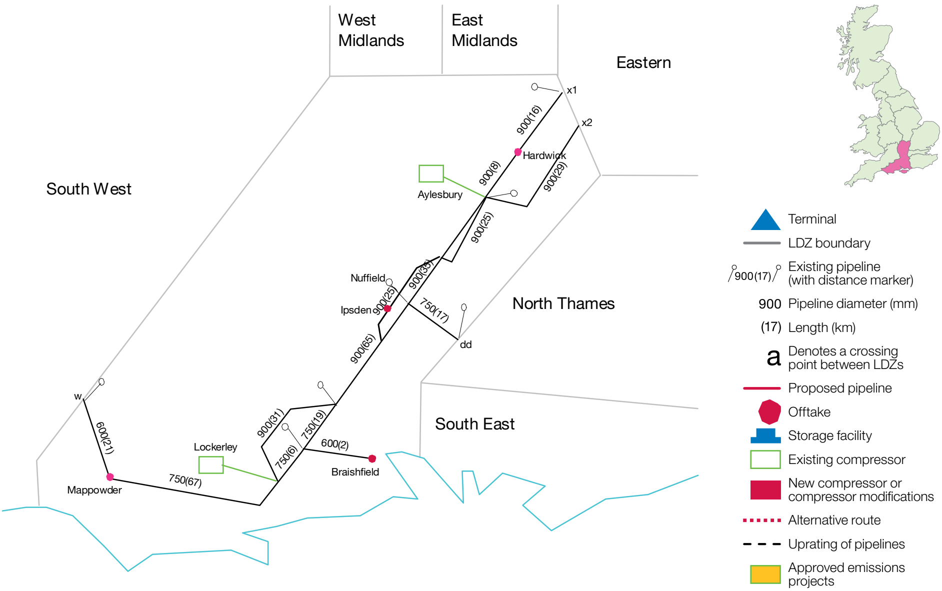
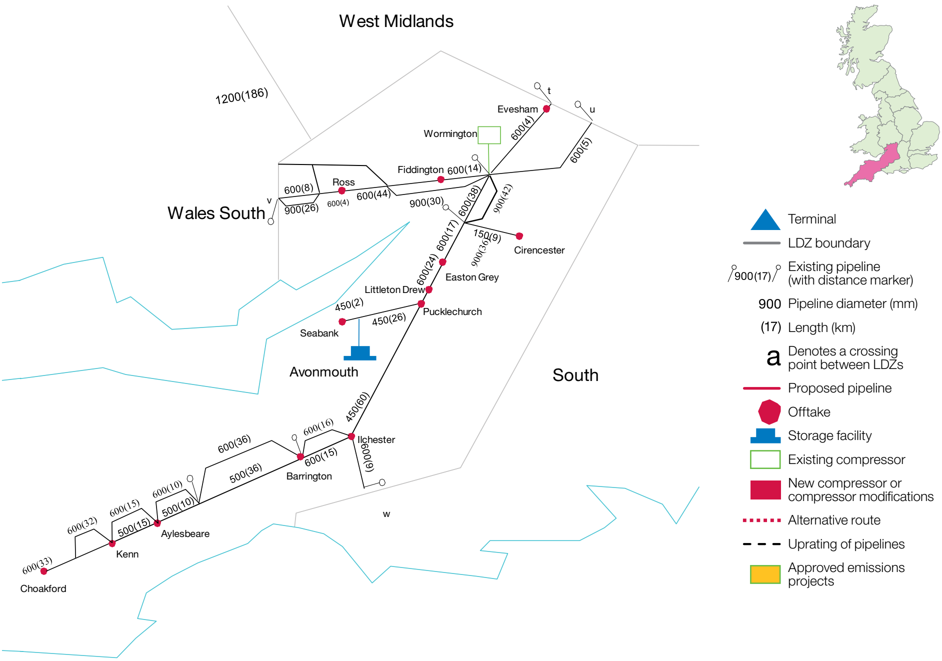


Figure A4.11
South (SO) – NTS



Appendix 4 continued
The Gas Transportation System

Figure A4.12
South West (SW) – NTS



Appendix 5
Connections to the National Transmission System (NTS)

A5.1
Introduction

We provide a service to our customers to connect their facilities to our high-pressure National Transmission System (NTS). Customers can choose other parties to build their facilities or have the connection adopted by the host gas transporter (depending on circumstances). They can pass assets to a chosen system operator or transporter, or retain ownership of them.

There are various categories of NTS connection:
- **Entry connections:** connections to delivery facilities processing gas from gas producing fields or LNG vaporisation (importation) facilities, for the purpose of delivering gas into the NTS
- **Exit connections:** these connections allow gas to be offtaken from the NTS 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 that is not a gas transporter, for transporting gas to premises consuming more than 2,196MWh per annum
- **Storage connections:** connections to storage facilities, for offtaking gas from the NTS and delivering it back later
- **International interconnector connections:** these are connections to pipelines that connect Great Britain to other countries. They can both offtake gas from and/or deliver gas to the NTS.

Please note that there are specific NTS entry and exit connections arrangements for storage and international interconnector connections.

If a customer wants to change a connection arrangement (such as an increased supply of gas) it will be considered similar to a request for a new NTS connection.

Appendix 5 continued
Connections to the National Transmission System (NTS)

A5.2
NTS connections – customer application and offer

The Uniform Network Code (UNC) provides a robust and transparent framework for our customers who require a new connection to the NTS or a revision to an existing connection. The Code provides:

- a formal connection application template for customers to complete
- definition of the content of an initial connection offer
- definition of the content of a full connection offer
- how to request a modification to a full connection offer
- timescales for National Grid to produce a connection offer:
  – initial connection offer – up to two months
  – full connection offer – up to six months (simple), or nine months (medium/complex)
- timescales for customers to accept an initial/full connection offer (up to three months)
- application fees for an initial connection offer (fixed) and full connection offer (variable and reconciled)
- a requirement for National Grid to review the application fees on an annual basis.

You can read more about the processes for new connections and changes to existing connections on our website:

http://www.nationalgrid.com/uk/Gas/Connections/National+Transmission+System+-+Gas+Connections/

Customers should contact us as early as possible if they want to connect to the NTS or change their existing connection arrangements. Early notification helps us to fully understand and assess the customer's connection requirements and enables us to deliver to the customer's desired timescales. Early notification is particularly important as system reinforcements and/or a NTS licence change may be required as outlined in A5.4.3.

Our 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* (please use the link to our website above to read this document).

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 operators of all delivery, storage and interconnector facilities. These agreements 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

We are committed to environmental initiatives that combat climate change. During the last year, an increasing number of customers have asked about entry into our pipeline system for biomass-derived renewable gas. We have also received requests for gas entry from unconventional sources, such as coal bed methane.

We welcome these developments and would like to help connect these supply sources to the network, but note that all existing network entry quality specifications, as detailed in Section A5.3.2, still apply.

It should be recognised that the pressure requirements of biomass-derived renewable gas mean it may need to be connected to the gas distribution networks instead of the National Transmission System. For information about connections to the gas distribution networks, please read the documents for the relevant distribution network.

The twelve local distribution zones (LDZs) are managed within eight gas distribution networks. The owners of the distribution networks are now:

North West, London, West Midlands and East of England (East Midlands LDZ and East Anglia LDZ) are owned and managed by National Grid. To contact National Grid-owned DNs about new connections please go to **www.nationalgrid.com**

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

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

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

Appendix 5 continued
Connections to the National Transmission System (NTS)

A5.3.2 Network entry quality specification
For any new entry connection to our system, the connecting party should tell us as soon as possible what the gas composition is likely to be. We will then determine whether gas of this composition would be compliant with our statutory obligations and our existing contractual obligations. From a gas quality perspective our ability to accept gas supplies into the NTS is affected by a range of factors including the composition of the new gas, the location of the system entry point, volumes provided and the quality and volumes of gas already being transported within the system.
In assessing the acceptability of the gas quality of any proposed new gas supply, we will consider:

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
c) the implications of the new gas supply on our ability to continue to meet our existing contractual obligations.

For indicative purposes, the specification 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 85 barg
6. Water dewpoint – Not more than -10°C at 85 barg
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 might 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 that does not have 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, which will 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 agreement to include an operational tolerance to ensure compliance with the GS(M)R.

A5.3.3 Gas quality developments

At the end of its ‘three-phase’ gas quality exercise, initiated in 2003, the UK Government reaffirmed in 2007 that it will not propose any changes to the GB gas specifications in the GS(M)R to the Health and Safety Executive until at least 2020. The Government’s forward plan proposed continued engagement with the European Commission (EC) and Member States on gas quality, with particular regard to the CEN (Comité Europeén de Normalisation, the European committee for standardisation) mandate M/400. Under this mandate, CEN was invited to draw up the broadest possible standards for natural gas quality, within reasonable costs.

In 2014, CEN published its proposed natural gas quality standard for public consultation. After gathering views from interested UK parties, the British Standards Institute (BSI) voted against the adoption of this standard, as did a number of other Member States. The UK’s main difficulty was the wider Wobbe Index range that CEN had proposed (46.44–54.00 MJ/m^3) compared to the current UK range specified in GS(M)R (47.20–51.41 MJ/m^3), raising longstanding concerns about whether gases towards the outer limits of such a range would burn safely and efficiently on UK gas appliances.

At the time of writing, the CEN working group was meeting to consider all the comments made in the public consultation and agree a way forward. Whilst the EC’s aspiration is to see the eventual standard implemented by all Member States, there are currently no firm plans to achieve this.

In another European development, the EU Interoperability and Data Exchange Network Code passed through its comitology procedure in November 2014. This EU Code will oblige European TSOs to cooperate to prevent different specifications from being a barrier to cross-border flows and to engage with their domestic stakeholders to explore whether enhanced information provision to end-consumers that are sensitive to changes in gas quality would be desirable and achievable.

Carbon dioxide limits have been the subject of GB industry debate (UNC Modification Proposals 0498 and 0502) in seeking to bring additional gas to market from the UKCS. This debate centres on whether a higher limit at the Teesside entry terminals would be more economic and efficient than upstream installation of CO_2 removal plant and operating it when necessary. The other side of the debate includes consideration of potential impacts for operators downstream of NTS exit points in terms of potential costs for plant integrity, operation, and emissions. An industry workgroup is examining the issues involved and expects to conclude its deliberations in Spring 2015.

The development of shale gas is still in its infancy in the UK and at present there is uncertainty over the quality of such gas until wells are drilled. We will continue to work with customers and monitor developments in this area.

Appendix 5 continued
Connections to the National Transmission System (NTS)

A5.4
Additional information specific to system exit connections

Anyone can contact us to request a connection, whether a shipper, operator, developer or consumer. However, gas can be offtaken from that new supply point only 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 25 barg. Although system pressure is typically higher, it will vary over time and location on the network. We currently plan normal NTS operations with start-of-day pressures no lower than 33 barg. Note that these pressures cannot be guaranteed as pressure management is a fundamental aspect of operating 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 throughout the day, from day-to-day, season-to-season and year-to-year. Generally, 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. Shippers may also 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 customer wants to lay its own connecting pipeline from the NTS to premises expected to consume more than 2,196MWh per annum, ownership of the pipe remains with the customer. This is our preferred approach for connecting pipelines.

The Statement and Methodology for Gas Transmission Connection Charging describes other options for the installation and ownership of connecting pipelines, but in all options the connecting party is responsible for the costs of the pipeline.

A5.4.3 Reasonable demands for capacity

Operating under the Gas Act 1986 (as amended 1995), we must develop and maintain an efficient and economical pipeline system and comply with any reasonable request to connect premises, as long as it's economic to do so.

Often, after connecting a new supply or demand, specific system reinforcement is needed to maintain system pressures for the winter period. Please note that, depending on scale, reinforcement projects may require significant planning, resourcing and construction lead-times and we need as much notice as possible. Project developers should 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 the optimum time is at least several years before customers need to book capacity through the formal Uniform Network Code (UNC) processes.

Appendix 6
Introducing the Transmission Gas Customer Service Team

We would like to take this opportunity to introduce the Transmission Gas Customer Service team and let you know what we have been doing and plan to do to help improve your experience with National Grid. Based on your feedback we aim to act on this by providing transparency of our processes and decision making; in doing this we will look to work with you through dedicated workshops and face-to-face engagement. We will continue to engage with you as we work together in shaping the future.

We have been listening, and you told us that the connections process should be a key priority for us and that it needs to be improved, simplified and fit for purpose. We are committed to improving the services we provide to you, as well as ensuring everything we do provides value for money.

- Throughout 2014/15 we will engage with you on the development of key industry framework changes, such as the implementation of new EU codes and the new Planning and Advanced Reservation Capacity Agreement (PARCA) process
- In July 2014 we held our second annual gas customer seminar, in order to provide a platform to engage on connection-related issues. We will continue to act on your feedback in order to further improve this through 2015.
- We will meet our obligations to deliver timely offers for connections to our Network and work to ensure (where possible) that we can meet your desired connection date and explain to you the reasons if we can't
- We will continue to work with you to improve engagement throughout the lifetime of your project and reconcile any charges within the agreed time scale.

We have dedicated Customer Account Managers to ensure you have a point of entry into our organisation; this ensures our people are accessible to you, and can work with you from day one in order to meet your expectations for your projects and queries.

John Twomey
Transmission Gas Customer Manager
Contact me – John.Twomey@Nationalgrid.com
Call me – 01926 656712

Kyla Cox
Gas Customer Portfolio Manager
Contact me – Kyla.Cox@Nationalgrid.com
Call me – 01926 654152

Joy Kentish
Gas Customer Portfolio Manager
Contact me – Joy.Kentish@Nationalgrid.com
Call me – 01926 654473

Appendix 7
Industry Terminology

Term	Definition
ANOP – Anticipated Normal Operating Pressure	A pressure that we may make available at an offtake to a large consumer connected to the NTS under normal operating conditions. ANOPs are specified within the NExA agreement for the site.
AOP – Assured Offtake Pressure	A minimum pressure at an offtake from the NTS to a DN that is required to support the downstream network. AOPs are agreed and revised through the annual OCS process.
AQ – Annual Quantity	The AQ of a Supply Point is its annual consumption over a 365-day year.
ARCA – Advanced Reservation of Capacity Agreement	An agreement between us and shippers relating to future NTS pipeline capacity for large sites in order that shippers can reserve NTS Exit Capacity in the long term. (See also PARCA and PCA)
ASEP – Aggregate System Entry Point	A System Entry point where there is more than one, or adjacent connected delivery facilities; the term is often used to refer to gas supply terminals.
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.
BAT – Best Available Technique	A term used in relation to Industrial Emissions Directive (IED) 2010. In this context BAT is defined as Best Available Technique and means applying the most effective methods of operation for providing the basis for emission limit values and other permit conditions designed to prevent and, where that is not practicable, to reduce emissions and the impact on the environment as a whole.
BBL – Balgzand–Bacton Line	A 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.
BREF – BAT Reference Documents	BAT Reference Documents draw conclusions on what the BAT is for each sector to comply with the requirements of IED. The BAT conclusions drawn as a result of the BREF documents will then form the reference for setting permit conditions.

Appendix 7 continued
Industry Terminology

Term	Definition
Cathodic protection	A method of inhibiting corrosion of buried steel plant by ensuring that it is permanently cathodic, i.e. electrically negative, to the electrolyte in the surrounding soil. It protects a metal from corrosive attack by causing a direct current to flow from its electrolytic environment into the entire metal surface. Cathodic protection is applied to buried steel pipelines and other plant such as valves and above-ground installations, e.g. compressor stations. Either sacrificial anode or impressed current cathodic protection can be used. Sacrificial anodes are generally used in more built-up areas, where they provide corrosion resistance over short distances, and are unlikely to interact with other plant. The sacrificial anode must possess a more negative electrode potential than that of the cathode (the plant to be protected), by reference to its position in the electrochemical series. For impressed current, an electric current is applied, which makes the pipe or plant more negative than the surrounding soil. Impressed current provides a higher level of coverage, more suitable for protecting long lengths of cross-country pipelines, where danger of electrical interaction with other buried metallic structures is very low.
CCGT – Combined Cycle Gas Turbine	A type of thermal generation that uses a two-stage process. Natural gas is fed into a jet engine which then drives an electrical generator. The exhaust gases from this process are then used to drive a secondary set of turbines and in turn, a second electrical generator. (See also OCGT)
CCS – Carbon Capture and Storage	The process of trapping carbon dioxide produced by burning fossil fuels or other chemical or biological processes and storing it in such a way that it is unable to affect the atmosphere.
CEN – Comité Europeén de Normalisation	European committee for standardisation concerned with the development, maintenance and distribution of standards and specifications.
CLNG – Constrained LNG	A service available at some LNG storage facilities whereby shippers agree to hold a minimum inventory in the facility and flow under certain demand conditions at our request. In exchange Shippers receive a transportation credit from us.

Term	Definition
CM – Capacity Market	The Capacity Market is being developed to ensure that there are sufficient quantities of flexible generation available to supply electricity demand for periods with low renewable generation. Both existing and new generation are able to participate in the capacity market. With the first capacity market auction in December 2014, delivery of the first new capacity is expected in 2018. One of the aims of the capacity market is to incentivise new generation to connect, and if new gas-fired generation is successful in the capacity auction, then these new gas-fired power stations will require additional gas capacity prior to 2018 to allow them to meet their EMR Capacity Market contract.
CO_2e – Carbon Dioxide Equivalent	A term used relating to climate change that accounts for the basket of greenhouse gases and their relative effect on climate change compared to carbon dioxide. For example UK emissions are roughly 600m tonnes CO_2e. This constitutes roughly 450m tonnes CO_2 and less than the 150m tonnes remaining of more potent greenhouse gases such as methane, which has 21 times more effect as a greenhouse gas, hence its contribution to CO_2e will be 21 times its 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.
CSEP – Connected System Exit Point	A point at which natural gas is supplied from the NTS to a connected system containing more than one supply point. For example a connection to a pipeline system operated by another Gas Transporter.
CV – Calorific Value	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.
CWV – Composite Weather Variable	A measure of weather incorporating the effects of both temperature and wind speed. A separate composite weather variable is defined for each LDZ.
DC – Directly Connected (offtake)	Direct connection to the NTS typically to power stations and large industrial users. I.e. the connection is not via supply provided from a Distribution Network.
DCO – Development Consent Order	A statutory Order under The Planning Act (2008) which provides consent for a development project. Significant new pipelines require a DCO to be obtained, and the construction of new compressor stations may also require DCOs if a new HV electricity connection is required.

Appendix 7 continued
Industry Terminology

Term	Definition
DECC – Department of Energy and Climate Change	DECC is a government department with functions relating to UK energy supply and the mitigation of climate change.
DFN – Daily Flow Notification	A communication between a Delivery Facility Operator (DFO) and us, indicating hourly and end of day entry flows from that facility.
DFO – Delivery Facility Operator	The operator of a reception terminal or storage facility, who processes and meters gas deliveries from offshore pipelines or storage facilities before transferring the gas to the NTS.
Distribution system	A network of mains operating at three pressure tiers: Intermediate (2 to 7 barg), medium (75 mbarg to 2 barg) and low (less than 75 mbarg).
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 in the form of linepack within transmission, i.e. >7 barg pipeline systems.
DM – 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.
DN – Distribution Network	A gas transportation system that delivers gas to industrial, commercial and domestic consumers within a defined geographical boundary. There are currently eight DNs, each consisting of one or more Local Distribution Zones (LDZs). DNs typically operate at lower pressures than the NTS.
DNO – Distribution Network Operator	Distribution Network Operators own and operate the Distribution Networks that are supplied by the NTS.
EIA – Environmental Impact Assessment	Environmental study of proposed development works as required under EU regulation and the Town and Country Planning (Environmental Impact Assessment) Regulations 2011. These regulations apply the EU directive on the assessment of the effects of certain public and private projects on the environment (usually referred to as the Environmental Impact Assessment Directive) to the planning system in England.
ELV – Emission Limit Value	Pollution from larger industrial installations is regulated under the Pollution Prevention and Control regime. This implements the EU Directive on Integrated Pollution Prevention and Control (IPPC) (2008/1/EC). Each installation subject to IPPC is required to have a permit containing emission limit values and other conditions based on the application of Best Available Techniques (BAT) and set to minimise emissions of pollutants likely to be emitted in significant quantities to air, water or land. Permit conditions also have to address energy efficiency, waste minimisation, prevention of accidental emissions and site restoration.

Term	Definition
EMR – Electricity Market Reform	A government policy to incentivise investment in secure, low-carbon electricity, improve the security of Great Britain's electricity supply, and improve affordability for consumers. The Energy Act 2013 introduced a number of mechanisms. In particular: ■ A Capacity Market, which will help ensure security of electricity supply at the least cost to the consumer ■ Contracts for Difference, which will provide long-term revenue stabilisation for new low carbon initiatives. Both will be administered by delivery partners of the Department of Energy and Climate Change (DECC). This includes National Grid Electricity Transmission (NGET).
ENA – Energy Networks Association	Represents the gas and electricity distribution network operators in the UK and Ireland.
ENTSOG – European Network of Transmission System Operators for Gas	Organisation to facilitate cooperation between national gas transmission system operators (TSOs) across Europe to ensure the development of a pan-European transmission system in line with European Union energy goals.
ETYS – Electricity Ten Year Statement	As National Electricity Transmission System Operator (NETSO), we publish the Electricity Ten Year Statement annually with the aim of providing clarity and transparency on the potential development of the GB Transmission system for a range of scenarios.
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.
FEED – Front End Engineering Design	The FEED is basic engineering which comes after the conceptual design or feasibility study. The FEED design focuses on the technical requirements as well as an approximate budget investment cost for the project.
FES – Future Energy Scenarios	Our annual industry-wide consultation process encompassing questionnaires, workshops, meetings and seminars to seek feedback on our latest scenarios and shape future scenario work. The Future Energy Scenarios document is produced annually and contains our latest scenarios.
Gas deficit warning	The purpose of a Gas Deficit Warning is to alert the industry to a requirement to provide a within-day market response to a physical supply/demand imbalance.
Gasholder	A vessel used to store gas for the purposes of providing diurnal storage.
Gas supply year	A twelve-month period commencing 1 October, also referred to as a Gas Year.

Appendix 7 continued
Industry Terminology

Term	Definition
Gone Green	A scenario defined in the Future Energy Scenarios (FES) document whereby the 2020 renewables target is met.
GS(M)R – Gas Safety (Management) Regulations 1996	Regulations which apply to the conveyance of natural gas (methane) through pipes to domestic and other consumers and cover four main areas: (a) the safe management of gas flow through a network, particularly those parts supplying domestic consumers, and a duty to minimise the risk of a gas supply emergency; (b) arrangements for dealing with supply emergencies; (c) arrangements for dealing with reported gas escapes and gas incidents; (d) gas composition. Gas Transporters are required to submit a safety case to the HSE detailing the arrangements in place to ensure compliance with GS(M)R requirements.
GT – Gas Transporter	Formerly Public Gas Transporter (PGT), GTs, such as National Grid, are licensed by the Gas and Electricity Markets Authority (GEMA) to transport gas to consumers.
GTYS – Gas Ten Year Statement	The Gas Ten Year Statement is published annually in accordance with our obligations in Special Condition 7A of the Gas Transporters Licence relating to the National Transmission System and to comply with Uniform Network Code (UNC) requirements.
IEA – International Energy Agency	An intergovernmental organisation that acts as energy policy advisor to 28 member countries.
IED – Industrial Emissions Directive	The Industrial Emissions Directive came into force on 6th January 2011. IED recasts seven existing Directives related to industrial emissions into a single clear, coherent legislative instrument. The recast includes IPPC, LCPD, the Waste Incineration Directive, the Solvents Emissions Directive and three Directives on Titanium Dioxide.
IGMS – Integrated Gas Management Control System	Used by us to control and monitor the Gas Transmission system, and also to provide market information to interested stakeholders within the gas industry.
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.

Term	Definition
IPPC – Integrated Pollution Prevention & Control (IPPC) Directive 1999	Emissions from our installations are subject to EU-wide legislation; the predominant legislation is the Integrated Pollution Prevention & Control (IPPC) Directive 1999, the Large Combustion Plant Directive (LCPD) 2001 and the Industrial Emissions Directive (IED) 2010. The requirements of these directives have now been incorporated into the Environmental Permitting (England and Wales) (Amendment) Regulations 2013 (with similar regulations applying in Scotland). IPPC aims to reduce emissions from industrial installations and contributes to meeting various environment policy targets and compliance with EU directives. Since 31 October 2000, new installations are required to apply for an IPPC permit. Existing installations were required to apply for an IPPC permit over a phased timetable until October 2007.
IUK	Owner and operator of the Belgian Interconnector.
kWh – Kilowatt Hour	A unit of energy used by the gas industry. Approximately equal to 0.0341 therms. One Megawatt hour (MWh) equals 1000kWh, one Gigawatt hour (GWh) equals 1000MWh, and one Terawatt hour (TWh) equals 1000GWh.
LCPD – Large Combustion Plant Directive (LCPD) 2001	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.
LDZ – Local Distribution Zone	A geographic area supplied by one or more NTS offtakes. It consists of LTS and distribution system pipelines.
Linepack	The volume of gas within the National or Local Transmission System at any time. (See also PCLP)
LNG – Liquefied Natural Gas	Gas stored and/or transported in liquid form.
LNGS – Liquefied Natural Gas Storage	The storage of liquefied natural gas.
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.

Appendix 7 continued
Industry Terminology

Term	Definition
Low Carbon Life	A scenario defined in the Future Energy Scenarios (FES) document whereby compared to the Gone Green scenario more money is available and there is less emphasis on sustainability. There is higher economic growth and society has more disposable income which results in higher uptake of electric vehicles, and more renewable generation at a local level.
LTS – Local Transmission System	A pipeline system operating at >7 barg that transports gas from NTS/LDZ offtakes to distribution system low-pressure pipelines. Some large users may take their gas direct from the LTS.
LTSEC – Long-Term System Entry Capacity	NTS Entry Capacity available on a long-term basis (up to 17 years into the future) via an auction process. This is also known as Quarterly System Entry Capacity (QSEC).
m^3 – Cubic Metre	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.
Margins notice	The purpose of the Margins Notice is to provide the industry with a day-ahead signal that there may be the need for a market response to a potential physical supply/demand imbalance.
MCP – Medium Combustion Plant (Directive)	The Medium Combustion Plant (MCP) directive will apply limits on emissions to air from sites below 50MW thermal input. MCP is likely to come into force by 2020.
MRS – Medium-Range Storage	Typically, these storage facilities have very fast injection and withdrawal rates that lend themselves to fast day-to-day turn rounds as market prices and demand dictate.
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, odourisation equipment etc.
NBP – National Balancing Point	A notional point which represents the system for balancing purposes.
NDM – Non-Daily Metered	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 73.2 MWh pa, reconciled individually when the meter is read.

Term	Definition
NGSE – Network Gas Supply Emergency	A NGSE occurs when we are unable to maintain a supply–demand balance on the NTS using its normal system balancing tools. A NGSE could be caused by a major loss of supplies to the system as a result of the failure of a gas terminal or as the result of damage to a NTS pipeline affecting the ability of the system to transport gas to consumers. In such an event the Network Emergency Co-ordinator (NEC) would be requested to declare a NGSE. This would enable us to use additional balancing tools to restore a supply – demand balance. Options include requesting additional gas supplies be delivered to the NTS or requiring gas consumers, starting with the largest industrial consumers, to stop using gas. These tools will be used, under the authorisation of the NEC, to try to maintain supplies as long as possible to domestic gas consumers.
No Progression	A scenario defined in the Future Energy Scenarios (FES) document whereby compared to Gone Green there is less money available and less emphasis on sustainability. There is slower economic recovery and government policy and regulation remains the same as today, and no new targets are introduced. The 2020 renewable energy target for 2020 is unlikely to be met.
NTS – National Transmission System	A high-pressure gas transportation system consisting of compressor stations, pipelines, multijunction sites and offtakes. NTS pipelines transport gas from terminals to NTS offtakes and are designed to operate up to pressures of 94 barg.
NTS Security Standard	Our Gas Transporters Licence Standard Special Condition A9: Pipe-Line System Security Standards sets out the security standard for the NTS. It requires that we plan and develop the NTS to meet the Security Standard, which is that the pipeline system must, taking into account operational measures, meet the "1-in-20" peak aggregate daily demand including within-day gas flow variations.
OCGT Open Cycle Gas Turbine	An Open Cycle Gas Turbine is a unit whereby electricity is generated by a single gas-powered turbine and hot exhaust gases are expelled to atmosphere. (See also CCGT)

Appendix 7 continued
Industry Terminology

Term	Definition
OCS – Offtake Capacity Statement	The Offtake Capacity Statement process allows DNOs to request changes to their Exit (Flex) Capacity holdings and to also request increases in Assured Offtake Pressures. Further details on Capacity Allocation, the OCS Process and Assured Offtake Pressures can be found in the following National Grid documents: ■ Transmission Planning Code[1] ■ Entry Capacity Release (ECR) Methodology[2] ■ Exit Capacity Release (ExCR) Methodology[3].
OCM – On the Day Commodity Market	This market constitutes the balancing market for GB and enables anonymous financially cleared on the day trading between market participants.
Odourisation	The process by which the distinctive odour is added to gas supplies to make it easier to detect leaks.
OFGEM – Office of Gas and Electricity Markets	The regulatory agency responsible for regulating Great Britain's gas and electricity markets.
OM – Operating Margins	Gas used by us to maintain system pressures under certain circumstances, including periods immediately after a supply loss or demand forecast change, before other measures become effective and in the event of plant failure, such as pipe breaks and compressor trips.
OUG – Own Use Gas	Gas used by us to operate the transportation system. Includes gas used for compressor fuel, heating and venting.
PARCA – Planning and Advanced Reservation of Capacity Agreement	PARCAs have been developed in line with solutions for enduring incremental capacity release following the implementation of the Planning Act (2008). PARCAs will be implemented in February 2015 following the approval by OFGEM of UNC Modification 0465v and will replace the functions of ARCAs and PCAs. A PARCA is a multi-phased bilateral contract, between National Grid and a customer, which would allow Firm Quarterly System Entry Capacity and / or Firm Enduring Annual NTS Exit (Flat) Capacity to be reserved for that customer, whilst they develop the initial phases of their own project. Any NTS Capacity initially reserved via a PARCA would, subject to the need case for that capacity being sufficiently demonstrated and any necessary planning permissions being received, be allocated exclusively to the PARCA applicant, or, where the PARCA applicant is not a UNC party, a NTS user(s) nominated by the PARCA applicant. (See also ARCA and PCA)

[1] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Gas-Ten-Year-Statement/Transmission-Planning-Code
[2] http://www2.nationalgrid.com/UK/Industry-information/Gas-capacity-methodologies/Entry-Capacity-Release-Methodology-Statement/
[3] http://www2.nationalgrid.com/UK/Industry-information/Gas-capacity-methodologies/Exit-Capacity-Release-Methodology-Statement/

Term	Definition
PCA – Planning Consent Agreement	Planning Consent Agreements are made in relation to NTS Entry and Exit Capacity requests and comprise a bilateral agreement between us and developers, DNOs or shippers whereby we will assess the needs case for NTS reinforcement and undertake any necessary planning activities ahead of a formal capacity signal from the customer. Where a needs case is identified, the customer will underwrite us to undertake the required statutory Planning Act activities such as strategic optioneering, Environmental Impact Assessment, statutory and local community consultations, preparation of the Development Consent Order (DCO) and application. (See also ARCA and PARCA)
PCLP – Projected Closing Linepack	Linepack is the volume of gas stored within the NTS. Throughout a gas day linepack levels fluctuate due to imbalances between supply and demand over the day. We, as residual balancer of the UK gas market, need to ensure an end-of-day market balance where total supply equals, or is close to, total demand. The Projected Closing Linepack (PCLP) metric is used as an indicator of end-of-day market balance. (See also Linepack)
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	NTS entry capacity available on a long-term basis (up to 17 years into the future) via an auction process. Also known as Long-Term System Entry Capacity (LTSEC).
RIIO-T1	RIIO relates to the current Ofgem price control period which runs from 1 April 2013 to 31 March 2021. For us this is referred to as RIIO-T1.
Safety Monitors	Safety Monitors in terms of space and deliverability are minimum storage requirements determined to be necessary to protect loads that cannot 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 monitor for space and one for deliverability. These are determined by us to meet our Uniform Network Code requirements and the terms of our safety case. Total shipper gas stocks should not fall below the relevant monitor level (which declines as the winter progresses). We are required to take action (which may include use of emergency procedures) in order to prevent storage stocks reducing below this level.

Appendix 7 continued
Industry Terminology

Term	Definition
SEAL – Shearwater Elgin Area Line	The offshore pipeline from the Central North Sea (CNS) to Bacton.
SEPA – Scottish Environment Protection Agency	The environmental regulator for Scotland.
SIU – Scottish Independent Undertakings	The SIUs comprise four independent gas networks that serve consumers located in the remote Scottish towns of Wick, Thurso, Oban and Campbeltown. The SIUs are supplied with LNG from the Liquefied Natural Gas Storage (LNGS) facility at Avonmouth, which provides a service for Scotland Gas Networks (SGN) for supplying LNG through tankers to the four SIU towns.
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.
SHQ – Supply Hourly Quantity	The maximum hourly consumption at a Supply Point.
Slow Progression	A scenario defined in the Future Energy Scenarios (FES) document whereby the 2020 renewable energy target for 2020 is not met. Although regulation and targets are similar to the Gone Green scenario there is less economic growth which prevents delivery of environmental policy and targets.
SNCWV – Seasonal Normal Composite Weather Variable	The seasonal normal value of the CWV is the smoothed average of the values of the applicable CWV for that day in a significant number of previous years. (See also CWV)
SO – System Operator	We are the System Operator of the National Transmission System (NTS) and have responsibility to transport gas from NTS supply points to NTS offtakes, subject to operational obligations in relation to safety and system resilience, environmental aspects, and the facilitation of efficient market operation.
SOQ – Supply Offtake Quantity	The maximum daily consumption at a Supply Point.
SOR – Strategic Options Report	Output of the PCA, ARCA and PARCA statutory Planning Act activities reporting to the customer on the findings of optioneering analysis by us in relation to the customer request for NTS Entry or Exit Capacity.
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 Point	A group of one or more meter points at a site.

Term	Definition
Therm	An imperial unit of energy. Largely replaced by the metric equivalent: the kilowatt hour (kWh). 1 therm equals 29.3071kWh.
TPC – Transmission Planning Code	The Transmission Planning Code describes our approach to planning and developing the NTS in accordance with our duties as a gas transporter and other statutory obligations relating to safety and environmental matters. The document is subject to approval by the Gas and Electricity Markets Authority (GEMA).
TSO – Transmission System Operator	Operator of a Gas Transmission Network under licence issued by the Gas and Electricity Markets Authority (GEMA) and regulated by OFGEM.
UAG – Unaccounted for Gas	Gas lost during transportation. Includes leakage, theft and losses due to the method of calculating the Calorific Value.
UKCS – United Kingdom Continental Shelf	An underwater landmass extending from the UK.
UNC – Uniform Network Code	The Uniform Network Code is the legal and commercial framework that governs the arrangements between the Gas Transporters and Shippers operating in the UK gas market. The UNC comprises different documents including the Transportation Principal Document (TPD) and Offtake Arrangements Document (OAD).
VSD – Variable Speed Drives	Compressor technology where the drive speed can be varied with changes in capacity requirement. Variable speed drive compressors compared to constant speed compressors are more energy efficient and operate more quietly by varying speed to match the workload.

Appendix 8
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.

	GWh	mcm	Million therms	Thousand toe
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 calorific value (CV) of 39.6 MJ/m^3

GWh = Gigawatt hours
mcm = Million cubic metres
Thousand toe = Thousand tonne of oil equivalent
MJ/m^3 = One million joules per metre cubed

Appendix 9
Meet the Team

Introducing the Gas Network Development and Transmission Strategy Teams

We would like to take this opportunity to introduce the **Gas Network Development** and **Transmission Strategy** team leaders.

The **Gas Network Development Team** is responsible for defining the most economic solutions to future gas system capability needs, taking into account customer requirements, Future Energy Scenarios and operability requirements.

The Transmission Strategy Team considers and directs strategic policy options that will maintain and enhance our current system operator and transmission owner roles for both gas and electricity, whilst working with a broad spectrum of stakeholders.

It is the purpose of the Gas Ten Year Statement to engage with our stakeholders on the future development of the gas system. We would very much appreciate your suggestions and feedback.

Feedback on all aspects of the 2014 GTYS can be made by email to:

Box.systemoperator.gtys@nationalgrid.com

or complete our online survey at:

http://surveymonkey.com/s/2014GTYS

Appendix 9
Meet the Team

Craig Dyke
Gas Network
Development Manager
E: Craig.Dyke
@nationalgrid.com
T: 01926 653397

Eddie Blackburn
Gas Network
Capability Manager
E: Eddie.J.Blackburn
@nationalgrid.com
T: 01926 656022

James Whiteford
Gas Network
Strategy Manager
E: James.Whiteford
@nationalgrid.com
T: 01926 653513

Ben Graff
Transmission
Strategy Manager
E: Ben.Graff@
nationalgrid.com
T: 07836 293164

Hannah Kirk-Wilson
Transmission
Strategy Lead
E: Hannah.Kirk-Wilson
@nationalgrid.com
T: 01926 653133

This statement is produced for the purpose of and in accordance with National Grid Gas plc's obligations in Special Condition 7A[1] 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 the remainder of this statement, National Grid Gas plc will be referred to as National Grid.

[1] Special Condition 7A requires that 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.

National Grid plc
National Grid House,
Warwick Technology Park,
Gallows Hill, Warwick.
CV34 6DA United Kingdom
Registered in England and Wales
No. 4031152

www.nationalgrid.com

We have won Business in the Community's highest award, Responsible Business of the Year 2014. This accolade acknowledges all of our efforts in getting involved with the things that really matter to us and to society, and doing the right things in the right way.